U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-373/89018(DRS); 50-374/89018(DRS)

Docket Nos. 50-373; 50-374 License Nos. NPF-11; NPF-18

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: LaSalle County Station, Units 1 and 2

Inspection At: Commonwealth Edison Offices, Chicago, Illinois
LaSalle Site, Marseilles, Illinois

Inspection Conducted: July 24 through October 10, 1989

Inspectors: M. P. Phillips, Team Leader — 11/14/89 Date

M. P. Huber — 11/14/89 Date

R. Mendez — 11/15/89 Date

R. A. Hasse — 11/14/89 Date

I. T. Yin — 11/14/89 Date

Consultants: R. Spilker
H. Stramberg
W. Lundgren

Reviewed By: E. W. Weiss, Acting Chief — 11/14/89 Date
Operations Branch

Inspection Summary

Inspection on July 24 through October 10, 1989 (Report No. 50-373/89018(DRS); and No. 50-374/89018(DRS))
Areas Inspected: Announced Safety System Functional Inspection (SSFI) of the high pressure core spray (HPCS) system and evaluation of the licensee's self-initiated Safety System Audit of the same system. The inspection was conducted using inspection procedure 93801.
Results: Based on the inspection, the team made the following conclusions:

- The HPCS was operable; however, the unresolved item related to component operability at battery minimum voltage could affect HPCS operability (Section 4.1.2.3).

- There were several examples where the actual design margins were less than stated in the Updated Final Safety Analysis Report (UFSAR) or in conflict with the Technical Specification requirements. Sections 4.1.1.1, 4.1.1.2, 4.1.1.3, and 4.1.2.1).

- The performance of safety evaluations for the most part was acceptable; however, the evaluation performed for modification M-1-1-84-019 was inadequate and may have resulted in the performance of the modification despite the presence of an unreviewed safety question. Plant procedures also did not properly reflect this modification. (Sections 4.1.4.2 and 4.4.1).

- The licensee's program for check valve maintenance was considered a strength. In addition, the implementation of the IST program and logical functional testing programs were acceptable. (Sections 4.3.6 and 4.3.7).

- The SSFI conducted by Commonwealth Edison in 1987 on this same system did an excellent job of finding and correcting labeling problems and most drawing concerns. The effort was conducted by a multi-disciplinary team composed of individuals experienced in electrical and mechanical design. However, this SSFI was heavily oriented toward walkdowns of the system and review of completed modifications and maintenance performed on the system. The evaluation contained two major limitations that contributed to not identifying the items found by the NRC inspection. These limitations were (1) the assumption that the existing surveillance procedures covered all applicable Technical Specification surveillance requirements and (2) the assumption that all activities associated with the original design and installation were acceptable. The Task Force formed by Commonwealth Edison to evaluate the effectiveness of licensee SSFIs had also recognized this latter limitation and had recommended that future efforts SSFIs be expanded to incorporate some amount of original design validation (Section 4.7.1).

- The team identified seven open items, four unresolved items, and nine violations of NRC Rules and Regulations. Of these violations, five met the criteria of 10 CFR Part 2, Appendix C, for non-issuance of a Notice of Violation. The remaining four violations dealt with an inadequate 10 CFR 50.59 evaluation (Section 4.1.4.2); inadequate post-calibration test (Section 4.2.1.3); inadequate procedure for diesel generator fuel pressure surveillance (Section 4.3.5); and inadequate corrective actions for the 2B diesel-generator air start solenoid valve (Section 4.6.2).

- The four unresolved items dealt with whether the batteries, battery racks, and chargers meet the requirements of 10 CFR Part 50, Appendix B (Section 4.1.2.2); whether the installed equipment will operate at the minimum voltage they will experience during an event (Section 4.1.2.3); whether the diesel-generator skid wiring conforms with the standards of IEEE 383-1974 (Section 4.1.2.5); and whether the implementation of modification M-1-1-84-019 created an unreviewed safety question (Section 4.1.4.2)

TABLE OF CONTENTS

SAFETY SYSTEM FUNCTIONAL INSPECTION (SSFI) AT LaSALLE COUNTY STATION

INSPECTION REPORT NOS. 50-373/89018; 50-374/89018

1.0 INSPECTION OBJECTIVES

The dual objectives of the Team inspection at LaSalle were to evaluate the quality of Commonwealth Edison's effort to conduct Safety System Functional Inspections (SSFI) and to assess the operational readiness of the high pressure core spray (HPCS) system. The inspection was designed to determine the following:

a. The system was capable of performing the safety functions required by its design basis and safety analysis.

b. Testing was adequate to demonstrate that the system would perform all of the safety functions required.

c. System maintenance (with emphasis on pumps and valves) was adequate to ensure system operability under postulated accident conditions.

d. Operator and maintenance technician training was adequate to ensure proper operations and maintenance of the system.

e. Human factors considerations relating to the HPCS system (e.g., accessibility and labeling of valves) and the system's supporting procedures were adequate to ensure proper system operation under normal and accident conditions.

f. System initiating and control functions were effective and reliable.

g. The licensee's self-initiated SSFI conducted on the same system found the same problems which were identified by the NRC team, and if not, why not.

2.0 OVERVIEW OF THE HIGH PRESSURE CORE SPRAY SYSTEM

The HPCS system is one of four emergency core cooling systems (ECCS) at the LaSalle County Station (LSCS), and is made up of a single 4.16 kV motor driven pump and associated piping, valves, electrical distribution system, controls and instrumentation for each unit. The system is designed to operate from normal offsite auxiliary power or from a standby diesel-generator supply if offsite power is not available.

The HPCS system is designed to cool the reactor core sufficiently to prevent fuel cladding temperatures from exceeding 2200°F following any break in the nuclear system piping. The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid depressurization, the system maintains reactor water level and depressurizes the vessel. For large breaks, the HPCS system cools the core by a spray. The HPCS system, in conjunction with the automatic depressurization system (ADS), constitute the two trains of an ECCS system. As such, the HPCS system, by itself, is not required to meet single failure criteria for postulated accidents.

The HPCS system takes its normal suction from either the condensate storage tank or the suppression pool through a strainer and motor-operated valve. At present, the condensate storage tank suction is out of service due to microbiologically induced corrosion in the underground piping. The HPCS pump discharges through a check valve, manual discharge valve and motor operated injection valve, located outside of the containment, and a testable check valve and manual isolation valve, located inside containment, to the sparger located inside the reactor vessel.

The system is provided with a full flow test line to allow for system testing under rated conditions. A minimum flow bypass line is also provided to protect the pump during low flow conditions.

A water leg pump is provided to ensure that the HPCS pump discharge piping remains full.

The HPCS system relies on a number of ancillary systems for power, cooling, and control, including: Pump Room Cooling; Cycled Condensate Storage; HPCS Diesel Generator; Fire Protection; Station Heating; Diesel Generator, Switchgear, and Pump Rooms Ventilation; Diesel Fuel Oil; Diesel Generator Cooling Water; 4160 volt distribution; 4.16 kV to 480 volt transformer; 480 V Motor Control Center; and 125 V dc Battery.

3.0 SUMMARY OF SIGNIFICANT INSPECTION FINDINGS

The Safety System Functional Inspection at the LaSalle County Nuclear Station reviewed the design basis, operating history, maintenance history, surveillance history, and self-SSFI of the High Pressure Core Spray System and concluded that the system was functional.

During the course of the inspection, as detailed in Section 4 of this report, the team identified seven open items, four unresolved items, and nine violations of NRC Rules and Regulations. Of these violations, five met the criteria of 10 CFR Part 2, Appendix C, for non-issuance of a Notice of Violation. In addition, the team evaluated the effectiveness of the licensee's self-SSFI on the same system for Unit 2.

The design evaluation determined that the basic design was satisfactory and no common mode failures were detected; however, there were several examples where the actual design margins were less than stated in the Updated Final Safety Analysis Report (UFSAR) or in conflict with the Technical Specification (TS) requirements. For example, the station batteries were designed to operate at temperatures above 65°F; however, the TS allowable minimum temperatures were as low as 50°F for the battery room and 60°F for the battery cells. At these lower temperatures, some of the station batteries would not have been capable of performing their intended functions. The team verified that the batteries had not reached sufficiently low temperatures to render them inoperable since initial licensing.

The team was unable to determine if all equipment would be operable at minimum dc voltages that could be experienced during an event. This unresolved issue has the potential to render the system inoperable.

The performance of safety evaluations for the most part was acceptable; however, the evaluation performed for modification M-1-1-84-019 was inadequate and may have resulted in the performance of the modification despite the presence of an unreviewed safety question.

For the most part, relays that were examined were set in accordance with station requirements; however, two exceptions were identified. In one case, the different setting did not compromise the effectiveness of the associated relay; however, the overcurrent relay for phase B of bus 243-1 was sufficiently out of tolerance that a failure of the phase A relay would have resulted in no overcurrent protection for this bus.

The licensee's program for check valve maintenance was considered a strength. In addition, the implementation of the IST program and logic functional testing programs were acceptable.

Weaknesses were found relating to the review of design calculations, establishment of electrical QC hold points, incorporation of vendor recommendations in diesel generator maintenance, and technical review of work requests to ensure proper post-maintenance testing is performed.

The licensee's self-SSFI was conducted by a multi-disciplinary team composed of individuals experienced in electrical and mechanical design. The self-SSFI was heavily oriented toward walkdowns of the system and review of completed modifications and maintenance performed on the system. Findings from the self-SSFI primarily involved labeling/drawing deficiencies. These appeared to have been corrected prior to the NRC effort, since such discrepancies were not identified by the NRC team. The self-SSFI contained two major limitations that were attributed to be the cause for non-identification of the items found by the NRC. These limitations were (1) the methodology for evaluating surveillance requirements and (2) the assumption that all activities associated with original design/installation were acceptable. The licensee had recognized this latter limitation, and had recommended that future self-SSFIs not be so limited. However, based on the NRC team's findings, these self-SSFIs conducted prior to the implementation of the Task Force recommendation should not be exclusively relied upon to assure system operability.

4.0 DETAILED INSPECTION FINDINGS

The team conducted in-depth reviews in a number of areas, which are described below. The team identified a number of concerns, along with several positive items. Each is discussed below:

4.1 System Design and Modifications

4.1.1 Mechanical Systems Design

This portion of the inspection consisted of a detailed review of the HPCS system, pump room and diesel generator cooling, cycled condensate storage, fuel oil for the HPCS diesel generator, fire protection, station heating, and associated ventilation systems.

The inspection focused on whether there was a potential for common mode failures of the ECCS. The mechanical systems design evaluation determined that the basic design was satisfactory and no common mode failures were detected; however, the following six issues were identified, which include examples where the actual design margins were less than stated in the Updated Final Safety Analysis Report (UFSAR):

4.1.1.1 HPCS Diesel Generator Fuel Oil Consumption

Changes in the HPCS Diesel Generator electrical loading were not factored into the fuel oil consumption rate that formed the basis for the fuel oil storage requirements.

UFSAR Section 9.5.4.1.1 specified the safety design bases for the HPCS fuel oil storage. Table 8.3.1 in the UFSAR listed the loads on the HPCS diesel generator, and identified the maximum diesel loading as 3280 bhp. However, the associated storage capacity calculation, DO-7, dated 3/11/76, calculated the seven day fuel oil storage requirement based on a maximum diesel loading of 3087 bhp. Based on the larger diesel generator loading, the fuel oil consumption rate increased, which in turn increased the fuel oil storage requirements. There was no evidence that the increase was ever factored into the design.

The licensee acknowledged the increased consumption (500 gallons for the seven day storage requirement) but stated that it was included in the 1000 gallon margin identified in the UFSAR Section 9.5.4.1.1.d.3. The licensee agreed to revise the UFSAR to indicate that the margin had been reduced to 500 gallons. This will be tracked as an Open Item (373/89018-01; 374/89018-01).

The team determined that sufficient capacity was available in the HPCS fuel oil storage tank to meet the increased fuel consumption such that minimum storage requirements need not be modified. However, the failure of the licensee to adequately address the interface between the diesel loadings and fuel requirements points to weakness in the interdisciplinary engineering review of original design assumptions.

4.1.1.2 HPCS Diesel Generator Day Tank Level

During the review of the licensee's self-initiated SSFI report, the Team noted that the low level alarm on the HPCS Diesel Generator day tank was not set to provide 50 minutes of fuel remaining in the day tank, as specified in Section 9.5.4.1.1.e of the UFSAR, although this had been a finding (6B) from the CECo self-initiated SSFI. The corrective action implemented to address the original finding was to perform a revised calculation which indicated that 50 minutes of fuel was remaining after alarm initiation. However, the assumptions used in the calculation were contrary to the actual operation of the fuel oil pumping equipment. The calculation used an incorrect use rate

from the day tank which led to an incorrect conclusion that the required amount of fuel was present. In fact, the amount of fuel available would be insufficient to meet the UFSAR commitment with the current alarm setting.

The licensee was made aware of this situation and had initiated corrective action while the team was still on site to revise the alarm setpoint. However, the occurrence of this error points to a fault in the licensee's program for performance and review of design calculations.

The failure to detect errors in the calculation to support the current alarm setpoint indicated a weakness in the performance of calculational reviews and verifications that are prescribed in ANSI/ASME NQA-1-1983. This weakness is further discussed in Paragraph 4.1.1.4 below.

4.1.1.3 HPCS Diesel Generator Load Rejection Tests

The team determined that the TS Sections 4.8.1.1.2.d.2 & 3 identified values for performing the full load rejection test and single largest load rejection test that were less than the values given in UFSAR Table 8.3.1. Table 8.3.1 of the UFSAR identified the single largest load on the HPCS diesel as 3050 bhp which equates to 2528 kw and gave the total load as 3280 bhp which equates to 2719 kw. These loads were at variance with the TS which identified 2381 kw for the large load rejection test and 2600 kw for the full load rejection test.

The intent of these TS surveillances was to ensure that the diesel generator would not trip off if the bus it was powering was lost and to ensure that the diesel generator would continue to supply power to the bus with no more than a 75% drop in voltage if the largest load on the bus were to trip off. This position is consistent with that presented in Regulatory Guide 1.9, "Selection, Design, and Qualification of Diesel-Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants," Revision 2.

The team agreed that the single largest load contained in Table 8.3.1 used a conservative pump efficiency of 90% in arriving at the 2528 kw; however, the manufacturer's certified pump curve gave a load of 2408 kw at 3030 bhp. The 2381 kw load specified in TS appeared to come from data obtained during a prototype test performed at LaSalle by General Electric. The team considered that the conditions under which that prototype test was performed did not represent the design or normal operational conditions of the plant, for example, the strainer was not 50% plugged per the design requirement and water temperature of the suppression pool was lower than seen during normal operations. It appeared that a non-conservative value was used for the TS surveillance.

The licensee stated that the requirement for the full load reject test was the continuous rating of the diesel generator, which is 2600 kw. However, the licensee had utilized the 2000 hour rating in the actual sizing of the diesel.

The licensee committed to revise the TS to incorporate the appropriate values for "full load" and "single largest load" that met the intent of the surveillance requirement. This will be tracked as an Open Item (373/89018-02; 374/89018-02).

4.1.1.4 Design Calculations

During the review of the design bases for HPCS, the team found many examples where calculations were inconsistent, utilized different assumptions for the same variable, were incomplete, or were missing. With few exceptions, these calculations had been performed as part of the original station design in 1973. Some examples included the following:

Calculation entitled "HPCS Pump Discharge Pressure - Design" used a maximum suction pressure of 30 psig from the cycled condensate storage tank and 56 psig from the suppression pool, while calculation entitled "HPCS Design Pressure & Temperature" identified the suction line pressure as 100 psig.

Calculation "HPCS Design Pressure & Temperature" was missing the design temperature and pressure for the discharge of the water leg pump, even though the need for this information was noted in the calculation.

Calculation entitled "HPCS Safety/Relief Valve Sizing" identified the set point for valve E22-F035 as 1100 psig and operating pressure as 1225 psig. The 1100 psig should have been 1100 psid, and the operating pressure did not agree with calculation "HPCS Operating Conditions." Further, the portion of the calculation dealing with valve E22-F035 had been superseded by calculation HP-11, "Resetting Valve E22-F035", which was not noted in either calculation. The new calculation used a maximum shutoff head and suction head which differed from those in the "HPCS pump Discharge Pressure - Design" calculation.

Calculation DO-7, "Diesel Oil Storage Capacity," concluded that the HPCS diesel generator fuel oil storage tank capacity was insufficient to meet the seven day fuel storage requirement. Although, the tank was subsequently modified, there was no calculation confirming the adequacy of the modified tank. A preliminary, unreviewed and unapproved calculation, DO-11, "Diesel Oil Storage and Day Tank Usable Capacity - HPCS Diesel," dated 8/7/89 was prepared during this inspection which indicated that sufficient fuel oil storage capacity was available.

Although Section 9.2.7.2 of the UFSAR specified that a minimum of 135,000 gallons of the condensate storage tank capacity was reserved for HPCS/RCIC, there was no calculation available which confirmed that this requirement was met. A preliminary, unreviewed and unapproved calculation, CY-01, Cycled Condensate Storage Tank Usable Capacity for HPCS/RCIC, was prepared during the inspection which indicated that sufficient capacity was dedicated in the condensate storage tank for HPCS/RCIC.

These examples of deficient calculations, as well as those noted in paragraphs 4.1.1.1 and 4.1.1.2 above, point to a weakness in the licensee's program to ensure that calculations performed as part of design activities be performed in a controlled manner which includes review and approval. Although the team found numerous examples of conflicting information between calculations and incomplete calculations, either the design conditions enveloped the differences or the differences were not significant. In the case of missing calculations, the licensee was able to provide preliminary calculations sufficient to assure the team that the design was adequate. Although the licensee's new modification program had provisions to ensure that calculations were adequately reviewed, most of the problems with calculations dated back to original design.

4.1.1.5 Location of Diesel Cooling Water Relief Valves

The team found that the relief valves on the diesel generator coolers discharge directly into the personnel access areas around the diesels at heights ranging from approximately three to six feet from the floor. At this level, a relief discharge could impinge directly on personnel working in the area. The licensee should consider modifying the discharge of these valves to avoid potential impingement on personnel.

4.1.1.6 Unit 2 HPCS Relief Valve ALARA Concerns

The Unit 2 HPCS relief valve, E-22-F035, discharges directly into the HPCS equipment room, while the Unit 1 relief valve has its discharge routed to the reactor building equipment drain. The team could not identify any reason why there should be a difference between the two units. In the event that the Unit 2 relief valve should actuate, the potential exists to needlessly contaminate personnel who may be present or enter the room after such an actuation. The licensee should consider modifying the discharge of the Unit 2 relief valve to match that currently installed in Unit 1.

4.1.2 Electrical Systems Design

This portion of the inspection consisted of a detailed review of the HPCS diesel-generator, 4160 volt distribution; 4.16 kV to 480 volt transformer; 480 V Motor Control Center; and 125 V dc battery. In addition, deficiencies identified in the HPCS

system were evaluated in similar systems, including the 125 V dc batteries for electrical divisions I and II, and the 250 V dc batteries. The following significant issues were identified:

4.1.2.1 DC Battery Sizing Calculation

Each HPCS diesel generator set is supplied with its own respective 125V DC battery and DC power panel from which various electrical components are powered. The HPCS system is designated as Division III. The team reviewed the battery sizing calculation for the Unit 1 Division III battery and noted the following:

A. Battery temperature correction factor of 65F versus 60F was used.

B. No aging factor was used in the calculation.

C. The dc loading profile that was used was the UFSAR Load Table 8.3-14 which was originally developed by General Electric for the initial purchase of the battery.

In response to the team's specific investigation with respect to determination of the dc current value that was associated with diesel generator flashing field circuit, Sargent & Lundy determined that a value of 1.9 amperes should be utilized instead of the UFSAR value of 1.0 amperes that had been used in the above calculation. The licensee was requested to determine what the actual loads would be and determine if the battery size was appropriate for those loads.

CECo's analysis determined that there was conservatism between the load profile that was used to size the battery and the actual approximate loads. They noted that the battery sizing calculations indicated a Unit 1 battery remaining margin of 9.5% and for Unit 2 8.1%. Their analysis utilized the value of 1.9 amperes noted above and was based on load information obtained from tabulations that were recently supplied by the diesel generator vendor and walkdowns utilized to obtain individual equipment nameplate information.

The team determined that design calculations were based on a temperature correction factor of 65F, but TS 4.8.2.3.2.6 allowed the electrolyte temperature to decrease to 60F. The capacity of a lead acid battery decreases below 100% when temperature is less than 77F. When battery rooms are not maintained at 77F, compensation for the lower temperatures must be included when sizing the battery. This had not been done at the TS temperature value. Therefore, the team reviewed the adequacy of the battery sizing for the other batteries based on temperature concerns.

Further investigation indicated that all of the other plant batteries, i.e. the 125V Division I, Division II, and the 250V Division I batteries were sized on the basis of 65F. Also our

review of plant documentation determined that the licensee's engineer advised CECo in February 1985 that the 125 V Division I, Unit 1, and 250 V Division I, Units 1 & 2, had little or no margin above what would be required for maintaining minimum dc system design voltage.

Talks with cognizant CECO and Sargent & Lundy engineering staff indicated that the Division I, Unit 1 battery would be inadequate in a 60F temperature environment. The operability of the Divisional batteries is further discussed in paragraph 4.3.2 below.

The team reviewed the history of the establishment of the TS temperature requirement, and determined that the licensee's original submittal to NRR indicated that the minimum battery temperature should be 65F; however, the TS issued to the licensee stated 60F. The licensee had failed to identify the significance of this change made during the TS review process, and had not determined that their batteries could meet the revised specification as issued.

4.1.2.2 Battery Specification

The team was unable to obtain a copy of the Division III 125V battery and battery charger equipment specifications. CECo's purchase order documentation that was used when the battery was replaced provided a reference to the battery vendor's work order number.

Without a specification, the team was unable to determine if the batteries conform with the requirements specified in 10 CFR Part 50, Appendix B, in that there is no indication that quality requirements were imposed on the vendor for the battery replacement. In addition there is a concern as to whether this equipment conforms with the requirements for class 1E components. The UFSAR states that the batteries, battery racks, and chargers are Class 1E equipment and design documentation requirements are contained in ANSI N45.2.11. This is an Unresolved Item (373/89018-03; 374/89018-03) pending a determination as to whether the batteries conform with 10 CFR Part 50, Appendix B, requirements and the standards for class 1E components.

4.1.2.3 DC Components - Maximum and Minimum Voltage

During normal or float operation the battery and respective bus is at a value of 130.5 volts. When an equalizing charge is applied the voltage is increased to a maximum value of 135.6 volts. Similarly when the battery is called upon to operate when AC power is unavailable, its initial voltage decreases during the period of discharge. During this time frame the minimum voltage may decrease to 105 volts. The team was concerned as to whether the devices connected to the dc busses could sustain the overvoltages that were present during either the float or equalizing condition or perform their intended functions during periods of low voltage.

NRC Information Notice 83-08, "Component Failures Caused by Elevated DC Control Voltage," was issued in March 1983. Based on the licensee's inability to initially determine that the end devices connected to the DC busses could sustain the overvoltages, it was not clear what type of effort had been expended by the licensee in the evaluation of this information notice.

The results of the licensee's analysis determined that for maximum voltage conditions, a majority of the components specified maximum voltage operating ranges greater than 135.6 volts. For the remaining components the licensee determined that they were not exposed to the maximum voltage condition on a continuous basis due to their intermittent periods of operation.

The licensee also provided a detailed listing of the minimum DC voltage associated with each device and compared that to the minimum battery terminal voltage. This was obtained from actual service tests performed on the batteries, indicating that these voltages were 109.4 V for Unit 1 and 106.3 V for Unit 2. While this voltage occurs at the main DC battery and distribution bus, the licensee had not included the voltage drops associated with line losses through the cabling connecting the component to the bus. However, due to low current values, it was expected that the voltage drop through the cable would be minimal.

The licensee needs to determine the capability of the equipment to operate properly based on the lowest expected dc voltage that would be present at the end device. The assessment that the equipment will remain operable at minimum voltage conditions is an unresolved item (373/89018-04; 374/89018-04).

4.1.2.4 DG Cabling

Page B.1.95 of Appendix B to the UFSAR described how the station complied with the position specified in Regulatory Guide 1.75. It stated that all class 1E circuits should comply with the requirements of IEEE Standard 383-1974.

Based on the team's review of the diesel generator equipment specification, it was not clear that the vendor supplied cabling that interconnects between skid mounted equipment was in conformance with IEEE 383-1974. The licensee's engineer, Sargent & Lundy had previously completed an evaluation of the wiring that was utilized on the emergency diesel generator sets at LaSalle on May 8, 1985. They determined that while the majority of the cabling was qualified, several unmarked wires were found that lacked sufficient identification to allow qualification by either testing or analyses.

As the diesel generator is a Class 1E equipment item, it is necessary to provide equipment, including associated components, that meets all technical and quality requirements that are

commensurate with Class 1E requirements. The design documentation that is provided must provide assurance that the equipment performance will be in accordance with design requirements.

The licensee had taken the position that wiring which was installed by a vendor on the vendor's own equipment, which was supplied as a single component (i.e., diesel generator skid), was beyond the scope of that which was addressed in the UFSAR commitments. Therefore, they felt that the qualification of the wiring was beyond the scope of the UFSAR. However, there must still be assurance that the equipment will perform in accordance with design requirements, regardless of whether supplied by the vendor, or installed by the licensee.

The determination of how the associated class 1E wiring for the diesel-generator supplied by the vendor complies with IEEE 383-1974, is an unresolved item (373/89018-05; 374/89018-05).

4.1.3 Instrumentation and Control Systems Design

The portion of the inspection consisted of a detailed review of instrumentation and control systems associated with the HPCS system valves and pump, HPCS diesel-generator, diesel fuel oil pumps, and associated electrical distribution networks. The following issues were identified:

4.1.3.1 Division 3 Electrical Power System Annunciation & Status Display

Modification No. M-1-84-019 changed the function of the HPCS 4.16kV normal power supply overcurrent lockout relay without adequately addressing the control room alarms or system inoperable status displays.

The original design provided for a dedicated lockout relay to trip and lockout the HPCS 4.16kV normal supply breaker on overcurrent and to actuate the control room annunciator window "4kV Bus 143 (243) MAIN FD. BKR LKO TRIP." The modification changed the function of lockout relay 86-N/1432 by using spare contacts to add tripping and locking out of the diesel generator breaker. However, the modification failed to make any changes to the annunciator window to inform the operator that this was a ...MAIN FD. BKR/DG BKR LKO TRIP." In addition, no changes were made to the associate annunciator procedure to alert the operator that the 4kV bus was dead and would remain so. The procedural revision portion of this modification is discussed in Paragraph 4.4.1 below.

Status indication for diesel generator lockout relay K1 was reviewed and found to be acceptable. The impact of providing inconsistent status indication for lockout relay 86-N/1432 and

lockout relay K1 may be confusing to the control room operator and has the potential for an incorrect or slow response in restoring power to the HPCS 4.16kV bus following a trip and lockout of its power source breakers. The licensee should consider modifying the annunciator window for this lockout trip of the bus to provide correct status indication.

4.1.3.2 Protective Relaying/Circuit Breakers

The team reviewed the relay and circuit breaker networks to determine if they were adequately coordinated and provided sufficient protection to the components, motor control centers, or electrical buses in the event of faults. In addition, the review verified that installation was in accordance with the design as specified in the UFSAR, and that TS surveillance requirements could be performed. In all cases, the relays and circuit breakers were found to be acceptably coordinated. However, a review of the diesel generator lockout features revealed that the generator trip on overcurrent was bypassed on an ECCS actuation signal. This appeared to be contrary to the surveillance requirement specified in the TS.

Section 4.8.1.1.2.7.b of the TS required verification that the following automatic trips were not bypassed on an ECCS actuation signal: engine overspeed, generator differential or overcurrent, and emergency manual stop. The TS commitments for Division 3 Section 4.8.1.1.2.7b and 4.8.1.1.2.13e were inconsistent, since the test requirement of section 4.8.1.1.2.13e indicated that the generator overcurrent trip is bypassed on an ECCS actuation signal. A review of the corresponding TS requirements for the diesel generators Division 1 and 2 revealed that the generator overcurrent trip is also bypassed on an ECCS actuation signal.

Based on discussions with NRR and the licensee, no reason could be given why the HPCS diesel generator TS surveillance requirement should be different from the division 1 or division 2 requirement. The licensee had interpreted the "or" within the specification to mean that as long as either generator differential or overcurrent was not bypassed, the TS was satisfied; and the generator differential trip was not bypassed.

The licensee agreed to request a TS change for the Division 3 requirements to make them consistent with the Division 1 and 2 requirements. This will be tracked as an Open Item (373/89018-06; 374/89018-06).

4.1.4 10 CFR 50.59 Evaluations

For most of the modifications reviewed, the safety evaluation determinations conducted by the licensee were adequate; however, there were two exceptions as follows:

4.1.4.1 Isolation of Condensate Storage Tank as Source to HPCS System

A safety evaluation was performed for what the licensee termed an "ongoing maintenance activity." Due to a pipe failure of the return line from HPCS to the condensate storage tank (CST) during a surveillance test in 1985, the valves connecting HPCS to the CST were closed and power removed. In addition, part of the return piping was dug up and permanently capped. Maintenance hold tags were used as the administrative control to ensure that the valves remained closed and deenergized. Although safety evaluations are not normally performed for maintenance activities, the NRC considers this particular activity to be a temporary modification to the facility as described in the UFSAR, and as such, a safety evaluation would be required prior to the performance of the temporary modification. At the time of the pipe failure, the NRC reviewed the interim corrective actions for this event and concluded that plant operations were acceptable with the CST valved out as a source of water.

The team considered the conclusion of the safety evaluation to be valid; however, the documentation of the bases supporting this conclusion was not in compliance with the requirements of 10 CFR 50.59(b)(1). Weaknesses in the documentation of safety evaluations had also been identified by the licensee's self-initiated SSFI, and changes had been made to the 50.59 safety evaluation performance process which should correct the problem. Since the criteria of 10 CFR Part 2, Appendix C, Section V.G.1 were met, no notice of violation is being issued for this example.

4.1.4.2 Modification M-1-1-84-019

This modification added a function to relay 86-N/1432 which would lockout the diesel-generator from providing power to its associated 4.16 kV bus. Prior to this modification, the relay isolated the HPCS 4.16 kV bus from its normal supply on bus overcurrent. After the modification, the diesel generator output breaker would also trip and lockout. In this case, the diesel would be unable to provide power to the bus. The intent of the modification was to prevent connecting the diesel generator onto a faulted bus.

As a result of this modification, the consequences of relay 86-N/1432 failing closed were changed. Before the modification, failure of this relay would cause isolation of the HPCS 4.16 kV bus from its normal offsite power source followed by a diesel generator auto-start and restoration of power to the bus. In this case, the availability of the HPCS system is not changed. However, after the modification, the failure of this relay would isolate the 4.16 kV bus from all power, thus rendering the entire HPCS system inoperable.

The 10 CFR 50.59 evaluation for this modification concluded that an unreviewed safety question did not exist; however, the bases for this conclusion did not address the issues discussed above. Specifically:

a) Why the modification did not increase the consequences of failure of equipment important to safety (e.g., relay 86-N/1432).

b) Why the modification did not increase the probability of failure of equipment important to safety (i.e., the failure of the HPCS to perform its safety function due to loss of normal and emergency power sources due to the failure of relay N-86/1432 [bus is normal, with no overcurrent conditions]).

The failure to document adequate bases for the conclusion that this modification did not generate an unreviewed safety question is a violation of 10 CFR 50.59(b)(1). As noted above, the licensee's self-initiated SSFI, conducted in 1987, had also identified inadequate documentation of 50.59 evaluations as a finding. This modification was installed in 1988; therefore, corrective actions implemented as a result of the self-SSFI failed to ensure that subsequent modifications had adequate 50.59 documentation. Therefore, since criteria V.G.1.d and e of 10 CFR Part 2, Appendix C were not satisfied, a notice of violation will be issued (373/89018-07; 374/89018-07).

As noted above, the licensee has not addressed whether an unreviewed safety question exists. Installation of a change to the facility when an unreviewed safety question existed would also be a violation of 10 CFR 50.59(a)(1). An unreviewed safety question is defined in the regulations as a condition where: (a) the probability of occurrence of an accident may be increased; (b) the consequences of an accident may be increased; (c) the possibility for an accident or malfunction of a different type than any evaluated previously may be created; or (d) the margin of safety as defined in the basis for any technical specification is reduced. Until the above issue is satisfactorily addressed, the existence of an unreviewed safety question is an unresolved item (373/89018-08; 374/89018-08).

4.2 Maintenance

This portion of the inspection was conducted to evaluate the licensee's maintenance of the HPCS system and its selected support systems. Representative procedures, vendor manuals, completed work packages, general housekeeping, and material condition were reviewed. A detailed NRC evaluation of the licensee's maintenance programs was conducted earlier this year and is documented in inspection report Nos. 50-373/89010(DRS) and 50-374/89010(DRS). Maintenance activities were reviewed in two general areas, electrical (relays, motors, motor control centers, generator, transformer, breakers, etc.) and mechanical (pumps, valves, and the diesel).

4.2.1 Electrical Maintenance

4.2.1.1 Circuit Breakers

Inspection of circuit breaker preventive and corrective maintenance practices consisted of visual inspections during plant walkdowns, review of maintenance procedures, and review of work requests for breakers associated with the HPCS. A review of preventive maintenance documentation and work requests indicated that the licensee was maintaining the circuit breakers in accordance with vendor recommendations; was meeting the required maintenance schedules; and was performing the required post-maintenance testing.

Although the licensee appears to be properly maintaining their circuit breakers, a weakness was observed in the area of QC inspections after corrective maintenance was performed. The team review of work requests L8334 and L75521 that were performed for the replacement of a breaker and a temperature switch, respectively, found that no QC inspections of the electrical circuitry were performed. Similarly, a review of modification package M-1-1-84-090 associated with the replacement of motors on motor-operated valves also found that no electrical QC inspections were performed. Licensee representatives indicated that the procedure governing QC hold points (LAP 1700-3, "Guidelines for Quality Control Hold/Witness Points") only applied to major modifications. For minor modifications or repairs, where parts installed were "like-for-like" QC hold points were optional. Although the team found no examples where electrical circuitry was incorrect or the wrong component was installed, the licensee's establishment of electrical QC hold points was considered a weakness in that its implementation was discretionary.

4.2.1.2 Diesel Generator and Associated Wiring

The team reviewed maintenance records for the HPCS diesel generator. Examination of completed maintenance records indicated that the licensee met the required maintenance schedules and frequency, and performed the work in accordance with procedure LES-DG-102. However, a review of the vendor instruction manual for the generator against the procedure indicated that several vendor recommendations had not been incorporated into the procedure. The maintenance activities specified in the vendor manual, SM-100, "Synchronous Motors, Generators, D.C. Exciters and Brushless Equipment," were either not performed by the licensee or performed at less frequent intervals than specified in the manual. For example, the licensee changed the bearing grease every 18 months, but the manual indicated this should be done every 6 months. Additionally, the vendor manual specified that an insulation resistance test of the windings be performed on a yearly basis; but the licensee was not performing such tests.

The licensee acknowledged that they had not incorporated the maintenance activities outlined in the vendor manual in their procedures because the manual applied to several different types of generators. The licensee was in the process of contacting the vendor in order to formulate a maintenance program for the generator.

During the inspection of the Unit No. 1 diesel generator DG-1A the team noted that the wiring (3 leads) between the Woodward governor casing and the governor motor was installed without being routed through flexible tubing to protect against damage. The installation of the governor wiring on the other Unit 1 and 2 diesel generators had similar installation deficiencies. However, the Woodward Governor company bulletin 03032, Fig 7-8 indicated that the governor motor wiring connection was to be routed through a flexible tubing. This was the case for all the diesel generators where the vendor installation had been unchanged.

Because the engine speed control governor is located in the midst of heavy components which require regular checking and maintenance and the wire sizes are small, the installation of the flexible tubing for routing of the wiring between governor motor and the governor casing is necessary to prevent degradation of the wiring, which could increase the probability of faults in the engine speed control system.

When notified of the team's concerns, the licensee stated that they intended to issue work orders to restore the flexible tubing installation to the condition as originally furnished by the manufacturer.

The discrepancies between vendor recommendations and the licensee's activities were considered a weakness.

4.2.1.3 Protective Relays

The team reviewed procedures used by the licensee to maintain protective relays and walked down the relays to verify that set points were in accordance with the Relay Setting Orders (RSO) required by the licensee's corporate office For the most part, relay settings were acceptable. However, this was not the case for two relays identified by the inspection team. These two cases involved the magnetic trip setting for the HPCS injection valve, E22-F004; and the phase B overcurrent protection relay for bus 243-1, 2451-AP074B.

For the HPCS injection valve, E22-F004, the magnetic trip setting was 6.5, although the RSO set point sheet specified a setting of 4.0. An evaluation of relay performance determined that this

discrepancy in setting had no effect on the timing of the trip, which occurred within the required band. Therefore, the setting was acceptable.

For the Type IAC 51 relay 2451-AP074B, the phase B overcurrent protection relay for safety related bus 243-1, the time lever was improperly set at 3.0L. The RSO set point sheet specified a time lever setting of 1.0L to correspond to a pick up time of 0.5 seconds. This relay was calibrated on November 22, 1988, and the associated documentation indicated that the relay had been left at a setting of 1.0L, but due to other complications, the as left results were not acceptable and a new relay had been ordered. This as found trip lever setting would result in a relay pick up time far in excess of 0.5 seconds. Calibration procedure LES-GM-229, Revision 0, "Unit Two Southern Division OAD Periodic Protective Relay Calibration Procedure at LaSalle County Station for Relays Not Mentioned in Tech Specs," establishes the tolerance for this type of relay be no more than 5%.

Bus 243-1 is protected by two relays, phase A and phase B, for all three phases. A current imbalance in one phase would be sensed in the other two phases and as a consequence, two relays provide protection for a three phase circuit. Although the phase A relay was properly calibrated, a single failure of the phase A relay would have resulted in no overcurrent protection, since the phase B relay was out of tolerance by a substantial margin.

The licensee subsequently initiated actions to recalibrate the relay.

The process of calibrating these relays involved the removal of the relay from its case, placing it on a cart, and transporting it to the I&C shop. The relay is then calibrated, placed back on the cart, transported back to the switchgear room, and reinstalled into its case. A simple functional test is then performed to verify that the relay works. This test does not evaluate whether the relay is properly timed; but only tests to see that the relay trips. The failure to verify appropriate relay settings upon completion of the calibration activity is a violation of Criterion XI of 10 CFR Part 50 Appendix B (374/89018-09).

4.2.2 Mechanical Maintenance

4.2.2.1 Maintenance Work Request Review

Overall, detailed procedures were in place for the conduct of maintenance. The work requests were written to incorporate the existing procedures, where applicable, in the work request packages. Maintenance personnel used the procedures during maintenance

performed, both in the shop and at the job site. In most cases, the team found that vendor manuals and recommendations were incorporated into the procedures and work request packages. Appropriate manual references and copies of the manual pages were used directly by the maintenance and technical staff personnel. The technical staff reviewed the vendor manuals to ensure that the procedures would be workable with the specific work request package for the component to be maintained.

4.2.2.2 Post-Maintenance Testing

Operations specified the required testing for determining operability. For example, when a valve was serviced as part of the licensee's routine maintenance program, the work requests were not reviewed by the engineering staff to ensure adequate testing was specified. This was also true for non-routine maintenance. The team was concerned that insufficient technical review was given to work requests to ensure that proper post-maintenance testing was specified. This is considered a weakness.

However, the team found no examples where testing had been inadequately performed. In addition, the CECo corporate office had issued a Nuclear Operations Directive requiring the station to revise the governing procedures to ensure that engineering would be involved in the establishment of post-maintenance testing requirements. These revisions should alleviate the team's concerns in this area.

4.2.2.3 Preventive Maintenance

Preventive maintenance (PM) at LaSalle included general inspection of component physical condition, wiring inspections, and periodic lubrications. This work was accomplished by regularly scheduled surveillances through the general surveillance program (GSRV) and the lubrication surveillance program (LUBQ).

The team reviewed preventive maintenance procedures, completed surveillances, and the preventive maintenance histories of selected components. No problems were noted.

A system walkdown was conducted which found the majority of components to be in good physical condition. Valve 1E22-F023, the HPCS full flow test valve, had both gear grease and stem grease on the stem, indicating that a gearcase seal could have been leaking. The licensee wrote a work request to evaluate this condition.

The licensee's check valve PM program was considered a strength by the team. This included all plant check valves. The valves were prioritized and plans were made to inspect and in some cases test the check valves using diagnostic equipment, based on priority.

The licensee indicated that the program would commence during the upcoming outage. The current inspection frequency for these valves varies from four to six years. The program did provide continual review of the inspection results for verification of inspection frequency. If the program was implemented as planned, check valve reliability should improve and failures should be precluded due to the evaluation and continued monitoring of valve characteristics.

4.3 Surveillance and Testing

The team reviewed the surveillance and routine testing program for the HPCS and supporting systems described in Paragraph 4.0 of this report. When potential concerns were identified, this review was extended to other similar plant systems. The review was conducted by identifying the TS surveillance requirements and comparing these to the surveillance procedures. The procedures were reviewed for technical adequacy and selected surveillance results were reviewed for compliance with the acceptance criteria. The acceptance criteria were reviewed against the TS UFSAR system design parameters and assumptions, and as-installed conditions, to verify that the intent of the surveillance was met.

The inservice testing (IST) program implementation was reviewed utilizing "CECo IST Program for LaSalle County Station," dated September 18, 1988. The tests performed were reviewed to determine if all required components were tested in accordance with both the licensee's IST program and Section XI of the ASME Code, except where relief had been requested and granted.

4.3.1 Division 3 Switchgear Room Temperature Surveillance

TS 4.7.7.A.4 required that the temperature in the switchgear rooms be monitored every 24 hours and that these temperatures be within the band of 54F to 104F. This temperature surveillance for the Division 3 switchgear rooms had consisted of monitoring the return air temperature on a ventilation system which served part of the switchgear room. The licensee had not included a direct temperature measurement of the switchgear room in their surveillance program and therefore had not actually monitored room temperature as required by Technical Specifications. The Division 3 switchgear room temperature is significant because the temperature of the Division 3 batteries, located in this room, is critical in determining whether or not they can perform their design function. During the inspection a revision to the daily surveillance procedure was issued to require that the switchgear room temperature be taken using a thermometer in accordance with the Technical Specification required schedule. This revision was reviewed by the team and found to address the NRC concerns. The failure to monitor the Division 3 switchgear room temperature is a violation of Technical Specification 4.7.7.A.4; however, since this was an isolated example where no procedure addressed the surveillance requirement, the violation was of Severity Level V, and corrective

actions were instituted prior to the end of the inspection, no notice of violation is being issued per the criteria of 10 CFR Part 2, Appendix C, Section V.A.

4.3.2 Acceptance Criteria for Battery Electrolyte Temperatures

TS 4.8.2.3.2.b.3 requires that the electrolyte temperatures for the station batteries be determined every seven days and that this temperature be at least 60F. A review of battery sizing calculations (see Paragraph 4.1.2.1 above) determined that a minimum electrolyte temperature of 65F had been assumed in the design calculations for all of the batteries, and as a result of battery loading, there was insufficient margin for the batteries in some of the divisions to ensure that they would operate if the temperature dropped below 65F. The surveillance procedures implementing the TS requirement used 60F as the acceptance criteria. Thus, the electrolyte temperature could be within the acceptance criteria, with the batteries unable to perform their design function. Sargent & Lundy had advised CECo in February 1985 that the 125 V Division I batteries for Unit 1 and the 250 V batteries for Unit 2 had little or no margin above that which would be required for maintaining minimum DC system design voltages based on the design temperature of 65F.

During the inspection the licensee revised Procedures LOS-AA-D1, Unit Daily Surveillance, Revision 22, dated August 15, 1989 and LOS-DC-W1, Weekly Surveillance for the Safety Related 250V DC, 125V DC and Diesel Fuel Pump Batteries, Revision 14, dated August 18, 1989, to require daily monitoring of the ambient temperatures associated with battery rooms to assure that the temperature is greater than or equal to 65.6F. This will ensure that the electrolyte temperature is above 65F. The licensee also agreed to initiate a change to the TS to reflect the correct design assumptions. Implementation of this revision will be tracked as Open Item No. 373/89018-09; 374/89018-10.

The team reviewed the surveillances which had been conducted on the 125 V division 1 batteries for Unit 1 and the 250 V batteries for Unit 2 since initial operation. During that time period, the team found four weekly surveillance results where the division 1 battery pilot cell temperatures were below 65F. On all of these occasions, the unit was shutdown either for a maintenance or refueling outage, and the TS requirements for operable batteries under shutdown conditions (TS 3.8.2.4 - only one division required to be operable) would have been met.

With regard to the 250 V batteries, the team found all surveillances during the period December 5, 1985, through December 26, 1985, to have results where the pilot cell temperatures were below 65F. In this case, the unit had been shutdown for a maintenance outage until approximately December 22, and at the time of the last weekly

surveillance with a temperature below less than 65F, the unit was operating at 45% power. The lowest surveillance temperature recorded was 64F during this period. The February 1989 capacity test performed on these batteries resulted in 112.5% capacity measured. Similarly, the service test conducted on January 27, 1987, resulted in a minimum voltage of 222.9, with the acceptance criteria being greater than 210 volts. Based on these test results, and the fact that the battery temperature was only one degree below design allowable (temperature correction factor less than 1%), the team concluded that the batteries could be considered operable at 64F.

4.3.3 Division 2 Battery Load Profile

TS 4.8.2.3.2.2.b and d provide a loading profile to be used for determining the Division 2 battery capacity. This loading profile was less than that given in the UFSAR, which represented the actual emergency loads. A review of the procedures implementing these TS required surveillances indicated that the correct loading profiles (from the UFSAR) were being used in performing these tests. The licensee agreed to initiate a change to the TS to accurately reflect the actual emergency loads. Completion of this action will be tracked as Open Item No. 373/89018-10; 374/89018-11.

4.3.4 HPCS Testable Check Valve

The team reviewed testing requirements for HPCS components and determined that the HPCS testable check valve 1(2)E22-F005 was not tested as required in 10 CFR Part 50, Appendix J. This was an acceptable practice for LaSalle, because TS 3.6.3 and the UFSAR allowed this valve to be considered as a containment isolation valve without requiring a Type C test. Upon further review, the team found that the testable check valves in low pressure core spray [1(2)E21-F006], reactor core isolation cooling [1(2)E51-F066], and low pressure coolant injection [1(2)-F041A,B, and C] were also not tested for the same reason. The NRC had previously approved this testing methodology in the Safety Evaluation Report; however, based on a re-evaluation performed by the NRC at Clinton, these valves had been put back in the required Type C testing program.

Based on the above, the NRC will re-evaluate the licensee's program to not Type C test these valves. This item will be tracked as open item No. 373/89018-11; 374/89018-12.

4.3.5 Monitoring Diesel Generator Fuel Pressure

LaSalle surveillance procedure LOS-DG-M3, Revision 19, "1B(2B) Diesel Generator Operability Test," required that fuel pressure be monitored for the engine driven fuel pump while the DG was loaded

to ensure proper functioning of the fuel pump, suction strainer, and fuel filter. However, for the HPCS diesels (Division 1B and 2B) there is a separate motor driven fuel supply train having its own strainer, filter, and pump running continuously to provide fuel that is used to cool the fuel injectors. The motor-driven fuel supply train was not being monitored to ensure proper functioning of this train. The licensee agreed to revise procedure LOS-DG-M3 to provide for monitoring of the motor-driven pump fuel line pressure during monthly DG tests.

The failure of the licensee to provide an adequate surveillance procedure appropriate to the circumstances for monitoring the motor driven fuel oil system pressure is considered an example of a violation of Criterion V of Appendix B to 10 CFR Part 50 (373/89018-12; 374/89018-13).

4.3.6 Inservice Testing Program

The licensee's IST program had received approval for implementation from the NRC, provided certain items identified during that review were corrected. The team reviewed selected surveillance procedures, test results, and documentation to verify adequate program implementation. In addition, Piping and Instrumentation Diagrams (P&IDs) were reviewed to ensure that all components that were required to be in the IST program were tested appropriately.

Results reviewed indicated that the testing was conducted in accordance with the procedure and met the requirements of the licensee's IST program. Test data from completed testing was reviewed and was within appropriately established acceptance criteria. The check valve reliability program established by the licensee was viewed as a strength. The program is comprehensive incorporating industry reports and guidelines, and NRC information notices. Failures should be precluded due to the evaluation of adverse trends through continued monitoring of valve characteristics.

The review of the program scope determined that the diesel generator air start compressor discharge check valves [1(2)E22-F362A and B] were not listed in the licensee's IST program. Based on the licensee's review of Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," the licensee had determined that these check valves required additional testing, and they were being added to the IST program to address the generic letter.

4.3.7 Logic Functional Testing

The review of the licensee's procedures for performing logic functional tests for the HPCS autostart and other logical functions revealed a good program that covered a check of the operation of all relay contacts.

4.4 Operations and Training

The operations area was reviewed primarily from the standpoint of operator training and procedure adequacy. Interviews with operations personnel were also conducted. Procedures reviewed included HPCS operating procedures and Emergency Operating Procedures (EOPs).

In general, procedures and operator training were adequate; however, two concerns were identified, which are discussed in the following paragraphs:

4.4.1 Modification M-1-1-84-019

This modification added a lockout preventing the Division 3 diesel generator from closing onto a faulted bus (see Paragraph 4.1.4.2 above). The initiation of this lockout was alarmed in the Control Room using an existing alarm (2HP12A). The annunciator response procedure (1H13-P601 A302) for this alarm had not been revised to reflect the modification although the operators had been trained on the modification prior to the completion. The procedure erroneously directed the operator to ensure that the diesel generator had loaded onto the bus, which was what the modification prevented from occurring.

Upon identification by the team, the licensee immediately issued a night order and processed a revision to the procedure. The procedure revision was issued prior to the conclusion of the inspection, was reviewed by the team, and was determined to be acceptable. The failure to provide a procedure appropriate to the situation is a violation of 10 CFR Part 50, Appendix B, Criterion V. However, since this violation was isolated, would normally be classified as a Severity Level V violation, and corrective actions were completed prior to the conclusion of the inspection, no notice of violation will be issued per the criteria of 10 CFR Part 2, Appendix C, Section V.A.

4.4.2 HPCS Operating Procedures

The HPCS operating procedures had not been revised to reflect the isolation of the system from the CST. Since the isolation had been handled as an ongoing maintenance activity utilizing "out of service" (OOS) tags rather than a modification, procedure revisions were not triggered by the program.

Review of the HPCS operating procedures indicated that except for LOP-HP-05, "Raising Suppression Pool Level," these procedures addressed both the CST and the suppression pool as suction sources. The team concluded that these operating procedures did not present an immediate problem since training on the current HPCS configuration mitigated the inaccurate procedures, and all operations personnel interviewed were aware of what actions were required to operate the system without the CST as a water source. However, allowing procedures to exist for over four years that did not reflect actual plant

configuration is considered a weakness. During this inspection the licensee had in place a modification package to permanently isolate the CST from the HPCS system that should trigger the revision of the above procedures.

4.5 Modification Process

The team reviewed the following licensee procedures for performing plant modifications that were current as of July 31, 1989:

LAP-240-6, Revision 19, Temporary System Changes;

LAP-900-4, Revision 35, Equipment Out-Of-Service Procedure;

LAP-1300-2, Revision 24, Modification Program;

LAP-1300-2A, Revision 1, Modification Request;

LAP-1300-2B, Revision 1, Plant Modifications Designed By Engineer;

LAP-1300-2C, Revision 1, Plant Modifications Designed By Technical Staff;

LAP-1300-2D, Revision 1, Processing of Modifications;

LAP-1300-2E, Revision 0, Station Modification Review Committee;

LAP-1300-5, Revision 10, Field Change Requests;

LAP-1500-4, Revision 13, Action Item Records;

NSED Procedure Q.6, Revision 0, Design Modifications; and

NSED Procedure Q.8, Revision 12, Field Change Requests (FCRs) Written Against An Engineering Change Notice (ECN).

These procedures were considered adequate with the procedure for temporary system changes found to be considerably improved. There were no major modifications of HPCS and its supporting systems which had been completed based on these upgraded procedures; therefore, the effectiveness of implementation was not assessed.

4.6 Handling of Industry/Equipment Experience

The team reviewed the licensee's activities related to the evaluation and resolution of equipment problems that had either been forwarded to the licensee by the NRC in the form of information notices or had been identified through the licensee's deficiency reporting system. The team conducted walkdowns of the HPCS and associated support systems to determine if the issues described in the information notices had been acceptably addressed. Two deficiencies were found associated with emergency diesel generators that could be associated with the material contained in information notices 88-24, "Failures of Air-Operated Valves

Affecting Safety-Related Systems"; and 89-07, "Failures of Small Diameter Tubing in Control Air, Fuel Oil, and Lube Oil Systems Which Render Emergency Diesel Generators Inoperable." These deficiencies were associated with the HPCS diesel generator's air start system and the small bore tubing installed on the diesel.

4.6.1 Deficiencies Associated with Air Start System

The air start system for the diesel consisted of two compressors that maintain a pressure of 210 to 240 psig in four large air receivers. This air then passes through a regulator to a pilot solenoid valve. The regulator is required to maintain maximum air pressure between 195 and 200 psig. When the valve is operated, the air drives four air start motors on each diesel to start the engines.

During the walkdown of the Division 3 Diesels, 240 psig air pressure was found in the receivers for the 1B diesel and 230 psig was found for the 2B diesel. The air pressures measured downstream of the regulators for the 2B diesel were 225 psig and 210 psig, which is the pressure impinging on the pilot solenoid valve. However, the maximum rated operating pressure for the pilot valve was 200 psig. The 1B diesel was not instrumented with a pressure gauge downstream of the regulator; therefore, the team was unable to determine whether the maximum operating pressure had been exceeded. During the inspection, the licensee prepared work requests to install temporary pressure gauges on the 1B diesel to check and adjust the system pressure to 195 to 200 psig, and to adjust the 2B diesel regulators to this same pressure band.

NRC Information Notice 88-24 dealt with a condition where certain air-operated valves failed to operate because they were exposed to pressures in excess of rated pressure. A review of past maintenance work requests showed that air leaks through the pilot solenoid valve had been a recurring problem, requiring valve repair on both of the valves on the 2B diesel in 1987. Sargent & Lundy (S&L) had been asked to determine the cause of these recurring valve leaks. In January 1989 S&L informed the licensee that the cause of these leaks was excessive line pressure at the valve.

The licensee reviewed the S&L evaluation and in July 1989 established a requirement to check all DG air start system pressures downstream of the pressure regulator once per week to determine if the regulators were allowing pressure to build up beyond 200 psig. These checks were performed for diesel generators 0, 1A, and 2A; however, when performing the check at diesel 1B, which did not have a pressure gauge, the check was not performed. The Unit 2 installation was assumed to match Unit 1. Therefore, these two diesels were not checked. The failure of the licensee staff to implement corrective action for the 1B and 2B diesel generators is a violation of Criterion XVI in Appendix B to 10 CFR Part 50 (374/89018-13; 374-89018-14).

LaSalle procedure LEP-DG-102, Revision 3, "Diesel Generator Air Start Pilot Solenoid Valve Repair/Replacement and Testing," required two leak checks to be performed on the DG air start solenoid valves every 18 months. The first leak check was to be done on the bench after valve refurbishment and the second after installation on the diesel. The pressure specified in the procedure for both of these checks was 90 psig, even though the operating pressure was maintained at approximately 200 psig. Although not so stated in the procedure, the team determined that the second test had been performed at the system pressure of 200 psig. This is an example of the procedure not being appropriate to the circumstances in violation of Criterion V in Appendix B to 10 CFR Part 50. The licensee agreed with this observation and revised the procedure during the inspection. Since the criteria of 10 CFR Part 2, Appendix C, Section V.A were met, no notice of violation is being issued.

4.6.2 Deficiencies Associated with Small Bore Tubing

During a walkdown of the 2B diesel, several small diameter piping and tubing deficiencies relating to routing and restraining were identified. As a result the team performed a detailed walkdown of the 2A diesel. The following specific deficiencies were identified:

a. Lube oil drops were found below the pressure switches at some tubing branch connections.

b. Some piping restraints were inadequate. Some were completely off of the line; some consisted of only half of the clamp; and some were made with thin sheet metal electrical conduit with large gaps between restraints.

c. Minor tubing cuts and wall thinning were observed due to rubbing. In some of the wall thinning cases, the associated tubing showed signs of leakage.

d. Wire harnesses on DG speed control motors above the governors were either not installed, or improperly installed (see Paragraph 4.2.1.2).

Based on the team's walkdown, licensee personnel conducted detailed walkdowns of the 0, 1A, and 1B diesels, found similar problems, and initiated several work requests to restore line configuration back to the original conditions, such as replacing pipe clamps and tightening fasteners. The apparent cause of these deficiencies was vibration, and improper installation.

NRC Information Notice 89-07 was issued on January 25, 1989, to alert licensees that failure of tubing in control air, fuel oil, and lube oil systems could be caused by (1) wall thinning by material rubbing, (2) inadequate design, and (3) inadequate support; and that these failures could render the diesel generator inoperable. These

conditions were present on the diesels which the team walked down. In addition, the licensee experienced a fuel oil system leak when the bourdon tube of one of the two fuel oil pressure gauges on DG 2B ruptured, apparently due to excessive vibration, on March 4, 1989, the second day of continuous operation. This resulted in DG shutdown to prevent possible fire. The licensee's corrective action as a result of this event had been to replace the failed gauge, inspect the other gauges on this diesel for damage, and replace the one other gauge found to be damaged. However, this corrective action was not extended to other diesel generator fuel oil gauges that had been subjected to similar vibration. The licensee has since issued a work request to replace all susceptible gauges.

The team conducted a detailed review of actions that had been implemented by the licensee as a result of the issuance of information notice 89-07 and the DG 2B tube failure. Licensee followup to the information notice did not result in a detailed DG small diameter piping and tubing inspection which could have identified some of the deficiencies observed by the team prior to the NRC inspection. However, the licensee did propose, in May 1989, that the lube oil, fuel oil, and engine cooling tubing and piping be re-routed to provide adequate separation, and that additional supports be provided to handle the vibration.

The licensee's actions to correct the conditions which could result in small diameter piping and tubing failure, as described in Information Notice 89-07, will be tracked as an Open Item (373/89018-14; 374/89018-15).

4.7 Evaluation of Licensee-Initiated SSFI on HPCS

The licensee began a program for conducting the equivalent of SSFIs at their sites in early 1987. This was a voluntary initiative conducted in an effort to utilize this inspection technique to evaluate system functionality. Through this process, the licensee could obtain a considerable amount of information about plant performance. The first sites chosen were Dresden, Quad Cities, and Zion. Consultations were then held with WESTEC, who had been involved in the conduct of several NRC SSFIs. WESTEC reviewed what had been done at Dresden, Quad Cities, and Zion, and made some recommendations on how to improve the licensee efforts. These recommendations were implemented during the licensee's conduct of an SSFI at LaSalle conducted between July 27 and November 24, 1987.

The LaSalle self-SSFI was conducted under the auspices of the corporate QA Department. The inspection group consisted of 16 inspectors, including 8 members of the QA Department and 8 mechanical and electrical design engineers from Sargent & Lundy. The inclusion of design engineers was a positive effort to utilize personnel with appropriate engineering disciplines.

The licensee's inspection methodology involved the collection of a sample of work requests and all modifications that had been completed on the

Unit 2 HPCS. Of these, the inspection included a review of six temporary change packages, eight completed modification packages, and 36 work requests. In addition, over 3000 hours were spent in walkdowns of the HPCS and associated systems to determine that components were designated per P&ID and installation drawings, position and location of components allowed operation and ease of maintenance, pipe size was per design documents, material condition was good, and electrical wiring was routed per drawings.

The findings included 20 cases where there was an apparent discrepancy between an identified condition and a requirement, and 37 instances where there was a substantiated discrepancy between an identified condition and a requirement. In addition, four generic issues were identified: (1) voluntary entrance into LCOs without a report to NRC; (2) poor documentation of basis utilized from the TS and FSAR in 50.59 safety evaluations; (3) procedures, drawings, and labeling of equipment were not in agreement; and (4) changes to the UFSAR were not timely nor accurate. The specific findings mostly related to drawing and installation discrepancies.

On November 20, 1987, the licensee established an SSFI Task Force to review the results of the first four licensee-conducted SSFIs to determine whether changes in methodology should be made and to evaluate the results for potential generic findings. The SSFI Task Force issued their final report on June 30, 1988, which contained several recommendations regarding the conduct of future SSFIs and the resolution of apparent generic deficiencies at all stations. These recommendations were reviewed and considered to represent positive improvements to the licensee's program.

In addition, the Task Force concluded that: (1) that all systems evaluated would function as designed when needed; (2) no immediate safety concerns were identified; (3) the self-SSFIs were effective, useful initiatives that reached credible conclusions; (4) the self-SSFI process should continue on a planned schedule; and (5) the self-SSFIs should be conducted in such a way that the impact on plant activities were minimized.

Upon completion of the NRC team's HPCS inspection activities, the team reviewed the licensee's SSFI Task Force Final Report, self-SSFI report, SSI 01-87-01, and held discussions with the licensee's SSFI team leader and lead inspectors in the areas of mechanical and electrical. Findings made by the NRC team were evaluated to determine if they had also been identified by the licensee's efforts, and if not, the root cause for non-identification. The corrective actions implemented as a result of the licensee's findings were also reviewed.

The NRC Team agreed that no immediate safety concerns existed; however, the team did not agree that the system would always function as required due to the potential electrical design concerns noted above. The team also agreed that the self-SSFI did an excellent job of finding and correcting labeling problems and most drawing concerns, based on the fact that the NRC team did not find situations where labeling or drawings for the evaluated unit were inappropriate.

As noted above, the NRC team identified several deficiencies involving the HPCS and associated support systems during this inspection which were not identified during the licensee's efforts. These differences in findings could be attributed to limitations in the licensee's SSFI methodology. The team identified only three cases where findings from the licensee's SSFI had not been corrected and were also identified by the NRC team. These are discussed below.

4.7.1 Limitations in SSFI Methodology

Two major limitations were identified related to the methodology for conducting SSFIs. The first limitation related to the limited review of design documents. The licensee's efforts were limited to changes made as a result of the completed modification process. A basic assumption was made that the original design of the system, as licensed, was correct unless evidence to the contrary was identified in the subsequent review of material. Similarly, components were not checked to verify that they conformed with design requirements if they were the original components. The primary emphasis of the licensee's efforts were walkdowns and review of changes made to the systems through modifications.

As noted during the NRC effort, several deficiencies were identified relating to original installation, some of which related to calculations, battery purchase specifications, battery load profiles, and discrepancies between the UFSAR, TS, and design assumptions. In the case of UFSAR discrepancies, the self-SSFI had identified a generic concern; however, all of the specific examples had not been identified that related to the HPCS system. By limiting their efforts to installed modifications, the licensee did not determine whether the system "as installed" was capable of performing its design functions but rather that the system as originally designed had not been changed to invalidate the condition it was in at the time of initial licensing. This was apparent by the considerable amount of time required for the licensee to determine what were the actual loads on electrical buses, the original purchase specifications of the battery, and the maximum and minimum voltage that components installed in the system were capable of withstanding.

The licensee also recognized this shortcoming in their Task Force report that recommended that future SSFIs incorporate efforts for design validation although it indicated that this should not be done until the design reconstitution effort is completed. Since all functionality concerns related to initial installation or design may not be identified by a self-SSFI conducted before implementation of the Task Force recommendations, those prior efforts should not be exclusively relied upon to justify that the associated systems are operable.

The second limitation related to the methodology used by the licensee to verify appropriate surveillances were conducted at required times for the electrical portion of the self-SSFI. The licensee began by reviewing all of the surveillance procedures to ensure that acceptance criteria in the procedure conformed

with the TS requirements and that the procedures were implemented as required. However, by not comparing TS, the UFSAR, and design values for consistency and then utilizing the appropriate values to verify that the requirements were covered within an appropriate surveillance procedure, a vulnerability existed where surveillances required by TS but not specified in a procedure would be missed, as was the case for the switchgear room temperature surveillance identified in section 4.3.1 above. To ensure future self-SSFIs do not miss these findings, the licensee needs to revise their methodology related to the review of surveillance procedures.

4.7.2 Implementation of SSFI Corrective Actions

The NRC team noted three cases where deficiencies identified by the self-SSFI were also found by the NRC team, indicating that corrective actions may not have been sufficiently complete. These related to the alarm setpoint for the diesel generator day tank, the performance of 50.59 safety evaluations, and the incorporation of as-built conditions for the diesel generator air-start system into appropriate drawings. The team noted that there was a distinct different cause for each of these items not being corrected.

The first case dealt with the inappropriate alarm setpoint for the diesel generator day tank, where the licensee's finding had been closed out. The closeout was based on the fact that an S&L calculation had been QA certified, and had shown that required run time would be met. As noted in section 4.1.1.2 above; the fuel drawdown assumption made in the calculation was erroneous, and reflected a lack of knowledge about the system. This would indicate that not only were the individuals involved in the performance of the calculation and its QA review unfamiliar with system operation but that the acceptance of the calculation to close the SSFI concern was based strictly on the fact that paperwork was provided without independent assessment of its validity by the individual knowledgeable of the system who had made the original finding. In this case the corrective action had been inadequate to address the finding. The appropriate corrective action would have been to revise the alarm setpoint.

The second case dealt with the performance of 50.59 safety evaluations. In this case, the corrective actions were incomplete in that they had focused on future performance of 50.59 activities without consideration of those activities in process. The specific modification identified by the NRC team had not been completed as of the time when the self-SSFI was performed, and although deficiencies were identified by the self-SSFI in the performance of 50.59 reviews, the corrective actions were focused on providing adequate requirements in the new modification program. However, it was not apparent that any actions had been taken to address modifications that were "in the pipeline" to ensure that the safety evaluations associated with them were acceptable. These would include modifications that were yet to be completed utilizing the old modification program or that had been

installed after completion of the self-SSFI. In this case, the corrective actions were incomplete regarding the finding and have resulted in an additional violation.

The third case dealt with the updating of drawings to reflect as-built conditions for the Unit 1 diesel generator air start system. The self-SSFI on Unit 2 HPCS had identified several cases where drawings did not match the as-built conditions. However, in one case, the corrective action for the air start drawing had been Unit 2 specific. In this case, P&IDs for the HPCS diesel generator air start systems for units 1 and 2 were compared. Although the drawings for Unit 2 had been revised to incorporate the air pressure gauges that were installed, the P&IDs for diesel generator air start systems 1B, 1A, 2A, and 0 did not show the installed pressure gauge at the end of the air manifold. In this case, the corrective actions were incomplete regarding the finding in that the drawing errors were not corrected for the other diesel generator air start system P&IDs. The licensee initiated corrective actions to correct these drawings. The failure to extend corrective actions to all affected nonconformances is an example of a violation of Criterion XVI of Appendix B to 10 CFR Part 50; however, since this example would be considered to be a Severity Level V based on minor safety significance; and the licensee initiated corrective actions prior to completion of the inspection; no notice of violation is being issued because the criteria of Section V.A of 10 CFR Part 2, Appendix C, have been met.

5.0 OPEN ITEMS

Open items are matters which have been discussed with the licensee which will be reviewed further by the inspector, and which involved some action on the part of the NRC or the licensee or both. Open items determined during this inspection are discussed in Paragraphs 4.1.1.1, 4.1.1.3, 4.1.3.2, 4.3.2, 4.3.3, 4.3.4, and 4.6.2 of this report.

6.0 UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during this inspection are discussed in Paragraphs 4.1.2.2, 4.1.2.3, 4.1.2.5, and 4.1.4.2 of this report.

7.0 PERSONNEL CONTACTED

Commonwealth Edison

* G. J. Diederich, Station Manager, LaSalle County Station (LSCS)
* J. C. Renwick, Production Superintendent, LSCS
+* W. R. Huntington, Technical Superintendent, LSCS
+* T. A. Hammerich, Regulatory Assurance Supervisor, LSCS
* H. L. Massin, Engineering Project Manager, LaSalle, CECo
* G. L. Swihart, Safety Systems Group Leader, Technical Staff, LSCS

Commonwealth Edison

* D. A. Spencer, Technical Staff, LSCS
+* B. M. K. Wong, BWR Systems Engineering, CECo
+* W. Morgan, LaSalle Licensing Administrator, CECo
G. P. Wagner, Nuclear Engineering Manager, CECo
M. L. Reed, BWR Systems Engineering, CECo
* D. R. Szumski, Technical Staff, LSCS
J. S. Abel, BWR Systems Engineering Manager
+ L. O. DelGeorge, Assistant Vice President, Quality Programs and Assessment
+ P. F. Manning, Team Leader, CECo Self-Initiated SSFI
+ J. D. Brunner, Assessment Administrator, Performance Assessment
D. A. Brown, Superintendent of Quality Assurance/Nuclear Safety
R. J. Cozzi, Senior Participant, Offsite Review and Investigative Function
* T. Benoit, Quality Assurance
* M. A. Harper, Quality Assurance
* L. A. Lauterbach, Onsite Nuclear Safety
* R. D. Crawford, Master Electrician, Electrical Maintenance
J. Miller, Assistant Technical Staff Supervisor
P. Sampson, Technical Staff, Systems Engineer
J. Foster, Principal Engineer, Mechanical Maintenance
F. J. Lentine, Superintendent, PWR Design Engineering

Sargent and Lundy Engineers

* M. A. Navarro, Licensing
* G. I. Zwarich, Project Manager
* D. A. Kolczak, Electrical Project Engineer
+ H. A. Furlager, Project Engineer
R. H, Pullock, Project Manager

Illinois Department of Nuclear Safety

* J. Roman, Resident Engineer

U.S. Nuclear Regulatory Commission

+ C. J. Paperiello, Deputy Regional Administrator
+ H. J. Miller, Director, Division of Reactor Safety
+* T. O. Martin, Deputy Director, Division of Reactor Safety
* G. C. Wright, Chief, Operations Branch, Division of Reactor Safety
* R. M. Lerch, Acting Chief, Section 1B, Division of Reactor Projec
* R. D. Lanksbury, Senior Resident Inspector

*Attended the preliminary exit meeting on August 25, 1989.

+Attended the management exit meeting on October 10, 1989.

Other persons were contacted during the course of the inspection, including members of the licensee's system and design engineering staff, training department, operations department, and maintenance department.

8.0 MANAGEMENT EXIT INTERVIEWS

The team met with the licensee representatives denoted in Paragraph 7.0 above at the conclusion of the inspection. The team summarized the scope and findings of the inspection at a preliminary exit meeting on August 25, 1989. A management exit meeting was held on October 10, 1989, to characterize those findings which had been determined to be apparent violations of NRC requirements and to present the overall conclusions reached by the inspection team. The team also discussed the likely informational content of this inspection report during the August 25, 1989 meeting. The licensee acknowledged the information presented, and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.