UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, ILLINOIS 60532–4352

February 13, 2018

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2—NRC INTEGRATED INSPECTION REPORT 05000373/2017004; 05000374/2017004 AND EMERGENCY PREPAREDNESS ANNUAL INSPECTION REPORT 05000373/2017501; 05000374/2017501

Dear Mr. Hanson:

On December 31, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your LaSalle County Station, Units 1 and 2. On January 9, 2018, the NRC inspectors discussed the results of this inspection with Mr. W. Trafton and other members of your staff. The U.S. Nuclear Regulatory Commission also completed its annual inspection of the Emergency Preparedness Program. The Emergency Preparedness inspection began on January 1, 2017, and the issuance of this letter closes Inspection Report 05000373/2017501; 05000374/2017501. The results of these inspections are documented in the enclosed report.

Based on the results of this inspection, the NRC has identified three issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that three violations are associated with these issues. Because the licensee initiated action reports (ARs) to address these issues, these violations are being treated as Non-Cited Violations (NCVs), consistent with Section 2.3.2 of the Enforcement Policy. These NCVs are described in the subject inspection report.

If you contest the violations or significance of these 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 copies to the Regional Administrator, Region III; the Director, Office of Enforcement, and the NRC Resident Inspector at the LaSalle County Station.

If you disagree with the cross-cutting aspect assignment or a finding not associated with a regulatory requirement 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001; with copies to the Regional Administrator, Region III; and the NRC Resident Inspector at the LaSalle County Station.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Billy Dickson, Chief
Branch 5
Division of Reactor Projects

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

Enclosure:
IR 05000373/2017004; 05000374/2017004;
05000373/2017501; 05000374/2017501

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Letter to Bryan C. Hanson from Billy Dickson, February 13, 2018

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000373; 05000374
License Nos:	NPF–11; NPF–18
Report No:	05000373/2017004; 05000374/2017004; 05000373/2017501; 05000374/2017501
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles, IL
Dates:	October 1, through December 31, 2017
Inspectors:	R. Ruiz, Senior Resident Inspector J. Havertape, Resident Inspector J. Bozga, Senior Reactor Inspector J. Neurauter, Senior Reactor Inspector L. Smith, Reactor Inspector C. Zoia, Senior Operations Engineer M. Bielby, Senior Operations Engineer G. Hansen, Senior Emergency Preparedness Inspector R. Zuffa, Resident Inspector, (Illinois Emergency Management Agency)
Approved by:	B. Dickson, Chief Branch 5 Division of Reactor Projects

Enclosure

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SUMMARY

Inspection Report 05000373/2017004, 05000374/2017004; 10/01/2017–12/31/2017, and 05000373/2017501, 05000374/2017501; 01/01/2017–12/31/2017; LaSalle County Station, Units 1 & 2; Licensed Operator Requalification Program, Operability Determinations and Functionality Assessments; Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3–month period of inspection by resident inspectors, regional support staff, and announced baseline inspections by regional inspectors. A total of three Green findings are documented in this report. Two findings were identified by the inspectors and one was self-revealing. The findings involved Non-Cited Violations (NCVs) of U.S. Nuclear Regulatory Commission (NRC) requirements. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Initiating Events

Green. A finding of very low safety significance and an associated NCV of LaSalle Technical Specification (TS) 5.4.1, "Procedures," occurred on February 13, 2017, for the station's failure to maintain instructions of a type appropriate to the circumstances for energizing offsite electrical systems during a Unit 2 backfeed evolution (an activity affecting quality per Regulatory Guide 1.33). Specifically, the steps of backfeed procedure, LOP–AP–01, Revision 35, led to a Unit 1 scram because the prescribed switchyard configuration left both units connected to the 345 kilovolt (kv) ring bus, leaving the operating unit susceptible to the large in-rush current induced by the backfeed energization of the Unit 2 main power transformer. As a corrective action from Action Request (AR) 03973724, the licensee revised the backfeed procedure to eliminate the tie between the units on the ring bus when main power transformers are energized.

This performance deficiency was more than minor because it was associated with the Procedure Quality attribute of the Initiating Events Cornerstone, and adversely affected the Cornerstone objective of limiting the likelihood of events that upset plant stability because it resulted in a Unit 1 Scram. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At Power," issued June 19, 2012, the inspectors determined that this finding was of very low safety significance because, although the performance deficiency caused a reactor scram, it did not result in the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition. The inspectors determined there was no cross-cutting aspect because the performance deficiency was not indicative of licensee's current performance since the design modification occurred greater than 3 years before the event. This inspection report will also bring to closure the associated Licensee Event Report, (LER) 05000373/2017–003–00. (Section 4OA3)

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the failure to establish instructions with acceptance criteria that were appropriate to the circumstances for the brazing repair of the Unit Common Division I diesel generator (DG) starting air system. Specifically, through worker skill of the craft, the use of a heat sink device was relied upon to ensure that the adjacent joint of a brazed connection did not cross a temperature threshold that could have melted or otherwise unacceptably weakened the filler material; however, the procedure used did not contain any quantitative acceptance criteria for the adjacent joint temperature to determine that this important activity had been satisfactorily accomplished. The finding was considered more than minor because if left uncorrected it had the potential to lead to a more significant safety concern. Specifically, without quantitative acceptance criteria for temperature of the adjacent joints in close proximity of a brazed connection it is possible that joints could be reheated to near the solidus temperature of the filler material, resulting in joint weakening and potential failure. The licensee entered the issue into its CAP as AR 04090775. Corrective actions included revising procedures associated with brazing repairs to include a temperature value as a quantitative acceptance criteria for determining that important activities have been satisfactorily accomplished and to address the physical condition of the adjacent joint by verifying its conditions under work order (WO) 4702099 performance.

The inspectors determined that the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," dated October 7, 2016. Because the finding impacted the Mitigating Systems Cornerstone the inspectors screened the finding through IMC 0609, Appendix A, "The SDP for Findings At-Power," dated June 19, 2012. The finding screened as very low safety significance (Green) because it did not result in the loss of operability or functionality; thus, the inspectors answered "No" to all of the mitigating system screening questions. The inspectors determined that the finding had a cross-cutting aspect in the area of Human Performance, under the aspect of Work Management. Specifically, WO 4702099 designated DG air start system repair activities as non-code when an American Society of Mechanical Engineers (ASME) code brazing procedure specification, (BPS) 107–107–BR Revision 0, was being used to satisfy the standard of record, the diesel engine manufacturer's standards. [H.5] (Section 1R15.1.b(2))

Cornerstone: Barrier Integrity

Green. A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to ensure the adequacy of the design for the primary containment, suppression pool columns, downcomer and downcomer vent bracing. Specifically, the inspectors identified three representative examples where the licensee failed to perform adequate design calculations resulting in the design not being in conformance with Seismic Category I requirements as defined in Updated Final Safety Analysis Report (UFSAR) Sections 3.8.1.4.1, 3.8.1.5 and 3.8.6. The licensee documented these violation examples in ARs 4070065, 4074674 and 4070067 and initiated actions to restore compliance.

The inspectors determined the licensee's failure to perform adequate evaluations to demonstrate Seismic Category I compliance for the primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing was contrary to the design control measures per 10 CFR Part 50, Appendix B, requirements and was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the Barrier Integrity Cornerstone attribute of design control and adversely affected the Cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. The inspectors determined the finding could be evaluated using the SDP in accordance with Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012, Exhibit 3, "Barrier Integrity Screening Questions," for the Barrier Integrity Cornerstone (reactor containment). The inspector answered "no" to the Barrier Integrity questions for reactor containment. The finding screened as having very low safety significance (Green). The inspectors determined there was no cross-cutting aspect associated with this finding because the deficiency was a legacy design calculational issue and, therefore, was not indicative of licensee's current performance. (Section 1R15)

REPORT DETAILS

Summary of Plant Status

Units 1 and 2

With the exception of planned minor power changes for rod pattern adjustments and turbine valve surveillance testing, the plant remained at or near full–power throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station CAP procedures. Documents reviewed are listed in the Attachment to this report. The inspectors' reviews focused specifically on switch gear ventilation, ultimate heat sink and core standby cooling system (CSCS) due to their risk significance or susceptibility to cold weather issues.

This activity constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition—Severe Thunderstorm Watch

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for December 18, 2017, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On December 18, 2017,

the inspectors observed control room activities in addition to the readiness of the licensee's emergency alternating current (AC) power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or a loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station CAP procedures. Documents reviewed are listed in the Attachment to this report.

This activity constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01–05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2 high pressure core spray (HPCS) emergency DG;
- Unit 2 standby gas treatment system;
- Unit 1 residual heat removal (RHR) low pressure coolant injection lineup; and
- Unit 2 low pressure core spray.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, TS requirements, outstanding WOs, ARs, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable.
The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate

significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted four partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On October 30, 2017, the inspectors performed a complete system alignment inspection of Unit 2, Division III during Division II unavailability to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

These activities constituted one complete system walkdown sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant fire zones:

- 8C5, 2B RHR service water pump outlet valve hotwork;
- 3G, Unit 2 transient combustible control;
- 4F1, Unit 1, Division I, essential switchgear room, at 710' 6"; and
- 4E1, Unit 1, auxiliary equipment room, at 731' 0".

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.
The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event.
Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.
Documents reviewed are listed in the Attachment to this report.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On November 9, 2017, the inspectors observed a fire brigade activation for drill scenario 17–Q4–01, a combustible liquid on fire inside the Unit 2 hydrogen seal oil berm. Based on this observation, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's CAP documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 1, Division III CSCS pump room, freeze seal for valve replacement; and
- Unit 2, Division I CSCS pump room 2A RHR service water pump seal leak.

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

This inspection constituted two internal flooding samples as defined in IP 71111.06–05.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of 1 B RHR heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents reviewed for this inspection are listed in the Attachment to this document.

This activity constituted one annual heat sink performance sample as defined in IP 71111.07–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On October 18, 2017, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and that training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On November 9, 2017, the inspectors observed Unit 1 Level 8 turbine trip testing and on November 13, the inspectors observed Unit 1 Rod 220 insertion for maintenance by operators in the control room. These were activities that required heightened awareness or were related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;

- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This activity constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Biennial Written Examination, and the Annual Operating Test, administered by the licensee from October 17, 2017, through November 17, 2017, as required by 10 CFR 55.59(a). The results were compared to the thresholds established in Inspection Manual Chapter 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process (SDP)," to assess the overall adequacy of the licensee's Licensed Operator Requalification Training (LORT) Program to meet the requirements of 10 CFR 55.59. (02.02)

This inspection constituted one annual licensed operator requalification examination results sample as defined in Inspection Procedure (IP) 71111.11–05.

b. Findings

No findings were identified.

.3 Biennial Review (71111.11B)

a. Inspection Scope

The following inspection activities were conducted during the weeks of October 23 and October 30, 2017, to assess: (1) the effectiveness and adequacy of the facility licensee's implementation and maintenance of its systems approach to training based LORT Program, put into effect to satisfy the requirements of 10 CFR 55.59; and (2) conformance with the requirements of 10 CFR 55.46 for use of a plant referenced simulator to conduct operator licensing examinations and for satisfying experience requirements; and (3) conformance with the operator license conditions specified in 10 CFR 55.53. The documents reviewed are listed in the Attachment to this report.

- Licensee Requalification Examinations (10 CFR 55.59(c); SAT Element 4 as Defined in 10 CFR 55.4): The inspectors reviewed the licensee's program for development and administration of the LORT biennial written examination and annual operating tests to assess the licensee's ability to develop and administer examinations that are acceptable for meeting the requirements of 10 CFR 55.59(a).

  - The inspectors conducted a detailed review of one biennial requalification written examination version to assess content, level of difficulty, and quality of the written examination materials. (02.03)

  - The inspectors conducted a detailed review of 13 job performance measures and 4 simulator scenarios to assess content, level of difficulty, and quality of the operating test materials. (02.04)

  - The inspectors observed the administration of the annual operating test to assess the licensee's effectiveness in conducting the examination(s), including the conduct of pre-examination briefings, evaluations of individual operator and crew performance, and post-examination analysis. The inspectors evaluated the performance of one crew in parallel with the facility evaluators during dynamic simulator scenarios, and evaluated various licensed crew members concurrently with facility evaluators during the administration of several job performance measures. (02.05)

  - The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the last requalification examinations and the training planned for the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans. (02.07)

- Conformance with Examination Security Requirements (10 CFR 55.49): The inspectors conducted an assessment of the licensee's processes related to examination physical security and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of Examinations and Tests." The inspectors observed the implementation of physical security controls (e.g., access restrictions and simulator I/O controls) and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the inspection period. (02.06)
- Conformance with Operator License Conditions (10 CFR 55.53): The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators, and which control room positions were granted watch-standing credit for maintaining active operator licenses. Additionally, medical records for eight licensed operators were reviewed for compliance with 10 CFR 55.53(l). (02.08)
- Conformance with Simulator Requirements Specified in 10 CFR 55.46: The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements. The inspectors reviewed a sample of simulator

performance test records (e.g., transient tests, malfunction tests, scenario based tests, post-event tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy corrective action process to ensure that simulator fidelity was being maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics. (02.09)

- Problem-Identification and Resolution (10 CFR 55.59(c); SAT Element 5 as Defined in 10 CFR 55.4): The inspectors assessed the licensee's ability to identify, evaluate, and resolve problems associated with licensed operator performance (a measure of the effectiveness of its LORT Program and their ability to implement appropriate corrective actions to maintain its LORT Program up to date). The inspectors reviewed documents related to licensed operator performance issues (e.g., licensee condition/problem identification reports including documentation of plant events and review of industry operating experience from previous 2 years). The inspectors also sampled the licensee's quality assurance oversight activities, including licensee training department self-assessment reports. (02.10)

This inspection constituted one biennial Licensed Operator Requalification Program inspection sample as defined in IP 71111.11–05.

b. Findings

(Open) Unresolved Item: Complete versus Truncated Shifts on Proficiency Watches

Introduction: The inspectors identified an unresolved item (URI) related to the adequacy of the shifts for proficiency watches stood by specific reactor operators (ROs). Clarification was requested for whether the 8-hour proficiency watches stood by only these specific ROs, should be considered complete or truncated watches, which may not meet the requirements of 10 CFR 55.53(e).

Description: Title 10 CFR 55.53(e) states, in part: "To maintain active status, the licensee shall actively perform the functions of an operator or senior operator on a minimum of seven 8–hour or five 12–hour shifts per calendar quarter." In NUREG–1021, Revision 11, ES-605 further explains that: "In accordance with 10 CFR 55.53(e), to maintain an active status, licensed operators are required to maintain their proficiency by 'actively performing the functions of an operator or senior operator' on at least seven 8–hour or five 12–hour shifts per calendar quarter. This requirement may be completed with a combination of complete 8– and 12–hour shifts (in a position appropriately credited for watch-standing proficiency as discussed below) at sites having a mixed-shift schedule, and watches shall not be truncated when the operator satisfies the minimum quarterly requirement (56 hours). Overtime may be credited if the overtime work is in a position appropriately credited for watch-standing proficiency."

As documented in AR 04070501, dated November 3, 2017, it has been LaSalle Station's practice to use an individual's normal shift work hours to determine the length of his/her proficiency watch. While the operating shift crews were assigned to 12–hour shifts, those licensed ROs assigned to other staff positions at LaSalle normally worked 8 hours per day. LaSalle refers to these individuals as Administrative ROs. Thus, when

LaSalle's Administrative ROs stood their proficiency watches, they stood 8–hour watches, and turned over to another operator to complete the normal 12–hour operating shift.

As stated in this AR, 8–hour shifts minimized the overtime costs to maintain active licenses for these individuals. The Operator Licensing and Training Branch was requested via Regional Office Interaction ROI–17–25, "Clarification of Complete vs. Truncated Shift for Proficiency Watches," because Administrative ROs stood 8–hour proficiency watches, while all other operators stood 12–hour shifts. Clarification is needed from the Operator Licensing and Training Branch and the Office of the General Counsel to determine if the current practice meets the requirements of 10 CFR 55.53(e) to maintain an operating license in an active status. **(URI 050000373/2017004–01; 050000374/2017004–01, Complete versus Truncated Shifts on Proficiency Watches)**

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- primary containment ventilation, Unit 1A VP chiller trip;
- Unit 1 main steam line radiation monitors; and
- Unit 1 switchgear ventilation.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This activity constituted three quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment to verify that the appropriate risk assessments were performed prior to removing equipment for work. The inspectors reviewed Units 1 and 2, Division I protected equipment during yellow risk work for this sample.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

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

These activities constituted one maintenance risk assessment and emergent work sample as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- unit-common DG inoperable, due to disconnected air line;
- secondary containment operability for unplanned plant barrier impairment; and
- Unit 1A DG operability with AC and Direct Current soakback pumps tagged out.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the

appropriate sections of the TS and UFSAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of CAP documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

This operability inspection constituted three samples as defined in IP 71111.15–05.

b. Findings

(1) Failure to Establish Brazing Repair Procedures with Appropriate Acceptance Criteria

Introduction. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the failure to establish instructions with acceptance criteria that were appropriate to the circumstances for the brazing repair of the Unit Common Division I DG starting air system. Specifically, through worker skill-of-the-craft, the use of an unqualified heat sink device was relied upon to ensure that the adjacent joint of a brazed connection did not cross a temperature threshold that could have melted or otherwise unacceptably weakened the filler material; however, the procedure used did not contain any quantitative acceptance criteria for the adjacent joint temperature to determine that this important activity had been satisfactorily accomplished.

Description. On October 22, 2017, an operator performing rounds in the Unit Common Division I DG room found an air-line disconnected at the pipe-to-elbow joint of a brazed fitting on the safety-related portion of the 'A' starting air train. The unit-common Division I DG was subsequently declared inoperable. The disconnected fitting was repaired using WO 4702099 and procedure CC–AA–501–1009, "Brazing General Requirements and Tubing Repairs," Revision 1. The DG was subsequently started for post-maintenance testing and returned to operable status on October 22, 2017.

The inspectors conducted a walkdown of the system and noted that only one of the two pipe-to-elbow joints had been re-brazed and that the two joints were in very close proximity to one another. The inspectors reviewed procedure CC–AA–501–1009 and noted that it neither contained measures to protect joints in close proximity from overheating nor gave acceptance criteria for determining if the repair activity had been satisfactorily accomplished (e.g. take a temperature measurement of brazed connections within the area of influence repair activities, or use another widely-used method of visually ensuring that a specific temperature threshold is not reached, etc.). The inspectors raised a concern with the licensee that the joint adjacent to the brazing site may have been overheated during the repair, thus weakening the filler material of the joint.

The licensee stated that, through worker skill-of-the-craft, the use of a heat sink device was relied upon to ensure the nearby elbow joint was not adversely affected by the repair of the disconnected joint, but that no quantitative measures were taken to ensure its efficacy in protecting the adjacent joint from overheating. The licensee also stated that based on the measures taken to protect the adjacent joint, a visual inspection of the

area, and a successful post maintenance test, that they did not have a concern regarding the operability of the DG or DG air start system. The licensee's corrective actions included revising procedures associated with brazing repairs to include a temperature value as a quantitative acceptance criteria for determining that important activities have been satisfactorily accomplished and to address the physical condition of the adjacent joint by verifying its conditions under WO 4702099 performance. Since the licensee evaluated the adjacent joint and determined it to be operable on the basis of the heat sink device and a successful pressure test, the inspectors have no immediate safety concern in the intervening time before the licensee's full evaluation of this component is completed in the future. The inspectors consider this component to be operable but non-conforming, in the interim.

Analysis. The inspectors determined that the failure to establish instructions with acceptance criteria that were appropriate to the circumstances for the brazing repair of the safety-related portion of the Unit Common Division I DG starting air system was not in accordance with the requirements of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," and was a performance deficiency. Using guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated February 13, 2017, the inspectors determined that the performance deficiency was more than minor, because if left uncorrected it had the potential to lead to a more significant safety concern. Specifically, without quantitative acceptance criteria for temperature of the adjacent joints in close proximity of a brazed connection it is possible that joints could be reheated to near the solidus temperature of the filler material, resulting in joint weakening and potential failure.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," dated October 7, 2016. Because the finding impacted the Mitigating Systems Cornerstone the inspectors screened the finding through IMC 0609, Appendix A, "The SDP for Findings At-Power," dated June 19, 2012. The finding screened as very low safety significance (Green) because it did not result in the loss of operability or functionality; thus, the inspectors answered "No" to all of the mitigating system screening questions.

The inspectors determined that the finding had a cross-cutting aspect in the area of Human Performance, under the aspect of Work Management. Specifically, WO 4702099 designated DG air start system repair activities as non-code when an ASME code brazing procedure specification, BPS 107–107–BR, Revision 0, was used to satisfy the standard of record, the diesel engine manufacturer's standards. [H.5]

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, as of October 22, 2017, the procedures used for the repair of the safety-related portion of the DG starting air system did not include appropriate qualitative or quantitative acceptance criteria. Specifically, procedure CC–AA–501–1009 relied upon the worker to use skill-of-the-craft to prevent the adjacent joint from reaching its melting point through the use of a heat sink device; however, did not contain acceptance criteria for adjacent joint temperature.

Because this violation is of very low safety significance and it was entered into the licensee's CAP as AR 04090775 this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000373/2017004–02; 05000374/2017004–02, Failure to Establish Brazing Repair Procedures with Appropriate Acceptance Criteria)**

.2 (Closed) Unresolved Item 05000373; 05000374/2016001–01: Adequacy of Changes to Pool Swell Analysis

a. Inspection Scope

During the 2016 first quarter integrated inspection period, the inspectors reviewed the operability evaluation associated with loss of coolant accident suppression pool analysis. The inspectors identified an unresolved item involving changes to the methodology and design assumptions of the suppression pool analysis and whether those aforementioned changes provide a reasonable expectation that the affected systems, structures and components were operable.

During the follow-up inspection activities to the Unresolved Item (URI), the inspectors reviewed LaSalle County Station, Units 1 and 2—Issuance of Amendments Re: Request to Revise Suppression Pool Swell Design Analysis and the Facility Licensing Basis (CAC NOS. MF8702 AND MF8703); dated October 30, 2017. The inspectors also reviewed Operability Evaluation OE 12–003; Potential to Increase Pool Swell Loads; Revision 5 and supporting calculations of record. The inspectors determined the licensee's operability evaluation provided a reasonable expectation of operability. Based on this review, the inspectors sufficiently resolved these concerns and consider URI 05000373; 05000374/2016001–01 closed with no performance deficiencies identified; however, during this review, the inspectors identified one additional issue described below.

This operability inspection constituted one sample as defined in IP 71111.15–05.

b. Findings

Primary Containment Structure, Suppression Pool Columns, Downcomer Vent and Downcomer Vent Bracing Did Not Meet Seismic Category I Requirements

Introduction. A finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to ensure the adequacy of the design for the primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing. Specifically, the inspectors identified three representative examples where the licensee failed to perform adequate design calculations resulting in the design not being in conformance with Seismic Category I requirements as defined in UFSAR Sections 3.8.1.4.1, 3.8.1.5 and 3.8.6.

Description. UFSAR Table 3.2–1 delineated the primary containment structure and downcomer vent as Seismic Category I and meeting the quality assurance requirements of 10 CFR Part 50 Appendix B. The suppression pool columns were part of the primary containment structure and support the drywell floor. The columns were designed to transfer design loading from the drywell floor to basemat.

In UFSAR Section 3.8.1.1.1.1 described the primary containment as utilizing a Mark II over/under pressure-suppression configuration. The primary containment consisted of a steel pressure vessel enclosed by a concrete shield wall both supported by a concrete basemat. The primary containment was enclosed by the reactor building, a reinforced-concrete structure functioning as a secondary containment.

The drywell was connected to the suppression chamber by downcomer pipes. Steam that could be released in the drywell during a postulated loss-of-coolant accident was channeled through these downcomer pipes into the suppression pool where it is condensed thus effecting pressure-suppression. This would result in a lower pressure and temperature.

The downcomer vent pipes were braced at Elevation 697'-1" and Elevation 721'-0". The downcomer vent bracing design function was to provide horizontal restraint for applied lateral loading on downcomer vent pipes due to the seismic and loss-of-coolant accident design event. The downcomer vent and downcomer vent bracing design requirements are delineated in Section 5.3.3.4 of LaSalle County Station, "Mark II-Design Assessment Report (LSCS-DAR)," Commonwealth Edison Company, Chicago, Illinois, September, 1982. The design assessment report was incorporated by reference in UFSAR Section 3.8.6.

During a review of calculations for the primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing, the inspectors identified the following three representative examples in which the licensee failed to meet the design requirements:

- Calculation No. 195B; Containment Assessment; Revision 0; and Calculation No. 161I; Suppression Pool Columns; Revision 0. UFSAR Section 3.8.1.4.1 stated, in part, "The design and analysis procedure is in full compliance with the requirements of Article CC–3000 of the ASME B&PV Code, Section III, Division 2…" The design yield strength of reinforcement shall not exceed 60,000 psi as described in Section CC–3422 of Article CC–3000. In addition, UFSAR Section 3.8.1.5 defined the allowable of Fy as the minimum guaranteed reinforcing steel yield strength. The licensee used certified material test reports or actual material yield strength for the reinforcing steel in the evaluation of the containment structure and suppression pool columns. The use of actual material yield strength did not meet American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code Section III, Division 2 and UFSAR requirements. The licensee documented these deficiencies in Issue Report No. 4070065; NRC Id: Clarification on Material Strength Values in Calcs; dated October 16, 2017.

- Calculation No. L–002547; Assessment of Containment Wall, Basemat, Liner, Reactor Pedestal, Downcomer Bracing, Drywell Floor, and Suppression Pool Columns for 105 percent Power Uprate; Revision 0. As delineated in Section 5.3.3.4 of LaSalle County Station, "Mark II-Design Assessment Report, the stresses within the downcomer were considered acceptable if they satisfy the ASME B&PV Code, Section III, Subsection NE. As permitted by Subsection NE–1120 for Metallic Containment components the downcomers were analyzed using Subsection NB–3650 of Section III. The licensee did not use the ASME code acceptance limits. The licensee documented these deficiencies in Issue Report No. 4074674; NRC Id: Clarification of Design Basis Code of Downcomer Vent; dated November 14, 2017.

- Calculation No. L–002547; Assessment of Containment Wall, Basemat, Liner, Reactor Pedestal, Downcomer Bracing, Drywell Floor, and Suppression Pool Columns for 105 percent Power Uprate; Revision 0. Section 5.3.3.4 of LaSalle County Station Mark II-Design Assessment Report described the allowable acceptance limits are based on the 1.6 times the American Institute of Steel Construction (AISC) allowables but no greater than 0.95 times Fy (minimum specified yield strength of section). The licensee increased the allowable stresses by 50 percent based on using plastic section modulus properties which exceeded the elastic acceptance limits set forth in Section 5.3.3.4 of LaSalle County Station Mark II-Design Assessment Report. The use of plastic section modulus properties would allow for permanent deformation of the material. Also, the downcomer bracing gusset plate uses plastic section modulus properties as well. Lastly, the licensee used a dynamic increase factor of 10 percent to increase the allowable acceptance limits. The dynamic increase factor was not contained in Section 5.3.3.4 of LaSalle County Station Mark II-Design Assessment Report. The licensee documented these deficiencies in Issue Report No. 4070067; NRC Id: Clarification on Acceptance Criteria in Calcs; dated October 16, 2017.

The inspectors reviewed the operability evaluation in accordance with IMC 0326; Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety; dated November 20, 2017 to assess whether the nonconforming primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing were operable. The inspectors identified no performance deficiencies with the operability evaluation. In response to the inspector's concern, the licensee initiated CAP documents as AR 4070067; NRC Id: Clarification on Acceptance Criteria in Calcs; dated October 16, 2017, AR 4070065; NRC Id: Clarification on Material Strength Values in Calcs; dated October 16, 2017 and AR 4074674; NRC Id: Clarification of Design Basis Code of Downcomer Vent; dated November 14, 2017.

Analysis. The inspectors determined the licensee's failure to perform adequate evaluations to demonstrate Seismic Category I compliance for the primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing was contrary to the design control measures per 10 CFR Part 50, Appendix B, requirements and was a performance deficiency.

The performance deficiency was determined to be more than minor because the performance deficiency was associated with the Barrier Integrity Cornerstone attribute of design control and adversely affected the Cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Specifically, compliance with Seismic Category I design basis requirements was to ensure the primary containment structure, suppression pool columns, downcomer vents and downcomer vent bracing would function as required during a Seismic Category I design basis event and not adversely affect the function of the containment barrier.

The inspectors determined the finding could be evaluated using the SDP in accordance with Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process for Findings At-Power," dated June 19, 2012, Exhibit 3, "Barrier Integrity Screening Questions," for the Barrier Integrity cornerstone (reactor containment). The

inspector answered “no” to the Barrier Integrity questions for reactor containment. The finding screened as having very low safety significance (Green).

The inspectors determined there was no cross-cutting aspect associated with this finding because the deficiency was a legacy design calculational issue and, therefore, was not indicative of licensee’s current performance.

Enforcement. Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” states in part, that the 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,

- On October 16, 2017, in Calculation No. 195B; Revision 0 and Calculation No. 161I; Revision 0, the licensee’s design control measures failed to verify adequacy of the primary containment structure and suppression pool column design. Specifically the yield strength of reinforcement did not meet UFSAR 3.8.1.4.1 and 3.8.1.5 requirements.

- On November 14, 2017, in Calculation No. L–002547; Revision 0, the licensee’s design control measures failed to verify adequacy of the downcomer vent design. Specifically the acceptance limits did not meet ASME B&PV Code, Section III, Subsection NE.

- On October 16, 2017, in Calculation No. L–002547; Revision 0, the licensee’s design control measures failed to verify adequacy of the downcomer vent bracing design. Specifically the licensee’s downcomer vent bracing calculation used the acceptance limits based on a plastic section modulus and a dynamic increase factor. The use of these acceptance limits would allow for permanent deformation of the material. The use of these acceptance limits did not meet UFSAR 3.8.6 requirements.

Because this violation was of very low safety significance (Green) and it was entered into the licensee’s CAP as ARs 4070067, 4070065 and 4074674, this violation is being treated as an NCV in accordance with Section 2.3.2 of the Enforcement Policy. **(NCV 05000373/2017004–03; 05000374/2017004–03, Primary Containment Structure, Suppression Pool Columns, Downcomer Vent and Downcomer Vent Bracing Did Not Meet Seismic Category I Requirements)**

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the Unit 2 Division III HPCS fuel oil storage tank abandoned diesel fire pump isolation permanent modification. The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the Technical Specification (TS), as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors, as applicable, observed ongoing and completed work activities

to ensure that the modification was installed as directed and consistent with the design control documents; the modification operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modification did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This activity constituted one permanent plant modification sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance testing (PMT) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 reactor core isolation cooling (RCIC) rupture disc replacement;
- Unit 2A residual heat removal (RHR) service water pump outlet valve replacement;
- Unit 2B RHR service water pump outlet valve replacement;
- Unit 2 diesel fire pump fuel oil transfer pump PMT after electrical maintenance;
- B diesel fire pump PMT after annual maintenance;
- Unit 2A RHR service water pump discharge valve replacement; and
- Unit 2A RHR low pressure switch replacement (2E12–N512A).

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed CAP documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the

problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This activity constituted seven post-maintenance testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 1 RCIC cold start (routine); and
- Unit 1 to Unit 2 tie bus duct inspection 14ZY to Z4ZY (routine).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, ASME code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;

- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

These inspections constituted two routine surveillance testing samples as defined in IP 71111.22, Sections–02 and–05. In addition, the inspectors did not identify any performance degradation in the reactor coolant system leakage for the entire cycle. The reactor coolant system leak detection inspection sample was not performed as defined in IP 71111.22, Section–02.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The regional inspectors performed an in-office review of the latest revisions to the Emergency Plan, Emergency Action Levels, and Emergency Action Level Bases document to determine if these changes decreased the effectiveness of the Emergency Plan. The inspectors also performed a review of the licensee's 10 CFR 50.54(q) change process, and Emergency Plan change documentation to ensure proper implementation for maintaining Emergency Plan integrity.

The NRC's review was not documented in a safety evaluation report, and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection. The specific documents reviewed during this inspection are listed in the Attachment to this report.

This Emergency Action Level and Emergency Plan Change inspection constituted one sample as defined in IP 71114.04.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS5 Radiation Monitoring Instrumentation (71124.05)

.1 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors assessed select portable survey instruments that were available for use for current calibration and source check stickers, and instrument material condition and operability.

The inspectors observed licensee staff demonstrate performance checks of various types of portable survey instruments. The inspectors assessed whether high-range instruments responded to radiation on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. The inspectors compared monitor response with actual area conditions for selected monitors.

The inspectors assessed the functional checks for select personnel contamination monitors, portal monitors, and small article monitors to verify they were performed in accordance with the manufacturer's recommendations and licensee procedures.

These inspection activities constituted one complete sample as defined in Inspection Procedure (IP) 71124.05–05.

b. Findings

No findings were identified.

.2 Calibration and Testing Program (02.03)

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance. The inspectors assessed whether appropriate corrective actions were implemented in response to indications of degraded instrument performance.

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use and assessed whether check sources were appropriate and aligned with the plant's isotopic mix. The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

Inspectors reviewed select containment high-range monitor calibration and assessed whether an electronic calibration was completed for all range decades, with at least one

decade at or below 10 rem/hour calibrated using an appropriate radiation source, and calibration acceptance criteria was reasonable.

The inspectors reviewed select monitors used to survey personnel and equipment for unrestricted release to assess whether the alarm setpoints were reasonable under the circumstances to ensure that licensed material was not released from the site. The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

The inspectors reviewed calibration documentation for select portable survey instruments, area radiation monitors, and air samplers. The inspectors reviewed detector measurement geometry and calibration methods for portable survey instruments and area radiation monitors calibrated onsite and observed the licensee demonstrate use of the instrument calibrator. The inspectors assessed whether appropriate corrective actions were taken for instruments that failed performance checks or were found significantly out of calibration, and that the licensee had evaluated the possible consequences of instrument use since the last successful calibration or performance check.

The inspectors reviewed the current output values for instrument calibrators. The inspectors assessed whether the licensee periodically measured calibrator output over the range of the instruments used with measuring devices that have been calibrated by a facility using National Institute of Standards and Technology traceable sources and corrective factors for these measuring devices were properly applied in its output verification.

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

These inspection activities constituted one complete sample as defined in IP 71124.05–05.

b. Findings

No findings were identified.

.3 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring instrumentation.

These inspection activities constituted one complete sample as defined in IP 71124.05–05.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

.1 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down select effluent radiation monitoring systems to evaluate whether the monitor configurations aligned with Offsite Dose Calculation Manual (ODCM) descriptions and to observe the materiel condition of the systems.

The inspectors walked down selected components of the gaseous and liquid discharge systems to evaluate whether equipment configuration and flow paths align with plant documentation and to assess equipment materiel condition. The inspectors also assessed whether there were potential unmonitored release points, building alterations which could impact effluent controls, and ventilation system leakage that communicated directly with the environment.

For equipment or areas associated with the systems selected for review that were not readily accessible, the inspectors reviewed the licensee's materiel condition surveillance records.

The inspectors walked down filtered ventilation systems to assess for conditions such as degraded high-efficiency particulate air/charcoal banks, improper alignment, or system installation issues that would impact the performance or the effluent monitoring capability of the effluent system.

As available, the inspectors observed selected portions of the routine processing and discharge of radioactive gaseous effluent to evaluate whether appropriate treatment equipment was used and the processing activities aligned with discharge permits.

The inspectors determined if the licensee has made significant changes to their effluent release points.

As available, the inspectors observed selected portions of the routine processing and discharging of liquid waste to determine if appropriate effluent treatment equipment was being used and that radioactive liquid waste was being processed and discharged in accordance with procedure requirements and aligned with discharge permits.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

.2 Calibration and Testing Program (02.03)

a. Inspection Scope

The inspectors reviewed calibration and functional tests for select effluent monitors to evaluate whether they were performed consistent with the ODCM. The inspectors assessed whether National Institute of Standards and Technology traceable sources were used, primary calibration represented the plant nuclide mix, secondary calibrations verified the primary calibration, and calibration encompassed the alarm set points.

The inspectors assessed whether effluent monitor alarm set points were established as provided in the ODCM and procedures.

The inspectors evaluated the basis for changes to effluent monitor alarm set points.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

.3 Sampling and Analyses (02.04)

a. Inspection Scope

The inspectors reviewed select effluent sampling activities and assessed whether adequate controls had been implemented to ensure representative samples were obtained.

The inspectors reviewed select effluent discharges made with inoperable effluent radiation monitors and assess whether controls were in place to ensure compensatory sampling was performed consistent with the ODCM and that those controls were adequate to prevent the release of unmonitored effluents.

The inspectors determined whether the facility was routinely relying on the use of compensatory sampling in lieu of adequate system maintenance.

The inspectors reviewed the results of the Inter-Laboratory Comparison Program to evaluate the quality of the radioactive effluent sample analyses and assessed whether the Inter-Laboratory Comparison Program included hard-to-detect isotopes as appropriate.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

.4 Instrumentation and Equipment (02.05)

a. Inspection Scope

The inspectors reviewed the methodology used to determine the effluent stack and vent flow rates to determine if the flow rates were consistent with plant documentation, and that differences between assumed and actual stack and vent flow rates did not affect the results of the projected public doses.

The inspectors assessed whether surveillance test results for TS required ventilation effluent discharge systems met TS acceptance criteria.

The inspectors assessed calibration and availability for select effluent monitors used for triggering emergency action levels or for determining protective action recommendations.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

.5 Dose Calculations (02.06)

a. Inspection Scope

The inspectors reviewed significant changes in reported dose values compared to the previous radiological effluent release report to evaluate the factors which may have resulted in the change.

The inspectors reviewed radioactive liquid and gaseous waste discharge permits to assess whether the projected doses to members of the public were accurate.

Inspectors evaluated the isotopes that are included in the source term to assess whether analysis methods were sufficient to satisfy detectability standards. The review included the current Part 61 analyses to ensure hard-to-detect radionuclides are included in the source term.

The inspectors reviewed changes in the licensee's offsite dose calculations to evaluate whether changes were consistent with the ODCM and Regulatory Guide 1.109. Inspectors reviewed meteorological dispersion and deposition factors used in the ODCM and effluent dose calculations to evaluate whether appropriate factors were being used for public dose calculations.

The inspectors reviewed the latest Land Use Census to assess whether changes have been factored into the dose calculations.

For select radioactive waste discharges, the inspectors evaluated whether the calculated doses where within the 10 CFR 50, Appendix I, and TS dose criteria.

The inspectors reviewed select records of abnormal radioactive waste discharges to ensure the discharge was monitored by the discharge point effluent monitor. Discharges

made with inoperable effluent radiation monitors, or unmonitored leakages were reviewed to ensure that an evaluation was made to account for the source term and projected doses to the public.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

.6 Problem Identification and Resolution (02.07)

a. Inspection Scope

Inspectors assessed whether problems associated with the Effluent Monitoring and Control Program were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. In addition, they evaluated the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving radiation monitoring and exposure controls.

These inspection activities constituted one complete sample as defined in IP 71124.06–05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (PI) Units 1 and 2, for the fourth quarter 2016 through the third quarter 2017. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, and NUREG–1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance WOs, ARs, event reports and NRC Integrated Inspection Reports for fourth quarter 2016 through the third quarter 2017 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's corrective action program (CAP) database to determine if any problems had been identified with the PI data collected or

transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This activity constituted two safety system functional failures samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index—Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Heat Removal System PI, Units 1 and 2, for the fourth quarter 2016 through the third quarter 2017. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the fourth quarter 2016 through the third quarter 2017 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index—Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI, Units 1 and 2 for the fourth quarter 2016 through the third quarter 2017. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, ARs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the fourth quarter 2016 through the third quarter 2017 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this

indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This activity constituted two MSPI cooling water system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity PI for LaSalle County Station, Units 1 and 2, for the period from the third quarter 2016 through the third quarter 2017. The inspectors used PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's reactor coolant system chemistry samples, technical specification requirements, ARs, event reports and NRC Integrated Inspection Reports to validate the accuracy of the submittals. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two reactor coolant system specific activity samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.5 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Exposure Control Effectiveness PI for the period from the third quarter 2016 through the third quarter 2017. The inspectors used PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted

walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.6 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the Radiological Effluent Technical Specification (TS)/ODCM radiological effluent occurrences PI for the period from the third quarter 2016 through the third quarter 2017. The inspectors used PI definitions and guidance contained in the Nuclear Energy Institute Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's CAP database and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one Radiological Effluent TS/ODCM radiological effluent occurrences sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, adequate attention was being given to timely corrective actions, and adverse trends were identified and addressed. Some minor issues were entered into the licensee's CAP as a result of the inspectors' observations; however, they are not discussed in this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6–month period of July through December 2017, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the corrective action program in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This activity constituted one semi-annual trend review inspection sample as defined in IP 71152.

b. Observations

During the review of recent inspection issues for potential trend identification, the inspectors followed up on the battery cell issue (documented in Section 1R15.1 of this report). Initially, the inspectors' concerns were not captured accurately by the licensee and placed into the CAP, which required follow-up conversations to clarify the issue. The inspectors discussed this communication issue with the licensee, and the licensee implemented a corrective action to discuss the communication issues experienced with each operating crew. The inspectors determined that this corrective action was effective because no further issues were experienced, therefore this issue did not constitute a trend.

c. Findings

No findings were identified

.3 Annual Follow-Up of Selected Issues: Through Wall Leak Identified on Lake Screen House Service Water Line

a. Inspection Scope

The inspectors selected the following ARs for in-depth review:

- AR 4066977; "NRC Identified-White Crust on WS Piping Under 2WS325";
- AR 4068598; "NRC Identified Thru Wall Seepage Identified on 0WS07AE";
- AR 4074746; "Extent of Condition Review for 0WS07AE Seepage";
- AR 4075479; "UT Results for 0WS07AE"; and
- AR 4081428; “WR Required for Extent of Condition Inspections”.

As appropriate, the inspectors verified the following attributes during their review of the licensee's corrective actions for the above ARs and other related ARs:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the root and contributing causes of the problem;
- identification of corrective actions, which were appropriately focused to correct the problem;
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue;
- effectiveness of corrective actions taken to preclude repetition; and
- evaluate applicability for operating experience and communicate applicable lessons learned to appropriate organizations.

The inspectors discussed the corrective actions and associated evaluations with licensee personnel.

This activity constituted one in-depth problem identification and resolution inspection sample as defined in IP 71152.

b. Observations and Assessments

On October 25, 2017, while conducting a routine plant-status walkdown of the Lake Screen House, the inspectors identified a small through wall leak on the 0WS07AE Service Water Line, a line that supplies non-safety related loads. This issue was documented in the licensee’s CAP as ARs 4066977 and 4068598. The licensee determined that a postulated break of this line would not challenge safety related equipment.

The licensee performed an ultrasonic examination of the service water line in question to evaluate the wall thickness in the area of the leak. The licensee determined there were several small sections of piping that were less than the minimum required wall thickness. The licensee evaluated the localized sections of thinned piping and determined that it did

not present a challenge to the structural integrity or invalidate the seismic qualification of the line as documented in AR 4075479.

The licensee identified a bent chemical injection line, internal to the pipe, as a potential cause of the thinning in AR 4075479 due to accelerated corrosion. The licensee has corrective actions in place to inspect the chemical injection line for damage as well as to conduct ultrasonic inspections for pipe thinning near chemical injection sites on the other service water lines. The licensee performed a temporary repair of the line on November 22, 2017, and has a corrective action in place to perform a permanent repair of the line under work order (WO) 4706723. The inspectors reviewed the licensee's corrective actions and had no safety concerns.

c. Findings

No findings were identified.

.4 Annual Follow-Up of Selected Issues: Failure to Update the UFSAR for an Item in the Interim Abandonment Process

a. Inspection Scope

During review of the equipment modification sample described in Section 1R18.1 of this report, the inspectors noted that an automatic action described in Section 9.5.4.2 of the Updated Final Safety Analysis Report (UFSAR), Revision 18, had not been removed from the description of the Diesel Fuel Oil Transfer System in a timely manner as a result of the abandonment of Diesel Fire Pump Fuel Oil Transfer Pump Suction Solenoid Valve. The inspectors chose to do an expanded scope review of the Interim Abandonment Process as a selected issue follow-up to determine if other UFSAR system descriptions had been similarly affected by the removal of functions or automatic actions due to abandoned equipment.

The inspectors selected the following AR relating to interim abandonment of equipment for in-depth review:

- AR 4070286; "NRC Question Regarding Abandonment of 1(2)DO024 Function"

As appropriate, the inspectors verified the following attributes during their review of the licensee's corrective actions for the above AR and other related ARs:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the root and contributing causes of the problem;
- identification of corrective actions, which were appropriately focused to correct the problem;
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue;
- effectiveness of corrective actions taken to preclude repetition; and
- evaluate applicability for operating experience and communicate applicable lessons learned to appropriate organizations.

The inspectors discussed the corrective actions and associated evaluations with licensee personnel.

This activity constituted one in-depth problem identification and resolution inspection sample as defined in IP 71152.

b. Observations and Assessments

After further review of the 2001 abandonment of diesel fire pump fuel oil transfer pump suction solenoid valves, the inspectors identified the issue to be a violation of 10 CFR 50.71(e) since the abandonment affected a function described in the UFSAR and was not updated in a timely manner. However, using the guidance in the NRC Enforcement Policy, Section 2.3.1, Dated January 28, 2013, and the Enforcement Manual, Section 7.3, Dated December 22, 2008, the inspectors determined the issue to be a minor violation because the inspectors concluded that the inaccurate information did not have a material impact on safety or licensed activities. Additionally, the licensee had documented the issue in their CAP as AR 4070286 and committed to updating the affected section of the UFSAR by April 30, 2018. The inspectors conducted a review of the UFSAR for other equipment in the interim abandonment process. The inspectors did not identify any other examples of inaccurate descriptions of equipment functions in the UFSAR, or examples of equipment abandonments impacting system safety functions.

c. Findings

No findings were identified.

.5 Annual Follow-Up of Selected Issues: Feed Pump Piping Rupture in the Unit 1 Low Pressure Heater Bay

a. Inspection Scope

On September 28, 2017, a piping rupture occurred in the Unit 1 low pressure heater bay, resulting in water collecting in the lower level of the turbine building. The rupture was caused by a failure of a Victaulic-style mechanical coupling on a 4" fire protection (FP) line. There was no impact to safety-related equipment as a result of the event, however the inspectors selected the issue for follow-up due to the potential for transient initiation due to wetted equipment and to review the licensee's extent of condition determination.

The inspectors selected the following AR for in-depth review:

- AR 4056713; "FP Piping Rupture Requires Repair".

As appropriate, the inspectors verified the following attributes during their review of the licensee's corrective actions for the above AR and other related ARs:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the root and contributing causes of the problem;
- identification of corrective actions, which were appropriately focused to correct the problem;
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue;
- effectiveness of corrective actions taken to preclude repetition; and
- evaluate applicability for operating experience and communicate applicable lessons learned to appropriate organizations.

The inspectors discussed the corrective actions and associated evaluations with licensee personnel.

This activity constituted one in-depth problem identification and resolution inspection sample as defined in IP 71152.

b. Observations and Assessments

The inspectors reviewed the licensee's initial response to the FP line break in the Unit 1 low pressure heater bay, including operator actions and fire protection compensatory actions. No deficiencies were identified. Additionally, the inspectors walked down accessible areas to determine the extent of equipment that may have been wetted by water flowing into the turbine building basement through the floor drain system. No additional wetted equipment was noted beyond that identified by the licensee.

The licensee's corrective actions for this event were documented in AR 4056713. The inspectors reviewed this document, including the determination of the failure mechanism

of the mechanical coupling. An evaluation by Exelon Power Labs, LAS–63813, concluded that the coupling failed due to long term corrosion of the coupling bolts, which had likely been degraded by wetting from gasket leakage. The most probable cause of the gasket leakage was identified to be from environmental degradation of the coupling gasket surface, a phenomena accelerated by high temperature environments.

To determine extent of condition, the licensee conducted a walkdown of FP mechanical couplings located in accessible areas within the protected area. The licensee concluded that there was no evidence of active leakage or loss of bolting material due to corrosion identified on any other fittings. The licensee has scheduled walkdowns of mechanical couplings in inaccessible areas, including those areas most likely to accelerate degradation, for the upcoming refueling outages for Unit 1 and Unit 2. The inspectors independently conducted a walkdown of FP piping in safety-related areas and did not identify any mechanical couplings that constituted a safety concern.

c. Findings

No findings were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000373/2017003–00, Automatic Reactor Scram Due to Main Generator Trip on Differential Current During BackFeed Operations

a. Inspection Scope

This event, which occurred on February 13, 2017, occurred when Unit 1 was at 100 percent power when it received a reactor scram signal due to turbine control valve fast closure. This occurred while the station was aligning backfeed operation to the Unit 2 Main Power Transformer (MPT). The plant was placed in stable condition with reactor pressure maintained by the turbine bypass valves and reactor water level controlled using feedwater. The root cause was determined to be a marginal generator differential relay design prone to responding to faults outside its zone of protection. Documents reviewed are listed in the Attachment to this report. This Licensee Event Report (LER) is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

Failure of Offsite Power Backfeed Procedure to be Appropriate to the Circumstances Caused Unit 1 Scram

Introduction. A finding of very low safety significance and an associated NCV of LaSalle TS 5.4.1, “Procedures,” occurred on February 13, 2017, for the station’s failure to maintain procedures of a type appropriate to the circumstances for energizing offsite electrical systems during a Unit 2 backfeed evolution (an activity affecting quality per Regulatory Guide 1.33, appendix A, section 4.w(1)). Specifically, LaSalle’s backfeed procedure, LOP–AP–01, Revision 35, maintained the 345 kilovolt (kv) tie between Unit 1 and Unit 2 while energizing the Unit 2 MPT, which allowed the switching transient to adversely affect Unit 1, causing an automatic reactor scram.

Description. While performing a closeout review of LER 05000373/2017–003–00 per IP 71153, inspectors reviewed the associated root cause evaluation, AR 03973724, "LaSalle Unit 1 tripped from 100 percent power upon energization of backfeed to Unit 2," and evaluated the circumstances surrounding the unplanned scram for issues of regulatory concern.

The licensee's root cause evaluation concluded that the causal factors of this Unit 1 scram included the 345kv switchyard alignment methodology used for MPT backfeeding challenged low protective relay margins. Specifically, the procedure-driven practice of leaving the opposite unit tied to the 345kv ring bus during backfeed switching put Unit 1 at heightened risk of being adversely effected by Unit 2. This practice, coupled with the recent replacement of the MPTs (circa 2013) with larger transformers, created a situation where a larger in-rush current was generated when energizing the Unit 2 MPT, which was imposed upon Unit 1 as it was still tied to the ring bus in accordance with the backfeed procedure, LOP–AP–01.

The inspectors concluded that the implementation of procedure LOP–AP–01, as written, directly caused the Unit 1 scram, which was consistent with the conclusions of the licensee's causal evaluation. The inspectors recognized that performance of LOP–AP–01 was an activity affecting quality as described in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Analysis. The inspectors determined the failure of the backfeed procedure to account for the change in the expected response of the Offsite/Onsite power system as a result of the recent installation of upgraded Unit 1 and Unit 2 MPTs was a performance deficiency. The existence of the new MPTs created a situation in which unintended system interactions resulted in the backfeed procedure no longer being appropriate as required by RG 1.33. Specifically, with the larger MPTs installed, a larger in-rush current was imposed upon the Unit 1 MPT and associated components (such as the Unit 1 bus duct bars that experienced localized overheating/melting during this in-rush current event) when the Unit 2 MPT was energized; thus revealing that the procedural guidance to leave the 345kv ring bus connection intact between units was no longer appropriate to the circumstances.

This performance deficiency was more than minor because it was associated with the Procedure Quality attribute of the Initiating Events Cornerstone, and adversely affected the Cornerstone objective of limiting the likelihood of events that upset plant stability, because it resulted in a Unit 1 Scram. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At Power," issued June 19, 2012, the inspectors determined that this finding was of very low safety significance because although the performance deficiency caused a reactor scram, it did not result in the loss of mitigation equipment relied upon to transition the plant from the onset of the scram to a stable shutdown condition. The inspectors determined there was no cross-cutting aspect because the performance deficiency was not indicative of licensee's current performance since the design modification occurred greater than 3 years before the event. Regarding corrective actions, the site revised the backfeed procedure to eliminate the tie between the units on the ring busses when MPTs are energized.

Enforcement. LaSalle TS, Section 5.4.1 states, in part, that "written procedures shall be established, implemented, and maintained covering the applicable procedures

recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978." Section 4 of the Regulatory Guide states, in part, that instructions for energizing, filling, venting, draining, startup, shutdown, and changing modes of operation should be prepared, as appropriate for the following systems: [per subsections w(1) & (2)] Offsite (access circuits) and Onsite Electrical System.

Contrary to the above, in February 2013, following the replacement of the Unit 1 and Unit 2 MPTs, the licensee failed to maintain/revise licensee procedure LOP–AP–01, "Unit Auxiliary Transformer UAT 141 (241) backfitting operations for UAT 241." This failure resulted in the licensee executing a procedure that was inappropriate for energizing the Unit 2 offsite and onsite electrical systems. This was a violation. Specifically, this procedure was inappropriate in that the procedure steps directed that the 345kv ring bus connection between units remain intact, allowing the larger in-rush current of the newer design MPTs to adversely impact the opposite unit.

As a corrective action, the licensee revised the LOP–AP–01 procedure to eliminate such further cross-unit interactions during backfeed operations by directing that the 345kv oil circuit breakers for the tie to the opposite unit be opened prior to energizing MPTs. To prevent recurrence, the licensee also installed a more robust differential relay protective scheme.

Since this issue was entered into the licensee's CAP (as AR 03973724), this violation of TS 5.4.1.a, is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000373/2017004–04; 05000374/2017004–04, Failure of Offsite Power Backfeed Procedure to be Appropriate to the Circumstances Caused Unit 1 Scram)**

.2 (Closed) Licensee Event Report 05000374/2017002–00, High Pressure Core Spray System Declared Inoperable Due to Cooling Water Strainer Backwash Valve Stem-Disc Separation

a. Inspection Scope

On January 30, 2017, during routine surveillance testing of the Unit 2 Division III diesel generator (DG) cooling water system, the cooling water strainer backwash valve was unable to open due to stem-disc separation. Technical Specification 3.7.2 and 3.5.1 were entered when the DG cooling water and the high pressure core spray (HPCS) system were determined to be inoperable. The valve was replaced and the HPCS system returned to operable status on February 2, 2017.

Details regarding the inspectors' review of the technical aspects of this reportable event were previously documented in section 1R15 of LaSalle's first quarter 2017 integrated inspection report. Additionally, a Green NCV (05000373/2017001–02, Failure to Perform Preventive Maintenance Resulted in Stem-to-Disc Separation of Safety-Related Valve) was documented at that time. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.3 (Closed) Licensee Event Report 05000373,05000374/2017004–00, Secondary Containment Inoperable Due to Interlock Doors Open

a. Inspection Scope

On February 16, 2017, Unit 1 was in Mode 2 for startup at five percent power and Unit 2 was defueled for a planned refueling outage when both air-lock doors of the Unit 1 reactor building to chemistry corridor were opened simultaneously for approximately five seconds. Secondary containment was declared inoperable for the period that both interlock doors were open. The licensee entered and exited TS 3.6.4.1 Required Actions A.1 and C.1 to restore secondary containment and to immediately suspend movement of irradiated fuel on Unit 2. The licensee's causal evaluation determined that the most probable cause of the interlock failure was the intermittent failure of a circuit board designed to prevent more than one door being open at a time. Corrective actions to replace interlock door circuit cards was ongoing at the time of this event. The door interlock was satisfactorily tested by maintenance technicians and the door interlock was returned to service on February 18, 2017. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.4 (Closed) Licensee Event Report 05000374/2017003–00 and Revision–01, High Pressure Core Spray Inoperable Due to Injection Valve Stem-Disc Separation

a. Inspection Scope

On February 11, 2017, Unit 2 was in a Mode 5 for a planned refueling outage. While attempting to fill and vent the Unit 2 HPCS system, no flow was observed from the drywell vent valves or downstream of the HPCS injection valve. The cause of the valve failure was determined to be stem-disc separation. The valve was replaced prior to the restart of the unit. Documents reviewed are listed in the Attachment to this report. The technical aspects of this failure were inspected as part of an NRC special inspection, which occurred in the second quarter of 2017. The results of that detailed inspection can be found in inspection report number 05000373/2017009; 05000374/2017009. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.5 (Closed) Licensee Event Report 05000373/2017005–00, Manual Reactor Scram Resulting from Feedwater Regulating Valve Failure Causing High Reactor Water Level

a. Inspection Scope

On February 17, 2017, during Unit 1 power ascension from a previous forced shutdown operators inserted a manual scram as a result of a high reactor water level condition caused by a rapid change in feedwater flow. The high reactor water level condition

occurred due to a failure of the feedwater regulating valve 1FW005 positioner arm, which caused the regulating valve to be driven to the full-open position. This resulted in a rapid increase of reactor water level that required the manual reactor scram, per operating procedure requirements. The unit was restarted after repairs. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.6 (Closed) Licensee Event Report 05000373/2017006–00, Low Pressure Core Spray Inoperable Due to Minimum Flow Valve Failure in Closed Position

a. Inspection Scope

On May 17, 2017, during Unit 1 full-power operations, operators received an unexpected alarm for the low pressure core spray pump injection high flow and automatic closure of the low pressure core spray minimum flow valve. The valve was determined to have a faulty diaphragm which allowed water intrusion into the device. There were no impacts on plant operations. Technical Specification 3.5.1, "ECCS — Operating" and TS 3.3.5.1, "Emergency Core Cooling System Instrumentation" were entered. The switch was replaced and low pressure core spray system tested. The system was fully restored on May 17, 2017. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 9, 2018, the inspectors presented the inspection results to Mr. W. Trafton, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for the inspection results for:

- the Radiation Safety Program review with Mr. H. Vinyard, Plant Manager, on November 3, 2017;
- the Biennial Written and Annual Operating Test Results and Biennial Review with Mr. H. Vinyard, Plant Manager, on November 3, 2017;
- the Operability Determination and Functionality Assessment for the Adequacy of Changes to Pool Swell Analysis on December 6, 2017, with T. Riddle, Senior Design Engineering Manager and other members of the licensee's staff; and

- the Emergency Preparedness Program inspection with Mr. M. Hayworth, Emergency Preparedness Manager, conducted over the phone on December 18, 2017.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

W. Trafton, Site Vice President
H. Vinyard, Plant Manager
J. Kowalski, Maintenance Director
J. Keenan, Engineering Director
J. Ward, Work Control Director
J. Stovall, Operations Director
G. Ford, Regulatory Assurance Manager
J. Moser, Radiation Protection Manager
A. Schierer, Programs Engineering Manager
M. Hayworth, Emergency Preparedness Manager
J. Van Fleet, Operations Manager
D. Murray, Senior Regulatory Specialist
E. Ingram, Emergency Preparedness Coordinator
S. Tanton, Design Engineering Manager
R. Conley, Radiation Engineering Manager
D. Wright, Operations Training Manager
D. Anthony, Exelon Non-Destructive Examination Specialist Manager West
D. Bakalar, Security Manager
E. Stein, Dry Cask Storage (DCS) Program Manager
G. Chavez, DCS Senior Manager
T. Lanc, Regulatory Assurance
M. Cichon, DCS Project Manager
L. Simpson, Corporate Licensing
G. Brumbelow, Emergency Preparedness Coordinator
M Venaas, Organizational Effectiveness
S. Tutoky, ODCM Specialist/Counting Room Chemist
W. Buinickas, Chemistry

U.S. Nuclear Regulatory Commission

B. Dickson, Chief, Reactor Projects Branch 5

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000373/2017004–01; 05000374/2017004–01	URI	Complete versus Truncated Shifts on Proficiency Watches (Section 1R11)
05000373/2017004–02; 05000374/2017004–02	NCV	Failure to Establish Brazing Repair Procedures with Appropriate Acceptance Criteria (Section 1R15)
05000373/2017004–03; 05000374/2017004–03	NCV	Primary Containment Structure, Suppression Pool Columns, Downcomer Vent and Downcomer Vent Bracing Did Not Meet Seismic Category I Requirements (Section 1R15)
05000373/2017004–04; 05000374/2017004–04	NCV	Failure of Offsite Power Backfeed Procedure to be Appropriate to the Circumstances Caused Unit 1 Scram (Section 4OA3)

Closed

05000373/2017004–02; 05000374/2017004–02	NCV	Failure to Establish Brazing Repair Procedures with Appropriate Acceptance Criteria (Section 1R15)
05000373/2017004–03; 05000374/2017004–03	NCV	Primary Containment Structure, Suppression Pool Columns, Downcomer Vent and Downcomer Vent Bracing Did Not Meet Seismic Category I Requirements (Section 1R15)
05000373/2017004–04; 05000374/2017004–04	NCV	Failure of Offsite Power Backfeed Procedure to be Appropriate to the Circumstances Caused Unit 1 Scram (Section 4OA3)
05000373; 05000374/2016001–01	URI	Adequacy of Changes to Pool Swell Analysis (Section 1R15)
05000373/2017003–00	LER	Automatic Reactor Scram Due to Main Generator Trip on Differential Current During BackFeed Operations (Section 4OA3)
05000374/2017002–00	LER	High Pressure Core Spray System Declared Inoperable Due to Cooling Water Strainer Backwash Valve Stem-Disc Separation (Section 4OA3)
05000373,05000374/ 2017004–00	LER	Secondary Containment Inoperable Due to Interlock Doors Open (Section 4OA3)
05000374/2017003–00	LER	High Pressure Core Spray Inoperable Due to Injection Valve Stem-Disc Separation (Section 4OA3)
05000374/2017003–01	LER	High Pressure Core Spray Inoperable Due to Injection Valve Stem-Disc Separation (Section 4OA3)
05000373/2017005–00	LER	Manual Reactor Scram Resulting from Feedwater Regulating Valve Failure Causing High Reactor Water Level (Section 4OA3)
05000373/2017006–00	LER	Low Pressure Core Spray Inoperable Due to Minimum Flow Valve Failure in Closed Position (Section 4OA3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or 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.

1R01 Adverse Weather Protection

- A/R 2416849; Model AR for Site Winter Readiness Actions; 11/24/2014
- AR 4071755; "Issues Identified from Winter Readiness Walkdown"
- AR 4073156; "Div 2 Swgr Temp Low—1VX07Y Stuck Open"
- AR 4076063; "Unexpected Alarms on U1"
- AR 4076065; "Unexpected U2 MCR Alarms Believed to be Weather Related"
- AR 4077504; "2017 LOS–ZZ–A2 Attachment A Exceptions List"
- Email from W. Keller re: 2017 LaSalle Winter Readiness; 11/22/2017
- LOA–AN–101; Loss of Annunciators; Revision 24
- Operations Log; 11/17/2017
- System Engineer System Summary Sheet/Recommendation Form; Winter Readiness Items; 2017/20188 Winter
- W/R 1371386, Div 2 SWGR Temp Low—1VX07Y Stuck Open; 12/11/2017
- WC–AA–107; Seasonal Readiness; Revision 18
- WO 4572356–01; LOS–ZZ–A2 Winterize Station; 10/11/2017
- WO 4572356–02; LOS–ZZ–A2 Winterize Station; 10/21/2017
- WO 4572356–03; LOS–ZZ–A2 Winterize Station; 10/18/2017
- WO 4572356–06; LOS–ZZ–A2 Winterize Station; 10/27/2017
- WO 4714298; Unexpected Alarms on U1; 12/12/2017

1R04 Equipment Alignment

- 1RB 673; Raceway Map 800; 11/6/2017
- 1RB673; B/C RHR Corner Map 804; 11/6/2017
- 1RB694; B RHR Corner Map 808; 11/6/2017
- 1RB710; B RHR Corner Map 813; 11/6/2017
- 22078; Fuel Oil Schematic 2600 KW Generator Set; Revision G
- ANSI/ANS–59/51–1989; Fuel Oil Systems for Emergency Diesel Generators; 10/27/1989
- AR 4050623; "VG Loop Seal Line Plugged"
- AR 2604934; "Adverse Trend in Configuration Control"
- AR 2618169; "CCP—Gap to Excellence in Configuration Control"
- AR 3979418; "NDE UT Thickness Readings Below TMIN. On 2RH90B–6"
- AR 3980612; "Valve Leaks By When Closed"
- AR 4039943; "Void Discovered During UT of 1B RHLPCI"
- AR 4053063; "2E21–C002 Oil Leak Walk Down"
- AR 4054289; "High Suppression Pool Level Due to Leakby"
- AR 4062413; "Replacement of RHR Moto Termination Exceeded EQ Life"
- AR 4063404; "Unable to Perform As-Found Testing Due to Water Leakage"
- AR 4075834; "NRC ID'd, Discrepancy Between P&ID and Mechanical Checklist"
- AR 4079414; "NRC Question Regarding Mechanical Checklist and Pre-Fire Plan"
- AR 4079420; "NRC Identified P&ID M–96 Sheet 4 Requires a Revision"
- CSCS–1; Training Diagram, Core Standby Cooling; Revision 3

- DG–2; Training Diagram, HPCS and Non-HPCS Fuel Oil Systems; Revision 1
- DG–5; Training Diagram: D/G Air Start System; Revision 1
- HP–1; Training Diagram, High Pressure Core Spray System; Revision 2
- Issuance of Amendment 81, Letter to T. Kovach, from B. Siegel, NRR; 10/27/1991
- LSCS–UFSAR; Table 3.2–1; CSCS Equipment Cooling Water System/ Diesel Generator System; Revision 21
- LOP–DG–05E; Unit 2 B Diesel Generator Electrical Checklist; Revision 12
- LOP–DG–05M; Unit 2 B Diesel Generator Mechanical Checklist; Revision 7
- LOP–DG–10M; Unit 2B Diesel Generator Cooling System Mechanical Checklist; 6/17/2017
- LOP–HP–02E Unit 2 High Pressure Core Spray Electrical Checklist; 10/18/2017
- LOP–HP–02M; Unit 2 High Pressure Core Spray Mechanical Checklist; 10/18/2017
- LOP–LP–02E; Unit 2 Low Pressure Core Spray System Electrical Checklist; Revision 5
- LOP–LP–02M; Unit 2 Low Pressure Core Spray System Mechanical Checklist; Revision 12
- LOP–RH–02E; Unit 1 Residual Heat Removal System Electrical Checklist; Revision 20
- LOP–RH–18M; Unit 1 B Residual Heat Removal System Mechanical Checklist; Revision 4
- LOP–VG–02E; Unit 2 Standby Gas Treatment System Electrical Checklist; Revision 6
- LOP–VG–02M; Unit 2 Standby Gas Treatment System Mechanical Checklist; Revision 7
- LP–1; Training Diagram: Low Pressure Core Spray System; Revision 0
- M–83 & Sheet 4; P&ID Diesel Generator Lube Oil System; Revision G
- M–83; P&ID Diesel Generator Auxiliary System; Revision BB
- M–83; P&ID Diesel Generator Lube Oil System; Revision G
- M–89; P&ID Standby Gas Treatment; Revision AG
- M–95; P&ID High Pressure Core Spray (HPCS); Revision AQ
- M–96; P&ID Residual Heat Removal System (R.H.R.S.); Revision BC
- M–132; P&ID Diesel Oil System; Revision AC
- M–134; P&ID CSCS Equipment Cooling Water System; Revision AZ
- M–140; P&ID Low Pressure Core Spray (LPCS); Revision AP
- M–1340; Instrument Installation Details: Description: For Record per DCR 970408, As-Built; Revision L
- OP–AA–108–103; Locked Equipment Program; Revision 2
- RH–1; Training Document, Residual Heat Removal System; 5/13/2009
- RH–2; Training Document, RHR Modes of Operation; 5/13/2009
- Trend Search for Mispositioning / Configuration Control: Code ‘CC10’ *(prior to 1/1/2017)*, Search for ‘Config Control’ *(after 1/1/2017)*
- VG–1; Training Diagram: Standby Gas Treatment System; Revision 3

1R05 Fire Protection

- 1E–0–3933C; Fire Detection System Floor El. 731’ 0” Unit 1 & 2; Revision 13
- AR 2454902; “Review of Hot Work Paperwork”
- AR 2593653; “Hot Work Gap Identified”
- AR 2606404; “Mid-Cycle EGTE: Inadequate Oversight of Hot Work Activities”
- AR 3953223; “RWCR Alarm: IRSF Fire Detection Trouble, Spurious Alarm”
- AR 3970392; “Alarm Function Not Working”
- AR 4070832; “4.0 Critique for LPHB FP Pipe Break”
- AR 4070838; “FP Victaulic Coupling Walkdown Results”
- AR 4073426; “Paint on Sprinkler Head Fusible Link”
- AR 4074077; “Fire Drill Post Drill Critique”
- AR 4079414; “NRC Question Regarding Mechanical Checklist and Pre-fire Plan”
- AR 4079952; “NRC Identified Housekeeping Issues”
- Calc L–000776; Combustible Loading Calculation; Revision 8

- CC–AA–501–21027; Hot Work Precautions and Safety Practices; Revision 2
- DS 17–11; Fire Drill Scenario Unit 2 H2 Seal Oil Skid731 TB
- DS 17–11; LaSalle Station Fire Drill Record, U–2 H2 Seal Oil System; 11/9/2017
- FZ 3G; RX Bldg. 710'–6" Elev. U2 General Area & Suppression Pool Entrance
- FZ 4E1; LaSalle Pre-Fire Plan Unit 1 Elevation 731' 0" Auxiliary Equipment Room; Revision 4
- FZ 4F1; LaSalle Pre-Fire Plan Layout, Unit 1 Elevation 710' – 0" Division 1 Essential Switchgear Rm; Revision 2
- FZ 5B8; LaSalle County Generating Station Pre-Fire Plan TB. Bldg. 731' 0" Elev. U2 Hydrogen Seal Oil Unit; Revision 2
- FZ 8C5; LaSalle County Generating Station Pre-Fire Plan, DG Bldg. 674' 0: Elev. Unit 2 Div 1 RHR Service Water Pump Room
- H.3–85; LSCS-FPR Design Basis Fire, Unit 1 Division 1 Essential Switchgear Room – Fire Zone 4F1 (710' 6")
- LOA–FP–201; HardCard B Fire Alarm Quick Response; Revision 37
- LOA–FP–201; Unit 2 Fire Protection System Abnormal; Revision 37
- OP–AA–201–003; Fire Drill Performance; Revision 16
- OP–AA–201–004; Fire Prevention for Hot Work; Revision 14
- OP–AA–201–008; Attachment 1 "Sample" Pre-Fire Plan Template; Revision 4
- OP–AA–201–008; Pre-Fire Plan Manual; Revision 4
- OP–AA–201–009; Attachment 16, "Aid to Determine if a Transient Combustible Permit is Required for Transient Combustible Materials"; Revision 19
- OP–AA–201–009; Control of Transient Combustible Material; Revision 19
- Operations Log; 10/10/2017

1R06 Flood Protection Measures

- AR 4075634; "NRC Question on 2E12–C300A Seal Leak"
- MA–AA–736–610; Application of Freeze Seal to All Piping; Revision 11
- PRA 3–54; Table 3.3–2, LaSalle 2014A PRA, Top 9% of The Accident Sequences Contributing to CDF; 11/11/2015

1R07 Heat Sink Performance

- LTS–200–17; RHR Heat Exchanger Thermal Performance Monitoring; Revision 16
- EC 622290; Evaluation of Unit 1B RHR Heat Exchanger Thermal Performance Data Using Alternate (EPR) Methodology: Revision 000

1R11 Licensed Operator Requalification Program

- "FRV" Failure Post-Event Transient Review Simulator Test; 8/15/2017
- "GC" Runback Post-Event Transient Review Simulator Test; 6/4/2017
- "OBE" #1; Crew Grading Attachment (Crew Failure); 5/16/2017
- 2017 NRC Exam Week 3; RO Exam; 11/2017
- 2017 NRC Exam Week 3; SRO Written Exam; 11/2017
- AP–1; AC Distribution, Training Diagram; Revision 0
- AR 4048627; "RM—U1 Control Rod 22–07 Declared Slow During SCRAM Timing"
- Eleven Cycle 17–6 Individual Grading Attachments; Revision 4
- ESG 12; Annual LORT Scenario, NRC #15; Revision 4
- Five Simulator Core Performance Tests; 6/5/2016
- Focused Area Self-Assessment (FASA), 6/22/2017, PI–AA–126–1001–F–01, Revision 1
- Hardened Containment Vent System (HCVS) Simulator Testing; 3/3/2017
- Individual Written Exam Failure of LORT Cycle 17–5; 9/29/2017

- LaSalle Unit Difference Book; 10/11/2017
- LIS–FW–301; Unit 1 Reactor Vessel High Water Level 8 Main Turbine/Feedwater Pump Trip Functional Test; Revision 17
- OP–AA–101–111; Roles and Responsibilities of On-Shift Personnel; Revision 10
- OP–AA–101–111–1001; Operations Standards and Expectations; Revision 15
- OP–AA–101–113; Operator Fundamentals; Revision 7
- OP–AA–103–102; Watch-Standing Practices; Revision 13
- OP–LA–101–111–1001; On-Shift Staffing Requirements; Revision 9
- OP–LA–101–111–1002; LaSalle Operations Philosophy Handbook; Revision 69
- OP–LA–102–106, LaSalle Station Operator Response Time Program, Revision 8
- POD; Plan of the Day; 11/9/2017
- Sample of Medical Records (8); Various Dates
- Sample of Training Attendance Records; Various Dates
- Scenario-Based Testing for Scenario 101 (ESG), Revision 3; 2/18/2017
- Scenario-Based Testing for Scenario 120 (ESG), Revision 0; 2/23/2016
- Scenario-Based Testing for Scenario 81 (ESG), Revision 5; 2/13/2017
- Scenario-Based Testing for Scenario 86 (ESG), Revision 4; 2/18/2017
- Seven 2017 NRC Exam Week 1 JPMs; 10/30/2017
- Simulator Review Board Meeting Minutes; February 2016 to June 2017
- Six 2017 NRC Exam Week 3 JPMs; 10/30/2017Three “OBE” #1; Individual Grading Attachments (Individual Failure); 5/16/2017
- Three ESG 43 Crew Grading Attachments; Revision 4
- Turbine Trip Post-Event Transient Review Simulator Test; 6/4/2017
- Two 2017 NRC Exam Week 1 Evaluated Scenario Guides (ESG); 10/30/2017 Two 2017 NRC Exam Week 3 Evaluated Scenario Guides (ESGs); 10/30/2017Two ESG 28 Crew Grading Attachments; Revision 4
- Various “LASER”s (Living ASER) for Licensed Operator Requalification; Various Dates
- Various Curriculum Review Committee (CRC) Minutes; Various Dates
- Various Evaluation Summaries, TQ–AA–224–F070, Revision 2; Various Dates
- Various LaSalle 1 (L1C16) Simulator Tests; 3/10/2016
- Various Operations Related Action Requests (ARs); September 2016 to October 2017
- Various Simulator Work Requests (SWRs); Various Dates

1R12 Maintenance Effectiveness

- AR 2584683; “2VP01CA Tripped on Low Oil Pressure During Swap”
- AR 2585945; “Unit 1 A VP Chiller Oil Reservoir Temp High”
- AR 2678672; “ENV—Small Refrigerant Leak on Refrigerant Filter”
- AR 4037236; “2VX01C Div 1 SWGR Room SPLY Fan BKR Trip”
- AR 4047132; “Unit 1 MSL Rad Monitors are Degraded”
- AR 4061890; “1A VP Chiller Trip”
- ER–AA–310; Implementation of the Maintenance Rule; Revision 10
- ER–AA–310–1001; Maintenance Rule—Scoping; Revision 4
- ER–AA–310–1003; Maintenance Rule—Performance Criteria Selection; Revision 5
- ER–AA–310–1004; Maintenance Rule—Performance Monitoring; Revision 14
- LAS–1–AP; Maintenance Rule System Basis Document; 12/18/2017
- LAS–1–VX; Maintenance Rule System Basis Document; 12/13/2017
- LAS–2–VX; MR Function Evaluation; 11/14/2017
- Maintenance Rule(A)(3) Report, Sorted by 1) Limit 2) Current Value; 12/2017
- MR LAS–1–PR–06; Process Radiation Monitoring; Main Steam Line Log Radiation Monitoring System; 11/29/2017

- Numarc 93–01; Nuclear Energy Institute, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants; April 2011
- PMD–17–004315 LaSalle: 01 Moving Late date (crit date) on PMID 95671–01 due to Part Issue; 9/6/2017
- PMRQ 95671–01; LRA—MN STM Line Rad Monitor Calibration; 5/5/2010
- WO 1027668–01; MN STM Line Rad Monitor Calibration; 4/30/2010

1R13 Maintenance Risk Assessments and Emergent Work Control

- AR 3971033; "Protected Equipment Needs Robust Barrier"
- AR 4056931; "NRC Question on Division 3 Protected Pathways"
- Paragon 1.3, Model LS2–PRD–M–29; PRA LS2–PRD–P–63; Schedule LS–PRD–2017; 10/10/2017
- POD; Plan of the Day: 10/10/2017

1R15 Operability Determinations and Functional Assessments

- 22076; Air Start Schematic 2600 KW Generator Set 0DG01K, 1DG01K & 2DG01K; Revision L
- AR 1041521; "1B DG Fuel Line Leak"
- AR 1063484; "1B DG Instrument Lines"
- AR 1066182; "Replace EDG Fuel Lines"
- AR 1095832; "NRC Questions on 1B EDG Fuel Line IR 1041521"
- AR 1423523; "Deteriorating Concrete U2 RB 761"
- AR 3994367; "Flex Barrier Pipe Penetrations Leaking in U–2"
- AR 4004040; "Enhancement to Assist with CR Operability Determination"
- AR 4021832; "Door 20 Seal Degradation"
- AR 4061087; "Phase 2 HCVS Schedule Conflict"
- AR 4065514; "Disconnected Air Line Discovered on 0 DG"
- ASME B16–1996; Flange Rating Table 2.3.16 Ratings for Group 3.18 Materials; *Undated*
- B 3.6; Containment Systems, Standby Gas Treatment System; Revision 0
- BPS 107–107–BR; ASME Brazing, Torch Brazing; 1/9/2003
- CQD 010330; Sargent & Lundy Seismic Qualification of the Accessory Components for Stewart & Stevenson Diesel Generators; 9/7/1984
- CR 143974; Search Results for Steps: 1AP60E–F6 Replace CNT PWR XFMR & Contactor EC 397773
- EC 337814; DG Operability; 6/30/2002
- EC 348521; Temporary Increase in the Maximum Cumulative Opening Size in the Secondary Containment (Ref. LOP–CS–02); Revision 0
- ECR 383664; L1R12 Secondary Containment Opening Holes Size
- EMD 004169; Sargent & Lundy Review of Seismic Analysis Report for Standby Diesel Generator; 6/29/1976
- ER–AA–310–1004; Attachment 8 Functional Failure Cause Determination Evaluation; IR 1041521; 5/5/2010
- Figure 11–10; Training Document, Non-HPCS Engine Air Starting System; 11/14/2000
- GM/EMD 20E576, Section 14; Engine Maintenance Manual; Starting System
- GM/EMD 43A587; Stationary Power Starting System, Section 4; *Undated*
- GM/EMD P5810,9509592; Starter Motor and Mounting Parts List B25; *Undated*
- LOP–CS–02; Tracking and Authorization of Controlled Openings in the Secondary Containment; Revision 12
- LOS–CS–SR1; Secondary Containment Leak Rate Test; Revision 7
- LSCS—UFSAR Table 3.2–1; Components CSCS/DG; Revision 21

- LSCS—UFSAR Table 3.2–4; Code Requirements for Components & Systems Ordered after July 1, 1974; Revision 20
- M–83; P & ID Diesel Generator Auxiliary System; Revision AF
- M–865; Diesel Generator 1B Miscellaneous Tubing; Revisions F, E, D
- M–87; P&ID Core Standby Cooling System Equipment Cooling Water System; Revision BL
- M–965; Diesel Generator "2B" Miscellaneous Piping; Revisions E, C
- ODG–4; Weld Data Report Drawing; 8/17/1977
- Operations Log; 10/9/2017
- PL C1079–DR; Air Start System; Undated
- Spec J–2544, Specification for Diesel Engine –Generator Sets, Sargent & Lundy; 11/9/1976
- W/R 1368152; Governor, Diesel Generator, Disconnected Air Line Discovered on 0 DG; 10/22/2017
- WO 1335445–01; IM Install Spacers on 1B DG Instrument Lines; 1/5/2012
- WO 1336532; Replace EDG Fuel Lines; 3/22/2013
- WO 849184; 1E22–F319 Inspect/Replace/Refurb Valve
- WR 335121; 1B DG Instrument Lines
- WR 335630; Replace EDG Fuel Lines; 12/21/2012

1R18 Plant Modifications

- 7–10; Reactor Operations, Chapter 7, Enforcement of 10 CFR 50.59 and Related FSAR; 12/22/2008
- AR 2701465; "Clarify Div 3 DG FOST Operability Levels"
- CC–AA–109; Abandoned Equipment Evaluation, Diesel Oil (1(2) DO024); 10/2017
- EC 331699; 50.59 Review, "Abandon 1(2) DO024 in the Closed Position with Power Removed or Remove Valve"; Revision 0
- FP–1; Training Document, Fire Protection System; Revision 2
- FP–2; Training Document, Fire Protection System; Revision 1
- LOP–DO–03; Transferring Oil to the Diesel Fire Pump Day Tanks; Revision 22
- LOS–FP–M1; Fire Protection Fuel Oil Transfer Pump Test and Day Tank Level Verification; Revision 26
- LSCS–UFSAR 9.5–27; Diesel-Generator Fuel Oil Storage and Transfer System; Revision 18
- M–132; P&ID Diesel Oil System; Revision AC
- M–85; P&ID Diesel Oil System; Revision AE

1R19 Post Maintenance Testing

- 1E–2–4026AA; Schematic Diagram Diesel Fuel Oil System "DO" Part 1; Revision R
- 1E–2–4220AR; Schematic Diagram Residual Heat Removal Alarms System "RH" (E12) Part 16; Revision Q
- 1E–2–4220CM; Schematic Diagram Residual Heat Removal System "RH" (E12) Part 60; Revision G
- 94–13670; 16"–150# Gate Valve Outline; Revision 0
- Activity Tracking Listing; 10/2017
- AR 2588865; "A RHR WS Strainer Stuck in Backwash—Timer Not Actuating"
- AR 2588879; "2A RHRWS Strainer DP Annunciator Did Not Actuate as Designed"
- AR 2597724; "Backed Out of Clearance Order"
- AR 2603876; "Failed PMT, 1B In Switching Solenoid Manifold Leak"
- AR 2613313; "A RHR WS Pumps Flow"
- AR 2616101; "Clearance Related Issue Tracking—Clearance Request"
- AR 2617947; "0VD02C K–M 1AP72E–A6 Cube PMT Unable to Be Done As Written"

- AR 2635241; “1E12–B001A 1A RHRWS Flow Low During PMT”
- AR 3957315; “U2 RCIC Cold Quick Start TADS 164 Data Read High”
- AR 3978544; “Discharge Pressure for B&C RHR Water Leg Pump is Low”
- AR 3979418; “NDE UT Thickness Readings Below TMin. On 2RH90B–6”
- AR 3980080; “2B RHR Low Pressure Alarm Will Not Clear”
- AR 3980612; “Value Leaks by when Closed”
- AR 3995801; “U–2 RCIC Turbine RPM Peak Value TADS 164”
- AR 4029628; “RCIC Turbine Speed Peak >4950 RPM During LOS–RI–Q5”
- AR 4030361; “2VY04A Cooling Water Flows Out of Band”
- AR 4030408; “2A RHR Seal Cooler Flow as Found Low LOS–RH–SR1”
- AR 4058562; “RCIC Pump Second Peak for Turbine Speed High”
- AR 4073156; “Div. 2 SWGR Temp Low 1VX07Y Stuck Open”
- AR 4074995; “2E12–C300A Seal Leak”
- AR 4076050; “2A RHR Pump Discharge Low Pressure Alarm Will Not Clear”
- C/O & Checklist; 143741–000; 0FP01KB—Fall Inspections & Surveillances; 11/6/2017
- C/O, Checklist 00067419; Repair Damaged Wires in Panel 2PLE6J; 11/8/2017
- Catalog ID 44432; Bill of Materials, Reference BOM for LAS 02 E51 N/A D001 R26, Disk, Rupture, 6 In.; *Undated*
- LIS–RH–216A; Unit 2 RHR Pump 2A Discharge High/Low Pressure Calibration; Revision 6
- LOP–FP–02; Fire Pump Diesel Startup and Shutdown; Revision 25
- LOP–FP–M6; Diesel Fire Pump Operational Check; Revision 16
- LOS–FP–M1; Fire Protection Fuel Oil Transfer Pump Test and Day Tank Level Verification
- LOS–RH–Q1– AH 2E; PMT 2E12–F332D D RHR Service Water Pmp DSCH Stop;10/19/2017
- LOS–RH–Q1; RHR (LPCI) and RHR Service Water Pump and Valve Inservice Test for Modes 1,2,3,4 and 5; Revision 92
- M–134; P&ID CSCS Equipment Cooling Water System; Revision AY
- M–134; P&ID, Core Standby Cooling System Equipment Cooling Water System; Revision AN
- M–134; P&ID, Core Standby Cooling System, Equipment Cooling Water System; Revision AO
- M–2142; P&ID And C&ID Details RHR System “RH”; Revision H
- M–85; P&ID Diesel Oil System; Revision AE
- MA–AA–716–012; Control Circuits Test Matrix; Revision 23
- MA–AA–716–012; Post Maintenance Testing; Revision 23
- MFRC502, Model 697847; Bill of Material; Reference BOM for LAS–02–E51 N/A D001 R26
- Owner Key 67419000; Repair Damaged Wires in Panel 2PLE6J; 11/8/2017
- Report 17–301; Magnetic Particle Examination: WO 124299–01, Weld 4; 11/15/2017
- Report E17–554; VT–2 Visual Examination NDE Report, 2E12–F332A PMT; 11/16/2017
- WO 1078480; OP PMT Panel 2PLE6J Equipment Operates SAT; 7/20/2017
- WO 1078480–02; WP PMT Panel 2PLE/W Equipment Operates SAT;11/18/2017
- WO 1242990; Disassemble, Inspect and Repair Valve; 10/13/2017
- WO 1242991–01; MM Replace 2E12–F332A with SS Valve; 11/15/2017
- WO 1242991–02; OP PMT: 2E12–F332A, Verify No Leaks and Flow Test Valve and Pump; 11/15/2017
- WO 1242991–07; EP PMT, Perform VT–2 after Valve 2E12–F332A Replaced; 11/16/2017
- WO 1791223–01; MM Replace Rupture Disc 2E51–D002; 10/2/2017
- WO 1791224–01; MM Replace Rupture Disc 2E51–D001; 10/2/2017
- WO 1966987; “B” Diesel Fire Pump Engine Annual Surveillance; 11/1/2017
- WO 4624569; LRA–LOS–RI–Q5, U2 RCIC Cold-Quick Start Att 2A; 7/10/2017
- WO 4661511–01; LRA LOS–RI–Q5 U2 RCIC Cold-Quick Start Att 2A; 10/3/2017
- WO 4705823–01; LRA LOS–FP–M6 Diesel Fire Pump Operational Check Att B; 11/8/2017
- WO 4714299–01; 2A RHR Pump Discharge Low Pressure Alarm Will Not Clear; 11/18/2017

1R22 Surveillance Testing

- 1E–1–4000AM; Key Diagram 4160V Switchgear 142Y (1AP06E); Revision E
- 1E–1–4000B; Single Line Diagram, Part 2 Standby Generators and 4160V Buses; Revision N
- 1E–2–4000AM; Key Diagram 4160V Switchgear 242Y (2AP06E); Revision F
- 1E–2–4000B; Single Line Diagram Stand-By Generators and 4160V Buses, Part 2; Revision N
- 1E–1–4005AR; Schematic Diagram 4160V Switchgear 142Y Unit Tie ACB 1424 System "AP" Part 16; Revision L
- AR 2617207; "LL "0" DG Bus Duct Inspection Lessons Learned"
- AR 3970957; "FME During P.M. We Found a Loose Bolt in B Bus Duct"
- C/O 143400–000; Inspect Bus Duct 142Y to 242Y; 10/23/2017
- LOP–AP–03; Racking in a 6900 Volt or 4160 Volt Manually Operated Air Circuit Breaker to Test or Connected Position; Revision 18
- LOP–AP–101; Unit 1 Non-Segregated Phase Bus Duct Preventive Maintenance Inspection; Revision 21
- WO 1246572–01; (LR) 142Y to 242Y Bus Duct Inspection Per LEP–AP–101; 10/24/2017

1EP4 Emergency Action Level and Emergency Plan Changes

- 10 CFR 50.54(q) Qualified Evaluator List; 6/6/2017
- 10 CFR 50.54(q) Evaluation No. 16–125; EP–AA–1005 Addendum 3, "Emergency Action Levels for LaSalle Station" (Revision 2) Evaluation / Assessment Review; 9/6/2016
- EP–AA–120; Emergency Plan Administration; Revision 20
- EP–AA–120–1001; 10 CFR 50.54(q) Change Evaluation; Revision 9
- EP–AA–1005; Exelon Nuclear Radiological Emergency Plan Annex for LaSalle Station; Revision 39
- EP–AA–1005 Addendum 3; Emergency Action Levels for LaSalle Station; Revisions 1 and 2

2RS5 Radiation Monitoring Instrumentation

- AR 1316805; "Station Vent Stack WRGM Inlet Line Flow Restriction"; 01/23/2012
- AR 2407951; "Self-Assessment – Radiation Protection Instrumentation"; 01/07/2015
- AR 2517506; "OPEX – Review of NRC Information Notice 2013–13 Revision 1"; 06/21/2015
- AR 3984874; "Self-Assessment – Radiation Protection Instrumentation"; 08/16/2017
- AR 4047132; "Unit 1 MSL Rad Monitors are Degraded"; 08/30/2017
- AR 2588496; "Self-Assessment – Power Labs"; 02/28/2016
- Calibration of the Canberra ACCUSCAN II WBC System at the LaSalle Country Generating Station; 06/02/2016
- Calibration of the Canberra ACCUSCAN II WBC System at the LaSalle Country Generating Station; 06/10/2015
- Calibration of the Canberra FASTSCAN WBC System at the LaSalle Country Generating Station; 05/32/2016
- Calibration of the Canberra FASTSCAN WBC System at the LaSalle Country Generating Station; 06/09/2015
- Certificate of Calibration; Eberline AMS–4 #076437; 10/12/2017
- Certificate of Calibration; MGP Telepole #0017091; 10/12/2017
- Certificate of Calibration; Thermo Electron RO20 #078626; 01/13/2017
- Eberline AMS–4 #076437; 10/12/2017
- Implementation of Weekly Source Checks for RCA/PA Exit Monitors; 06/03/2016
- RP–AA–700–1216; Attachment 1; RadeCo H–809V, H–809V–1, H–809V–II Calibration Data Sheet; Serial Number 7021; 10/27/2017

- RP–AA–700–1235; Attachment 3; PM–12 Calibration Data Sheet; Serial Number 12055; 01/27/2017
- RP–AA–700–1239; Attachment 2; SAM–12 Calibration Data Sheet; Serial Number 12088; 09/28/2017
- RP–AA–700–1240; Attachment 1; ARGOS–5 Calibration Data Sheet; Serial Number 1405–071; 01/31/2017
- RP–LA–723; Attachment 1; Wide Range Gas Monitor Low Range Detector Calibration; Standby Gas Treatment; 06/08/2016
- RP–LA–723; Attachment 1; Wide Range Gas Monitor Low Range Detector Calibration; Station Vent Stack; 07/14/2016
- RP–LA–724; Attachment 1; Wide Range Gas Monitor Mid/High Range Detector Calibration; Detector Serial Number 1390–6; 06/10/2016
- RP–LA–724; Attachment 1; Wide Range Gas Monitor Mid/High Range Detector Calibration; Detector Serial Number 880–11; 06/10/2016
- RP–LA–724; Attachment 1; Wide Range Gas Monitor Mid/High Range Detector Calibration; Detector Serial Number 1552–6; 07/15/2016
- RP–LA–724; Attachment 1; Wide Range Gas Monitor Mid/High Range Detector Calibration; Detector Serial Number 88012; 07/15/2016
- RP–LA–724; Attachment 1; Wide Range Gas Monitor Mid/High Range Detector Calibration; Detector Serial Number 1552–6; 07/15/2016
- Self-Assessment—Radiation Protection Instrumentation; 10/05/2016
- WO 01804134–01; Unit 2 Post Accident Monitoring (Division 1) Containment Gross Gamma Radiation Monitor Calibration; 05/18/2017

2RS6 Radioactive Gaseous and Liquid Effluent Treatment

- 2015 Annual Radioactive Effluent Release Report; 04/29/2016
- 2016 Annual Radioactive Effluent Release Report; 04/27/2017
- AR 03981597; Alternate WS Sample Point Needed; 03/05/2017
- AR 2608138; Step Change in SVS Release Rate; 01/05/2016
- AR 2681590; Abnormal SBGT WRGM Count Readings; 06/15/2016
- AR 2682353; NOS ID: Chemistry Program Enhancements; 06/16/2016
- AR 3963667; Replace Old Worn Out SVS WRGM Sample Solenoids Low A & B; 01/17/2017
- AR 4021965; 2B RHR Service Water High Rad Alarm; 06/14/2107
- AR 40223881; Received WS Effluent Rad Monitor Flow Low Alarm; 06/20/2017
- CY–LA–110–009; Sampling of Reactor Coolant and RHR at the High Radiation Sampling System in Post-Accident Conditions; Revision 0
- CY–LA–170–2001; Airborne Tritiated Water Analysis; Revision 0
- CY–LA–170–201; Station Vent Stack Airborne Tritiated Water Sampling; Revision 3
- Effluent Monitor Availability Records; Various Records
- Effluent Monitor Out of Service Compensatory Sampling Analysis; Various Records
- Land Use Census; 2015–2017
- LCP–310–52; Wide Range Gas Monitor Normal Noble Gas, Iodine and Particulate Sampling, Revision 12
- ODCM Change Documentation; Revisions 6–8
- ODCM; Revision 8
- Results of Radiochemistry Cross Check Program—Peach Bottom; First Quarter 2017–Third Quarter 2017 Data
- Results of Radiochemistry Cross Check Program—Three Mile Island; Third Quarter 2016
- Results of Radiochemistry Cross Check Program; Fourth Quarter 2015–Third Quarter 2017 Data
- SBGT System WRGM Calibration; 06/07/2016

- SBGT WRGM Low Range Detector Calibration; 06/08/2016
- Self-Assessment Radioactive Gaseous and Liquid Effluent Treatment; 08/16/2017
- Station Vent Flow Instrument Calibration; 01/09/2017
- Station Vent Main Stack WRGM Calibration; 07/12/2016
- Station Vent Stack Gaseous Effluent Analysis; 10/31/2017
- U1 RHR A Service Water Effluent Rad Monitor Calibration; 05/16/2016
- Unit 1 A RHR WS Radiation Monitor Periodic Calibration, 06/08/2016
- Unit 1 A RHR WS Setpoint Determination; 05/12/2011
- Unit 1 Charcoal Sample from Standby Gas Treatment Train 1; 10/03/2016
- Unit 1 Standby Gas Treatment Charcoal Filter Leak Test; 10/03/2016
- Unit 1 Standby Gas Treatment HEPA Filter Leak Test; 10/03/2016
- Unit 2 Standby Gas Treatment Charcoal Filter Leak Test; 04/11/2016
- Unit 2 Standby Gas Treatment HEPA Filter Leak Test; 04/11/2016

4OA1 Performance Indicator Verification

- Radioactive Effluent Dose Summary Data; Third Quarter 2016–Third Quarter 2017
- Radioactive Reactor Coolant Dose Equivalent Iodine (DEI) Data; Third Quarter 2016–Third Quarter 2017
- Section 2.3.6; MSPI Basis Document, LaSalle, pages 49–53; Revision 15
- MSPI Derivation Report (Units 1 & 2), MSPI Heat Removal System, Performance Limit Exceeded (PLE), Unreliability Index (URI), Unavailability Index (UAI); 9/2017
- MSPI & WANO Reporting, LaSalle County Generating Station; 10/2016 – 9/2017
- MSPI Basis Document, Sections 2.5 & 2.6; Revision 15
- MSPI & WANTO Reporting; Core Standby Cooling Systems; 10/2016 – 9/2017
- MSPI Derivation Reports (Units 1 & 2); MSPI Cooling Water System, Unavailability Index (UAI), Unreliability Index (URI), Performance Limit Exceeded (PLE); 9/2017

4OA2 Problem Identification and Resolution

- 1E–1–4000FB; Key Diagram 125V DC Distribution Essential Div. 1; Revision T
- 1E–2–4000FB; Key Diagram 125V DC Distribution Essential Div. 1; Revision 0
- 50.59 L01–0421; CC–AA–109 Attachment 1 for Abandonment of Valve 1B21–F533 (B MSL Process Sample Stop) Revision 0
- Abandoned Equipment 1DG035 “LPCS (Low Pressure Core Spray) Pump Cooler Valve”; 50.59 Evaluation
- Abandoned Equipment 1(2) DO024 Diesel Fire Pump Fuel Oil Transfer Pump Suction Valves; 50.59 Evaluation
- AR 4070838; “FP Victaulic Coupling Walkdown Results”
- AR 4056764; “1HD048A Spuriously Opened Due to DC Grounding Issue”
- AR 4056805; “Multiple DC Grounds Causing Several Flashes of 1PM01J-A409”
- Station Log; Unit 1, 09/28/2017
- LOA–FP–101, Unit 1 Fire Protection System Abnormal, Revision 33
- LOA–FLD–001, Flooding, Revision 20
- AR 4066977; “NRC Identified–White Crust on WS Piping Under 2WS325”
- AR 4068598; “NRC Id’d Thru Wall Seepage Identified on 0WS07AE”
- AR 4070286; “NRC Question Regarding Abandonment of 1(2)DO024 Function”
- AR 4074746; “Extent of Condition Review for 0WS07AE Seepage”
- AR 4075479; “UT Results for 0WS07AE”
- DC Circuit Breaker Settings for 1DC08E–3B; Undated
- Drawing; Turbine Building—Mezzanine Elev. 728’0” & 731’-0”; Various Dates, 1970–1984

- EC 331699; 50.59 Review, Abandon 1(2) DO024 in the Closed Position with Power Removed or Remove Valve; Revision 0
- EC 374695; Update Drawings M–68 & M–787 to Show that Backing Rings were Installed; Revision 000
- EC 622002; Min Wall Evaluation for 36" WS Piping to Service Water Tunnel—OWS07AA/AB/AC/AD/AE/AF; Revision 000
- ER–AA–335–004; Ultrasonic Thickness Calibration, WO 4706723–05; 11/9/2017
- J–2530; Sargent & Lundy Engineers, Piping Classifications; 2/29/1980
- LAS–63813; Exelon Power Labs Report, Failure Analysis of a Fire Protection Pipe Mechanical Coupling from LaSalle Unit 1
- LaSalle Plant Status Report; 11/17/2017
- LSCS–UFSAR 9.5–29; Power Generation Design Bases; Revision 18
- CC–AA–109; Equipment Abandoned VIA Operational Configuration Change, Revision 0
- CC–AA–109; Equipment Abandoned VIA Operational Configuration Change, Revision 8
- CC–AA–109; Attachment 1, Abandoned Equipment Evaluation, Diesel Fire Pump Fuel Oil Transfer Pump Suction Solenoid Valve 1(2) DO024; Revision 0
- CC–AA–109; Attachment 1, Abandoned Equipment Evaluation, B MSL Process Sample Stop Valve 1B21-F533; Revision 0
- CC–AA–109; Attachment 1, Abandoned Equipment Evaluation, LPCS Pump Cooler Isolation Valve 1DG035; Revision 1
- CC–AA–109; Attachment 2, Interim Abandoned Equipment Log, Dated 12/15/2017
- EC 331751; Engineering Change, Switchgear Heat Recovery Fans; Revision 0
- EC 358662; Engineering Change, U1/U2 Hydrogen Recombiner Skid; Revision 0
- EC 368137; Engineering Change, U2 Off Gas O2 Monitor; Revision 0
- L01–0273, 50.59 Screening; Abandon 1(2) DO024 in the Closed Position with Power Removed or Remove Valve; Revision 0
- L01–0421, 50.59 Screening; Abandonment of Valve 1B21–F533 (B MSL Process Sample Stop); Revision 0
- L01–0375, 50.59 Screening; Abandon LPCS Pump Cooler Isolation Valve 1DG035; Revision 1
- M–106; P&ID Diesel, Auxiliary, Turbine & Service Building Floor Drains; Revision AB
- M–106; P&ID Turbine Building Floor Drains System; Revisions K, P
- M–151; P&ID Turbine Building Floor Drains System; Revision I
- M–68; P&ID Service Water System; Revision AI
- M–68; P&ID Service Water System; Revision AI
- M–72; P&ID Fire Protection; Revision AG
- M–814; Fire Protection Piping Turbine Building; Revisions L, R
- NES–MS–03.1; Piping Minimum Wall Thickness Calculation; Revision 5
- Op Logs; 9/28/2017
- PDT–002LS; Sargent & Lundy Engineers, LaSalle County Station Piping Design Table 002LS Carbon Steel; 1986
- WO 4706723; NRC Identified–White Crust on WS Piping Under 2WS325

<u>Action Requests Generated from NRC or IEMA Inspection</u>

- AR 4048381; "Typographical Errors Found In License Amendment Documents"
- AR 4048569; "NRC Resident Questions Regarding U1 MSL Rad Monitors"
- AR 4049563; "NRC Question on Cerification *(sic)* of Temperature Monitor"
- AR 4051196; "NRC Id Violation for HCVS Top Hat"
- AR 4051714; "NRC Identified. Fire Coating Degradation"
- AR 4052192; "IEMA Identified: 2E51–F026 Air Line In Contact With Support"

- AR 4052197; “IEMA Identified: 1E51–F026 Air Line In Contact With Support”
- AR 4052616; “NRC Id'd: Possible Lead–Acid Stains Div 3 Battery Room Floor”
- AR 4052661; “NRC Identified: 1FP147 Emergency Trip Stop Leaking 1–2 DPM”
- AR 4053598; “NRC Id: WLP Location Corrections Needed In LMP–GM–26”
- AR 4053974; “NRC Questions on LLRT LAR”
  AR 4054663; “NRC I'd: Sediment in Bottom of Battery #44 On Div 3 125 VDC”
- AR 4056841; “NRC I'd Additional Questions on Div 3 125VDC Sediment”
- AR 4056931; “NRC Question on Division 3 Protected Pathways”
- AR 4057588; “NRC Identified: Door 129 Not Latching Properly”
- AR 4058901; “NRC Identified: Fire Door 234 Needs Closure Adjustment”
- AR 4059193; “IEMA Identified Door 225 Binding Issue”
- AR 4062322; “Replace Battery 2DC18E Cell 44”
- AR 4062878; “IEMA Identified Belt on 2DG08CA Appears Loose”
- AR 4062885; “NRC Identified SSA Cable Incorrectly Named In FPR”
- AR 4063528; “NRC Id: Correspondence Did Not Include Required Statement”
- AR 4064907; “NRC Question on Local Position Indication for 2E22–F004 VLV”
- AR 4065288; “NRC Question— LOP–CS–02”
- AR 4066977; “NRC Identified—White Crust on WS Piping under 2WS325”
- AR 4068598; “NRC Id'd Thru Wall Seepage Identified On 0WS07AE”
- AR 4068735; “NRC Question on 0 DG Braze Repair”
- AR 4069268; “NRC Question Regarding Diesel Generator Air Start Tubing”
- AR 4069968; “NRC Id'd Potential Enhancement to RP–LA–801 Identified”
- AR 4070020; “NRC Id: Lighting In U1 RB 740 RCIC VLV Room (1E51–F013)”
- AR 4070065; “NRC Id: Clarification on Material Strength Values in Calcs”
- AR 4070067; “NRC Id: Clarification on Acceptance Criteria in Calcs”
- AR 4070196; “Communication Gaps Regarding U2 Div 3 Battery Sediment Issue”
- AR 4070286; “NRC Question Regarding Abandonment of 1(2)DO024 Function”
- AR 4070501; “NRC Id: Active License Proficiency Watches”
- AR 4070533; “NRC Id: Enhancement Gaseous Tritium Sampling”
- AR 4074674; “NRC Id: Clarification of Design Basis Code of Downcomer Vent”
- AR 4075059; “NRC Identified—Door 282 Broken Floor Pin”
- AR 4075178; “NRC Question—Assurance 2E12–C300A Will Start”
- AR 4075182; “NRC Id: Tether on Cable Tray”
- AR 4075634; “NRC Question on 2e12–C300a Seal Leak”
- AR 4075834; “CCP NRC Id'd: Discrepency *(sic)* between P&ID and Mech Checklist”
- AR 4076617; “NRC Id Fire Protection Mechanical Couplings Corrosion”
- AR 4076683; “NRC Questions Regarding U1 Defeated Annunciators”
- AR 4078654; “Door 259 Alarm Works Intermittently”
- AR 4079414; “NRC Question Regarding Mechanical Checklist and Prefire Plan”
- AR 4079420; “NRC Identified P & Id M–96 Sheet 4 Requires a Revision”
- AR 4079580; “NRC Question: PCI Interam *(sic)* Fire Wrap For 2E22–F004”
- AR 4079952; “NRC Identified Housekeeping Issues”
- AR 4084144; “NRC Question Related To Winter Readiness”
- AR 4085645; “NRC Question Regarding MS Rad Monitor Performance Criteria”
- AR 4090480; “NRC Question on Reportability for U2 LPCS”
- AR 4090775; “NRC Identified Potential Finding on 0 Dg Braze Repair”

LIST OF ACRONYMS USED

AC	Alternating Current
AR	Action Request (Issue Report, Condition Report)
ASME	American Society of Mechanical Engineers
BPS	Brazing Procedure Specification
CAP	Corrective Action Program
CFR	*Code of Federal Regulations*
DG	Diesel Generator
FP	Fire Protection
HPCS	High Pressure Core Spray
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
Kv	Kilovolt
LER	Licensee Event Report
LORT	Licensed Operator Requalification Training
MPT	Main Power Transformer
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PI	Performance Indicator
PMT	Post-Maintenance Testing
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
SDP	Significance Determination Process
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VDC	Volts Direct Current
WO	Work Order