UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

February 15, 2011

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO), Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2 COMPONENT DESIGN BASES INSPECTION (CDBI) 05000373/2010006(DRS); 05000374/2010006(DRS)

Dear Mr. Pacilio:

On January 3, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed a component design bases inspection at your LaSalle County Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed during an interim exit meeting on November 19, 2010, with the Director of Engineering Mr. Harold Vinyard and other members of your staff, and during a subsequent discussion on January 3, 2011, with Mr. T. Simpkin.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, four NRC-identified findings of very low safety significance were identified. The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of any NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the LaSalle County Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the LaSalle County Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Ann Marie Stone, Chief
Engineering Branch 2
Division of Reactor Safety

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

Enclosure: Inspection Report 05000373/2010006; 05000374/2010006
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-373; 50-374
License Nos:	NFP-11; NFP-18
Report No:	05000373/2010006(DRS); 05000374/2010006(DRS)
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles, IL
Dates:	October 18, 2010 through January 3, 2011
Inspectors:	Z. Falevits, Senior Reactor Engineer, (Team Lead) D. Szwarc, Reactor Engineer, Mechanical J. Gilliam, Reactor Engineer, Electrical R. Walton, Reactor Engineer, operations J. Neurauter, Senior Reactor Engineer, Structural G. Skinner, Electrical Contractor S. Spiegelman, Mechanical Contractor D. Passehl, Senior Reactor Analyst
Approved by:	Ann Marie Stone, Chief Engineering Branch 2 Division of Reactor Safety

Enclosure

SUMMARY OF FINDINGS

Inspection Report (IR) 05000373/2010006(DRS); 05000374/2010006(DRS); 10/18/2010 – 01/03/2011; LaSalle County Station, Units 1 and 2; Component Design Bases Inspection.

The inspection was a 3-week on-site baseline inspection that focused on the design of components that are risk-significant and have low design margin. The inspection was conducted by regional engineering team and two consultants. Four Green findings were identified by the team. The findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The team identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to have an adequate calculation to demonstrate the seismic qualification of the standby liquid control (SBLC) system test tanks. Specifically, the licensee could not ensure that the Units 1 and 2 SBLC test tanks, if filled with water, would not collapse and damage nearby safety-related components during a design basis event. The licensee entered this finding into their corrective action program and drained the water from the SBLC test tanks to restore seismic qualification.

  The team determined that this finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability of the SBLC system to respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was determined to be of very low safety significance (Green) utilizing the Risk-Assessment Standardization Project Handbook based on the frequency of seismic events. The finding did not have a cross-cutting aspect because it was not reflective of current performance. (Section 1R21.3.b.(1))

- Green. The team identified a finding of very low safety significance and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control" for the licensee's failure to account for allowable frequency variations on the emergency diesel generators (EDG) in the diesel fuel oil consumption and residual heat removal (RHR) pump net positive suction head (NPSH) calculations. Specifically, the team noted the calculations assumed a frequency of 60 Hz whereas the Technical Specifications (TS) allowed steady state operation at a frequency of up to 61.2 Hz. The licensee entered this finding into their corrective action program and implemented a standing order and procedural limitations to ensure an adequate supply of fuel was available.

The team determined that this finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of the EDGs to respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, operating the EDGs at a frequency of 61.2 Hz would result in higher fuel consumption and reduced RHR pump NPSH margins. The finding is of very low safety significance (Green) because it did not result in a loss of operability. This finding had a cross-cutting aspect in the area of problem identification and resolution, operating experience because the licensee did not properly evaluate relevant operating experience. (P.2(a)) (Section 1R21.3.b.(2))

- Green. The team identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to have appropriate analyses for the loss of voltage relay setpoints and the second level undervoltage [degraded voltage] relay timer settings. Specifically, licensee's analysis and technical basis for the auxiliary power system (AP) second level undervoltage relay time delay settings failed to demonstrate the ability of the permanently connected safety-related loads to continue to operate during the 5.5 minutes relay time delay without sustaining damage during a worst case, non-accident degraded voltage condition (when voltage was still above the setpoint of the loss of voltage relay setpoint). The licensee entered this finding into their corrective action program to verify the adequacy of the degraded voltage relay setpoint and time delay design.

  The team determined that this finding was more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, there was reasonable doubt as to whether the permanently connected safety-related loads would remain operable during a worst case, non-accident degraded voltage condition for the duration of the time delay chosen for the degraded voltage relay. The finding was of very low safety significance (Green) since the existing settings for the inverse time relay currently being used for the loss of voltage relay would limit the duration of degraded voltage below 75 percent to only a few seconds.

  This finding had a cross-cutting aspect in the area of problem identification and resolution because similar concerns raised at the Byron Nuclear Station, during the 2009 CDBI, were not promptly evaluated and correctly dispositioned at LaSalle. [P1(c)] (Section 1R21.3.b.(3))

- Green. The team identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to analyze the capability of the electrical system to transfer safety related 4160V buses as described in the Updated Final Safety Analysis Report (UFSAR). The licensee entered this finding into their corrective action program and issued a standing order restricting alignment of safety buses to the unit auxiliary transformer (UAT) pending resolution of this issue.

The team determined that this finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance (Green) since the safety buses had not been aligned to the UAT, the team determined the finding design deficiency did not result in loss of operability or functionality.

The team did not identify a cross-cutting aspect associated with this finding because the finding was not representative of current performance. (Section 1R21.3.b.(4))

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R21 Component Design Bases Inspection (71111.21)

.1 Introduction

The objective of the component design bases inspection is to verify that design bases have been correctly implemented for the selected risk significant components and that operating procedures and operator actions are consistent with design and licensing bases. As plants age, their design bases may be difficult to determine and an important design feature may be altered or disabled during a modification. The Probabilistic Risk-Assessment (PRA) model assumes the capability of safety systems and components to perform their intended safety function successfully. This inspectible area verifies aspects of the Initiating Events, Mitigating Systems, and Barrier Integrity cornerstones for which there are no indicators to measure performance.

Specific documents reviewed during the inspection are listed in the Attachment to this report.

.2 Inspection Sample Selection Process

The team selected risk-significant components and operator actions for review using information contained in the licensee's PRA and the LaSalle Standardized Plant Analysis Risk (SPAR) Model, Revision 3.45. In general, the selection was based upon the components and operator actions having a risk achievement worth of greater than 1.3 and/or a risk reduction worth greater than 1.005. The operator actions selected for review included actions taken by operators both inside and outside of the control room during postulated accident scenarios. In addition, the team selected operating experience issues associated with the selected components.

The team performed a margin assessment and detailed review of the selected risk-significant components to verify that the design bases have been correctly implemented and maintained. This design margin assessment considered original design reductions caused by design modification, or power uprates, or reductions due to degraded material condition. Equipment reliability issues were also considered in the selection of components for detailed review. These included items such as performance test results, significant corrective action, repeated maintenance activities, maintenance rule (a)(1) status, components requiring an operability evaluation, NRC resident inspector input of problem areas/equipment, and system health reports. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense in depth margins. A summary of the reviews performed and the specific inspection findings identified are included in the following sections of the report.

This inspection constituted 24 samples as defined in Inspection Procedure 71111.21-05, which included 16 components, 4 operating experience reviews and 4 operator actions.

.3 Component Design

a. Inspection Scope

The team reviewed the UFSAR, TS, design basis documents, drawings, calculations and other available design basis information, to determine the performance requirements of the selected components. The team used applicable industry standards, such as the American Society of Mechanical Engineers (ASME) Code, Institute of Electrical and Electronics Engineers (IEEE) Standards and the National Electric Code, to evaluate acceptability of the systems' design. The team also evaluated licensee actions, if any, taken in response to NRC issued operating experience, such as Bulletins, Generic Letters (GLs), Regulatory Issue Summaries (RISs), and Information Notices (INs). The review was to verify that the selected components would function as designed when required and support proper operation of the associated systems. The attributes that were needed for a component to perform its required function included process medium, energy sources, control systems, operator actions, and heat removal. The attributes to verify that the component condition and tested capability was consistent with the design bases and was appropriate may include installed configuration, system operation, detailed design, system testing, equipment and environmental qualification, equipment protection, component inputs and outputs, operating experience, and component degradation.

For each of the components selected, the team reviewed the maintenance history, system health reports, operating experience related information, vendor manuals, electrical and mechanical drawings, and licensee corrective action program documents. Field walkdowns were conducted for all accessible components to assess material condition and to verify that the as-built condition was consistent with the design. Other attributes reviewed are included as part of the scope for each individual component.

The following 16 components were reviewed:

- 4.16kV Switchgear 142Y (1AP06E): The team reviewed bus loading calculations to determine whether the 4160V system had sufficient capacity to support its required loads under worst case accident loading and grid voltage conditions. The team reviewed the design of the 4160V bus degraded voltage protection scheme to determine whether it afforded adequate voltage to safety related devices at all voltage distribution levels. This included review of degraded voltage relay setpoint calculations, motor starting and running voltage calculations, and motor control center (MCC) control circuit voltage drop calculations. The team reviewed procedures and completed surveillances for calibration of the degraded voltage relays to determine whether acceptance criteria was consistent with design calculations, and to determine whether relays were performing satisfactorily. Particular attention was devoted to the resolution of degraded voltage time delay issues previously identified at the Byron Nuclear Station. The team reviewed the fast bus transfer scheme, including drawings and procedures, to determine whether the transfer capability described in the UFSAR could be achieved without adverse effects on equipment and systems. The team reviewed operating procedures to determine whether the limits and protocols for maintaining offsite voltage were consistent with

design calculations. The team reviewed the LaSalle response to NRC Generic Letter 2006-02 to determine whether current procedures for maintaining the availability of offsite power were consistent with licensee responses. The team reviewed corrective action documents and maintenance records to determine whether there were any adverse operating trends. In addition, the team performed a visual inspection of the 4160V safety buses to assess material condition and the presence of hazards.

- System Auxiliary Transformer (SAT) 142, (1AP91E): The team reviewed load flow calculations to determine whether the capacity of the transformer was adequate to supply worst case accident loads. The team reviewed protective relaying schemes and calculations to determine whether the transformer was adequately protected, and whether it was subject to spurious tripping. The team reviewed maintenance schedules, procedures, and completed work records to determine whether the transformer was being properly maintained. The team reviewed corrective action histories to determine whether there had been any adverse operating trends. In addition, the team performed a visual inspection of the SAT to assess material condition and the presence of hazards.

- 125 Vdc Division 2 Battery (1DC14E): The team reviewed battery sizing, short circuit, voltage drop, and minimum voltage calculations in order to verify that the Unit 1 Division 2 battery is adequately designed to pick up the required loads during a loss of coolant accident (LOCA) and station blackout (SBO). Technical Specification (TS) values were also reviewed (i.e., specific gravity, electrolyte level, and temperature correction) and compared to the inputs, results, and assumptions of the calculations and procedures. The team also reviewed a sample of surveillance, service, performance, and modified performance test results and procedures to ensure that batteries are being tested in accordance with TS requirements and IEEE standards. A review of various discharge tests was performed to verify that the battery capacity was adequate to support the design basis duty cycle requirements and to verify that the battery capacity meets the requirements of the TS. In addition, maintenance procedures were reviewed to ensure maintenance activities (i.e., electrical termination/ connection, torque requirements, no-oxide grease, etc.), were being performed according to IEEE standards and vendor manuals. The team also completed a system walk down and reviewed corrective action documents, trend data, and System Health Report to determine material conditions of the batteries and if there was any indication of degradation.

- 125 Vdc Division 2 Battery Charger (1DC17E): The team reviewed electrical calculations associated with the safety-related Unit 1 Division 2 Battery Charger. These included sizing, voltage drop, and capacity calculation. The review verified methodology, design inputs, assumptions, and results. Battery Charger surveillance, corrective actions, and performance history were reviewed to ensure acceptance criteria were met and performance degradation would be identified. In addition, the test procedures were reviewed to determine whether maintenance and testing activities for the battery charger were in accordance with vendor's recommendations. The review also verified that the battery charger met the TS requirements. The electric capacitors of the battery charger were also reviewed to verify that they are being replaced within the frequency recommended by the

vendor. In addition, the physical and material condition of the charger was visually inspected and corrective action document were reviewed to verify identification of adverse trends.

- 1A Emergency Diesel Generator (EDG) Division 2 (1DG01K): The team reviewed selected mechanical support systems for the Division 2, 1A emergency diesel generator. These included diesel room cooling, lube oil, and jacket water cooling. The team conducted a field walkdown of the diesel generator to verify the ambient environmental and the material condition of the diesel generator. The team reviewed the design basis documentation, UFSAR and TS to ensure that design and licensing bases were met. In addition, the team interviewed system and design engineers and reviewed selected condition reports to assess the current condition of the diesel generator. The team reviewed diesel generator static loading calculations to determine whether the expected worst case loads during accident conditions were within the manufacturer's specified ratings. This included a review to determine whether the licensee had properly considered the effect of diesel generator frequency variations on loading. The team reviewed undervoltage logic and setpoints to determine where loads were subject to spurious load shedding while connected to the emergency diesels. The team reviewed the design and testing of the replacement voltage regulator to determine whether it was in conformance with the original design bases. The team reviewed the equipment system health reports, maintenance history and corrective action records to determine whether there had been any adverse operating trends. The team reviewed the design of the fuel oil transfer system to determine whether it was susceptible to common mode failure due to flooding through the floor drain system. The team performed a walkdown of the diesel generator to assess material condition, and the presence of hazards. This included an assessment of building ventilation and susceptibility of diesel generator support systems to damage from tornado depressurization.

- 1A EDG Fuel Oil Storage System (1DG01T): The team reviewed the system calculations including the storage and day tank set-points, loading and vortexing to ensure that the diesel fuel transfer pumps were capable of providing sufficient flow such that the day tanks remained filled during diesel operation. The team also reviewed calculations and drawings relating to fuel oil consumption and tanks sizing to ensure that the EDG fuel oil system was adequate to meet license and design basis requirements. The EDG fuel oil chemistry test results were reviewed to ensure the quality of the EDG fuel oil supply was being maintained and tested according to facility procedures and license requirements. In addition, corrective action documents were reviewed to verify identification of adverse trends.

- Low Pressure Core Spray (LPCS) Pump (1E21-C001): The team reviewed the LPCS pump to verify that the performance satisfied design basis flow rate requirements during postulated transient and accident conditions. To determine design basis performance requirements and operational limitations, the team reviewed design basis documents including calculations, operating instructions and procedures, system drawings, and surveillance tests. Surveillance test results were reviewed to determine whether established test acceptance criteria were satisfied. The team reviewed oil sample results to verify that they were within acceptance limits. Net positive suction head (NPSH) and submergence requirements were

reviewed to ensure satisfactory pump performance during transient and accident conditions. The team reviewed calculations related to pump cooling, vibration, pump capacity, minimum flow, and runout protection. The team also reviewed the pump vendor manual, pump curves, and piping and instrumentation diagrams. In addition, the team walked down the LPCS pump area to verify the ambient environmental conditions and the material condition of the pump and reviewed selected condition reports to assess the current condition of the pump. The team reviewed electrical load flow calculations to determine whether the LPCS pump motor had adequate voltage to start and run under degraded voltage conditions. The team reviewed the motor protective relaying scheme, including drawings, calculations and procedures to determine whether it was adequately protected, and whether it was subject to spurious tripping.

- LPCS Injection Isolation Valve (1E21-F005): The team reviewed motor operated valve (MOV) calculations and analysis to ensure the valve was capable of functioning under design conditions. The team reviewed the thrust, torque, differential pressure, and valve set-up calculations and weak link analyses. The team conducted a field walkdown of the valve to verify the installed configuration, accessibility to operators for manual operation, ambient environmental conditions, and the material condition of the valve. The team reviewed surveillance test results to determine whether testing, inspection, and maintenance were being performed in accordance with requirements. The team reviewed electrical load flow calculations to determine whether the valve had adequate voltage to start and run under degraded voltage conditions. The team reviewed the protective relaying scheme, including drawings, calculations and procedures to determine whether the MOV was adequately protected, and whether it was subject to spurious tripping under accident conditions.

- High Pressure Core Spray (HPCS) Injection Isolation Valve (1E22-F004): The team reviewed MOV calculations and analysis to ensure the valve was capable of functioning under design conditions. The team reviewed the thrust, torque, differential pressure, and valve set-up calculations and weak link analyses. The team conducted a field walkdown of the valve to verify the installed configuration, accessibility to operators for manual operation, ambient environmental conditions, and the material condition of the valve. The team reviewed surveillance test results to determine whether testing, inspection, and maintenance were being performed in accordance with requirements.

- 125 Vdc Division 3 Battery Charger (1DC19E): The team reviewed electrical sizing, voltage drop, and capacity calculations associated with the safety-related Unit 1 Division 3 Battery Charger. The calculation review verified methodology, design inputs, assumptions, and results. Battery charger surveillance, corrective actions, and performance history were reviewed to ensure acceptance criteria were met and performance degradation would be identified. The review also verified that the battery charger met the TS requirements. Test procedures were reviewed to determine whether maintenance and testing activities for the battery charger were in accordance with vendor's recommendations. The physical and material condition of the charger was visually inspected and corrective action document were reviewed to verify identification of adverse trends. In addition, electric capacitors of the

battery charger were also reviewed to verify that they are being replaced within the frequency recommended by the vendor.

- 1B Residual Heat Removal (RHR) Pump (1E12-C002B): The team reviewed the residual heat removal pump to verify that the performance satisfied the design basis flow rate and pressure requirements during postulated transients and design basis conditions that are specified in the design calculations and UFSAR. The team performed a walkdown of the pump and pump room to evaluate the observable condition of the pump and pump motor and adjoining components. The team reviewed the design calculations to determine if all limiting design conditions were identified including pump flow and NPSH. The team interviewed the design engineers to determine how the NSPH responded to excess speed of the RHR motor due to an industry issue regarding increased frequency of the emergency diesel generator. Further the design conditions and operating parameters were compared with surveillance testing to evaluate both current performance and trends. Operating, testing and maintenance procedures were compared with work orders and pump and motor instruction manuals to verify that manufacturer recommendations were integrated into the procedures. The NPSH calculation was reviewed including the water supply, resistance from the suppression pool filter, debris on the filter, piping resistance and fluid conditions to assure that the pump would not cavitate during operation. Corrective actions were reviewed including operability assessments, response to vibration testing, and industry issues to determine if appropriate and timely action is taken to resolve performance issues. In addition, the team reviewed electrical load flow calculations to determine whether the 1B RHR pump motor had adequate voltage to start and run under degraded voltage conditions. The team reviewed the motor protective relaying scheme, including drawings, calculations and procedures to determine whether it was adequately protected, and whether it was subject to spurious tripping.

- 1B RHR Heat Exchanger Bypass Valve (1E12-F048B): The team reviewed MOV calculations and analysis to ensure the valve was capable of functioning under design conditions. The team reviewed the thrust, torque, differential pressure, and valve set-up calculations and weak link analyses. The team reviewed surveillance test results to determine whether testing, inspection, and maintenance were being performed in accordance with requirements.

- Containment Vacuum Breaker (1PC001A): The team reviewed the containment vacuum breaker to assure that there is sufficient area in the component between the suppression pool and the dry well, during postulated events, to preclude excessive pressure on the drywell floor. The team interviewed the responsible design and system engineers to determine the recent operating condition of the vacuum breaker and to evaluate the response to recent corrective actions. The team reviewed the pressure transients of the suppression pool and the dry well to determine if the pressure exceeded the allowable upward and downward pressure requirements. Further, the team evaluated the impact on the pressure transients from the measurement uncertainty recapture (MUR) uprating to determine if the original calculation remained bounding or if the uprating pressures increased the floor loading. The team evaluated the pressure loading on the vacuum breaker mechanical components to assure that the vacuum breaker would continue to function following the pressure loading. Also, the team reviewed the results from

periodic functional tests of the vacuum breaker to evaluate the sealing of the vacuum breaker. Finally, the team performed a walk down of the region adjacent to the vacuum breaker to determine the access to the breaker in the event that it needed to be manually isolated due to a stuck open condition.

- Control Room Heating Ventilation and Air Conditioning (HVAC) System (0VC05CA): The team reviewed the control room ventilation system to assure that it would function during normal operating conditions and during a design basis accident. In particular the team reviewed the HVAC compressors to access the actions that had been taken to respond to a trend of negative compressor performance. The team reviewed a root cause report to determine if the recommendations were implemented and effective. The team reviewed the tracer gas tests to evaluate if the control room atmosphere would remain habitable following a design basis accident. Corrective action documents issued from the test were reviewed to assure that identified in-leakage adequately repaired. The team met with the control room HVAC engineer to inquire about the equipment operational performance and the venting of the control room following a postulated control room fire. The team walked down the control room and adjacent auxiliary building to assure that there were no critical components in the region exterior to the control room that would be required following the venting of the control room.

- 1B RHR Heat Exchanger (HX) (1E12-B001B): The team inspected the RHR HX to assure that it would have sufficient heat transfer capacity during a design basis accident. The team reviewed the heat exchanger design calculations to evaluate the flow requirements from the RHR service water pump and the RHR pumps to assure that there was sufficient cooling capacity water delivered to the heat exchanger. The team interviewed the design and system engineers to assess current operations and performance trends. The team also evaluated the test procedures and results from the heat exchanger surveillance tests to evaluate the heat exchanger performance. Finally, the team reviewed the hydrodynamic loading and corresponding impact on the heat exchanger from a bubble collapse water hammer to assure that the heat exchanger could withstand the water hammer event.

- Standby Liquid Control (SBLC) System Relief Valve 1C41-F029A: The team evaluated the SBLC system relief valve to assure that it would not prematurely open during a design basis accident due to system over pressure. The team met with the systems and design engineer to determine how they responded to an industry issue that identified the potential premature valve opening. The team reviewed an analysis that was performed by LaSalle engineers that defined a need for a valve setpoint change. The team also reviewed the design change documents that implemented the design change. The team reviewed the valve manual and system operating procedures to evaluate system operating performance. In addition, the team reviewed the pressure testing of the system prior to and after the design change to assure that the issue was fully addressed. The team walked down the system and reviewed the valve and adjacent components. In addition the team inquired about the supports for the test tank during a seismic event.

b. Findings

(1) Supporting Structure for Standby Liquid Control (SBLC) System Test Tank Non-Functional During Postulated Design Basis Earthquake (DBE)

Introduction: The team identified a finding of very low safety significance (Green) and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the failure to have an adequate calculation to demonstrate the seismic qualification of the standby liquid control (SBLC) system test tanks. Specifically, the licensee could not ensure that the SBLC system test tanks, if filled with water, would not collapse and damage nearby safety-related components during a DBE.

Description: The SBLC system test tanks in Units 1 and 2 are used to test flow in the SBLC system. The test tanks are classified as non-safety related and are located nearby safety related SBLC system components. During the inspection, the team identified that the test tanks were three-quarters full of water. The licensee's procedure LOS-SC-Q1, "SBLC Surveillance Pump Test, Attachments 1A, 1B, 2A, and 2B," allowed the water level in the test tanks to be maintained at 75 percent following testing. The team reviewed design calculation EMD-030015, "Foundation Loads for Standby Liquid Control Test Tank," which evaluated the seismic adequacy of the test tank supporting structure. The team noted that calculation EMD-030015 only evaluated the 5/8 inch test tank anchor bolts as the limiting structural component for the tank support design and concluded that these anchor bolts were structurally adequate for the seismic reaction forces determined in the calculation. The team informed the licensee of a very similar issue which was identified at the River Bend Nuclear Station in 2009 and questioned the licensee as to why other components of the test tank supporting structure were not evaluated at LaSalle. The licensee issued IR 01129847 to document and evaluates these concerns.

The team identified errors in calculation EMD-030015 including incorrect and non-conservative properties that were used for the structural angles that supported the tanks. The team further determined that these structural angles would be non-functional during a design basis seismic event if subjected to the seismic reactions determined in the calculation. These calculation deficiencies and concerns were communicated to the licensee who then identified additional calculation deficiencies. The licensee initiated IR 01131668 to document and addresses these concerns.

The team noted that after the discrepancies were identified, the licensee had not assessed the functionality of the tanks. The team questioned whether the SBLC safety-related equipment was operable when water that remained in the tanks at the conclusion of the test. Subsequently, the licensee promptly drained the existing water from the test tanks to ensure that the structural adequacy of the tanks would be maintained during a DBE. The licensee also revised procedure LOS-SC-Q1 to drain the test tanks following quarterly surveillance testing.

Upon further design review, the licensee determined that if the water was not fully drained from the test tank at the conclusion of the test, there was a possibility that one or more of the supporting legs could fail and result in the tanks falling over or collapsing. The licensee entered this issue into their corrective action program as IR 01132019 and initiated an operability evaluation OE 10-004, "Standby Liquid Control (SBLC) Test Tank." This functionality evaluation determined that the tank would not collapse if it was empty. However, if partially filled with water, a failure of the test tanks could adversely impact the

SBLC pumps [1(2)C41-C001A/B] or the test tank outlet valves [1(2)C41-F031]. Also, if the Unit 2 test tank supporting structure was to collapse, an adjacent conduit containing power cables for the safety-related SBLC storage tank outlet valve (2C41-F001A) could be adversely impacted. In addition, the test tank outlet valves have permissive interlocks that would prevent the SBLC pump solution tank suction valves from opening if the test tank outlet valves were not fully closed.

On October 28, 2010, the licensee submitted an event report (46372) pursuant to 10 CFR 50.72(b)(3)(v) to report this finding.

Analysis: The team determined the failure to ensure that the SBLC system test tanks would not collapse and damage safety related components during a design bases earthquake (DBE) is a performance deficiency. The performance deficiency was determined to be more than minor because the finding was similar to IMC 0612, Appendix E, Example 3j. The engineering calculation error resulted in a condition where the supporting structure of the SBLC test tanks was determined to be non-functional with the as-left water level inside tank following quarterly surveillance testing. This performance deficiency also impacted the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the cornerstone attribute of design control was impacted because the initial seismic design of the test tank supporting structure was not adequate. Therefore, with tanks not fully drained of water after quarterly testing, they could fail during a DBE and adversely impact safety related systems.

The team determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” and Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 3b, “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones.” The team determined that the cornerstone best reflecting the dominant risk was the Mitigating Systems cornerstone. In accordance with Table 4b, "Seismic, Flooding, or Severe Weather Screening Criteria," the finding screened as potentially risk significant due to external initiating event core damage sequences. Therefore, the Region III Senior Risk Analyst (SRA) performed an SDP Phase 3 risk-assessment of this performance deficiency. Since SBLC system is only used to mitigate anticipated transient without scram (ATWS) events, the Phase 3 analysis assumed that, given a seismic-induced (functional failure of the control rod drive and hydraulic units) the core damage probability was 1.0. The SRA used generic seismic fragility information from the Risk-Assessment Standardization Project (RASP) Handbook. Using Table 4A-1 from the RASP Handbook the frequency of various seismic events was determined. Using this information and assuming a conditional core damage probability of 1.0, the seismic core damage frequency for this issue was near 1.0E-7. This result showed that the change in core damage frequency for this issue was of very low safety significance (Green).

The team did not identify a cross-cutting aspect associated with this finding because the finding was not representative of current performance.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, from the time of original construction until October 27, 2010, the licensee's design control measures failed to verify the design adequacy of SBLC system test tanks. Specifically, the licensee failed to have an adequate calculation to demonstrate the seismic qualification of the SBLC system test tanks. This was required to ensure that the supporting structure for the SBLC system test tanks, if filled with water, would not collapse and damage safety-related components during a DBE. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program (CAP) as IRs 01129847, 01131668, and 01132019, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000373/2010006-01; 05000374/2010006-01, Supporting Structure for Standby Liquid Control System Test Tank Non-Functional During Postulated DBE).

(2) EDG Usable Fuel and RHR Pump NPSH Calculations Failed to Consider Appropriate EDG Frequency Variations

Introduction: The team identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," with two examples for the licensee's failure to account for allowable frequency variations in (1) the EDG fuel oil consumption calculations, and (2) the residual heat removal (RHR) pump net positive suction head (NPSH) calculations. Specifically, the licensee failed to calculate the effects of increased EDG frequency on diesel fuel consumption, and pump speed, flow, and NPSH of the RHR pump.

Description: The team identified two examples of the licensee's failure to account for allowable frequency variations in their calculations. Technical Specifications (TS) Surveillance Requirement 3.8.1.2 stated, "Verify each required DG starts from standby conditions and achieves steady state…frequency ≥ 58.8 Hz and ≤ 61.2 Hz." The "steady state" words were added to the TS in April 2001 during transition to Improved Technical Specifications. However, the licensee's calculations and procedures were based on frequencies of 60 or 60.5 Hz.

The team determined that an increase in frequency would result in increased pump motor speeds and pump flows that would lead to an increase in the EDG loading. The team identified the following specific concerns during the inspection:

Usable Fuel Calculations Failed to Consider Appropriate EDG Frequency Variations

Calculation L-003416, "Emergency Diesel Generators On-site Usable Fuel Volume Requirements" was based on the EDGs operating at a frequency of 60 Hz. Prior to this inspection, the licensee reviewed a similar issue identified at another plant relating to EDG frequency (IR 01122224) and evaluated this issue for potential impact at LaSalle.

Based on this review, the licensee recalculated their EDG fuel oil consumption based on operation of the EDGs at 60.5 Hz in calculation EC 381640, "Minimum Required On-Site Usable Diesel Fuel…" and determined that the fuel requirements for 6 and 7-day operation would increase by approximately 2.5 percent and be in excess of the values set forth in the TS Bases Table B 3.8.3-1. The licensee determined that the 7-day fuel oil supply for the Divisions 1 and 2 diesels was 34,635.6 gallons of fuel whereas the fuel oil storage tank alarm was set at 35,475 gallons. This resulted in a margin of 839.4 gallons. The licensee determined that the margin for the Division 3 EDG was 1,283.6 gallons. The low level alarms were set to alarm before the TS values were reached, therefore the licensee had

enough fuel to support operation at 60.5 Hz based on their low level alarm set points. As part of their immediate corrective action, on October 6, 2010, the licensee initiated a standing order to limit operation of the EDGs at a frequency not to exceed 60.5 Hz and documented their conclusion in operability evaluation OE 10-005, "Potential Non-Conservative Tech Spec for EDG Fuel Oil."

After reviewing calculations EC 381640 and L-003418, "Emergency Diesel Generator Fuel Oil Setpoints," which determined the EDG fuel oil setpoints, the team identified that instrument uncertainties were not considered in these calculations. The team determined that instrument uncertainties could result in a further decrease of 719 gallons for Divisions 1 and 2 EDGs. This resulted in a margin decrease down to 120.4 gallons, or approximately 38 minutes based on data and equations provided in calculation L-003416, a further decrease in margin of 85 percent. Instrument uncertainties were also not accounted for in the Division 3 EDG calculations and resulted in a decrease of 655 gallons (51 percent) in margin. Based on these calculations, the team had a reasonable doubt on the adequacy of EDG fuel supply.

In addition, the team noted that the TS (Surveillance Requirement 3.8.1.2) stated that the EDGs could operate at a steady state frequency up to 61.2 Hz. This would result in a higher fuel consumption that would exceed the TS minimum 6 and 7-day volumetric fuel requirements. Specifically, an increase in frequency to 61.2 Hz would increase EDG fuel consumption by approximately 6.12 percent.

The licensee was committed to using ANSI N195-1976 methodology for determining fuel oil storage requirements. The two methods provided in ANSI N195-1976 were time dependent load (load profile) and rated load. The licensee used one of the two methods to determine their fuel oil storage requirements for each EDG:

- Divisions 1 and 2 EDGs: Technical Specifications Surveillance Requirement 3.8.3.1 required that Divisions 1 and 2 EDGs have enough fuel to support 7-day operation at rated load. The team determined that the licensee had margin to operate the Divisions 1 and 2 EDGs at rated load at frequencies up to 61.2 Hz because rated load would not be directly affected by a change in EDG frequency.

- Division 3 EDG: Technical Specifications Surveillance Requirement 3.8.3.1 also required that Division 3 EDGs must have enough fuel to support operation for 7 days at maximum load profile. The load profile is dependent on the frequency of the EDG. Therefore, the licensee should have calculated the fuel requirements based on the maximum allowable steady state frequency by TS (61.2 Hz) for the Division 3 EDGs because those loads would vary with frequency changes. The team determined that the Division 3 EDG would not have enough fuel to operate at 61.2 Hz. However, because the licensee had a standing order to limit operation not to exceed 60.5 Hz, the team did not have an immediate safety concern.

The team concluded that credit could not be given to the licensee for self-identification. The licensee issued IR 01136071 to capture the team's concerns.

The NRC provided guidance for improper or inadequate TS in Administrative Letter 98-10. Imposing administrative controls in response to improper or inadequate TS was an acceptable short-term corrective action. However, the NRC expects that, following the imposition of administrative controls, an amendment to the TS would be submitted in a

timely fashion. Therefore, the licensee should not have relied on administrative controls (procedures and the SO limiting EDG operation to 60.5 Hz) on a permanent basis to address the nonconforming TS Bases Table B 3.8.3-1 fuel oil supply values.

Usable RHR Pump NPSH Calculations Failed to Consider Appropriate EDG Frequency Variations

The team reviewed the RHR pump design basis calculations and the UFSAR to assure that there was adequate NPSH margin for station blackout and design basis LOCA conditions. The team noted that an increased EDG frequency of 61.2 Hz, permitted by the TS, was not included in either the design basis analysis or UFSAR and asked the licensee if this case had been evaluated. The licensee provided its review of a similar industry issue identified at another plant regarding the impact of increased operating frequency on the RHR Pump speed and change of the required and available NPSH. The licensee also provided the evaluation as documented in EC-381008, "Assessment of EDG Frequency upon NPSH In Support Of OPEX Review." The licensee found that the NPSH margin was significantly reduced but still within allowable limits. The impact on RHR NPSH margin was a reduction from 1.1 to 0.32 feet. The team identified that although the licensee found that margin reduction was reduced, but acceptable, the revised limiting conditions were not reflected in either the RHR design basis calculations or UFSAR Section 6.3.2.2. As such, the design basis documents and the UFSAR did not provide correct values for limiting plant design conditions. The licensee issued AR 1141618 to document and addresses these concerns.

Analysis: The team determined that failure to account for allowable frequency variations in the diesel fuel oil consumption and the RHR pump NPSH calculations was contrary to 10 CFR Part 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency. The finding was determined to be more than minor because the performance deficiency was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, operating the EDGs at a frequency of 61.2 Hz would result in higher fuel consumption and reduced RHR pump NPSH margins. In addition, the usable fuel oil example was similar to IMC 0612, Appendix E, Example 3j in that the calculation L-003416 error resulted in a reasonable doubt on the adequacy of diesel fuel supply.

The team determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process" Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of findings," Table 4a, "Characterization Worksheet for IE, MS, and BI Cornerstones." The team determined that the cornerstone best reflecting the dominant risk was the Mitigating Systems cornerstone. The team confirmed that the finding did not result in a loss of operability or functionality per "Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment," because of the standing order already in place (limiting operation of the EDGs to 60.5 Hz). Therefore, this finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the area of problem identification and resolution, operating experience because the licensee did not properly evaluate relevant operating experience. Specifically, the licensee incorrectly assessed operating experience by not accounting for the maximum allowable frequency of 61.2 Hz as specified in the TS. [P.2(a)]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, from April 2001 until November 19, 2010, the licensee failed to perform an adequate design review of the effects of increased EDG frequency on fuel oil consumption and RHR pump NPSH. Specifically, the licensee failed to verify that the fuel oil consumption and RHR pump NPSH calculations were based on the appropriate TS basis of EDG operation at up to 61.2 Hz. The licensee also failed to verify that appropriate RHR pump NPSH values were incorporated into the design basis calculations and the UFSAR. Because this violation was of very low safety significance and it was entered into the licensee's CAP as IRs 01136071 and 01141618, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000373/2010006-02; 05000374/2010006-02, EDG Usable Fuel and RHR Pump NPSH Calculations Failed to Consider Appropriate EDG Frequency Variations).

(3) Insufficient Design Bases for Degraded Voltage (DV) Time Delay and Loss of Voltage (LOV) Relay Settings

Introduction: The team identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to have appropriate analyses for the loss of voltage (LOV) relay setpoints and the second level undervoltage [(degraded voltage (DV)] relay timer settings. Specifically, licensee's analysis of EC 379235, "Evaluation and Technical Basis for the AP System Second Level Undervoltage (Degraded Voltage) Time Delay Settings," dated October 18, 2010, failed to demonstrate the ability of the permanently connected safety-related loads to continue to operate for 5.5 minutes without sustaining damage during a worst case, non-accident degraded voltage condition, when voltage was still above the setpoint of the LOV relay setpoint.

Description: The licensee has not established the adequacy of the setpoints for second level undervoltage - DV relay time delay, and the LOV relay trip function described in TS. LaSalle Technical Specifications Table 3.3.8.1 specifies the Allowable Values for the second level undervoltage - DV relay time delay non-LOCA case as ≥270.1 and ≤329.9 seconds. The Allowable Value for the LOV relay setpoint is specified as ≥2422V and ≤3091V. The Allowable Value for the LOV relay time delay is specified as ≥3.1 and ≤10.9 seconds. The team identified the following issues:

- The licensee's recent analysis for the second level undervoltage - DV relay timer settings did not account for the potential worst case, non-accident degraded voltage condition and, therefore, did not demonstrate the operability of permanently connected safety-related loads under those conditions.

- The licensee was unable to provide an analysis to demonstrate the acceptability of the TS lower voltage limit for the LOV relay.

- Technical Specifications Table 3.3.8.1 does not contain parameters appropriate to the settings of the currently installed inverse-time type LOV relay.

Degraded Voltage Relay Time Delay

The original NRC Safety Evaluation Report, NUREG-0519 dated March 1981 – Section 8.2.2.2, "Low and/or Degraded Grid Voltage Condition" states, in part, "…the voltage and time setpoints will be determined from analysis of voltage requirements of the safety-related loads." The team reviewed EC 379235, dated October 18, 2010, and determined that the analysis did not address the worst case, non-accident degraded voltage condition. Specifically, the analysis only evaluated the operability of permanently connected safety-related loads to a maximum degraded voltage of 75 percent of nominal. The licensee chose 75 percent of nominal voltage as the lower limit of degraded voltage based on an operator manual action, not formally approved by NRC, to trip the offsite source, if the voltage were to degrade below 75 percent of nominal for more than a minute. Without the operator action, the voltage could drop to just above first level undervoltage setpoint of approximately 58 percent of nominal during the 5.5 minutes time delay period, however, the licensee did not address operability of permanently connected safety-related loads at those voltage levels.

Discussions with the licensee regarding this issue indicated that the licensee had received formal NRC approval in TS Amendments 103 and 108 for Dresden Nuclear Power Station (a different Exelon nuclear unit), for the use of operator manual action to trip the offsite power if the voltage dropped below 75 percent of nominal. The licensee then informed the NRC by letter dated April 21, 1989, that they planned to implement a similar scheme at their other nuclear plants including LaSalle Station. Although, the licensee implemented the use of operator manual action to trip the offsite power if the voltage dropped below 75 percent of nominal at LaSalle Station, the licensee did not follow through formally and did not obtain prior NRC acceptance and approval as part of licensing basis as was done at Dresden Nuclear Power Station. The team confirmed this with NRC's Office of Nuclear Reactor Regulation. Therefore, the team concluded that the licensee was required to demonstrate operability of permanently connected safety-related loads at the worst case degraded voltage, which is the first level (loss of voltage) undervoltage of approximately 57 percent of nominal, as specified in the LaSalle TS. The team noted that the permanently connected safety-related loads were protected to a higher level than allowed by TS since the existing settings for the inverse time relay currently being used for the loss of voltage relay, limit the duration of degraded voltage below 75 percent to a few seconds.

Loss of Voltage Lower Limit

The lower limit of the LOV relay setpoint is specified in TS Table 3.3.8.1 as an allowable value of ≥2422V. This corresponds to an analytical limit of 2363V or approximately 57 percent of 4160V. As noted above, the licensee has not justified the approximately 5.5 minute time delay of the degraded voltage relay intended to allow time for operators to improve voltage during non-LOCA conditions, and credited manual operator actions for voltage for voltage below 75 percent after one minute. The licensee did not have an analysis of the effects of sustained voltage as low as 57 percent for 1 minute. Induction motors can stall with bus voltage below approximately 70 percent and contactors and other control devices could drop out with voltage below approximately 60 percent. Since a sustained low voltage condition at the level allowed by TS could cause damage to, or tripping of loads or protective devices if allowed to persist, the specified voltage limit for the LOV relay setpoints is not consistent with either manual or automatic actions taking more than a few seconds to accomplish. The licensee has not provided analysis justifying either

the 1 minute manual actions provided for in procedures, or the approximately 5.5 minute delay for automatic action.

Technical Specifications Limits for LOV Relay Settings

The licensee in his response to the inspector's concerns regarding the time delay of the degraded voltage relay took credit for the inverse time characteristic of the LOV relay to limit the duration of potential exposure to low voltage. The team noted that although the current voltage and time dial setpoints for the LOV relay do limit the time that degraded voltage could persist, these setpoints are not constrained by the existing TS. Specifically, the existing TS list minimum and maximum limits for the voltage and time delay. The TS do not specify the use of an inverse time relay, and do not specify the time delays at particular voltages, as is required to constrain adequate settings for inverse time relays. The team concluded that less conservative setting than the existing setpoints could be used, or a discrete time delay relay could potentially be used within the constraints of the existing TS. The team concluded that, in order to credit the desirable characteristics of the inverse time type relay, TS should specify setting constraints suitable for the relay being credited. These constraints should be shown by analysis to afford adequate equipment protection and immunity from spurious separation.

Following NRC identification of this issue at the Byron plant in March 2009, LaSalle issued a CR to document and review applicability of this issue to LaSalle. The licensee concluded, in 2009, that this was not an issue applicable to LaSalle. Subsequently, during this CDBI, the licensee issued IR 01132036 on October 28, 2010, "Potentially Non-Conservative Degraded Voltage Time Delay" to verify the adequacy of the degraded voltage relay setpoint and time delay design and ensure that the permanently connected safety-related loads would have adequate voltage to continue to run without sustaining damage during a worst case, non-accident degraded voltage condition. The team also noted that, in August 2010 the licensee's corporate engineering group formed a high impact team (HIT) to review the issue and identify a fleet wide consistent resolution for all five applicable sites. The HIT was scheduled to have its first meeting on November 30, 2010.

The team concluded that no credit for identification of this issue could be given to the licensee because similar concerns raised at the Byron Nuclear Station, during the March 2009 CDBI, were not promptly evaluated and correctly dispositioned at LaSalle, as of the time of this CDBI.

Analysis: The team determined that the failure to perform adequate analysis to demonstrate that permanently connected, safety-related loads will not be damaged for the duration of the time delay for a worst case, non-accident, degraded voltage condition and to ensure that safe shutdown loads would be able to start and perform their safety function in response to a potential plant trip caused by such a degraded voltage condition, was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, there was reasonable doubt as to whether the permanently connected safety-related loads would remain operable during a worst case, non-accident degraded voltage condition for the duration of the time delay chosen for the DV relay. The team

determined the finding could be evaluated using the SDP in accordance with IMC 0609, Attachment 04, and Table 4a for the Mitigating Systems Cornerstone. The team answered "no" to the five questions in Column 2 of Table 4a since the existing settings for the inverse time relay currently being used for the loss of voltage relay limit the duration of degraded voltage below 75 percent to only a few seconds. Therefore, the finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the area of problem identification and resolution because when identified at the Byron Nuclear Station, the LaSalle licensee entered the condition into their corrective action program but did not fully evaluate and incorrectly dispositioned the issue as not applicable. [P1(c)])

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control" requires, in part, that design control measures provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of suitable testing program.

Contrary to the above, as of October 18, 2010, the licensee's design control measures failed to verify the adequacy of the degraded voltage relay setpoint and time delay design. Specifically, the licensee failed to analyze that, the permanently connected safety-related loads would have adequate voltage to continue to run without sustaining damage during a worst case, non-accident degraded voltage condition. Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IR 01132036, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000373/2010006-03; 05000374/2010006-03; Insufficient Design Bases for Degraded Voltage (DV) Time Delay and Loss of Voltage (LOV) Relay Settings).

(4) Fast Bus Transfer Analysis

Introduction: The team identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," involving the licensee's failure to analyze the capability of the electrical system to transfer safety-related 4160V buses as described in the UFSAR.

Description: Each of the two LaSalle units is equipped with three safety related buses. The preferred configuration for normal operation is to align the safety buses to the system auxiliary transformer (SAT), however, USFAR 8.1.2.1 states that the unit auxiliary transformer (UAT) is also capable of supplying all of the auxiliary power requirements of a unit during normal operation. The UFSAR also states that upon a trip of the main generator, those switch groups which, at that time are fed from UAT 141 (including non-safety buses), are transferred automatically to SAT 142 so that all seven switch groups of Unit 1 will continue to be energized and are available for operating auxiliaries as required for a safe and orderly shutdown. A similar scheme is used for Unit 2. The licensee was not able to provide a formal analysis to demonstrate that the transfer from the UAT to the SAT could be accomplished without damage or loss of safety related loads during an accident. (Fast transfer analyses typically address the effect of phase differences between the two sources and the effect of momentary power interruption, which could cause damage to or maloperation of equipment).

If one or both safety buses are aligned to the UAT and an accident occurs, the affected bus will, by design, be fully loaded with its permanently connected and automatic safety

loads from the UAT source and then be automatically transferred to the SAT upon tripping of the main generator. Since both safety buses could be aligned to the UAT, the team was concerned that the buses could be subject to simultaneous failure during an accident when the fast transfer occurs.

In response to the team's concern, the licensee initially responded that alignment of safety buses to the UAT during power operation was not permitted by station procedures or TS. However, a review of procedures and the TS revealed that either or both buses 141Y and 142Y could be aligned to the UAT during power operation without time restrictions, as described in the UFSAR. The licensee also provided a white paper (not a formal analysis) discussing fast transfer of safety buses, which was prepared during the early 1990's in response to questions by the NRC electrical distribution system functional inspection team. The team noted that this paper only considered minimal loading on the safety buses and did not address the potential adverse effects of momentary power interruption on control equipment and other devices. The licensee also cited operating experience with the transfer of non-safety buses to demonstrate capability of transferring safety buses, but the team noted that, although the effect of the transfer on motors would be similar, there was no analysis of non-motors loads that could be adversely affected.

The team further noted that LaSalle had actually experienced malfunctions in the 120V control circuits for the circulating water pumps during non-safety bus transfers. The licensee was not able to identify any operating experience or testing for the case where fully loaded safety buses were transferred from one source to the other. The team therefore concluded that the licensee had not established the capability for transfers stated in the UFSAR either by analysis, testing, or operating experience. The licensee was not able to identify specific instances where one or both safety buses had been aligned to the UAT during normal operation and the team concluded that this alignment was not typically used. However, in response to this concern, the licensee issued a standing order restricting alignment of safety buses to the UAT pending resolution of this issue. This item was entered in the licensee's CAP as IR 01141298.

Analysis: The team determined that the failure to perform analysis of fast transfer capability was a performance deficiency. The performance deficiency was determined to be more than minor because the issue was associated with the Mitigating Systems Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, there was reasonable doubt as to whether safety-related loads could be transferred as described in the UFSAR without adverse effects, pending analysis.

The team determined the finding could be evaluated using the SDP in accordance with IMC 0609, Attachment 04, and Table 4a for the Mitigating Systems Cornerstone. Since it was determined that the safety buses had not been aligned to the UAT, the team determined that was a design deficiency that had not resulted in loss of operability or functionality, and therefore determined the finding was of very low safety significance (Green).

The team did not identify a cross-cutting aspect associated with this finding because the finding was not representative of current performance.

Enforcement: Title 10 CFR 50, Appendix B, Criterion III, "Design Control" requires, in part, that design control measures provide for verifying or checking the adequacy of design,

such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of suitable testing program.

Contrary to the above, as of November 11, 2010, the licensee's design control measures failed to verify the adequacy of design of the fast bus-transfer capability described in the UFSAR. Because this violation was of very low safety significance and because the issue was entered into the licensee's CAP as IR 01141298, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000373/2010006-04; 05000374/2010006-04; Fast Bus-Transfer Analysis).

(5) Non-Conservative Voltage Input for Motor Starting Calculations

Introduction: The team identified an unresolved issue (URI) related to the licensee's failure to use worst case voltage for motor starting calculations. Specifically, the licensee assumed voltage near to the administratively controlled minimum offsite voltage rather than the voltage afforded by the setpoint of the DV relay defined in the TS.

Description: The original NRC Safety Evaluation Report, NUREG-0519, dated March 1981 - Section 8.2.2.2, "Low And/Or Degraded Grid Voltage Condition" required the implementation of a second level undervoltage scheme to protect safety-related loads and stated, in part, "…the voltage and time setpoints will be determined from analysis of voltage requirements of the safety-related loads." Updated Final Safety Analysis Report 8.2.3.2.2, "Criteria for Acceptable Voltage" states in part, "The minimum acceptable level (i.e., starting voltage) for safety-related motors is based on the minimum equipment terminal voltages postulated at the lower analytical limit or design basis of the second-level undervoltage protection setpoint." LaSalle TS Table 3.3.8.1 specified the Allowable Value for the degraded-voltage relay voltage setpoint as ≥3814V and ≤3900V. Calculation AN71 also defined the Analytical Limit for the degraded voltage relay as 3814V (approximately 91.7 percent of 4160V).

The team determined that Calculation L-003364 only analyzed steady state motor running and individual motor starting with 3814V on the safety bus. The calculation did not consider or analyze block loading at the worst case voltage allowed by the Technical Specification setpoint without disconnecting from offsite power. The team calculated the lowest value the relay will reset is at 3833V. This value reflects the vendor's specified dropout to reset ratio for the relay of 99.5 percent and the Technical Specification setpoint of 3814V (3814/0.995=3833). Therefore, based on a Technical Specification analytical limit of 3814V, a reset ratio of 99.5 percent, and block loading conditions, the lowest voltage that can occur on the bus immediately following block loading, without separating from the grid will be 3833V.

The team noted that Calculation L-003364 analyzed motor starting voltage during block loading using a switchyard voltage input of 352kV, which was intended to bound the minimum expected switchyard voltage of 354kV, defined in UFSAR 8.2.3.2, "Adequacy of Offsite Power." This resulted in safety bus voltage of approximately 3960V vs. the analytical limit of 3814V. The team determined that the corresponding switchyard voltage for a fully loaded safety bus at 3833V is 341.5kV, which is considerably below the value used by the licensee in their calculation of 352kV. Since licensee's approach was not consistent with UFSAR 8.2.3.2.2 which states that motor starting voltage was based on lower analytical limit or design basis of the second level undervoltage protection setpoint, the team concluded that the block motor starting results in Calculation L-003364 were non

conservative by approximately 3 percent. In response to the teams' concerns, the licensee stated that the LaSalle licensing basis did not require postulating a concurrent LOCA and degraded voltage condition. After consultation with NRR and review of the LaSalle licensing record, including FSAR Question 40.102 and NUREG-0519, they concluded that the licensee's position was incorrect.

During the inspection, the licensee performed preliminary calculations using the electrical transient analysis program (ETAP) and voltages based on the degraded voltage relay settings. These calculations showed that the safety related motors would start and accelerate satisfactorily. Based on these preliminary calculations the team concluded that this finding did not represent an operability concern. On November 12, 2010, the licensee issued IR 01139601 to determine whether the block start, at a bus voltage of 3833V (minimum degraded voltage relay reset afforded by the degraded voltage protection scheme), is part of the LaSalle design basis. On December 15, 2010, engineering initiated action item IR 01139601-03 to perform a formal analysis at a switchyard voltage that results in a recovery voltage at the minimum degraded voltage relay reset of approximately 3833V, at the 4 kV buses and revise Calculation L-003364 accordingly.

Concerning this finding, the licensee stated that the NRC previously reviewed License Amendment number 135/120 and the associated Safety Evaluation Report (SER) and concluded that the setpoint change for the undervoltage relay was acceptable. However, the team could not identify in the SER that the NRC specifically reviewed the licensee's motor block start analysis at the worst case bus voltage of 3833 Vac (minimum degraded voltage relay reset value).

This issue is considered unresolved pending resolution of differences in interpretation between the NRC and the licensee of the original licensing basis concerning motor-block-starting analysis. (URI 05000373/2010006-05; 05000374/2010006-05, Non-Conservative Voltage Input for Motor Starting Calculations.)

.4 Operating Experience

a. Inspection Scope

The team reviewed four operating experience issues to ensure that NRC generic concerns had been adequately evaluated and addressed by the licensee. The operating experience issues listed below were reviewed as part of this inspection:

- Information Notice 2006-22, "New Ultra-low-sulfur Diesel Fuel Oil Could Adversely Impact Diesel Engine Performance";
- Information Notice 2008-02, "Findings Identified During CDBIs";
- Generic Letter 2007-001, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant"; and
- Information Notice 2001-13, "Inadequate Standby Liquid Control Relief Valve Margin."

b. Findings

No findings of significance were identified.

.5 Modifications

a. Inspection Scope

The team reviewed four permanent plant modifications related to selected risk-significant components to verify that the design bases, licensing bases, and performance capability of the components had not been degraded through modifications. The modifications listed below were reviewed as part of this inspection effort:

- EC 377559, Standby Liquid Control Pump Discharge Relief Valve 1(2) C41-F029A/B Set Pressure Change;
- EC 375480, Install Additional High Point Vent Upstream of 1E22-F004 Valve;
- EC 333812, Install Backup Battery Unit 1 Div 2 125Vdc Battery Charger 1DC17E; and
- EC 353780, Revise Protective Relaying Circuit for Unit 1 SAT Feed Breakers 1412 and 1422 (provide 4.16kV power to ESF Division 1 and 2 Switchgears 141Y and 142Y, respectively.

b. Findings

No findings of significance were identified.

.6 Risk-Significant Operator Actions

a. Inspection Scope

The team performed a margin assessment and detailed review of four risk significant, time critical operator actions. These actions were selected from the licensee's PRA rankings of human action importance based on risk-achievement worth values. Where possible, margins were determined by the review of the assumed design basis and UFSAR response times, human reliability analysis and performance times documented by job performance measures and scenario/drill results. For the selected operator actions, the team performed a detailed review and/or walk through of associated procedures, including observing the performance of some actions in the station's simulator and in the plant for other actions, with an appropriate plant operator to assess operator knowledge level, adequacy of procedures, and availability of special equipment where required.

The following operator actions were reviewed:

- Operator fails to initiate ECCS with a medium steam LOCA;
- Operator fails to initiate Control Room or Auxiliary Electric Equipment Room ventilation post control room fire;
- Operator fails to manually initiate rapid depressurization;
- Operator fails to cross tie U1/U2 power with RCIC unavailable.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Review of Items Entered Into the Corrective Action Program

a. Inspection Scope

The team reviewed a sample of the selected component problems that were identified by the licensee and entered into the corrective action program. The team reviewed these issues to verify an appropriate threshold for identifying issues and to evaluate the effectiveness of corrective actions related to design issues. In addition, corrective action documents written on issues identified during the inspection were reviewed to verify adequate problem identification and incorporation of the problem into the corrective action program. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report.

4OA6 Meeting(s)

.1 Exit Meeting Summary

On November 19, 2010, the team presented the inspection results to Mr. Harold Vinyard, and other members of the licensee staff. The licensee acknowledged the issues presented. The team asked the licensee whether any materials examined during the inspection should be considered proprietary. Several documents reviewed by the team were considered proprietary information and were either returned to the licensee or handled in accordance with NRC policy on proprietary information.

On January 3, 2011, the team presented a change to the characterization of one issue of concern as stated on November 19, 2010, to Mr. T. Simpkin and other members of your staff.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
H. Vinyard, Engineering Director
K. Taber, Operations Director
J. Washko, Work Management Director
T. Simpkin, RA Manager
J. Freeney, Nuclear Oversight
J. White, Training Director
B. Hilton, Design Engineering Mgr
V. Shah, Elect Design Eng Supervisor
J. Houston, Regulatory Assurance
K. Lyons, Chemistry Manager
M. Peters, Design Engineering
E. Zacharias, Design Engineering
L. Bukantis, Maintenance
R. Harb, Maintenance
J. Vergara, Regulatory Assurance

Nuclear Regulatory Commission
A. Stone, Branch Chief, Division of Reactor Safety
G. Roach, Senior Resident Inspector
F. Ramirez, Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000373/2010006-01; 05000374/2010006-01	NCV	Supporting Structure for Standby Liquid Control System Test Tank Non-Functional During Postulated Design Basis Earthquake (DBE)
05000373/2010006-02; 05000374/2010006-02	NCV	EDG Usable Fuel and RHR Pump NPSH Calculations Failed to Consider Appropriate EDG Frequency Variations
05000373/2010006-03; 05000374/2010006-03	NCV	Insufficient Design Bases for Degraded Voltage Time Delay and LOV Relay Settings
05000373/2010006-04; 05000374/2010006-04	NCV	Non-Conservative Voltage Input for Motor Starting Calculations

Opened

05000373/2010006-05; 05000374/2010006-05	URI	Fast Bus Transfer Analysis

Discussed

None

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC team reviewed the documents in their entirety, but rather, that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

CALCULATIONS

Number	Description or Title	Date/Revision
EMD-030015	Foundation Loads for Standby Liquid Control Test Tank	04/29/81
L-003447	LaSalle Unit 1 and 2, 125VDC System Analysis	0
VX-09	Battery Rooms Hydrogen Concentration	12
NDIT LS-0772	Battery Total Resistance Values	1
Calculation A.3	LaSalle HRA Notebook: Operator Fails to Initiate Emergency RPV Depressurization.	07/13/07
Calculation A.25	LaSalle HRA Notebook: Close Cross Tie Bkrs 241Y and 141Y	07/13/07
Calculation A.43	LaSalle HRA Notebook: Operator Manually Initiates HPCS/RCIC/LPCI/LPCS Following Auto Actuation Failure	10/22/10
L-002305	WS-1 – Boron Injection Variables Worksheet	4/27/2000
L-002311	WS5 – Heat Capacity Limit Worksheet No. 2	04/29/00
L-002312	WS5a – Heat Capacity Limit Worksheet No. 3	04/28/00
ATD-0070	Limiting Operating Conditions for Net Positive Suction Head (NPSH) For HPCI, LPCI, RCIC and RHR Pumps	2,2A,2B
L-002540	NPSH Margins for HPCI, RHR and RHR Pumps, Backpressure for RCIC Turbine	1,1A,1B,1C
97-199	VY Cooler Thermal Performance Model 1(2) VY03A, Rev. B, B02	B, B02
97-201	Thermal Model of COMED/LSCS RHR Heat Exchangers	A, A00, A01
L-000718	Determination of Potential Water Hammer Forces From a Postulated RHRSW Void Formation	1
L-000731	Evaluation of RHR Hx for Water Hammer Effects	2,2A
L-000732	RHR Heat Exchanger Transient, Collapse of Void in Main Pipe and Heat Exchanger	1.3
L-002857	LSCS RHR Heat Exchanger K Factor Sensitivity Study	0,0A,0B
L-002724	Change to Flow to RHR Seal Coolers 1 (2) E12, C002A/B/C	0
L-000711	Evaluation of RHR Service Water Flow to Seal Coolers	4C
L-001260	ECCS and RCIC Suppression Pool Head Loss for 50 percent Plugged Strainers	1
L-003064	Suppression Pool pH Calculation for Alternative Source Term	2,2A
RH-4	RHR Pump Minimum Flow Orifice	0
3C7-0189-001	Station Blackout Condensate Inventory Coping Assessment	3
L-003458	Standby Liquid Control System Pressures	0
CQD 003893	Vacuum Breaker Deformation Study	2

CALCULATIONS

Number	Description or Title	Date/Revision
CQD 004259	File CQD 004259, Vacuum Breaker Valve Test	10/82
EMD-026641	Calculation for the Vacuum Breaker Valve – Upper Bound Accelerations	12/80
L-001249	Determination of Allowable Pressure Drop for ECCS Suction Strainers	08/20/97
L-003458	Standby Liquid Control System Pressure	12/17/09
L-002305	Boron Injection Variables Worksheet	3
L-002306	Boron Weight Equivalences Worksheet	3
L-002311	Heat Capacity Limit Worksheet No. 2	3
L-002312	Heat Capacity Limit Worksheet No. 3	4
L-002313	Minimum Debris Retention Rate Worksheet	3
L-002314	Pressure Suppression Worksheet	4
L-002316	RPV Variables Worksheet	4
L-003354	ECCS and RCIC Pumps NPSH Roadmap Calculation	0
L-001166	Post LOCA Control Rm, Aux Elec Equip Room Offsite Dose	3
3C7-277-003	Vacuum Breaker Sizing	3
19AN-7	Unit and System Auxiliary Transformer Relay Settings	08/29/77
AN-71	Second Level Undervoltage	002B
EAD-4	Relay Settings for 4.16kV Safety Related Buses	001A
EC 379235	Evaluation and Technical Basis For the AP System Second Level (Degraded Voltage) Non-LOCA Time Delay Setting	10/18/10
L-001562	Assessment of Unit 1 Protective Device Operation for S/R Loads during Block Start	002A
L-002588	Loss of Voltage Relay Setpoint for 4.16 kV Buses 141Y, 142Y, 143, 241Y, 242Y, 243 Undervoltage Function	001D
L-002589	Instrument Setpoint Analysis for 4.16kV Undervoltage (Loss of Voltage) Relay –Time Delay Function	001C
L-002591	Instrument Setpoint Analysis for 4.16kV Degraded Voltage – Time Delays – LOCA	001B
L-003364	Auxiliary Power Analysis	000
EMD-030015	Foundation Loads for Standby Liquid Control Test Tank	0
EQ-01	Temperature and Humidity Profile for the ECCS Pump Cubicles	1
EQ-07	Temperature and Humidity Profile for the DG Rooms and HPCS Rooms	0
L-001249	Determination of Allowable Pressure Drop for ECCS Suction Strainers	0
L-002901	Verification of the Division 1 and 2 Diesel Oil Storage and Day Tank Volumes	0
L-003416	Emergency Diesel Generators On-site Usable Fuel Volume Requirements	0
L-003418	Emergency Diesel Generator Fuel Oil Setpoints	0
LAS-1E12-F048B	AC Motor Operated Globe Valve Calculation	4
LAS-1E21-F005	AC Motor Operated Gate Valve Control Parameters	5

CALCULATIONS

Number	Description or Title	Date/Revision
LAS-1E22-F004	AC Motor Operated Gate Valve Control Parameters	5
R90.049	Anchor/Darling Valve Company Maximum and Required Thrust Analysis for Component 1E12-F048B	A
R90.248	Anchor/Darling Valve Company Maximum and Required Thrust Analysis for Component 1E22-F004	0
R93.228	Anchor/Darling Valve Company Design, Seismic, and Maximum Thrust Analysis	A
L-002589	Instrument Setpoint Analysis for 4.16kV Undervoltage (Loss of Voltage) Relay –Time Delay Function	001C
L-002591	Instrument Setpoint Analysis for 4.16kV Degraded Voltage – Time Delays – LOCA	001B
L-003364	Auxiliary Power Analysis	000
EMD-030015	Foundation Loads for Standby Liquid Control Test Tank	0
EQ-01	Temperature and Humidity Profile for the ECCS Pump Cubicles	1
EQ-07	Temperature and Humidity Profile for the DG Rooms and HPCS Rooms	0
L-001249	Determination of Allowable Pressure Drop for ECCS Suction Strainers	0
L-002901	Verification of the Division 1 and 2 Diesel Oil Storage and Day Tank Volumes	0
L-003416	Emergency Diesel Generators On-site Usable Fuel Volume Requirements	0
L-003418	Emergency Diesel Generator Fuel Oil Setpoints	0
LAS-1E12-F048B	AC Motor Operated Globe Valve Calculation	4
LAS-1E21-F005	AC Motor Operated Gate Valve Control Parameters	5
LAS-1E22-F004	AC Motor Operated Gate Valve Control Parameters	5
R90.049	Anchor/Darling Valve Company Maximum and Required Thrust Analysis for Component 1E12-F048B	A
R90.248	Anchor/Darling Valve Company Maximum and Required Thrust Analysis for Component 1E22-F004	0
R93.228	Anchor/Darling Valve Company Design, Seismic, and Maximum Thrust Analysis	A

CORRECTIVE ACTION DOCUMENTS GENERATED DUE TO THE INSPECTION

Number	Description or Title	Date
1127839	Loose Ladder Rung U1 LPCS Injection Valve	10/18/10
1127848	Nuts In LPCS Pump Room Suction Line Drain Pit	10/18/10
1128061	Missing Fastener On 1ADG Air Compressor	10/19/10
1128074	Door 259 Seal Degraded	10/19/10
1128119	DG Fuel Oil And Air Start System	10/19/10
1128138	152-3 Can't See Breaker Closed Light	10/19/10

CORRECTIVE ACTION DOCUMENTS GENERATED DUE TO THE INSPECTION

Number	Description or Title	Date
1128205	LaSalle HRA Notebook Procedure Reference Discrepancies	10/19/10
1128749	Discrepancy In NPSH Calc ATD 0070	10/20/10
1128754	LOP-AP-101 Does Not State Jumper Length	10/20/10
1128874	L-003418 Rev. 000 Typo	10/21/10
1128933	Calculations Not Updated for MUR	10/21/10
1129030	Error Procedure MA-LA0773-401 In Title	10/21/10
1129074	LOA-FX Procedure Not In EDMS Correctly/PCRA	10/21/10
1129563	NRC ID CDBI: Tornado Effects On Diesel Gen Ventilation	10/22/10
1129745	CDBI: 2C41-N006, SBLC Solution Tank Temperature Element	10/22/10
1129757	CDBI: SBLC Solution Tank Scaffold	10/22/10
1129847	SBLC Test Tank Seismic Mounting	10/22/10
1130414	DG Storage Tank Retired PM	10/25/10
1131668	Design Analysis 030015(EMD) RE: SBLC Test Tank	10/27/10
1132019	Update Re: Design Analysis 030015 (EMD) and SBLC Test Tank	10/28/10
1132036	Potentially Non-Conservative Degraded Voltage Time Delay	10/28/10
1133565	Remove RHR Pump Performance Curves From VETIP Binder	11/01/10
1134115	CDBI Calculation RH-4 References Outdated RHR Pump Curve	11/02/10
1134803	CDBI Concern On HRA Notebook Times/Margin	11/03/10
1134951	Extent Of Condition Calculation Review For MUR	11/03/10
1135464	NRC CDBI Discrepancy In Calculation EQ-01, Revision 1	11/04/10
1135479	CDBI TR Generated For Installing Locking Device	11/04/10
1135700	NRC ID'D CDBI Issue Calculation 3C7-0277-003 Requires Rev.	11/04/10
1136071	CDBI: Potential Non-Conservative Tech Spec For EDG Fuel Oil	11/05/10
1136254	CDBI NRC ID: Editorial Error In Calc VX-09	11/05/10
1139384	Administrative Error In Calculation L-003364	11/12/10
1139601	CDBI-Potential Deficiency In Calculation L-003364	11/12/10
1140631	Scaffold Placement Enhancement for LOA-FX	11/15/10
1140904	Administrative Error In Calculation L-003364	11/16/10
1141298	Fast Bus Transfer At 4kV Buses	11/16/10
1141618	NRC Identified, CDBI, ECCS NPSH With Increased DG Frequency	11/17/10

CORRECTIVE ACTION DOCUMENTS REVIEWED DURING THE INSPECTION

Number	Description or Title	Date
1106053-03	Revise ECs 371924, 369098, and 369099	08/26/10
1090957-08	Based on NER, System Eng to do the following for Battery Chargers	09/14/10
0987583	DC Calc Enhancement Opportunity- Historical Issue	11/02/09
1056715	NER NC-10-008 Yellow Buried Cable	04/14/10
1126512	Inspection of Cables in Underground Vaults	10/14/10
0680041	2B SW Pump: Roll-up of 2WS01PB Baker Motor Testing Results	10/04/07
00895165	1A DG Fuel Oil Storage Tank Low Level Alarm	03/19/09
00801979	NRC RAI for LCS TS 3.8.3 Amendment Request	07/30/08
00498484	OPEX Review – Fermi Impact of EDG Frequency on Loading	06/09/06
00921254	Tracer Gas Test Did not Complete Due to VE HVAC Failure	5/17/09
00920759	VC Compressor is making Abnormal Knocking Noise	5/17/09
00923965	Install Fans in EMU and Filter During Tracer Gas Test	5/26/09
00934958	A Train VE In leakage Into CRE is Greater Than Allowed	6/24/09
00943236	0VE04YA A VE Purge Outlet Damper Leaks By	7/17/09
00949421	Damper Work Performed to Gain Additional Tracer Gas Margin	07/17/09
1019471-14	LaSalle SBLC Relief Valve Root Cause Investigation Report	04/15/10
0920759-07	LaSalle VC/CE Compressor Root Cause Report	
00898202	Lack of Technical Basis for Degraded Voltage Relay 5-Minute	03/26/09
00912566	Degraded Voltage Relay 1427-AP271A OOT Trend Code 84	04/23/09
00953796	Entered LOA-Commitment Wording-201 Following Trip of “A” and “C” Circ Water Pumps	08/15/09
01006735	FASA (EN) CDBI (IP 7111-21)	12/17/09
01055806	FME Found in 1A DG Oil Cooler System	04/13/10
01087402	CDBI FASA ID – Effect of EDG Output Frequency Variations	07/02/10
01122224	DES Eng IDs Fermi/Braidwood CDBI Issue Applicable to LaSalle	10/05/10
01125842	Pre-CDBI Walkdown Items, 1E12-F048B Valve and Area	10/13/10
01125886	Pre-CDBI Walkdown Items, 1E22-F004 and Area	10/13/10
00297076	Vulnerability of Div. 1 and 2 Protective Relay Circuitry	02/02/05

DRAWINGS

Number	Description or Title	Date or Revision
M-1590 SH 7	Equipment Foundations Reactor Building	J
1E-1-4000FC	Key Diagram, 125V DC Distribution, Essential Div. 2	N
1E-1-4214AA	Schematic Diagram, Remote Shutdown System “RS” Part-1	K
1E-1-4000FD	Key Diagram, 125V DC Distribution, Essential Div. 3	M
1E-1-4000DB	Station Key Diagram, 125 Volt DC Distribution	H
F 240-369	LF 240-369, In-Line Vacuum Breaker 24” Wafer Design, Rev. M00	0
M99	M-99, P&ID Standby Liquid Control System, Rev. AD	AD
M145	M-145, P&ID Standby Liquid Control System, Rev. AB	AB
VPF2993-420	VPF 2993-420, Perform Test Curve for Pump 2993-420	06/01/83
731E996AA	Process Diagram RHR System	6
DS-C-60735	DS-C-60735, SBLC Pump Discharge Relief Valve Drawing	B
1E-1 4221AB	Schematic Diagram Low Pressure Core Spray System “LP” (E21) Part 2	T
1E-1-4000A	Single Line Diagram Generator Transformers and 6900V Buses Part 1	P
1E-1-4000AK	Key Diagram 4160V SW.GR. 141Y (1AP04E)	E
1E-1-4000AL	Key Diagram 4160V SW.GR. 142X	C
1E-1-4000AM	Key Diagram 4160V SW.GR. 142Y	D
1E-1-4000AN	Key Diagram 4160V SW.GR. 143	B
1E-1-4000B	Single Line Diagram Part 2 Standby Generators and 4160V Buses	N
1E-1-4000C	Single Line Diagram Pt. 3 480V Substations on SW. GR. 151 and 152	A
1E-1-4000D	Single Line Diagram Pt. 4 480V Substations on SW. GR. 141X and 141Y	A
1E-1-4000E	Single Line Diagram Pt. 5 480V Substations on SW. GR. 142X, 142Y and 143	A
1E-1-4000NF	Relay and Metering Diagram System Auxiliary Transformer 142	F
1E-1-4005AE	Schematic Diagram 6900V Switchgear 152 Main Feed ACB 1522 System “AP” Part 5	O
1E-1-4005AQ	Schematic Diagram 4160V Switchgear 142Y Main Feed ACB 1422 System “AP” Part 15	N
1E-1-4005AR	Schematic Diagram 4160V Switchgear 142Y Unit Tie ACB 1424 System “AP” Part 16	L
1E-1-4005AS	Schematic Diagram 4160V Switchgear 142Y Bus Tie ACB 1425 System “AP” Part 17	L
1E-1-4005AT	Diagram 4160V Switchgear 142Y Auxiliary Compartment System “AP” Part 18	N
Engineering Changes	Schematic Diagram 4160V Switchgear 142Y Feed to Transformer 134X and 134Y System “AP” Part 26	F

DRAWINGS

Number	Description or Title	Date or Revision
1E-1-4005BD	Schematic Diagram 4160V Switchgear 142Y Feed to Transformer 136X and 136Y System “AP” Part 28	H
1E-1-4005BV	Schematic Diagram System Auxiliary Transformer 142 Cooling System “AP” Part 44	G
1E-1-4005CN	Schematic Diagram Auxiliary Power System “AP” Part 61	H
1E-1-4005DQ	Schematic Diagram Auxiliary Power System “AP” Part 87	L
1E-1-4005ZA	Loop Schematic Diagram Auxiliary Power System “AP”	D
1E-1-4009AA	Schematic Diagram 4160V Switchgear 142Y Diesel Generator “1A” Feed ACB 1423 System “DG” Part 1	Z
1E-1-4009AB	Schematic Diagram Diesel Generator System “DG” Part 2	M
1E-1-4009AE	Schematic Diagram Diesel Generator “1A” Generator Engine Control System “DG” Part 5	T
1E-1-4009AF	Schematic Diagram Diesel Generator “1A” Generator/Engine Control System “DG” Part 6	W
1E-1-4009AG	Schematic Diagram Diesel Generator “1A” Generator/Engine Control System “DG” Part 7	O
1E-1-4009AH	Schematic Diagram Diesel Generator “1A” Generator/Engine Control System “DG” Part 8	R
1E-1-4220AC	Diagram Residual Heat Removal Pump 1B System “RH” (E12) Part 3	AA
1E-1-4222AD	Schematic Diagram High Pressure Core Spray System HP (E22) Pt. 4	P
1E-1-4303AA	Three Line Diagram 345kV/6.9kV-4.16kV System Auxiliary Transformer 142	P
1E-1-4343AA	Int/Ext Wiring Diagram 4160V Switchgear 141Y, Part 1	S
1E-1-4343AB	Int/Ext Wiring Diagram 4160V Switchgear 141Y, Part 2	S
M-105	P & ID Diesel Building Floor	P
M-106	P & ID Diesel Auxiliary Turbine and Service Building Floor Drains	Z
M-1444	P&ID Diesel Generator Room Ventilation System	J
M-151	P & ID Diesel Auxiliary Turbine and Service Building Floor Drains System	I
M-72	P & ID Fire Protection	AE
M-83	P & ID Diesel Generator Auxiliary System	AT
M-85	P & ID Diesel Oil System	AC
M-1590 Sh. 7	Equipment Foundations Reactor Building	J
1E-1-4000PG	Relaying and Metering Diagram 4160V Switchgear 141Y	`Q
1E-1-4552AM	Internal Wiring Diagram Section 1PM01J, Part 12	M
1E-1-4552AZ	Internal Wiring Diagram Section 1PM01J, Part 24	I
1E-1-4552BD	Int./Ext. Wiring Diagram Section 1PM01J, Part 28	S
1E-1-4552BF	Int./Ext. Wiring Diagram Section 1PM01J, Part 30	R
1E-1-4555AB	Internal Wiring Diagram Main and Aux Power System Instrument Panel 1PM04J, Part 2	D

DRAWINGS

Number	Description or Title	Date or Revision
1E-1-4555AC	Internal Wiring Diagram Main and Aux Power System Instrument Panel 1PM04J, Part 3	F
1E-1-4555AD	Internal Wiring Diagram Main and Aux Power System Instrument Panel 1PM04J, Part 4	Q
1E-0-3333	Cable in Raceway Segregation Chart	H

Engineering Changes

Number	Description or Title	Date or Revision
EC 366261	Change Setpoint of Division 1 and 2 Emergency Diesel Generator (EDG) Fuel Oil Storage Tank Low Level Alarm Switches	0
EC 364755	Impact of ULSD Fuel on the Emergency Diesel Generators and Fuel Oil Storage System	3
EC 381640	Minimum Required On-Site Usable Diesel Fuel Required to Support Both Six Days and Seven Days of Continuous Emergency Diesel Generator Operation per Tech Spec Bases Table B.3.8.3-1	0

Miscellaneous

Number	Description or Title	Date or Revision
VETIP J-0955	U-1 Div 2 125 VDC Battery Charger (1BB)	02/03/03
VETIP J-0146	U-1 Div 3 125 VDC Battery Charger	12/19/91
VETIP J-1050	U-1 Div 2 125 VDC Battery	02/01/04
MA-AA-716-210-1001	Motor Control Center/Molded Case Circuit Breakers (MCCBs) Template	07/23/10
EC 0380309	Evaluation to Document Cable Aging Management Related Activities Completed and in Progress	06/18/10
N/A	Unit 1 Div. 1 and 2 System Health Reports	09/29/10
EC 0342224	LES-DC-103B Voltage Range	04/17/03
L02-0237	Installation of new Backup Battery Chargers for the 125V Division 1 and 2 Batteries	0
Scenario S-10-6-7, Part 1	Operator Manual Actions: Manual ECCS Actuation	0
Scenario S-10-6-7, Part 2	Operator Manual Actions: Manual ADS Actuation.	0
CDBI Drill No. 3	1B RR Pump High Vibrations, LOCA, Loss of Aux Power	0
JPM P-AP-CDBI1J	Install Jumpers to Allow Closing the Unit Tie Breaker	0
JPM P-AP-CDBI2J	Install Jumpers to Allow Closing the Unit Tie Breaker	0

Miscellaneous

Number	Description or Title	Date or Revision
JPM S-RH-16	Initiate Division 1 ECCS with a Failure of Manual PB	2
JPM S-NB-05	Initiate ADS with a Failure of One SRV to Open	10
(List)	All Independent Operator Actions Ranked by RAW	10/22/10
AT 01006735	Pre-NRC CDBI Focus Area Self-Assessment (FASA)	07/15/10
EC 381008	Assessment of EDG Frequency Upon NPSH in Support of OPEX Review Regarding OE OE31354	0
EC 377559	Liquid Control Pump Discharge Relief	11/09
ASME OM Code	ASME OM Code Table ISTB-5200-1, Vertical Line Shaft and Centrifugal Pump Acceptance Criteria, 2001	2001
JHR:96:188	JHR:96:188, Letter from Siemens regarding Radioactive Release Analysis Source Term Values, May 20, 1996	05/20/96
NRC to ComEd	Staff Review of Modifications to Revision 4 of the BWR Emergency Procedure Guidelines	07/14/96
SC 10-13	GE/Hitachi 10 CFR Part 21 Communication, Standby Liquid Control System Dilution Flow	10/11/10
0056.001	General Electric Company for Commonwealth Edison Company of Chicago Ingersoll-Rand Order 006-36025, Residual Heat Removal Pumps, Updated by VMSS-130-3	06/02/83 updated
I-1199	Crosby Instruction Manual (SBLV Pump Discharge Relief Valve)	0
41-347.12C	Type HU and HU-1 Relays	C
	ComEd Letter C.W. Schroeder to NRC, Degraded Voltage Modification	09/07/83
	Doble Insulation Tests for SAT 142	02/19/08
	Doble Insulation Tests for SAT 142	03/02/10
EC 379235	Evaluation and Technical Basis for the AP System Second Level (Degraded Voltage) Non-LOCA Time Delay Setting	000
EC338375	Unit 1 Div 1 and 2, Emergency Bus Undervoltage Relay Setpoint	000
	Item Equivalency Evaluation for the Voltage Regulator Cat. ID 28296-1	Not Dated
	LaSalle Action Item 373-103-36-08700, Loss of Offsite Power on Automatic Bus Transfer	10/22/85
	Memorandum D.C. Lankin, SNED, to M.S. Turbak ComEd, NRC Information Notice 86-87 Loss of Offsite Power Upon an Automatic Bus Transfer	01/06/87
RS-06-036	EGC/Amergen Response to the Request for Additional Information Regarding Resolution of NRC Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power	04/03/06

Miscellaneous

Number	Description or Title	Date or Revision
RS-07-002	EGC/Amergen 60 Day Response to NRC Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power	04/03/06
HIT Charter	Second Level Degraded Voltage 5 Min Timer and Manual Action<75 percent Voltage (IR 1071667)	0a
EQ-LS037	Exelon Nuclear LaSalle County Station Units 1 and 2 – Environmental Qualification of System Control 250 VDC Motor Control Center	9

MODIFICATIONS

Number	Description or Title	Date or Revision
EC 375480	Install Additional High Point Vent Upstream of 1E22-F004 Valve	1
EC 377559	Standby Liquid Control Pump Discharge Relief Valve 1(2) C41-F029A/B Set Pressure Change	12/11/09
EC 0333812-02	Install Back-up Unit 1 Division 2 125 VDC Battery Charger	02/06/04
EC 353780	Revise Protective Relaying Circuit for Unit 1 SAT Feed Breakers 1412 and 1422 (provide 4.16kV power to ESF Div. 1 and 2 Switchgears 141Y and 142Y, Respectively	001

OPERABILITY EVALUATIONS

Number	Description or Title	Revision
OE 10-003	Standby Liquid Control System Head Tank	0
OE 10-004	Standby Liquid Control (SBLC) Test Tank	0
OE 10-005	Potential Non-Conservative Tech Spec for EDG Fuel Oil	0
01112902	Operability Determination for SBLC re: Head Tank	09/14/10

PROCEDURES

Number	Description or Title	Revision
LS-AA-115	Operating Experience Program	15
LES-DC-103B	Division II Charger Capacity Test	20
LES-DC-103C	Division III Charger Capacity Test	16
LOP-DC-01	Battery Charger Startup and Shutdown	37
LOP-DC-12	Station Battery Elevated Equalize Charge	3
LES-DC-719	Unit 1 Division II 125V Battery Modified Performance Test	1
LES-DC-703	Unit 1 Division II 125V Battery Performance Discharge Test	0

PROCEDURES

Number	Description or Title	Revision
LES-DC-101B	Division II 125 Volt Battery Inspection for Unit 1 and 2	16
LEP-DC-104	Installation of Division II Batteries	15
LOS-DC-M5	Monthly Surveillance for Safety Related 250 VDC and 125 VDC Batteries	7
LOS-DC-W1	Weekly Surveillance for Safety Related 250 VDC and 125 VDC Batteries and DC Distribution	48
LES-DC-102A	Battery Charger Inspection	13
ER-AA-3003	Cable Condition Monitoring Program	0
LES-DC-707	Unit 1(2) Division II Battery Service Test Discharge	1
LOS-DC-Q2	Battery Readings for Safety-Related 250 VDC and Div 1,2,3 125 VDC Batteries	31
LOA-AP-101	U1, AC Power System Abnormal	33
LOA-AP-201	U2, AC Power System Abnormal	27
LOA-FX-101	U1, Safe Shutdown with a Fire in the Control Room or the AEER.	20
LOA-FX-201	U2, Safe Shutdown with a Fire in the Control Room or the AEER.	22
LOS-DG-M2	U1 DG Monthly Surveillance Test	71
LOP-VE-01	Auxiliary Electric Equipment Room Ventilation	48
LGA-003	Primary Containment Control	8
LGA-001	Emergency Operating Procedure, RPV Control, Rev. 10	10
LGA-010	Emergency Operating Procedure, Failure to Scram, Rev. 9	9
LOS-SC-Q1	SBLC Surveillance Pump Test, Attachments 1A, 1B, 2A and 2B	29
LOP-SC-01M	Unit 1 Standby Liquid Control System Mechanical Checklist	9
LOP-SC-02M	Unit 2 Standby Liquid Control System Mechanical Checklist	5
LES-GM-111	Inspection of ‘A’ VC HVAC Unit	13
LOS VC-SR2	In-Leakage Test on VC/VE Using Tracer Gas	4
LTS-500-1	Drywell To Suppression Pool Vacuum Breaker Seat Leakage Test 1(2) PC001A/B/C/D	13
LOS-RH-Q1	1B RHR System Operability and In-Service Test	75
LOS-RH-Q2	RHR Valve In-Service Test for Operating Start-up and Shut-down Conditions	50
LES RH-106	Minimum Flow Bypass Calibration	3
CC-AA-309-101	Engineering Technical Evaluations	11
LES-GM-103	Inspection of 4.16kV and 6.9kV Circuit Breakers	40
LEP-AP-04	ITE Medium Voltage Switchgear Cleaning and Inspection	6
LEP-GM-172	ITE (ABB) Medium Voltage Circuit Breaker Lubrication and Parts Replacement	18
LES-GM-103D	Bus 142Y I.T.E. Breaker and TSC Switch Operational Test	5
LOA-Grid-001	Low Grid Voltage	11

PROCEDURES

Number	Description or Title	Revision
LOP-DG-02	Diesel Generator Startup and Operation	48
LOR-1PM01J-A314	4kV Bus 141X/Y Undervoltage 4kV Bus 141Y Degraded Voltage	3
LOR-1PM01J-A314	4KV Bus Undervoltage 4KV Bus Degraded Voltage	3
LOS-AA-W1	Technical Specifications Weekly Surveillances	65
LOS-DG-M2	1A(2A) Diesel Generator Operability Tests	82
LST-2009-010	1A Diesel Generator Voltage Regulator Test	0
MA-LA-773-231	Unit 1 System Aux Transformer Relay and Meter Calibrations by OAD	5
MA-LA-773-401	Unit 1 Emergency Bus “Loss of Voltage” Relay Calibrations by OAD	4
MA-MW-773-035	Nuclear Operational Analysis Department Testing of Power Transformers	0
MA-MW-773-040	Nuclear Operational Analysis Department Testing of Current and Potential Transformer and Sensing Circuits	0
OP-AA-108-103	Locked Equipment Program	2
WCAA-AA-8003	Interface Procedure Between COMED/PECO and Exelon Generation (Nuclear Power)	2
LOP-DO-02	Transferring Diesel Fuel Oil from Storage Tanks to Day Tanks	13

Surveillances (complete)

Number WO	Description or Title	Date or Revision
1197065-01	Clean and Inspect Div II 125V Battery Charger	04/01/10
1116808-01	Inspect Div III Battery Charger	07/30/09
0948292-01	Replace 125 VDC Div 2 Battery Charger CAPS/ PC Boards/ Fuses/Pots/TOGG	01/07/08
0832287-01	EM Replace 125VDC Div 3 Battery Charger Parts, Inspect, Load Test	07/03/07
1214020-01	Inspect U-1 Div 2 125 VDC Battery per LES-DC-101B	05/05/10
1116456-01	Unit 1 125V Battery Div II Service Test Discharge	05/19/09
0876430-02	Pre-outage Testing of U-1 Div. 2 125 VDC Batteries	01/27/06
1213892-01	LOS-DC-Q2 U-1 Div II 125VDC Battery Att. B	02/15/10
0726825-01	Unit 1 125V Battery Div II Performance Test Discharge	03/02/06
0934514-01	Unit 1 125V Battery Div II Service Test Discharge	01/30/08
1116805-01	U-1 Div 3 125 VDC Battery Charger Capacity Test	07/29/09
0948292-02	EM Replace 125VDC Div 2 Battery Charger	01/07/08
1197150-01	U-1 Div 2 125 VDC Battery Charger Capacity Test of 1DC17E	08/03/10
01341717	2A RHR System Operability and In-Service Test	08/23/10

PROCEDURES

Number	Description or Title	Revision
01320042	2A RHR System Operability and In-Service Test	05/24/10
01353960	1B RHR System Operability and In-Service Test	11/05/10
01330215	1B RHR System Operability and In-Service Test	07/12/10
01222331	1A SBLC Operability/Inservice Test/Valve Continuity Test	06/04/09
01246706	1A SBLC Operability/Inservice Test/Valve Continuity Test	09/23/09
01271528	1A SBLC Operability/Inservice Test/Valve Continuity Test	12/21/09
01211550	1B SBLC Operability/Inservice Test/Valve Continuity Test	05/12/09
01236285	1B SBLC Operability/Inservice Test/Valve Continuity Test	08/12/09
01259748	1B SBLC Operability/Inservice Test/Valve Continuity Test	11/12009

WORK DOCUMENTS

Number WO	Description or Title	Date or Revision
01343773 01	LOS-SC-Q1 U2 B SBLC Pump Quarterly Att 2B	09/02/10
01332263	Perform Maintenance Inspection of Control Room HVAC	06/01/10
01304535	Perform Maintenance Inspection of Control Room HVAC	03/08/10
01113613	Perform In-Leakage Test of VC/VE Using Tracer Gas	05/11/09
01114739	Perform 1PC001A LTS-500 Vac Brkr Seat Leakage Test	02/13/10
00934489	Perform 1PC001A LTS-500 Vac Brkr Seat Leakage Test	02/29/08
01114513	Perform 1PC001A LTS-500 Vac Brkr Seat Leakage Test	02/12/10
00713009 01	Perform LES-GM-103 for SAT Feed @ Swgr 142Y Cub 1 (1AP06E)	09/21/06
00832943 01	Perform Elect Winding/PF Test on Large Transformers, completed	02/20/08
00845262 01	Replace/ Swap Out U-1 Div. 2 Bus 142Y UV/DV Relays	04/29/07
00887615 01	U-1 Div. 2 UV/DV Rly. Cals.	04/29/07
00895062 01	Refurb Op Mech/Brkr Inspect LES-GM-103 1AP06E-3	09/17/07
01066709 01	U-1 Div. 2 UV/DV Rly. Cals.,	04/13/09
01094207 01	Replace/ Swap Out U-1 Div. 2 Bus 142Y UV/DV Relays	04/29/07
01142220 01	1A DG Replace Voltage Regulator	02/12/10
01142220 02	1A DG Replace Voltage Regulator	02/26/10
01181269 01	MA-LA-773-501 Attachment 10	03/19/10
01343773 01	LOS-SC-Q1 U2 B SBLC Pump Quarterly Att 2B	09/02/10
00096111 01	Diesel Fuel Oil Analysis Verification (New Fuel Oil)	03/19/10
01371253 01	LOS-DO-M1 Att 1A Verify and Record Fuel Analysis Data	10/13/10
01346427 01	LOS-DG-Q2 1A D/G Fuel Oil Water Check Att A2	09/13/10

LIST OF ACRONYMS USED

Vac	Volt Alternating Current
ADAMS	Agencywide Document Access Management System
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient without Scram
CAP	Corrective Action Program
CDBI	Component Design Basis Inspection
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DBE	Design Basis Earthquake
DV	Degraded Voltage
EC	Engineering Change
ECCS	Emergency Core Cooling Systems
EDG	Emergency Diesel Generator
ETAP	Electrical Transient Analysis Program
FASA	Focused Area Self-Assessment
GL	Generic Letter
gpm	Gallon per minute
HIT	High Impact Team
HPCS	High Pressure Core Spray
HVAC	Heating Ventilation and Air Conditioning
Hz	Hertz
IEEE	Institute of Electrical and Electronic Engineers
IMC	Inspection Manual Chapter
IN	Information Notice
IR	Inspection Report
IR	Issue Report
IST	Inservice Test
LOCA	Loss of Coolant Accident
LOV	Loss of Voltage
LPCS	Low Pressure Core Spray
MCC	Motor Control Center
MOV	Motor-Operated Valve
MUR	Measurement Uncertainty Recapture
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
^{o}F	Degrees Fahrenheit
PARS	Publicly Available Records
PRA	Probabilistic Risk Assessment
psig	Pounds Per Square Inch Gauge
RASP	Risk Assessment Standardization Project
RHR	Residual Heat Removal
RIS	Regulatory Issue Summaries
SAT	System Auxiliary Transformer
SBLC	Standby Liquid Control
SBO	Station Blackout
SDP	Significance Determination Process

SP	Surveillance Procedure
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
TS	Technical Specification
UAT	Unit Auxiliary Transformer
UFSAR	Updated Final Safety Analysis Report
Vdc	Volts Direct Current

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Sincerely,

/RA/

Ann Marie Stone, Chief
Engineering Branch 2
Division of Reactor Safety

Docket Nos. 50-373; 50-374
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