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ComEd

December 20, 1996

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: **NRC INSPECTION REPORT NO. 50-373/96011; 50-374/96011 (DRP) AND NOTICE OF VIOLATION**

References: **G. E. Grant Letter to W. T. Subalusky, dated November 15, 1996, Transmitting NRC Inspection Report 373/374-96011**

The enclosed attachment contains LaSalle County Station's response to the Notice of Violation, that was transmitted in the Reference letter and four additional unresolved items.

Attachment 1 to this letter contains the immediate corrective actions taken as well as long term corrective actions to preclude recurrence of the cited violations. Attachment 2 provides our response to the unresolved items.

Based on a telephone discussion with Ms. Patricia Lougheed of the Region III staff, the due date for the response was extended to December 20, 1996. Additionally, the subject Inspection Report identified four apparent violations for which a response was requested. Per a December 13, 1996, telephone discussion with Mr. Mark Ring of the Region III staff, the due date for the response of these four apparent violations was extended to January 10, 1997.

If there are any questions or comments concerning this letter, please refer them to me at (815) 357-6761, extension 3600.

Respectfully,

W. T. Subalusky
Site Vice President
LaSalle County Station

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Enclosure

Enclosure

cc: A. B. Beach, NRC Region III Administrator
M. P. Huber, NRC Senior Resident Inspector - LaSalle
D. M. Skay, Project Manager - NRR - LaSalle
DCD - Licensing (Hardcopy: Electronic:)
Central File

ATTACHMENT 1

LaSalle County Generating Station
Response to Notice of Violation
in Inspection Report No. 50-373/96011 (DRS); 50-374/96011 (DRS)

Violation A (96011-01 &96011-17):

10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to ensure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. It further requires that design changes be subject to design controls commensurate to those applied to the original design and that the changes be approved by the responsible design organization.

Contrary to the above:

1. On March 31, 1996, for Unit 1 and on May 31, 1996, for Unit 2, the fuel pool emergency makeup pumps were removed from service in order to be modified by adding a stainless steel weld overlay to the carbon steel pump casing and this design change was not subject to design controls commensurate to those applied to the original design. Furthermore, the design change was not approved by the responsible design organization because it was performed as a maintenance activity.

2. As of September 24, 1996, the design basis temperature of the high pressure coolant system was incorrectly translated into calculations VY-004, "Unit 1, Division I ECCS Equipment Cooling Water System," Revision 0, ATD-0375, "ECCS Pump Room Temperature During Shutdown With Area Coolers Inoperable," Revision 0, and 3C7-089-001, "ECCS Room Temperature Transient Following LOCA Concurrent With Loss of Area Cooler," Revision 1, Revision 0. This was due to a 1985 design change which modified the suction of the HPCS system from the condensate storage tank to the suppression pool and increased the design basis temperature.

This is a Severity Level IV violation (Supplement I).

Response to Item 1 (96011-01):

The reason for the violation:

ComEd agrees that described repair activities should have been controlled as a design change.

The FC Emergency Make-up (FCEM) Pumps (Safety Related & ASME Code Related) were to be disassembled and inspected as part of investigating high vibration levels. Corrosion internal to the pump was discovered and necessitated corrective action. It was decided to perform weld repair in accordance with ASME Section XI. To preclude future corrosion problems it was decided to overlay the high corrosion areas with stainless steel. Engineering issued NDIT No. LS-0300 (Approved on June 5, 1996) to provide the Repair Program. The NDIT states "This work is considered to be an ASME Section XI repair." However, Engineering failed to recognize that this action constituted a design change to the pump.

The work was performed for 2 of the 4 pumps, 1FC03PA & 2FC03PB, under Work Requests (WR) 950110761 and 950019472. During the repair, questions arose as some warpage occurred. The warping necessitated: 1) machining to ensure that critical dimensions (clearances) were maintained, and 2) additional welding to ensure that wall thicknesses were maintained. Additional upgrades (revisions) to NDIT No. LS-0300 were issued to resolve questions on use of alternate NDE methods, to increase the amount of acceptable undercutting, to allow welding on the backside of the pump casing to restore the required wall thickness and to require a hydrostatic test on the pump casing. Upgrades 1 through 5 were issued (approved between June 12 1996 and September 19, 1996).

This work was not identified as a design change because it was incorrectly considered routine maintenance. At the time no Safety Evaluation was performed nor was the UFSAR reviewed.

The corrective steps that have been taken and the results achieved:

1. A 10CFR50.59 Safety Evaluation was performed to address the weld repairs (On Site Review Number 96-080 approved September 19, 1996). No unreviewed safety question was identified.

2. Calculation No. L-000709 was performed which verified that the as-left conditions of the pump casings comply to ASME design requirements.

3. A revision to UFSAR section 9.2.1.2 was prepared (included with the 10CFR50.59 Safety Evaluation).

4. A hydrostatic test on the pump casings was performed which verified their structural integrity.

5. An as-built DCR 960146 was completed to clearly identify the weld repairs to the pumps. Vendor Drawings No. DP14450-6 Sheets 1 & 2 now reference NDIT No. LS-300.

The corrective steps that will be taken to avoid further violations:

Procedure LAP-1300-1 "Action Request Processing" has been revised to provide guidance on when weld repairs should be considered to be design changes.

The Site Vice President and Station Manager met with the Maintenance Masters to reinforce the expectation that the Maintenance Masters are responsible and accountable for the work accomplished in their area. To that end, Maintenance held a training session for first line supervisors and work analysts on what constitutes a modification and that a critical review be made of each work package to ensure that it does not result in an unauthorized modification. Any questionable work package is returned to Engineering for disposition.

The date when full compliance will be achieved:

Full compliance was achieved upon completion on the Safety Evaluation including the UFSAR change (Approved on September 19, 1996) and on the issuance of the changes to the ASME Section XI Repair Program (per NDIT No. LS-0300, Upgrades 0 - 5, the last upgrade being Approved on September 19, 1996).

Response to Item 2 (96011-17):

The reason for the violation:

ComEd agrees that calculation VY-004, "HPCS Pump Cubicle Cooler Ventilation System," Revision 0, did not properly address the heat load from the HPCS Piping. This calculation was performed in 1976. Based on our review of the calculation, it appears that the preparer failed to consider the HPCS piping heat load. This is a human performance error.

The corrective steps that have been taken and the results achieved:

1. Calculation VY-004, " HPCS Pump Cubicle Cooler Ventilation System," Revision 1, was approved on December 6, 1996, to address the higher cubicle heat load due to the HPCS Piping. The fan and coolers for the HPCS cubicles have adequate capacity for the increased heat loads.

2. Calculation ATD-0375, "ECCS Pump Room Temperature During Shutdown With Area Coolers Inoperable," Revision 0, was prepared to determine if the area coolers can be taken out of service during an outage without declaring the appropriate ECCS pumps inoperable. During an outage, the temperature of the HPCS piping will not be elevated; therefore, the calculation does not require revision.

3. Calculation 3C7-089-001, "ECCS Room Temperature Transient Following LOCA Concurrent With Loss of Area Cooler," Revision 1 does not require revision to reflect the increased heat load. This calculation was prepared as input to a feasibility study to examine ECCS equipment operation without area cooler operation. The purpose of the study was to determine if the testing/inspection requirements of Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment," could be waived for the VY Coolers by demonstrating that ECCS operation without area coolers will allow the current qualification status of equipment inside the ECCS cubicles to be met. The results of the study was that the VY cooler operation in each ECCS cubicle is necessary. Therefore, Calculation 3C7-089-001, Revision 1 is not part of the design basis and has been voided as Revision 2.

The corrective steps that will be taken to avoid further violations:

All ECCS Corner Room heat loading calculations will be reviewed and revised as necessary. Any calculations that used these heat loads as design input will be checked and revised as necessary. These calculation reviews and revisions will be completed prior to restarting Unit 1 and 2 from L1F35 and L2R07 respectively.

ComEd is in the process of performing System Functional Performance Reviews for systems important to safe and reliable operation, and has initiated preparation of selected Design Basis Documents (DBD). These activities include a review of the design basis of the system including calculations, UFSAR commitments, and procedures. Any inconsistencies will be identified and resolved in accordance with Station Procedures.

The date when full compliance will be achieved:

Full compliance was achieved when Calculation VY-004, "Unit 1, Division I ECCS Equipment Cooling Water System," Revision 1, was Approved on December 6, 1996, to address the higher cubicle heat load due to the HPCS Piping.

Violation B (96011-10 & 96011-11):

10 CFR Part 50, Appendix B, Criterion XI, "Test Control," requires, in part, that tests be performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents.

It further requires that test results be evaluated to ensure that test requirements have been satisfied.

Contrary to the above:

1. As of September 24, 1996, surveillance test procedure LTS 200-3, "RHR Heat Exchanger Tubeside DP Test," Revision 3, did not contain acceptance limits contained in the design equipment specification for the residual heat removal heat exchanger differential pressure.

2. As of September 24, 1996, the results of tests on the 2B residual heat removal heat exchanger had not been adequately evaluated in that an increase in differential pressure within the tubes by approximately 22 percent over a three year period from 1992 to 1995 was not detected or evaluated to ensure test requirements had been satisfied.

This is a Severity Level IV violation (Supplement I).

Response:

The reason for the violation:

ComEd agrees that the review of the subject test results was not timely, and the results are important to assessing the overall material condition and functionality of the residual heat removal heat exchanger. The purpose of LTS-200-3 is to obtain the differential pressure across the tubesides of the RHR heat exchangers. The test data is used to determine if gross differences from design conditions exist or if significant trends in differential pressure had occurred. The specific functional characteristic being monitored is (1) whether excessive leakage is occurring across the baffle in the heat exchanger water box and (2) whether major fouling of the tube side of the heat exchanger has occurred. The heat exchanger design flow rate and tubeside dP values were included in LTS-200-3 procedure as were the potential causes for both high and low differential pressure. Resolution of the discrepancies with test data is the responsibility of the Test Director. The Test Director did review the data for these purposes, but did not document his evaluation.

Procedure LTS-200-3 "RHR Heat Exchanger Tubeside dP Test", is not used to determine operability of the heat exchanger. Therefore, LTS-200-3 does not include specific acceptance limits. Procedure LOS-RH-Q1 "RHR(LPCI) & RHR Service Water Pump & Valve Inservice Test For Tube Side Operational Conditions 1,2,3,4, and 5" is used to verify RHR heat exchanger tube side flow for operability. It includes the appropriate acceptance criteria to compare test results to determine operability.

The corrective steps that have been taken and the results achieved:

Problem Identification Form 96-5282 was written on the inadequate documentation of LTS-200-3 test results. As part of the corrective action program review, the performance of the heat exchanger has been evaluated as operable for the current plant condition. The variation in pressure drop documented in the referenced corrective action program is within instrumentation accuracy.

The corrective steps that will be taken to avoid further violations:

Procedure LTS-200-3 has been enhanced to include clear prerequisites, to state that the results are used for engineering evaluation, and to provide better direction to the Test Director on the need for timely data evaluation.

Additionally, we will be reviewing all applicable surveillance procedures for systems important to safe and reliable operation as part of the ongoing System Functional Performance Review program, and will ensure that these procedures include adequate prerequisite requirements and acceptance criteria, or in lieu of acceptance criteria, the specific actions to be taken to review the data and whether any immediate actions are required.

The date when full compliance will be achieved:

Full compliance was achieved on December 19, 1996, when procedure LTS 200-3 was revised.

Violation C (96011-14):

Technical Specification surveillance 4.7.1.3.c requires, at least once per 18 months, determination that sediment deposition anywhere within the lake screen house behind the bar grill is not greater than one foot in thickness.

Contrary to the above, the following portions of the circulating water bays, within the lake screen house behind the bar grill, were not determined to have sediment depositions of no greater than one foot in thickness at least once in an 18 month period:

1. Between November 12, 1992, and February 9, 1996, the northwest and southeast corners of the three Unit 1 circulating water bays were not inspected.

2. Between January 8, 1992, and February 28, 1996, the northwest and southeast corners of the Unit 2A circulating water bay were not inspected.

3. Between December 6, 1991, and February 28, 1996, the northwest and southeast corners of the Unit 2B circulating water bay were not inspected.

4. Between February 18, 1992 and March 15, 1995, the northeast and southwest corners of the Unit 2C circulating water bay were not inspected.

5. Between September 27, 1993, and February 28, 1996, the northwest and southeast corners of the Unit 2C circulating water bay were not inspected.

This is a Severity Level IV violation (Supplement I).

Response:

The reason for the violation:

LaSalle acknowledges that the Technical Specification surveillance 4.7.1.3.c was implemented such that sediment deposition was not determined anywhere within the lake screen house behind the bar grill at least once in an 18 month period. Tech Spec 3.7.1.3 surveillance requirement 4.7.1.3.c is performed by LTS-1000-4, CSCS Pond Surveillance. The surveillance procedure had required inspecting only half of each of the Circulating Water (CW) Pump inlet bays (suction bays) during each 18 month surveillance interval. The cause of this inadequate surveillance was human error in preparation and review of the detailed implementing procedure.

The corrective steps that have been taken and the results achieved:

All four quadrants of the Unit 1 CW pump inlet bay were inspected during L1R07 (February 1996) and found to be satisfactory.

All four quadrants of the Unit 2 CW pump inlet bay were inspected on August 26, 1996, and found to be satisfactory.

Procedure LTS-1000-4 was revised to require inspection of all four quadrants of a CW pump inlet bay.

The corrective steps that will be taken to avoid further violations:

LaSalle is pursing the transition to Improved Technical Specification (ITS) and expect to implement during the Spring of 1998. Preparations for implementation will be underway during 1997. We will expand the scope of ITS implementation to include a verification that the associated surveillance procedures satisfy the literal wording of the proposed Technical Specification Surveillance Requirements. This will be accomplished by June 30, 1997.

The date when full compliance will be achieved:

Full compliance was achieved on August 26, 1996 with the completion of the Unit 2 CW pump inlet bay inspections.

Violation D (96011-13):

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be performed using documented instructions or procedures of a type appropriate to the circumstances.

Commonwealth Edison Quality Assurance Manual, Revision 65a, dated April 17, 1995, Section 5, "Instructions, Procedures, and Drawings," requires, in part, that activities governed by the quality assurance program be performed using documented instructions, procedures, and drawings appropriate for the activity.

Contrary to the above, in February 1996, the licensee first leveled the sedimentation such that it would comply with technical specifications and then removed the sediment from the Unit 1 circulating water bays without any documented instructions or procedures.

This is a Severity Level IV violation.

Response:

The reason for the violation:

ComEd agrees that removal of the subject sedimentation was not adequately controlled by formal documentation.

The Unit 1 Circulating Water (CW) traveling screen repairs were started the week of February 5, 1996 by Scott Diving Services. The same week the surveillance of the sediment level of Unit 1 CW pump bays to satisfy the requirements of LTS-1000-4 was also performed. The results were unsatisfactory and a Limiting Condition for Operation (LCO) was entered for Unit 2 (Unit 1 was in a defueled status). On February 9, a redistribution of the sediment was made by the divers and the surveillance was completed as satisfactory. An Action Request (AR) was prepared by the System Engineer to remove the sedimentation prior to returning to service the Unit 1 CW pumps. The AR was converted to a Work Request (WR) that was scheduled to be implemented by February 18, 1996.

Between February 9 and 25, 1996, the divers had been repairing CW traveling screens. The Construction Supervisor understood that the System Engineer would want to have the CW bays cleaned as part of his surveillance and directed the divers, as part of their cleanup, to remove the sediment deposits in the Unit 1 CW bays while the CW pumps were out of

service. The results of this activity were not documented in the WR package. When the WR initiated by the System Engineer came up, it was identified that the work had been completed and the WR was canceled. This error is a result of inadequate communication between the System Engineer and the Construction Supervisor.

The corrective steps that have been taken and the results achieved:

Both the Construction Supervisor and the System Engineer were counseled on the need for effective communication in the performance of daily work.

The System Engineer was counseled on procedural adherence and his responsibility to confirm as correct any information he receives that affects the safe operation of the plant. He has recently attended a training session on October 1, 1996, where Senior Engineering Management emphasized the use of quality, rigor, and safety focus in the performance of daily work. Also, the importance of clearly communicating expectations to personnel performing surveillances under his cognizance, maintaining adequate follow-up of activities under his responsibility, and the operating philosophy of conservative decision making were emphasized by his supervisor. The decision to level the sediment in the bays to meet the acceptance criteria did not demonstrate conservative decision making.

The decision to level the sediment instead of having the sediment removed prior to changing operational conditions was not a conservative decision. The Operations Manager discussed with the Shift Managers the expectation of conservative decision making.

The corrective steps that will be taken to avoid further violations:

Standard pre-approved work packages for the Lake Screen House have been developed and will be implemented by January 10, 1997. An aspect of theses work packages will be to ensure that the System Engineer is contacted prior to sediment cleaning in the CW bays.

The date when full compliance will be achieved:

Full compliance was achieved on October 1, 1996.

Violation E (96011-18):

10CFR50.71(e) requires, in part, that licensees update the Final Safety Analysis Report periodically to reflect modifications to the plant. Subsection (4) requires such updates to be no more than 24 months apart and to reflect all changes made up to a maximum of six months prior to the update.

Contrary to the above, as of September 24, 1996, the LaSalle Updated Final Safety Analysis Report had not been updated to reflect the change in initial and maximum suppression pool temperatures approved by License Amendments 67 (Unit 1) and 49 (Unit 2), issued in July 1989. This period exceeds 24 months.

This is a Severity Level IV violation (Supplement I).

Response:

The reason for the violation:

ComEd agrees that the subject upgrade was improperly implemented and untimely. When LaSalle processed the request for a Technical Specification change prior to the submittal to the NRC in October 1988, the originator of the change identified potentially affected UFSAR sections (incompletely). Although the sections were relevant to the primary containment and suppression pool cooling functions, the sections identified did not include the suppression pool temperature value.

Upon receipt of the license amendment in July 1989, and prior to the next UFSAR update, the UFSAR was again reviewed as part of preparation for the UFSAR update. The review incorrectly determined that no UFSAR changes were deemed necessary because the sections which were identified as part of the Technical Specification change package did not need updating.

This was a human performance error due to inadequate search of the UFSAR during both reviews. The reviewers failed to perform an adequate search for all affected portions of the UFSAR.

The corrective steps that have been taken and the results achieved:

The Technical Specification Amendment has been re-reviewed and a search of applicable sections of the UFSAR has been completed. The 10CFR50.59 evaluation is in the approval process. This is scheduled to be completed by January 10, 1997.

Procedure LAP-1200-12 "License Amendments" was revised in September, 1996, to include UFSAR changes (marked up on copies of the applicable UFSAR pages). This assures that the UFSAR impact is specifically included in the Onsite Review for each License Amendment request. The ability to do computer searches on UFSAR text aids in performing a thorough search of affected documents.

The corrective steps that will be taken to avoid further violations:

As part of the LaSalle Upgraded Operational Plan, each section of the UFSAR will be assigned an owner by January 15, 1997. The intent of this action is to improve accountability for UFSAR accuracy. This will also provide a resource to other personnel performing Technical Specification and other plant changes which could effect the UFSAR.

A sample of other Technical Specification changes will be reviewed to determine if the UFSAR was properly updated. Any UFSAR update problems will expand the sample. This review will be completed by June 30, 1997.

The date when full compliance will be achieved:

Full compliance will be achieved no later than January 10, 1997, when the safety evaluation of the applicable changes to the UFSAR are approved.

ATTACHMENT 2

LaSalle County Generating Station
Response to Unresolved Items
in Inspection Report No. 50-373/96011 (DRS); 50-374/96011 (DRS)

Unresolved Item 96011-12:

Flow through the safety-related room coolers was not balanced and that the effect of the RHRSW system on the coolers had not been adequately tested or analyzed. We request that you provide more information on how the maximum flow through the 1(2)VY04A room cooler was determined and a more structured review of the effects of the RHRSW back pressure on the room coolers to ensure adequate flow through all the room coolers under all conditions where they would be required to operate.

Part 1 - M-3.4:

The inspectors observed that the "integrated tests" performed during the preoperational testing were tests of a single loop (i.e., pump and heat exchanger). No true integrated testing was performed. This resulted in an untested system interaction being identified in that the RHRSW shared a common discharge line with the DGCW. As the RHRSW pumps had a larger capacity than the DGCW pumps (8000+ gpm RHRSW per division versus 2000 gpm DGCW), the inspectors surmised that back pressure from RHRSW could adversely affect the flow through the VY coolers.

The inspectors questioned the licensee whether this interaction was ever tested (see Comments 8 and 14). In response, the licensee stated that the interaction was tested in July 1996. The inspectors reviewed the results of this testing and noted that RHRSW was not identified as being running during the testing. The licensee formally responded that RHRSW was confirmed to have been running for Division 1 by review of operating logs. For Division 2, the licensee noted that the effect of RHRSW on the coolers was determined analytically. The inspectors determined that the July testing was not intended to examine the system interaction and that the running of the RHRSW pumps during the Division 1 test was fortuitous. The inspectors independently reviewed the latest VY cooler testing and determined that the cooler operability was not affected at the time of the inspection.

Conclusions : The inspectors concluded that the pre-operational testing did not identify a potentially significant interaction between the RHRSW and the DGCW. While this interaction did not appear to affect room cooler operability at the time of the inspection, it had the potential to so do, if not properly taken into account, especially if flow balancing was done to resolve the cooler velocity concerns expressed in Section M2.10. Determination of the effect of this interaction on the VY coolers is considered part of unresolved item 50-373/96011-12(DRS); 50-374/96011-12(DRS).

Response:

ComEd agrees that flow through the safety-related room coolers was not balanced during pre-operational testing, and that the effect on the flow imbalance had not been adequately tested or analyzed.

The Diesel Generator Cooling Water (DGCW) system supplies cooling water to the Core Standby Cooling System Ventilation (VY) room coolers. When Residual Heat Removal Service Water (RHRWS) is operated simultaneously with the operation of the DGCW, additional pressure drop occurs as a result of the higher flow rates in portions of the common piping. Calculation L-000679, Rev 0, Approved September 19, 1996, titled "Determination of Flow Correction Factors for Evaluating the Performance of Core Standby Coolant System - Equipment Cooling Water (CSCS-ECWS) Pump Operation," addressed the effects of simultaneous operation of RHRSW on the room cooler performance. Subsequently this calculation was updated to account for the "Keep-Fill" cross connections (refer to Unresolved Item 96011-19 concerning RHR Heat Exchanger Water Hammer) and Revision 1 was Approved on November 1, 1996.

This calculation demonstrates that adequate flow goes to the various room coolers (1/2VY01A, 1/2VY02A, 1/2VY03A and 1/2VY04A) under the bounding conditions listed below. Certain conditions exist under the design basis configuration of the Core Standby Cooling System (CSCS) (when it must be capable of supplying design basis flow to each CSCS load) that are not duplicated under normal or special surveillance test conditions. The purpose of this calculation is to determine the correction factors to be applied to the CSCS pump flow Acceptance Criteria to ensure that the test results are valid and comparable to the flow required under design conditions. The conditions that were evaluated are as follows:

1. Difference in lake level at the time of the test versus the design basis of 690 feet above mean sea level assuming loss of the main dike, leaving only the Ultimate Heat Sink.

2. Suction pressure considerations due to the use of the 54" CSCS bypass line around the traveling screens with all CSCS pumps operating (versus the test condition supply to the service water tunnel through the traveling screens and the six 36" service water tunnel inlet lines).

3. Suction pressure considerations due to additional CSCS Equipment Cooling loads on the train being tested that would be running during and after an accident and that are not running during the test.

4. While the test is conducted with clean strainers, those strainers could be partially plugged during design conditions.

5. Discharge pressure considerations (due to additional CSCS Equipment Cooling loads on the tested train, plus those on the same train of the opposite unit from the one being tested), that would be running under design conditions (but not during the test), and that would be discharging into the common discharge line with the train being tested.

6. Operation with Strainer Backwash flow in operation.

7. This calculation also evaluates the impact of Design Change Packages (DCP) 9600195 and 9600198 on the Division 2 CSCS. These DCPs provide a keep fill line connecting each Unit's Division 2 DGCW system to it's respective Division 2 RHR WS system piping.

Also, LaSalle is conducting a design review of the RHRWS system as part of the System Functional Performance Review program. This review began on November 12,1996, and is performed by a team of senior industry experts. This review is to confirm the consistency of the design basis, technical specifications, UFSAR, procedures, design documentation, surveillances and the physical plant. This will be completed by January 31, 1997. LaSalle will implement any required design changes identified by this self initiated review prior to restarting the Units from L2R07 and L1F35.

Part 2 - M2.10:

The inspectors reviewed the results for the safety-related "VY" room coolers. The inspectors observed that the flow rates through the coolers were considerably above the design flow rate (the worst case, for the 4A coolers on Unit 1, was 2.4 times the design flow). As discussed in Section E1.10, the inspectors reviewed the pump curves and determined that two of the pumps (the 0 DGCW and the high pressure coolant system (HPCS) DGCW pumps) were operating at the end of the pump curve (i.e., in a condition of high flow and low pressure). The test procedure provided a method to equate the dPs obtained back to the design flow rate, and the plotted dPs were compared to determine if any trends were developing.

The inspectors discussed with the system engineer a concern regarding maximum flow through the 1A and 4A room coolers for both units. Because all four room coolers receive cooling water from the 0 DGCW pump, the inspectors were concerned that unbalanced flows could result in (1) less than design flow through the 1A coolers and (2) tube erosion in the 4A coolers. For the first concern, the inspectors noted that the most recent surveillances demonstrated that flows through both 1A coolers were above design; therefore, this was not an immediate concern. In response to the second concern, the licensee responded that the manufacturer specified a flow velocity limit of 12 feet per second and calculation VY-12 demonstrated that tube velocity was below that value.

The inspectors reviewed calculation VY-12, "Evaluation of VY Cooler Tube Velocity Based on Test Data." As the name implied, this calculation evaluated the maximum velocity in the tubes using the highest flow rates obtained as of September 1993. The inspectors noted that higher flow rates were seen on at least one cooler during its 1995 surveillance test. The inspectors asked the licensee if any bounding calculation had been performed to determine the maximum flow through the coolers which would not exceed the manufacturer's velocity limits. The licensee replied that no bounding calculation had been performed.

Using the standard formula for determining flow (area times velocity), the inspectors determined a maximum flow value at a velocity of 12 feet per second. The inspectors then confirmed that none of the coolers had exceeded this value. The inspectors confirmed the validity of the formula by calculating the velocity for the flows used in the licensee's calculation and comparing them with the results of the calculation. For coolers 1A, 2A, and 3A, the velocity calculated by the inspectors agreed with the value obtained by the computer program used in the licensee's calculation.

For the 4A coolers, the inspectors noted that the calculation treated them as two separate coolers, with half the flow going to each "sub" cooler. The velocity through each "sub" cooler was then calculated. Therefore, the inspectors calculated the velocity for each 4A cooler using half the total flow.

The inspectors' calculated value, however, was exactly double what the licensee's calculation determined. The system engineer, when questioned, could not explain why this was the case. The engineer stated that one of the "sub" coolers was identical to the 1A coolers.

Conclusions: The inspectors concluded that the accuracy of the calculated velocities for the 4A coolers was questionable. The inspectors further questioned the calculation's conclusion that the maximum velocity would not be exceeded even if all the flow went through one of the 4A "sub" coolers. The licensee was requested to provide additional information about the 4A cooler and the formula used to calculate the velocity to support the calculation's results. This is an unresolved item
dependent upon NRC review of the calculations' formula for the 4A cooler and determination as to whether the maximum flows for the 4A cooler were acceptable
(50-373/96011-12(DRS); 50-374/96011-12(DRS)).

Response:

The 1(2)VY01A and 1(2)VY02A coolers consist of 2 coils each having a full serpentine coil arrangement with 8 tubes in the airflow direction and 20 tubes per row. This results in a total of 20 cooling water flow circuits per coil and since the coils are connected in parallel, this results in a total of 40 cooling water flow circuits per cooler.

The 1(2)VY04A coolers consist of 4 coils each having a double serpentine coil arrangement. Two of the coils have 8 tubes in the airflow direction and 20 tubes per row. Due to the double serpentine arrangement, this results in a total of 40 cooling water flow circuits per coil. The other two coils have 4 tubes in the airflow direction and 20 tubes per row. Due to the double serpentine arrangement, this results in a total of 40 cooling water flow circuits per coil. Since all 4 coils are connected in parallel, this results in a total of 160 cooling water flow circuits per cooler.

The 8 row coil for the 1(2)VY04A coolers have the same physical dimensions as the 1(2)VY01A and 1(2)VY02A coolers. However, since the 1(2)VY04A coolers are of the double serpentine coil arrangement, it has twice the number of cooling water flow circuits as does the 1(2)VY01A and 1(2)VY02A coolers which have a full serpentine coil arrangement.

Calculation VY-12 accurately models the VY cooler configurations and determines the correct cooling water tube velocity for the assumed 50% flow distribution between the 4 row and the 8 row coils of the 1(2)VY04A coolers to be 4.4 fps. This is well under the 12 fps maximum allowable tube velocity. The calculation did not determine the exact cooling water flow distribution between the 4 row and the 8 row coils of the 1(2)VY04A coolers, but the calculation allowed for this variation by concluding that even if 100% of the measured flow went to either of the 4 row or to the 8 row coil, the maximum

calculated cooling water tube velocity (8.8 fps) would still be under the 12 fps maximum allowable tube velocity.

We have independently verified the results of Calculation VY-12 via separate analysis.

The following document is available for review at LaSalle County Generating Station:

1. Calculation VY-12, Rev. 0, approved September 13, 1996, titled: "Evaluation of VY Cooler Tube Velocity Based on Test Data."

Unresolved Item 96011-16:

The inspectors noted that surveillances did not measure or otherwise account for lake level, which normally was around an elevation of 700 feet. This appeared to mean that an indicated value of 7400 gpm during surveillances would actually be below the design basis requirement. The inspectors did not have an operability concern because the recorded measured flow rates have consistently been above 7800 gpm. However the inspectors were concerned that surveillance tests, such as LTS-200-3, "RHR Tubeside DP Testing," which verified the design flow of 7400 gpm, might be inadequate, because they did not account for lake level. This is considered an unresolved item, awaiting the licensee determining the effect of the lake level on the surveillance procedures (50-373/96011-16(DRS); 50-374/96011-16(DRS)).

Response:

Correction factors for cooling lake level have not been included in surveillance procedures. This approach has been determined to be incorrect and is being evaluated within our corrective action program. A Problem Identification Form has been initiated. For example, LOS-RH-Q1 "RHR (LPCI) & RHR Service Water Pump & Valve Inservice Test For Tube Side Operational Conditions 1,2,3,4, and 5" verifies RHR heat exchanger tube side flow exceeds 7400 gpm and verifies that the RHRWS pumps meet ASME Section XI requirements but does not either correct for cooling lake level or specify a flow rate which would be satisfactory regardless of lake level.

We will be reviewing all applicable surveillance procedures for systems important to safe and reliable operation as part of the ongoing System Functional Performance Review program, and will ensure that these procedures include adequate prerequisite requirements and acceptance criteria, or in lieu of acceptance criteria, the specific actions to be taken to review the data and whether any immediate actions are required.

Unresolved Item 96011-19:

The review indicated that generally, the CSCS contained adequate provisions to preclude multiple division failures resulting from a single source failure. However, two instances were identified where this did not appear to be the case; one of which was resolved prior to the end of the inspection.

The first potential single failure was a possible water hammer event in the RHR heat exchangers which could result in tube damage. The heat exchangers were normally lined up to allow water from RHR into the shell side of the heat exchanger. Because RHRSW was manually initiated and did not normally run, the tube side would depressurize below atmospheric pressure as a result of the relative elevations of the tubes versus the ultimate heat sink elevation. If the lake was at the design basis low level of 690 feet, voiding would be present in the tubes under normal operating conditions. If the lake were at its normal level of 700 feet, boiling would occur in the heat exchanger within seconds of RHR being initiated in its injection mode. Once RHRSW was manually started, the steam voids would rapidly collapse as they were condensed by the cold RHRSW, causing a water hammer which could break tubes in both heat exchanger tubes in both RHR divisions. This could have rendered both trains of RHR inoperable. The licensee responded that a water hammer would occur as postulated by the inspectors. As of the end of the inspection, the licensee had not determined the effect of the water hammer on the tubes. This is considered an unresolved item, pending completion of the licensee's determination and associated operability analysis (50-373/96011-19(DRS); 50-374/96011-19(DRS)).

Response:

The configuration of both the Division 1 and the Division 2 RHR heat exchangers is essentially the same. However, the configuration of the Division 1 RHRWS piping is different from the Division 2 RHRWS piping for both Units. Because of these differences, the affect of a postulated water hammer in the system is different, as described below:

Division 1

Due to the physical configuration of the Unit 1/2 Division 1 Residual Heat Removal Service Water (RHRWS) systems, the only location within the system where the postulated water hammer event can occur is in the upper elevation of the RHR heat exchanger tubes. Since the pressure in the top of the highest elevation tube is slightly greater than the fluid pressure at normal conditions with the RHRWS pumps off, voiding and subsequent water hammer will not typically occur in the Division 1 RHRWS systems. However if the RHR heat exchanger tubes are heated prior to starting the RHRWS pumps, the vapor pressure could be higher than the fluid pressure

in the top of the RHR heat exchanger tubes. Such heating could occur during the initial stages of the LPCI injection when the suppression pool water has been heated up due to a LOCA or SRV blowdown. The situation could be aggravated if the lake level dropped, for example following a dike failure. In these cases the voiding could occur in the tube high points.

To ensure that the Division 1 RHRWS systems meet their design function in the unlikely event of a water hammer in the tubes of the RHR heat exchanger, a series of analyses have been completed:

A. General Electric (GE) performed an analysis in October 1996, to develop conservative water hammer pressure pulses resulting from a worst case water hammer event in the RHR heat exchanger tubes. Actual pressure pulse values resulting from any water hammer within the heat exchanger tubes are expected to be significantly lower than that calculated in the GE bounding analysis. Additionally, GE evaluated the impact of the conservative water hammer pressures on the RHR heat exchanger.

   GE concluded that the bounding water hammer pressures which could occur in the RHR heat exchanger tubes and water box were sufficiently low that they will not exceed the heat exchanger design allowables. Use of the more realistic water hammer pressures would further strengthen this conclusion.

B. Sargent & Lundy (S&L) performed an analysis which provided further confirmation of the adequacy of the RHR heat exchanger following a postulated water hammer in the heat exchanger tubes. Again, conservative water hammer pressure pulses were utilized. Actual water hammer loadings are expected to be significantly less than that considered.

   The conclusion of this analysis was that the stresses in the RHR heat exchangers are within design basis code allowables for the increase in pressure due to the potential water hammer in the RHR heat exchanger tubes.

C. S&L performed evaluations of the impact on the piping, equipment and supports of the Unit 1 and 2 Division 1 RHRWS system as a result of the conservative water hammer event in the RHR heat exchanger tubes. This evaluation concluded that the stresses in the system piping, valves, penetration, strainer and pumps and supports are within applicable Code allowables.

In addition to the above, an operability evaluation will be completed prior to startup to document that Division of RHRWS will remain operable in all reactor modes in its current condition. The RHRWS is operable in the current shutdown condition.

A series of analyses have been completed which are available onsite for review and include:

1. GE (F. Moody, B. Hughes) to ComEd (J. Rommel) Letter, October 1, 1996. Subject: LaSalle RHR Heat Exchanger Postulated Water Hammer

2. NDITLS-0397 Upgrade 2, October 24, 1996, "Potential for Water Hammer in the Tubes of the RHR Heat Exchanger and the Associated Forces"

3. LAS-ENDIT-0270, November 7, 1996, "RHR Heat Exchanger Water Hammer Assessment"

4. LAS-ENDIT-0275, December 6, 1996, "Assessment of Effects of Postulated RHR Heat Exchanger Water Hammer on Units 1 and 2 Division 1 Piping, Equipment and Supports - Non Design Basis"

5. Calculation L-000715, Rev 0 dated November 14, 1996 & Rev. 1 dated December 5, 1996, "Evaluation of Potential Water Hammer Event on RHR Heat Exchanger Service Water (CSCS) Piping Subsystems in Units 1 & 2"

6. Calculation L-000857, Rev. 0 dated December 2, 1996 & Rev. 1 dated December 5, 1996, "Assessment of Pipe Supports and RHR Heat Exchanger Support, Strainer Foundation, Sleeves and Buried Pipe for Water Hammer Loads - Units 1 & 2"

7. Calculation L-000731, Rev. 0 dated November 12, 1996, " Evaluation of RHR Heat Exchanger for Water Hammer Effect"

8. Calculation L-000854, Rev. 0 dated November 12, 1996 & Rev. 1 dated December 5, 1996, "Evaluation of RHR Heat Exchanger, Strainer, Pumps, Valves and Penetrations for Nozzle Load due to Postulated Water Hammer in Heat Exchanger"

Division 2

The physical configuration of the Units 1 and 2 Division 2 RHRWS system allows for the potential for a water hammer event to occur in the inlet piping to the heat exchanger as well as the heat exchanger tubes. The Division 2 piping has a loop in which the piping has a vertical rise and drop before terminating at the RHR heat exchanger inlet nozzle. This loop exists to provide a straight run of pipe necessary to assure the accuracy of flow measuring instrumentation. The piping/pipe supports have not been shown analytically to be able to withstand (within design allowables) water hammer originating in the piping. A keep fill system with cross ties to both WS and DGWC has been designed for both Division 2 RHR-WS systems to maintain the piping system full and thus eliminate the potential for a water hammer during design basis events. These design changes are documented in DCPs 9600195 (Unit 1) and 9600198 (Unit 2) and will be implemented prior to restart from L1F35 and L2R07 respectively.

DCPs 9600195 and 9600198 have been initiated to add two cross ties to each Division 2 RHRWS system to ensure that it is kept filled and pressurized. One cross tie is from the Service Water (WS) system, the other is from the DGCW system. This modification will prevent the formation of voids by keeping the Unit 1 and Unit 2 Division 2 -WS systems filled and pressurized to above the saturation pressure. Two cross ties are required because the WS system is non-safety-related and cannot be relied upon in the event of an accident, Loss of Offsite Power (LOOP), or seismic event. The DGCW system is safety-related, but does not operate continuously. It operates whenever the emergency diesel generators are running or when the ECCS pumps (including RHR) are running. Therefore, the cross tie from WS will keep the RHRWS system filled during normal operation, while the cross tie from DGCW will keep it filled in the event of an accident or LOOP.

Additional design or operational changes are being implemented during L1F35 and L2R07 respectively, to ensure the RHRWS system is not depressurized below water saturation pressures include:

1. An annunciator alarm will provide notification to the control room operators if the keep fill cross tie is not keeping the Division 2 RHRWS system pressurized and filled.

2. Should the periodic (every 8 hours) RHRWS strainer backwash cycle auto initiate while the RHRWS pumps are in standby, the backwash discharge valve would open, which would allow the keep fill flow to be diverted out the backwash

discharge line instead of keeping the RHRWS system filled and pressurized. Therefore, an interlock will be added to the control logic of the RHRWS strainer backwash to permit initiation of the periodic (once every 8 hours) automatic backwash cycle only if the RHRWS pumps are running.

3. The pump startup procedures will be revised to ensure that a RHRWS pump is started before valve 1(2)E12-F068B is opened. Should the RHRWS pumps be started after the 1(2)E12-F068B valve is open, the keep fill system would not be able to maintain the RHRWS system filled and voiding could occur. The piping will begin to void when the flow rate across valve 1(2)E12-F068B exceeds the keep fill rate plus the pump flow rate (the pump flow rate is initially zero). To preclude the possibility of water hammer, it is necessary to ensure that a RHRWS pump is running before the flow across the valve exceeds the keep fill flow rate.

Following the addition of the above changes, the Division 2 RHR-WS will meet the required design function and be operable during all reactor modes. Prior to operability of the keep fill cross ties, the Division 2 RHR-WS system remains operable for operating conditions 4, 5 and defueled. The determination that the design of Division 2 was not consistent with design basis in Modes 1,2 and 3 was reported to the NRC by 10CFR50.72 on December 17, 1996.

Unresolved Item 96011-20:

The inspectors noted an issue open from 1987 to July 1996. The issue related to a potential fire in a corridor where control panels for all three EDGs were located. The fire could render all three division EDGs inoperable. The action taken in 1987 was initiation of an hourly fire watch and origination of a modification request to install physical protective barriers. However, due to concerns with fire retardant materials, the modification package was put on hold in 1991 and was canceled in September of 1996.

The basis for canceling the modification was establishment of an alternative shutdown path: core cooling by the reactor core isolation cooling system, which did not require EDG operation. Other longer term actions, such as cooling the suppression pool, would be handled by cross-tying the emergency busses to the other unit. This assumption and the analysis was previously approved by the NRC for the Station Blackout issue.

The inspectors questioned the licensee on the adequacy of the compensatory actions in place from 1987 to 1996 and what guidance would have been available to the operators had a fire occurred during this nine-year period. The focus of the inspectors' concerns was on why the licensee required the EDGs to operate, as 10 CFR Part 50, Appendix R, did not require a licensee to assume that offsite power was lost, unless the fire caused it to be. The licensee stated that assuming loss of offsite power was a conservative measure. However, neither the original (1987) fire hazard analysis contained in Appendix H of the UFSAR, nor the revision proposed in 1996, stated that a conservative assumption of loss of offsite power had been applied. Therefore, the inspectors inquired whether the licensee had confirmed that offsite power cables either would or would not be affected by a fire in the zone.

Conclusions: The lack of compensatory actions for a nine-year period could be a significant failure to take adequate corrective actions. The significance, however, depended on whether offsite power would be affected for a fire in the EDG corridor. Although the licensee claimed that loss of offsite power was a conservative assumption, this was not reflected in either the original fire hazards analysis nor in the 1996 revision. The inspectors requested that the licensee respond in writing providing evidence to support the assertion that a fire in the EDG corridor would not result in loss of normal power to the affected components. This is considered an unresolved item, pending the licensee's response (50-373/96011-20(DRS); 50-374/96011-20(DRS)).

Response:

The design basis for postulating a fire simultaneously with a LOOP is documented in the SAFE Shutdown Analysis, Section H.4.1.5.c.

UFSAR Section H.4.2.57 (Safe Shutdown Analysis for Fire Zone 5C11) and associated tables were recently revised to add a new safe shutdown path that has been established for use in the event that there is a fire in Fire Zone 5C11. This satisfies the requirements of Appendix R to 10 CFR Part 50. Procedures were in place for Operations to establish unit crossties to either Unit for offsite power. In the event a fire in either Unit 1 or Unit 2 diesel generator corridors, caused by a loss of auxiliary power, operating procedures were available to direct operators in the restoration of offsite power sources. Specifically, LOA-AP-101 (Unit 1) and LOA-AP-201 (Unit 2) are used to establish unit crossties which can be implemented within 4 hours of the initial event.

Procedures LOA-AP-07, "Loss of Auxiliary Electrical Power," and LOA-AP 08, "Total Loss of AC Power," (which were superseded by Procedures LOA-AP-101 and LOA-AP-201) were available prior to 1987. They provided direction to establish unit crossties to either Unit for offsite power and to initiate RCIC in case of loss of all AC power.

Normal (offsite) power is supplied from the System Auxiliary Transformers (SAT) to the safety related 4.16-kV Buses 141Y, 142Y, 143, 241Y, 242Y and 243.

For the purpose of determining whether normal offsite power is affected by a fire in the diesel generator corridors, it is also necessary to identify all electrical connections that are needed in providing power to the subject divisional buses. These electrical connections include, 1) the 4.16-kV non-segregated phase bus ducts that supply power from the SAT's to the divisional buses; 2) the cables that are required to control and protect the feed circuit breakers from the SAT's to the divisional buses; 3) the cables required to maintain operability for the SAT's. Specifically, these cables primarily makeup the protective relaying circuits and transformer cooling systems for the SAT's.

The results of this evaluation, as documented in LAS-ENDIT-0297, conclude that there are no cables (or instruments) routed in these areas that are required to maintain offsite power to the divisional buses.

It is also noted that each unit's 4.16-kV non-segregated phase bus ducts connecting the divisional buses to the SAT's are routed in each unit's respective diesel generator corridor. However, a fire in these areas would not prevent these electrical connections from performing their functions (e.g., supplying power from the SATs to the divisional buses) on the following basis:

1. The non-segregated phase bus conductors are uninsulated, aluminum, tube-type conductors. The bus insulators are porcelain type construction. The bus supports, channels and bus connection hardware are metallic components. The bus enclosure is manufactured from sheet metal steel. Therefore, the entire bus assembly consists of materials that are non-combustible.

2. The diesel generator corridors are provided with fire detection and automatic suppression (water) systems. In the event of a fire, the suppression system would operate minimizing the exposure of the bus ducts to the fire. The bus duct enclosures are made of drip-proof, non-ventilated construction, that are provided with drains at various sections to eliminate any condensation or moisture that could occur internally. Therefore, the bus conductors would not be exposed to any direct water sprays or internal water accumulation and, hence, are not expected to fail during or after operation of any fire suppression systems.

3. The primary combustibles in the diesel generator corridors consist of electrical cable insulation routed in solid bottom/open top cable trays. The Division 2 power and control cable trays in each DG corridor are provided with a Darmatt Type KM1, one hour rated fire barrier. This was done to meet the requirements of 10CFR50.48 and to achieve separation between redundant electrical systems. The use of these barriers is part of the Station's overall Fire Protection program which is an operating license condition and a licensing commitment for the Station specified in the LaSalle UFSAR, Appendix H, Section H.4, "Safe Shutdown Analysis". Therefore, the cables routed in these trays are protected from fires and will not initiate nor support a fire in these areas.

   The Unit 1 DG corridor includes four additional cable trays. These consist of the Unit 1, Division 1, power and control trays, and the Unit 1, non-divisional power and control cable trays. The Unit 2 DG corridor includes two additional cable trays. These are the Unit 2, Division 1 power and control cable trays. While none of these trays are provided with a fire barrier, the cables in these trays are qualified to meet the

Vertical Burner Flame Test per IEEE 383-1974. Therefore, an electrically initiated fire in these exposed cable trays will not propagate.

In addition, the exposed cable trays in the Unit 2 DG corridor are located approximately 1 foot above and approximately 5 feet across (parallel) from the SAT non-segregated phase bus ducts. In the Unit 1 DG corridor, the exposed cable trays are located approximately 6 inches above and approximately 2 feet across (parallel) from the SAT non-segregated phase bus ducts. The entire corridor areas are provided with an early warning fire detection and automatic sprinkler systems. The fire detectors and automatic sprinklers are optimally located to detect and suppress fires. They are located in the higher elevations of the corridors in close proximity to the cable trays. Therefore, the impact of a fire in an exposed cable tray relative to the bus ducts is minimized by the physical location of the exposed cable trays to the bus ducts, in addition to the automatic detection and suppression systems

In summary, normal offsite power will not be affected by a fire in these areas primarily attributed to having no cables (or instruments) routed in these areas associated with providing offsite power from the SAT's to the divisional buses. In addition, these areas have a minimal amount of combustibles to support a sustained fire. In the unlikely event of a fire, both diesel generator corridors are provided with fire detection and suppression systems available to detect and mitigate the consequences of a fire.

Although the 4.16-kV SAT power feeds to the divisional buses are routed in this area, this equipment is non-combustible, and is expected to perform its function in the event of a fire and its subsequent detection and suppression. In addition, exposed cables meet the requirements of IEEE 383-1974 and the physical orientation of the exposed cable trays to the bus ducts minimize the impact of a cable tray fire relative to the bus ducts.