January 25, 2005

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000373/2004005;
05000374/2004005

Dear Mr. Crane:

On December 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your LaSalle County Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on January 11, 2005, with the Site Vice President, Ms. Susan Landahl, and other members of your staff.

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

Based on the results of this inspection, one NRC-identified and two self-revealed findings of very low safety significance were identified. Each of these findings involved a violation of NRC requirements. However, because the findings were of low safety significance and because the issues were entered into your corrective action program, the NRC is treating each of these violations as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. Additionally, two licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of any Non-Cited Violation in this report, 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, U.S. Nuclear Regulatory Commission, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspectors’ Office at the LaSalle County Station.

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Sincerely,

/RA/

Bruce L. Burgess, Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000373/2004005; 05000374/2004005
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - LaSalle County Station
LaSalle County Station Plant Manager
Regulatory Assurance Manager - LaSalle County Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-373; 50-374
License Nos:	NPF-11; NPF-18
Report No:	05000373/2004005; 05000374/2004005
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	October 1 through December 31, 2004
Inspectors:	D. Kimble, Senior Resident Inspector D. Eskins, Resident Inspector M. Franke, Reactor Engineer, Branch 2 M. Mitchell, Radiation Protection Specialist B. Palagi, Senior Operations Engineer D. Schrum, Regional Engineering Inspector J. Yesinowski, Illinois Dept. of Emergency Management
Observers:	D. Melendez-Colon, NRC Inspector-In-Training
Approved by:	B. Burgess, Chief Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000373/2004005, 05000374/2004005; 10/01/2004 - 12/31/2004; LaSalle County Station, Units 1 & 2; Maintenance Effectiveness and Surveillance Testing.

The inspection was conducted by resident inspectors and regional inspectors. The report covers a 3-month period of baseline resident inspection, and announced baseline inspections in radiation protection and engineering. Three Green findings and three associated Non-Cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green," or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was self-revealed when a plant non-licensed operator (NLO) conducted a backwashing evolution of the 2B residual heat removal service water (RHRSW) strainer without obtaining authorization for the activity from any operating supervisor or using any written procedures. The unauthorized and unplanned strainer backwashing caused the 2B RHRSW header to depressurize, rendering Unit 2 Division 2 RHRSW system inoperable for several minutes until the backwashing cycle was complete and the header automatically repressurized. An associated NCV for failure to implement an approved plant procedure for the RHRSW strainer backwashing activity, as required by plant Technical Specification 5.4.1(a) and Regulatory Guide 1.33, Revision 2, Appendix A, was also identified.

  The performance deficiency associated with this issue was a failure on the part of the NLO to have used an approved written plant procedure to conduct the backwashing of the 2B RHRSW strainer, a safety-related component. The finding was of more than minor significance in that it had a direct impact on the cornerstone objective. Specifically, the licensee's failure to properly use an approved written procedure for the backwashing of the 2B RHRSW strainer resulted in the inoperability of a safety-related service water train. The finding was of very low safety significance because the loss of operability for the 2B RHRSW train was only for a very short time and the actual loss of safety function did not exceed any Technical Specification allowed outage time limits, and because the event did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. Corrective actions planned and completed by the licensee include: the licensee had entered this issue into their corrective action program as Condition Report 262611; development and implementation of procedural guidance that outlines the activities that are considered skill-of-the-craft for operators; evaluation of need for establishing proficiency requirements for operations NLOs not normally assigned to on-watch duties; and resetting the operations and station event free clocks. The primary cause of the finding was determined to be related to the cross-cutting aspect of human performance. (Sections 1R22 and 4OA4)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance and an associated NCV during a review of the maintenance and performance history surrounding the 1E51-F028 reactor core isolation cooling (RCIC) containment isolation check valve. The licensee failed to effectively diagnose and correct a recurring performance problem with the valve sticking open following a failed local leak rate test (LLRT) and maintenance performed during the most recent Unit 1 refueling outage (L1R10) in January 2004. This failure to effectively diagnose and correct a degraded and nonconforming condition was determined to constitute a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

  The performance deficiency with this issue was a failure on the part of the licensee to have properly diagnosed the 1E51-F028 degraded condition and to have effectively enacted repairs in early 2004. The finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the licensee's failure to properly diagnose and effectively correct a degraded condition with the 1E51-F028 containment isolation check valve resulted in a subsequent failure, which occurred with the unit operating at power in a condition where the valve was required to be operable. Because the finding did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, reactor building, or the standby gas treatment (SBGT) system, and did not represent a degradation of the smoke or toxic gas barrier function for the control room, and did not represent an actual open pathway in the physical integrity of the primary containment or involve an actual reduction in defense-in-depth for the atmospheric pressure control or hydrogen control functions of the primary containment, it was determined to be of very low safety significance. Corrective actions planned or completed by the licensee included replacement of the 1E51-F028 valve disc and spring on September 17, 2004; replacement of the entire 1(2)E51-F028 check valves on both units during refuel outages in 2006 and 2007 with valves manufactured using austenitic stainless steel; repair of the ball float valve in the Unit 1 RCIC barometric condenser vacuum tank air discharge separator; repairs to the 1E51-F028 check valve line slope; and an additional on line test for the 1E51-F028 check valve by April 29, 2005, to confirm that it is operating properly The finding was determined to involve the cross-cutting aspect of problem identification and resolution. (Sections 1R12.2 and 4OA2.1)

- Green. A finding of very low safety significance and an associated NCV were self-revealed following a trip of the 'A' train of the auxiliary electric equipment room (AEER) ventilation (VE) system while operating in the purge mode. Written procedures for the operation of the VE system failed to properly account for ventilation compressor heat load capacity limitations during VE system alignment in the purge mode. The lack of proper written procedural guidance was determined to constitute a Non-Cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

The performance deficiency with this issue was a failure on the part of the licensee to establish and maintain adequate written procedures for the testing and operation of the VE system in the purge mode. The finding was of more than minor significance in that if left uncorrected it would constitute a more significant safety concern. The finding was determined to be of very low safety significance because it only involved the barrier function provided for the AEER. Corrective actions planned and completed by the licensee include revisions to procedures LTS-400-17, LOP-VC-01, and LOP-VE-01 to account for the newly identified limitations associated with VE operation in the purge mode. (Section 1R12.3)

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee’s corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1

The unit began the inspection period operating at full power. On November 14, 2004, power was reduced to approximately 80 percent to facilitate main turbine valve surveillance testing. The unit returned to full power operation later that same day. On December 5, 2004, a power reduction to approximately 68 percent was commenced to enable rod pattern adjustments and minor maintenance on the heater drain system. The unit returned to full power operation on December 6, 2004. On December 12, 2004, power was briefly reduced to approximately 92 percent for a Furmanite repair on a heater drain system valve. Full power operation was resumed later that same day, and the unit remained operating at or near full power for the remainder of the inspection period.

Unit 2

The unit began the inspection period operating at full power. On November 21, 2004, power was reduced to approximately 61 percent to facilitate main turbine valve surveillance testing, rod pattern adjustments, and minor maintenance activities. The unit returned to operation at full power on November 23, 2004. On December 19, 2004, power was briefly reduced to approximately 88 percent for another control rod pattern adjustment. Full power operation was resumed later that same day, and the unit remained operating at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather (71111.01)

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. Cold weather protection, such as heat tracing, was verified to be in operation where applicable.

The inspectors' review of winter weather preparations constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed a partial alignment verification of the following equipment trains to verify operability and proper equipment lineup. These systems were selected based upon risk significance, plant configuration, system work or testing, or inoperable or degraded conditions:

- ‘B’ diesel fire pump during overhaul of opposite train;
- Unit 1 fuel pool cooling while supporting both Unit 1 and 2 fuel pools;
- Unit 1 reactor core isolation cooling (RCIC) with Unit 1 high pressure core spray (HPCS) out of service for routine maintenance; and
- ‘0' emergency diesel generator (EDG) during maintenance on 1A EDG.

The inspectors verified the position of critical redundant equipment and checked for any discrepancies between the existing equipment lineups and the required lineups.

These quarterly partial alignment verifications constituted four inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Zone Inspections

a. Inspection Scope

The inspectors checked the following risk significant areas looking for any fire protection issues. The inspectors selected areas containing systems, structures, or components that the licensee identified as important to reactor safety.

- Fire Zone 3F; Unit 2 - Elevation 740'0" ;
- Fire Zone 3B1; Unit 2 - Elevation 820'6";
- Fire Zone 3B2; Unit 2 - Elevation 820'6" ;
- Fire Zone 7C1; Unit 1 HPCS - Diesel Fuel Tank Room - Elevation 674'0";
- Fire Zone 7C2; Unit 1 Division 2 - Diesel Fuel Tank Room - Elevation 674'0"; and
- Fire Zone 7C3; Unit 1 Division 1 - Diesel Fuel Tank Room - Elevation 674'0".

The inspectors reviewed the control of transient combustibles and ignition sources, fire detection equipment, manual suppression capabilities, passive suppression capabilities, automatic suppression capabilities, barriers to fire propagation, and any compensatory measures the licensee had enacted due to degraded fire protection features.

These quarterly fire zone inspections constituted six inspection samples.

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation

a. Inspection Scope

To evaluate the readiness of licensee personnel to fight fires, on October 14, 2004, the inspectors observed the fire brigade respond to a simulated fire in the Unit 2 Condensate Pump Aisle. The following aspects of the response were reviewed:

- Use of protective clothing and self-contained breathing apparatus (SCBAs);
- Use of fire hoses to demonstrate the capability to reach all necessary fire hazard locations without flow constrictions;
- Testing of hose nozzle patterns prior to entering the fire area;
- Entry into the fire area in a controlled manner;
- Presence of sufficient fire fighting equipment at the scene for the fire brigade to properly perform their fire fighting duties;
- Effectiveness and clarity of the fire brigade leader's directions;
- Efficiency and effectiveness of radio communications between plant operators and fire brigade members;
- Checking for fire victims and fire propagation into other plant areas; and
- Effectiveness of simulated smoke removal operations.

The inspectors' review of this annual fire drill constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed design basis and licensee Probable Risk Assessment (PRA) documentation that identified possible internal flood paths for areas which contain safety-related equipment. Internal flooding core damage frequency (CDF) accounts for 27 percent of the total CDF for LaSalle Station. This is due largely to the PRA assessment that a large circulating water line break in the turbine building outside the condenser pit has the capability, if not isolated, to flood the entire turbine and reactor buildings up to the 701 foot elevation.

The inspectors walked down accessible portions of the turbine building, reactor building, and auxiliary building to verify that the licensee's flooding mitigation plans and equipment were consistent with design requirements and risk analysis assumptions.

This internal flooding review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Biennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed documents associated with inspection, cleaning, and performance trending of heat exchangers, primarily focusing on the 1A residual heat removal (RHR) heat exchanger, 1A EDG coolant heat exchanger, and 1A and 2A RHR pump seal coolers.

These heat exchangers were chosen based upon their importance in supporting required safety functions as well as relatively high risk achievement worth in the plant specific risk assessment. The emergency diesel generator heat exchanger was also selected to evaluate the licensee's thermal performance testing methods. During the inspection, the inspectors reviewed calculations to verify that these activities adequately ensured proper heat transfer. The inspectors reviewed the documentation to confirm that the inspection methodology was consistent with accepted industry and scientific practices, based on review of heat transfer texts and Electrical Power Research Institute (EPRI) standards. Specifically, the inspectors reviewed the licensee's heat transfer related calculations and/or maintenance activities to confirm that the minimum design heat transfer capability was maintained for these heat exchangers, in accordance with licensee commitments to Generic Letter 89-13, and limiting design performance values identified in the Updated Final Safety Analysis Report (UFSAR).

The inspectors performed a field walkdown of the EDG coolant heat exchanger. The inspectors observed the thermal performance testing of this heat exchanger.

The inspectors reviewed documents associated with licensee controls for the service water from the ultimate heat sink (UHS) to prevent clogging due to macrofouling and calcium deposition. In addition, sufficient reservoir capacity was verified. These two attributes met the procedure requirements for verifying the performance of the UHS.

The inspectors reviewed condition reports concerning heat exchanger and ultimate heat sink performance issues to verify that the licensee had an appropriate threshold for identifying issues and entering them in the corrective action program. The inspectors also evaluated the effectiveness of the corrective actions for identified issues, including the engineering justifications for operability.

The inspectors' review of licensee activities and documents regarding the 1A RHR heat exchanger, 1A EDG coolant heat exchanger, and 1A and 2A RHR pump seal coolers constituted three inspection samples.

b. Findings

No findings of significance were identified. One unresolved item (URI) was identified.

The inspectors identified that the licensee had potentially incorporated into their calculations a non-conservative coolant water temperature for cooling the RHR mechanical seals. The licensee had received a vendor memorandum that stated that 250 degrees Fahrenheit (F) at 2 gallons per minute (gpm) was acceptable for cooling the seals. However, appropriate justification was not provided. This issue is considered an unresolved item pending further review of the licensee evaluation. This temperature was used in the licensee's calculations.

The licensee had problems with adequate coolant flow (cold side) in their RHR seal heat exchangers for several years. The heat exchanger became clogged with mineral deposits and silt which reduced the flow of water. Consequently, the licensee increased the frequency of testing the flow of water to quarterly. However, even with this increased frequency of testing (and cleaning as required), the flow was often reduced below the original design flow acceptance criteria. To change the acceptance criteria from 12.5 gpm to 5 gpm flow of water in the cold side of the RHR heat exchanger, the licensee requested a higher temperature of coolant flow to the RHR mechanical seals from the seal vendor. The licensee received permission to go from 184 degrees F coolant flow to 250 degrees F at 2 gpm seal water flow in a memorandum from the vendor. However, the licensee did not obtain any supporting information or test data from the vendor to support the use of the seals at these higher temperatures. The licensee also used this higher seal water temperature to support a calculation for an increased service water temperature from the UHS at 104 degrees F.

Attachment A (Memorandum from General Electric) to Calculation No. L-000711, "Evaluation of RHR Flow to RHR Pump Seal Coolers," Revision 4B, for the LaSalle RHR, low pressure core spray (LPCS), and high pressure core spray (HPCS) process water temperatures originally stated: "At 175 degrees F, seal degradation due to temperature is minimized and cooling is not expected to provide improvement. The 175 degrees F limit is based on General Electric experience with mechanical seals from several manufacturers. The limit (175 degrees F) is in general agreement with information obtained from Ingersoll Rand (180 degrees F) and Crane Packing Company (160 degrees F)." Also, this memorandum stated that seal failure can occur within minutes at 212 degrees F.

The above temperatures are consistent with those found at other licensees and consistent with information obtained from seal vendors. The temperature difference between those indicated (i.e., 175 degrees and 212 degrees F) is to account for heat generated from the friction in the seals when the two surfaces are in contact with each other. The frictional heat is dependent on the seal materials and rotational speed of the pump.

One problem with the cooling water supply at higher temperatures is that water film between the two surfaces of the seal will not support the seal surfaces as a lubricant. Without lubrication, the seal could fail in a relatively short period of time depending on the original condition of the seal. In addition, temperatures at boiling will flash to steam between the seals and open the seals. The seals will be damaged when they slap back together. Licensee calculations even prior to the change of seal temperature to 250 degrees F used seal water temperatures at 212 degrees. The licensee did not appear to account for the increase in water temperature from seal friction. Thus, it appears that the seals could be damaged at these temperatures.

The inspectors identified a second potential problem with the flow of water to the mechanical seal. The vendor memorandum stated with 2 gpm seal flow at 250 degrees F was acceptable. The vendor indicated that this was minimum amount of flow so the seal heat can be transferred to this amount of water without a substantial amount of additional rise in temperature in the water and seal. The licensee used the 2 gpm as a maximum flow in their calculations, not as a minimum flow. The licensee was notified that the flow could be less than 2 gpm. Licensee Calculation L-000711, design Input 4.7 stated: “RHR pump seal flush water flow rate is less than or equal to 2.0 gpm per Borg Warner Bulleten 1860 from VETIP Manual J-0057.000, John Crane, Inc.” In addition, other licensee documents indicated this flow could be as low as 0.3 gpm. An inspector review of the vendor data for seal water separators indicated that this volume of water to the seal was about 1 gpm. However, the volume was dependent on the system pressure. The licensee stated during the inspection that they have never measured this flow and did not know the amount of seal flow of water to the RHR seals.

The inspectors identified a third potential problem in a December 17, 2004, John Crane memorandum, “John Crane 3-1/2 Type 8B1 Seal CFSP-38327-8." This memorandum stated that in the 1990s it became popular to run balanced seals uncooled due to the cost of the heat exchangers. This memorandum appeared to indicate that the seals were a balanced design. However, the licensee stated that the RHR seals were original unbalanced seals subject to expected shorter seal life when used at elevated temperatures. In addition, this memorandum indicated that this seal can run with temperatures at 350 degrees F. But a September 17, 1996, John Crane memorandum stated that these same seals tested at elevated temperatures of 350 degrees F could run for 5 hours then degrade rapidly.

The licensee entered an action item into their corrective action program to contact the seal vendor and obtain supporting information for the 250 degrees F seal water coolant flow (IR 280803). Pending a review of the licensee’s information from the vendor, this issue is considered unresolved (URI 05000373/2004005-01; 05000374/2004005-01).

The inspectors considered the RHR pump seals operable based on the fact that the UHS (lake temperature) is cold and the cold water will keep the seal cooling water cool even at a 5 gpm flow rate.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Biennial Written Examination and Annual Operating Test Results

a. Inspection Scope

The inspector reviewed the overall pass/fail results of individual job performance measure (JPM) operating tests, and simulator operating tests (required by

10 CFR 55.59(a)(2)) administered by the licensee during calender year 2004. The overall results were compared with the SDP in accordance with NRC Inspection Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process .”

This review constituted one (partial) inspection sample.

b. Findings

No findings of significance were identified.

.2 Quarterly Resident Inspector Licensed Operator Training Observation

a. Inspection Scope

The inspectors observed a training crew during an evaluated simulator scenario and reviewed licensed operator performance in mitigating the consequences of events. The scenario included a scram condition with a failure of the reactor control rods to properly insert, as well as a loss of coolant accident (LOCA) that bypassed primary containment. The accident observed resulted in the declaration of a General Emergency condition. Areas observed by the inspectors included: clarity and formality of communications, timeliness of actions, prioritization of activities, procedural adequacy and implementation, control board manipulations, managerial oversight, emergency plan execution, and group dynamics. Additionally, the inspectors observed the instructors’ critique and evaluation of the training crew’s performance.

This quarterly training observation constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Service Water Supply to Unit 1 and 2 Division 1 Safety Related Heat Exchangers

a. Inspection Scope

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the selected components. Flow balancing issues associated with the ‘0’ diesel service water pump flow to Unit 1 and Unit 2 Division 1 safety related heat exchangers were selected based on the serviced components being designated as risk significant under the Maintenance Rule, and due to issues that potentially impacted system work practices, reliability, or common cause failures.

The inspectors’ review included verification of the licensee’s categorization of specific issues, including evaluation of the performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed the licensee's implementation of Maintenance Rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with the condition reports reviewed, and current equipment performance status.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 (Closed) Unresolved Item 05000373/2004004-01: Unit 1 RCIC F028 Containment Isolation Check Valve Maintenance History Indicates Repeated Failures Since 1991.

a. Inspection Scope

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the Unit 1 RCIC containment isolation check valve, 1E51-F028. This component was selected based on being designated as risk significant under the Maintenance Rule and because of an inspector identified issue or problem that impacted system reliability.

The inspectors' review included verification of the licensee's categorization of specific issues, including evaluation of the performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed the licensee's implementation of Maintenance Rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with the condition reports reviewed, and current equipment performance status.

This review constituted a single inspection sample.

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) during a review of the maintenance and performance history surrounding the 1E51-F028 RCIC containment isolation check valve. The inspectors' review revealed that the licensee had failed to effectively diagnose and correct a recurring performance problem with the valve sticking open following a failed local leak rate test (LLRT) and maintenance performed during the most recent Unit 1 refueling outage (L1R10) in January 2004. This failure to effectively diagnose and correct a degraded and nonconforming condition was determined by the inspectors to be contrary to the requirements of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

Description

During the Unit 1 refueling outage (L1R10), conducted in January – February 2004, the as-found 10 CFR 50, Appendix J, Type C LLRT, performed on RCIC system containment isolation check valve 1E51-F028, failed. Subsequent corrective action performed by the licensee consisted of component maintenance in which the valve was disassembled, internal parts cleaned and inspected, and the valve reassembled. Inspection of the valve internals during this maintenance activity revealed a buildup of corrosion products on the valve internals that were probably responsible for internal binding and resulted in the check valve's disc being stuck in the open position. A Type C LLRT performed following the valve's reassembly as a post-maintenance test yielded satisfactory results.

On August 2, 2004, the licensee identified that previous LLRTs performed on RCIC system containment isolation check valves 1(2)E51-F028 to satisfy the requirements of 10 CFR 50, Appendix J, were invalid. During a routine review, the licensee had determined that a head correction calculation used to establish test pressure was in error, and that the test pressure that both the Unit 1 and Unit 2 F028 valves had been subjected to during their last refueling outage was outside the specified value and non-conservative. The licensee immediately declared the 1(2)E51-F028 check valves inoperable, and shut and deenergized the companion 1(2)E51-F069 motor-operated containment isolation valves on each unit to comply with Technical Specifications.

On September 9-10, 2004, the licensee performed LLRTs on both units' RCIC F028 check valves in an attempt to restore the valves to an operable status. The Unit 2 E51-F028 check valve was tested satisfactorily and the Unit 2 RCIC system was returned to a normal alignment with the 2E51-F069 motor-operated valve (MOV) energized and open. The Unit 1 E51-F028 check valve was determined during its LLRT to be stuck open, and disassembly and repair were required. On September 17, 2004, the licensee disassembled the 1E51-F028 containment isolation check valve. Licensee maintenance personnel, as well as the NRC inspectors observing the work activity, noted a significant amount of corrosion product buildup inside the valve, to the extent that maintenance technicians had to twist the valve's plug repeatedly in order to facilitate its removal. The corrosion product buildup was cleaned up in accordance with licensee maintenance procedures for check valve overhauls, and the valve's plug and operating spring were replaced. Later that day, the licensee performed a LLRT on the 1E51-F028 check valve and obtained satisfactory results. The 1E51-F028 check valve was declared operable, and the Unit 1 RCIC system was subsequently returned to a normal alignment with the 1E51-F069 MOV energized and open.

Inspectors following up on the 1E51-F028 LLRT failure identified other similar failures of the component over the past several years. In each case, it appears that the licensee performed fairly similar corrective actions to clean up the valve internals, obtain satisfactory LLRT results, and return the valve to service. The licensee did not, however, diagnose the underlying cause of the corrosion product buildup until after the September 9, 2004, on line test failure.

An equipment apparent cause evaluation (EACE 253839) completed by engineering and maintenance personnel identified in October 2004 that the carbon steel disc of the check valve was corroding, and that the buildup of corrosion products over time was causing the valve disc to bind and stick in the open position. Contributing to the buildup of corrosion products was an unexpected accumulation of moisture within the body of the check valve. Investigation by licensee personnel revealed that the check valve line was sloped slightly towards the valve, thus promoting moisture retention in the check valve. Additionally, the licensee's investigation identified that a ball float valve in the RCIC barometric condenser vacuum tank air discharge separator may have been faulty. The faulty ball float valve is believed to have permitted the discharge of vacuum pump seal water into the 1E51-F028 line along with intended non-condensable gases from the barometric condenser.

Analysis

The inspector identified performance deficiency with this issue was a failure of the licensee to have properly diagnosed the 1E51-F028 degraded condition and to have effectively enacted repairs in early 2004. Following the Type C LLRT failure and the considerable degradation of the valve noted during disassembly and inspection during the 2004 Unit 1 refuel outage (L1R10), the licensee should have taken more extensive corrective actions. Instead, the licensee's corrective actions consisted of simple maintenance to clean and inspect the valve internals, a post-maintenance Type C LLRT, and revised the check valve's preventive maintenance (PM) frequency from disassembly and inspection once every two refuelings to each refueling. In examining the check valve's maintenance and testing history, the inspectors noted that Type C LLRT failures associated with internal corrosion and the valve's disc sticking open were a recurring issue throughout the component's history. Between 1996 and early 2004, the valve had been subjected to Type C LLRT and disassembly and inspection five times, or during each significant unit outage. In only two instances, refuel outage L1R08 in 1999, and refuel outage L1R09 in 2002, were the initial as-found LLRTs successful and the internals inspections satisfactory. In light of this information, the inspectors determined that the problems associated with the 1E51-F028 check valve were reasonably within the licensee's ability to foresee and correct, and that with the addition of more extensive corrective actions, the subsequent 1E51-F028 LLRT failure in September 2004, with the unit on line, could have been prevented.

The objective of the Barrier Integrity Cornerstone of Reactor Safety is to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radio nuclide releases caused by accidents or events. A key attribute of this objective is the reliability of systems, structures, and components (SSCs) associated with containment isolation. In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the licensee's failure to properly diagnose and effectively correct a recurring degraded condition with the 1E51-F028 containment isolation check valve resulted in a subsequent failure. The failure occurred with the unit operating at power and in a condition where the valve was required to be operable to meet a Technical Specification Limiting Condition of Operation (LCO).

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the finding did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, reactor building, or the standby gas treatment (SBGT) system, and did not represent a degradation of the smoke or toxic gas barrier function for the control room, and did not represent an actual open pathway in the physical integrity of the primary containment or involve an actual reduction in defense-in-depth for the atmospheric pressure control or hydrogen control functions of the primary containment, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band. Because the finding involves the cross-cutting aspect of problem identification and resolution, it is also noted in Section 4OA2.1, "Routine Review of Identification and Resolution of Problems," in this report.

Enforcement

Table 3.2-1 of the licensee's Updated Final Safety Analysis Report (UFSAR) indicated that the 1E51-F028 containment isolation check valve is subject to the requirements of 10 CFR 50, Appendix B. Criterion XVI, "Corrective Action," of this appendix states, in part, that: "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to this requirement, the licensee failed to promptly correct nonconformances associated with the 1E51-F028 containment isolation check valve during the Unit 1 L1R10 refueling outage in January - February 2004. As a result of this failure on the part of the licensee's staff, the same nonconforming conditions yielded an additional failure of the 1E51-F028 check valve in September 2004, when the valve was required to be operable to meet a Technical Specification LCO.

The licensee had entered this issue into their corrective action program as Condition Report (CR) 253839. Corrective actions planned and completed by the licensee include: replacement of the 1E51-F028 valve disc and spring on September 17, 2004; planned replacement of the entire 1(2)E51-F028 check valves on both units during refuel outages in 2006 and 2007 with valves manufactured using austenitic stainless steel; repair of the ball float valve in the Unit 1 RCIC barometric condenser vacuum tank air discharge separator; repairs to the 1E51-F028 check valve line slope; and an additional on line test for the 1E51-F028 check valve by April 29, 2005, to confirm that it is operating properly. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50, Appendix B, Criterion XVI is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000373/2004005-02)

.3 (Closed) Unresolved Item 05000373/2004004-02; 05000374/2004004-02: 'A' Train Auxiliary Electric Equipment Room Ventilation (VE) Compressor Tripped During Purge Mode Surveillance Testing Causing High Humidity Condition and Multiple Control Room Annunciator Alarms.

a. Inspection Scope

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the 'A' VE compressor and ventilation train. This system train was selected based on being designated as risk significant under the Maintenance Rule, and due to a self-revealed performance problem that impacted auxiliary electric equipment room (AEER) component operability and reliability.

The inspectors' review included verification of the licensee's categorization of specific issues, including evaluation of the performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed the licensee's implementation of Maintenance Rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with the condition reports reviewed, and current equipment performance status.

This review constituted a single inspection sample.

b. Findings

Introduction

A finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) were self-revealed following a trip of the 'A' train of the AEER VE system while operating in the purge mode. A subsequent review by the licensee's staff revealed that the written procedures for the operation of the VE system failed to properly account for ventilation compressor heat load capacity limitations during VE system alignment in the purge mode. The lack of proper written procedural guidance was determined by the inspectors to be contrary to the requirements of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description

On September 14, 2004, the licensee was conducting a surveillance test of the 'A' train of the VE system utilizing the purge mode of operation per an approved testing procedure. In this mode, 100 percent of the air being supplied to the AEER is outside air. Approximately 10 minutes after the start of the test, the 'A' VE compressor tripped. With the air being supplied to the AEER no longer being cooled and dehumidified, moisture began to condense on the coolest equipment panels in the AEER, and multiple control room annunciator alarms began to actuate.

Approximately 18 minutes after the trip of the 'A' VE compressor, the licensee completed shifting to the 'B' train of VE. The spurious control room alarms subsided as temperature and humidity conditions in the AEER were restored to normal. Three control room annunciator alarms (Unit 1 drywell equipment drain sump trouble; Unit 2 post-loss of coolant accident (LOCA); and the Unit 2 power supply alarm for Panel 2P05J in the control room) remained actuated and would not reset. The licensee performed appropriate compensatory measures, as required by procedure, until these were repaired the following day via replacement of the applicable alarm cards.

A subsequent EACE by the licensee's engineering and operations staff revealed that the 'A' VE compressor had tripped on high discharge pressure due to being overloaded. Moreover, the licensee's investigation uncovered the fact that the VE system was never designed to operate in purge mode and maintain AEER environmental conditions under the ambient air temperature and humidity conditions in place at the time of the test. In short, the licensee's approved test procedure for the surveillance attempted to operate the 'A' VE system and maintain AEER environmental conditions in a configuration that was outside of the design capabilities of the VE compressor.

Analysis

The performance deficiency with this issue was a failure on the part of the licensee to establish and maintain adequate written procedures for the testing and operation of the VE system in the purge mode. Testing procedure, LTS-400-17, "Control Room and Auxiliary Electric Equipment Room Heating, Ventilation, and Air Conditioning (HVAC) Isolation Damper Surveillance Smoke and Radiation Detection," as written on September 14, 2004, did not contain proper limitations for the operation of the VE system in the purge mode. Specifically, the procedure allowed for system operation in an alignment that was beyond VE system design capability for the given environmental conditions. A follow on extent-of-condition review by the licensee's engineering staff revealed that the same condition was true for procedures LOP-VC-01, "Control Room HVAC Operation," and LOP-VE-01, "Auxiliary Electric Equipment Room HVAC Operation."

The inspectors determined that the finding was of more than minor significance in that if left uncorrected it would constitute a more significant safety concern. Specifically, in the case of the testing that occurred on September 14, 2004, the improper operation of the VE system in the purge mode and the resultant high humidity condition in the AEER only caused nuisance alarms in the control room and the loss of 3 alarm annunciators of relatively low significance. However, this result was a simple matter of good fortune; in reviewing the event the inspectors determined that the consequences of the high humidity in the AEER could have been far more widespread, potentially resulting in the need for the activation of the licensee's emergency plan if enough control room annunciators had been disabled.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Under the Barrier Integrity Cornerstone, the inspectors determined the finding to be of very low safety significance (Green) and within the licensee's response band because it only involved the barrier function provided for the AEER.

Enforcement

Table 3.2-1 of the licensee's UFSAR indicates that the VE system, including all major components, is subject to the requirements of 10 CFR 50, Appendix B. Criterion V, "Instructions, Procedures, and Drawings," of this appendix states, in part, that: "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Contrary to this requirement, the licensee failed to prescribe adequate documented instructions and procedures for the operation of the VE system in the purge mode.

The licensee had entered this issue into their corrective action program as CRs 253769 and 252847. Corrective actions planned and completed by the licensee include revisions to procedures LTS-400-17, LOP-VC-01, and LOP-VE-01 to account for the newly identified limitations associated with VE operation in the purge mode. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50, Appendix B, Criterion V is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000373/2004005-03; 05000374/2004005-03)

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

a. Inspection Scope

The inspectors reviewed and observed emergent work, preventive maintenance, or planning for risk significant maintenance activities. The inspectors observed maintenance or planning for the following activities or risk significant systems undergoing scheduled or emergent maintenance:

- Unit 1 and Unit 2 station/instrument air dryers troubleshooting and repair;
- RCIC F065/66 pressure isolation valve (PIV) testing issues;
- Unit 1 turbine stop valve (TSV) limit switch issues; and
- Unit 1 and Unit 2 standby liquid control (SBLC) concentration issues.

The inspectors also reviewed the licensee's evaluation of plant risk, risk management, scheduling, and configuration control for these activities in coordination with other scheduled risk significant work. The inspectors verified that the licensee's control of activities considered assessment of baseline and cumulative risk, management of plant configuration, control of maintenance, and external impacts on risk. In-plant activities were reviewed to ensure that the risk assessment of maintenance or emergent work was complete and adequate, and that the assessment included an evaluation of external factors. Additionally, the inspectors verified that the licensee entered the appropriate risk category for the evolutions.

These reviews constituted four inspection samples.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

.1 Observation of Unit 2 Load Drop Activities on November 21-22, 2004

a. Inspection Scope

The inspectors performed several hours of continuous control room observation to evaluate operator performance in coping with the non-routine activities associated with a planned significant plant power reduction to facilitate various maintenance work items. The inspectors reviewed operator logs and plant computer data to determine how the unit responded and to verify that operator actions were appropriate, and consistent with operator training and plant procedures. The licensee's plan for the load reduction, procedures, reactivity manipulation briefings, and contingency plans were also reviewed by the inspectors to identify any personnel performance issues. In addition, the inspectors verified that any problems encountered during the non-routine evolution were identified by the licensee, and appropriately entered into the corrective action program.

The observation of this non-routine evolution by the inspectors constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Annual Review of Licensee Event Reports (LERs) for Personnel Performance Issues

a. Inspection Scope

The inspectors screened all LERs submitted by the licensee during the past 4 calendar quarters to determine if any involved operator performance errors. Where applicable, the inspectors verified that licensee personnel responded in accordance with applicable procedures and training.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of the following operability evaluations to determine the impact on Technical Specifications, the significance of the evaluations, and to ensure that adequate justifications were documented:

- General Electric (GE) control blade cracking (OE 04-010);
- Unit 2 jet pump no. 19 plugging (OE 04-011);

- 125 Vdc motor control center (MCC) cubicle doors – seismic issues; and
- Scram Discharge Volume (SDV) vent/drain fuse blocks (OE 04-012).

Operability evaluations were selected based upon the relationship of the safety-related system, structure, or component to risk.

These reviews constituted four inspection samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Standby Liquid Control (SBLC) Boron Tank Volume/Concentration Measurements

a. Inspection Scope

The inspectors reviewed a potential operator workaround involving the determination of the SBLC tank level and concentration for both units. Methods for measuring tank level and concentration were reviewed for adequacy and accuracy in determining Technical Specification required values. Instruments, measuring and test equipment, and procedural guidance utilized for these measurements were inspected as well as engineering evaluations and condition reports associated with the SBLC system.

The review of this issue constituted a single inspection sample.

b. Findings

No findings of significance were identified. One unresolved item (URI) was identified.

On November 19, 2004, the Unit 2 main control room received a SBLC tank level alarm. Plant operators concluded that the bubbler system that provides both tank level and alarm indications was plugged and required cleaning. After the bubbler was cleaned, however, the SBLC tank low level alarm still was actuated. A manual measurement conducted by operations personnel using a T-square indicated a tank volume of 4717 gallons. Since the low level alarm setpoint was at 4700 gallons, the licensee decided to add water to the SBLC tank to increase the volume of solution.

On November 23, 2004, operations and chemistry personnel added water to the Unit 2 SBLC tank and, as required by procedure, sampled the sodium pentaborate (boron solution) concentration afterwards. Volume was measured using the T-square at 4767 gallons and boron solution concentration was determined to be 12.99 percent. The minimum required Technical Specification boron solution concentration for this volume is 12.97 percent, per Technical Specification Figure 3.1.7-1. Chemistry technicians noted that there was little margin to the Technical Specification limit, and plans were made to perform a sodium pentaborate addition to the tank during the following week.

Just prior to midnight on November 25, 2004, Unit 2 operators were performing their daily Technical Specification surveillance to verify SBLC tank level within the limits of Technical Specification Figure 3.1.7-1. Measured tank volume was 4750 gallons. This volume was below the required Figure 3.1.7-1 limit for the current boron solution concentration of 12.99 percent. For a volume of 4750 gallons, Figure 3.1.7-1 specified a minimum boron solution concentration of 13.02 percent. SBLC tank volume was subsequently measured using the T-square, and 4762 gallons was the result. This volume was exactly at the Technical Specification Figure 3.1.7-1 limit for a boron solution concentration of 12.99 percent. However, questions by the on-watch operations crew raised doubt as to the accuracy of the T-square volume measurement when it was realized that an unauthorized operator aid in the form of a placard on the side of the SBLC tank was being used to convert inches measured with the T-square to tank volume in gallons. The conversion method on the placard was different than the calculation used by chemistry technicians specified in their approved plant procedures.

Using the approved calculation from a chemistry procedure, operators recalculated the SBLC tank volume from their T-square measurement and determined it to be 4757 gallons, which was once again below the Figure 3.1.7-1 limit. Both trains of SBLC were declared inoperable and the applicable Technical Specification 8-hour shutdown time clock entered. Chemistry technicians were called in to sample the SBLC boron solution tank concentration, and obtained a measured value of 13.11 percent. When compared with the T-square volume of 4757 gallons, this concentration value was within the limits of Technical Specification Figure 3.1.7-1 and both trains of SBLC were declared operable.

The licensee conducted an extent-of-condition review and determined that both Unit 1 and Unit 2 SBLC tanks had routinely been maintained with little margin to the Figure 3.1.7-1 limits for volume and boron solution concentration. The licensee has entered multiple issues associated with this event into their corrective action program (CRs 276755, 277113, 277439, 281247, and 281238). These condition reports have generated several corrective action program investigations, including a root cause report (RCR 276755) and an apparent cause evaluation (ACE 277113). These issues are considered unresolved, pending the inspectors' receipt and review of the licensee's corrective action program investigations, which are scheduled to be completed in January 2005. (URI 05000373/2004005-04; 05000374/2004005-04)

.2 Semiannual Operator Workaround Review for Cumulative Effects

a. Inspection Scope

The inspectors performed a semiannual review of the cumulative effects of operator workarounds. The inspectors reviewed the cumulative effects of workarounds on the reliability, availability, and potential for improper operation of various systems, structures, and components important to safety. Additionally, reviews were conducted to determine if the workarounds could increase the probability of an initiating event, affect multiple mitigating systems, or impact the operators' ability to respond to accidents or transients.

This cumulative effects review represented a single inspection sample.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT) (71111.19)

a. Inspection Scope

The inspectors selected the following post-maintenance activities for review. Activities were selected based upon the structure, system, or component's ability to impact risk:

- Confidence run of ‘A’ VE compressor following compressor failure and repair;
- ‘B’ diesel fire pump (DFP) maintenance window PMT run;
- Unit 1 main turbine stop valve #1 functional test following limit switch repair;
- Unit 1 ‘B’ residual heat removal heat exchanger isolation valve testing following maintenance; and
- Unit 2 SBLC sodium pentaborate chemical concentration correction.

The inspectors verified by witnessing the test or reviewing the test data that post-maintenance testing activities were adequate for the above maintenance or repair activities. The inspectors reviews included, but were not limited to, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use and compliance, control of temporary modifications or jumpers required for test performance, documentation of test data, Technical Specification applicability, system restoration, and evaluation of test data. Also, the inspectors verified that maintenance and post-maintenance testing activities adequately ensured that the equipment met the licensing basis, Technical Specifications, and Updated Final Safety Analysis Report (UFSAR) design requirements.

These PMT reviews constituted five inspection samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors selected the following surveillance test activities for review. Activities were selected based upon risk significance and the potential risk impact from an unidentified deficiency or performance degradation that a system, structure, or component could impose on the unit if the condition were left unresolved:

- Unit 1 and Unit 2 ‘0' diesel cooling water pump flow balance;
- 1B diesel generator idle start;
- Unit 1 and Unit 2 drywell leakage detection system functional tests; and
- 2A emergency diesel generator (EDG) cooling water pump/flow inservice testing.

The inspectors observed the performance of surveillance testing activities, including reviews for preconditioning, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use, control of temporary modifications or jumpers required for test performance, documentation of test data, Technical Specification applicability, impact of testing relative to performance indicator reporting, and evaluation of test data.

These surveillance test reviews constituted four inspection samples. In addition, the observation of the Unit 1 and Unit 2 drywell leakage detection system functional tests served to meet the annual requirement to select one to three reactor coolant system leakage detection surveillances for review.

b. Findings

Introduction

A finding of very low safety significance (Green) was self-revealed when a plant non-licensed operator (NLO) conducted a backwashing evolution of the 2B residual heat removal service water (RHRSW) strainer without obtaining authorization for the activity from any operating supervisor or using any written procedures. The unauthorized and unplanned strainer backwashing caused the 2B RHRSW header to depressurize, rendering Unit 2 Division 2 RHRSW system inoperable for several minutes until the backwashing cycle was complete and the header automatically repressurized. An associated NCV for failure to implement an approved plant procedure for the RHRSW strainer backwashing activity, as required by plant Technical Specification 5.4.1(a) and Regulatory Guide (RG) 1.33, Revision 2, Appendix A, was also identified.

Description

In the early morning hours of October 12, 2004, station operators were completing the final steps of LOS-DG-M2, Attachment 2A-Idle, “2A Diesel Generator Operability Surveillance.” This final sequence of steps backwashes the diesel generator service water cooling water strainer and stops the cooling water pump. The NLO performing the procedure correctly initiated the backwash cycle on the 2A EDG service water strainer. While waiting for the backwash cycle to complete, which takes several minutes, the NLO manually initiated a backwash cycle on the 2B RHRSW strainer, which was in the same room. The NLO did not have the applicable procedure with him for backwashing the 2B RHRSW strainer, nor did he have any authorization to conduct this activity from on-watch operations shift supervisory personnel.

With the associated RHRSW pumps not running, the opening of the backwash valve on the 2B RHRSW strainer caused system pressure to drop below the alarm setpoint, and the 2B RHRSW header pressure low alarm actuated in the main control room. Control room operators, unaware that the NLO had initiated a backwash cycle on the 2B RHRSW strainer, entered the appropriate abnormal operating procedure for low RHRSW header pressure and dispatched another NLO to investigate. Unit 2 Division 2 RHRSW was declared inoperable and the applicable Technical Specification Action Statement entered. After approximately 4 minutes, the low header pressure alarm cleared due to the normal repressurization of the system following completion of the 2B RHRSW strainer backwash cycle.

After a short investigation by the on-watch operations crew, the backwashing of the 2B RHRSW strainer as the cause of the low RHRSW header pressure condition was identified. The on-watch shift manager suspended the NLO involved from plant duties, and initiated a prompt investigation in accordance with the licensee's corrective action program. When interviewed following the incident, the NLO stated that he initiated the 2B RHRSW strainer backwashing cycle believing it to have been a skill-of-the-craft task and good operator practice. This particular NLO, however, was normally assigned to an operations staff position, and his recent experience with typical on-watch shift NLO duties was limited. An apparent cause evaluation (ACE) by the licensee concluded that inadequate human performance, specifically a failure to adhere to established plant procedures, was the primary cause of the event.

Analysis

The performance deficiency associated with this issue was a failure on the part of the NLO to have used an approved written plant procedure to conduct the backwashing of the 2B RHRSW strainer, a safety-related component. The objective of the Mitigating Systems Cornerstone of Reactor Safety is to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). A key attribute of this objective is human performance, and specifically, procedure use and adherence. In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the licensee's failure to properly use an approved written procedure for the backwashing of the 2B RHRSW strainer resulted in the inoperability of a safety-related service water train.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the loss of operability for the 2B RHRSW train was only for a very short time and the actual loss of safety function did not exceed any Technical Specification allowed outage time limits, and because the event did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band. Because the finding involves the cross-cutting aspect of human performance, it is also noted in Section 4OA4, "Cross-Cutting Aspects of Findings," in this report.

Enforcement

Technical Specification 5.4.1(a) requires the licensee to establish, implement, and maintain applicable written procedures for the safety-related systems and activities recommended in RG 1.33, Revision 2, Appendix A. Contrary to this requirement, the licensee failed to properly implement the approved written plant procedure, LOP-RH-14, "Backwash of the Residual Heat Removal Service Water Strainers," for the backwashing of the 2B RHRSW strainer on October 12, 2004. As a result of this failure on the part of the licensee's staff, the Unit 2 Division 2 RHRSW train was depressurized and rendered inoperable for a period of several minutes.

The licensee had entered this issue into their corrective action program as Condition Report 262611. Corrective actions planned and completed by the licensee include: development and implementation of procedural guidance that outlines the activities that are considered skill-of-the-craft for operators; evaluation of need for establishing proficiency requirements for operations NLOs not normally assigned to on-watch duties; and reset the operations and station event free clocks. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of Technical Specification 5.4.1(a) is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000374/2004005-05)

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed temporary modification EC345906, "Evaluation of the Work Order to Provide Temporary Air Downstream of Valve 2C11-F379 for Online Repair." The inspectors reviewed the safety screening, design documents, UFSAR, and applicable Technical Specifications to determine that the temporary modification was consistent with modification documents, drawings and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and that the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified.

The review of this temporary modification represented a single inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The resident inspectors reviewed a simulator-based quarterly full scale emergency preparedness drill to evaluate drill conduct and the adequacy of the licensee's critique of performance to identify weaknesses and deficiencies. The inspectors selected simulator scenarios that the licensee had scheduled as providing input to the Drill/Exercise Performance Indicator. The inspector observed, when applicable, the classification of events, notifications to off-site agencies, protective action recommendation development, and drill critiques. Observations were compared to the licensee's observations and corrective action program entries. The inspectors verified that there were no discrepancies between observed performance and performance indicator reported statistics. The simulator scenario observed resulted in a alert, site area emergency, and general emergency classifications.

This emergency preparedness drill observation and evaluation constituted a single inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's occupational exposure control cornerstone performance indicators (PIs) to determine whether or not the conditions surrounding the PIs had been evaluated, and identified problems had been entered into the corrective action program for resolution.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work area within radiation areas, high radiation areas and airborne radioactivity areas in the plant, and reviewed work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Pre-coat room valve bonnet leak

The inspectors reviewed the RWPs used to access this area and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down and surveyed (using an NRC survey meter) this area to verify that the prescribed radiation work permit (RWP), procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located.

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within spent fuel or other storage pools.

These reviews constituted four inspection samples.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, Licensee Event Reports, and special reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution.

The inspectors reviewed 13 corrective action reports related to access controls. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of Non-Cited Violations (NCVs) tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

The inspectors reviewed licensee documentation packages for all PI events occurring since the last inspection to determine if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. Unintended exposures >100 millirem total effective dose equivalent (or >5 rem shallow dose equivalent or >1.5 rem lens dose equivalent), were evaluated to determine if there were any regulatory overexposures or if there was a substantial potential for an overexposure.

These reviews constituted three inspection samples.

b. Findings

No findings of significance were identified.

.4 High Risk Significant, High Dose Rate HRA and VHRA Controls

a. Inspection Scope

The inspectors conducted plant walkdowns to verify the posting and locking of entrances to high dose rate HRAs, and very high radiation.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

The inspectors reviewed radiological problem reports which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with the Radiation Protection Manager.

These reviews constituted two inspection samples.

b. Findings

No findings of significance were identified.

.6 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated RPT performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed four radiological problem reports which found that the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

These reviews constituted two inspection samples.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable Planning And Controls (ALARA) (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following three work activities of highest exposure significance:

- L2R10 chemical decon;
- L2R10 dry well control rod drive pull/put and support activities; and
- L2R10 dry well LPRM replacements.

For these three activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

These reviews constituted two inspection samples.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the following job that was being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Valve re-work (torquing) on bonnet leak in pre-coat filter room.

The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.4 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and determined that the licensee was making allowances and had developing contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RPT performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.6 Problem Identification and Resolutions

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101(c).

The licensee's corrective action program was also reviewed to determine if repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution had been addressed.

These reviews constituted two inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstone: Occupational Radiation Safety

.1 Radiation Safety Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed Licensee Event Reports (LERs), licensee data reported to the NRC, plant logs, condition reports, and NRC inspection reports to verify the following performance indicators for information provided through the 3rd Quarter of 2004:

- Occupational Exposure Control Effectiveness

The inspectors verified that the licensee accurately reported performance as defined by the applicable revision of Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline.”

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the 3rd Quarter 2004 performance indicators for any obvious inconsistencies prior to its public release.

This review was performed in accordance with the requirements of IMC 0608, “Performance Indicator Program,” and did not represent a specific inspection sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the routine inspections documented above, the inspectors verified that the licensee entered the problems identified during the inspection into their corrective action program. Additionally, the inspectors verified that the licensee was identifying issues at an appropriate threshold and entering them in the corrective action program, and verified that problems included in the licensee's corrective action program were properly addressed for resolution. Attributes reviewed included: complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue.

These reviews did not represent any additional inspection samples. Rather, they were considered integral components of the samples documented elsewhere in this report.

b. Findings

A finding identified in Section 1R12.2 documents a failure on the part of the licensee to take effective corrective action for a degraded/nonconforming Unit 1 RCIC F028 containment isolation check valve.

.2 Daily Corrective Action Program (CAP) Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program (CAP). This review was accomplished through inspection of the station’s daily condition report packages.

These daily reviews did not constitute any additional inspection samples. Instead, by procedure they were considered part of the inspectors’ daily plant status monitoring activities.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP 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 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6 month period of July 2004 through December 2004, although some examples expanded beyond those dates when the scope of the trend warranted.

The review also included issues documented outside the normal CAP 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 semi-annual trend review did not constitute an additional inspection sample. Instead, by procedure it was considered part of the inspectors' daily plant status monitoring activities.

b. Findings and Issues

No findings of significance were identified. No issues were identified.

.4 Selected Issue Follow-up Inspection: Licensee Corrective Actions Related to the Failure of the Unit 1 Division 1 Emergency Core Cooling System (ECCS) Water Leg Keep Fill Pump

Introduction

On August 16, 2004, the Unit 1 low pressure core spray (LPCS) water leg keep-fill pump tripped off, rendering Unit 1 Division 1 low pressure ECCS inoperable. The applicable Technical Specifications 72-hour shutdown action statement was entered and Unit 1 operators transitioned from a "green" online risk condition to an increased risk, or "Yellow" condition. Operations personnel responding to the control room alarms found the LPCS water leg pump motor to be thermally hot to the touch and the motor control center (MCC) thermal overload (TOL) relay tripped. Visual inspection of the pump and motor breaker revealed no obvious problems. The TOL was successfully reset by pushing the reset button, after which the pump was restarted and remained running. The licensee initiated an adverse condition monitoring plan to monitor motor temperature, motor and pump vibration, and motor currents and voltage.

From August 17, 2004 through November 15, 2004, licensee maintenance and engineering personnel, with the assistance of an external diagnostic testing facility, conducted complex troubleshooting activities in an attempt to determine the cause of the pump trip. In addition to various other troubleshooting and online monitoring activities, the TOL package and pump motor contactor were replaced. Diagnostics and failure analyses were performed on both the removed TOL package and removed motor contactor assembly, but no problems with either could be found. Ultimately, the licensee terminated troubleshooting and failure analyses efforts and accepted an indeterminate apparent cause for the LPCS water leg pump trip.

Due to the risk significance of this event, the inspectors selected it and the associated corrective actions as an annual sample to evaluate with respect to the licensee's problem identification and resolution program. This review constituted a single inspection sample.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed the condition reports (CRs) and follow-up investigations for the above event to verify that the licensee's identification of the problems were complete, accurate, and timely, and that the consideration of extent-of-condition reviews, generic implications, common causes, and previous occurrences were adequate.

(2) Issues

No issues of significance were identified with respect to the effectiveness of problem identification. The licensee's CAP entries and follow on actions appeared reasonable. In independently reviewing condition reports for common cause issues, previous occurrences, and similar conditions, the inspectors concluded that the licensee's assessments were also adequate.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the CRs noted above to assess the licensee's evaluation and disposition of performance issues, and application of risk insights for prioritization of issues.

(2) Issues

Corrective actions were based on a qualitative assessment of risk. For the issues reviewed, the inspectors did not find any discrepancies with the apparent risk and the categorization assigned by the licensee. In one instance, however, the inspectors did note a lack of coordination between the operations group and maintenance personnel conducting the follow on evaluation of the issue. Operations personnel, proceeding under an assumption that the apparent cause for the pump trip had been narrowed down to some type of issue with the TOL package, nearly removed certain diagnostic recording equipment connected to the pump/motor when, in fact, maintenance personnel were pursuing an apparent cause lead involving an intermittent phase problem with the 3-phase 480 Vac power supplied to the motor. The 480 Vac phase issue was later ruled out by maintenance and engineering personnel investigating the issue, and the diagnostic equipment appropriately removed.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the related condition reports to determine if the CAP addressed generic implications. Additionally, the inspectors verified that corrective actions were appropriately focused to correct the problem.

(2) Issues

As noted above, the licensee's apparent cause evaluation was indeterminate. Diagnostics and failure analyses performed on both the removed TOL package and removed motor contactor assembly revealed no problems with either. To date, however, the LPCS water leg pump has not had any repeat trips that would indicate that any problem exists still with the component.

4OA3 Event Follow-up (71153)

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

.1 (Closed) Licensee Event Report (LER) 05000374/2004-001-00: Reactor Protection Bus 'B' Trip and Inoperable Automatic Depressurization Valves Due to Equipment Failure.

On February 1, 2004, at 11:34 p.m., the 2B Reactor Protection System (RPS) motor-generator (MG) set output breaker (D EPMA) tripped open resulting in the loss of the 'B' RPS bus. The trip of the 'B' RPS bus resulted in a ½ scram and associated primary containment isolation system (PCIS) groups 1 (partial), 2, 3, 5, 6, 7, and 10 isolations. The instrument nitrogen (IN) system operating compressor was isolated when IN system containment isolation valves closed on the group 10 isolation signal. This isolation resulted in the actuation of the IN system supply header rupture disk.

While the rupture disk was being replaced by maintenance, IN system header pressure to four of the Unit 2 automatic depressurization system (ADS) safety-relief valve (SRV) accumulators dropped below the Technical Specification 150 psig limit, requiring the ADS SRVs to be declared inoperable. The event required entry into multiple abnormal procedures, and also resulted in an 8-hour non-emergency telephone notification to the NRC Operations Officer for the multiple PCIS isolations that occurred, per 10 CFR 50.72(b)(3)(iv)(A).

The licensee determined the cause of the RPS MG set breaker trip to have been the result of an erratic voltage regulator gain potentiometer. The cause of the multiple ADS SRVs being rendered inoperable was found to be due to a faulty IN supply header regulating valve that would not perform properly under low loading conditions. A subsequent analysis by the licensee determined that although the ADS SRVs had been rendered inoperable by the low IN system header pressure, the faulty regulating valve would have been able to supply nitrogen to them at sufficient pressure and flow such that they would have been able to perform their safety functions if called upon. The inspectors had previously reviewed this issue, and documented the results of the inspections performed in NRC Inspection Report 05000373/2004002; 05000374/2004002, Sections 1R12, 1R13, 1R14, 1R15, 1R19, and 4OA2.2. The licensee had entered this event into their corrective action program as CR 198850. Corrective actions taken, which appeared to the inspectors to be adequate and appropriate for the circumstances, included: replacement of the locally mounted MG set voltage and current indication meters (2C71-R901B and 2C71-R902B); replacement of the 'D' EPMA circuit breaker control circuit board; calibration of the 'B' and 'D' circuit breaker control circuit boards; and a loaded 24-hour test run of the 2B RPS MG set. Additionally, the licensee procured a new style of pressure regulating valve for use in the IN system.

The review and closure of this LER constituted a single inspection sample. No findings of significance or violations of regulatory requirements were identified by the inspectors.

.2 (Closed) Licensee Event Report 05000373/2004-001-00: Invalid Containment Isolation Valve Local Leak Rate Test Due to Inadequate Procedure.

On August 2, 2004, during routine training for the licensee's local leak rate testing (LLRT) program, site engineering personnel identified that an inaccurate static head pressure correction factor had been used in the test for the Reactor Core Isolation Cooling (RCIC) barometric condenser vacuum pump discharge containment isolation check valves, 1(2)E51-F028. Upon discovery, the licensee declared these valves inoperable on both units and shut the companion motor-operated containment isolation valves, 1(2)E51-F069, in that penetration to comply with Technical Specification requirements.

The procedural deficiency responsible for the erroneous head correction factor was corrected, and on September 9-10, 2004, the 1(2)E51-F028 check valves were retested. While the Unit 2 valve satisfactorily passed its retest, the 1E51-F028 check valve was found to be stuck open. On September 17, 2004, the 1E51-F028 check valve was disassembled, the valve internals cleaned, and the valve disc and spring replaced. A post-maintenance test was performed with satisfactory results and the valve was subsequently declared operable.

In reviewing this event, the inspectors determined that the procedural deficiency responsible for the LLRT head correction factor error constitutes a licensee-identified violation of regulatory requirements that is of very low safety significance. The details of this violation are discussed in Section 4OA7 of this report. The licensee had entered this issue into their corrective action program as CR 253839. Corrective actions planned and completed by the licensee include: replacement the 1E51-F028 valve disc and spring on September 17, 2004; replacement of the entire 1(2)E51-F028 check valves on both units during refuel outages in 2006 and 2007 with valves manufactured using austenitic stainless steel; an additional on line test for the 1E51-F028 check valve by April 29, 2005, to confirm that it is operating properly; revisions to the affected LLRT procedures to correct the correction factor method; and incorporation of a verification signature for the individual calculating the correction factor and for the individual verifying the correction factor in all LLRT procedures requiring any calculated head corrections.

The inspectors reviewed the maintenance practices and related issues associated with the stuck open 1E51-F028 check valve separately. The results of that inspection are documented in Section 1R12.2 of this report.

The inspectors' review and closure of this LER constituted a single inspection sample.

.3 (Closed) Licensee Event Report 05000373/2004-002-00; 05000374/2004-002-00: 'B' Control Room Area Filtration Subsystem Inoperable Due to Unsecured Inspection Port Cover.

On September 29, 2004, during the performance of Technical Specification surveillance LTS-400-17, "Control Room and Auxiliary Electric Equipment Room (AEER) Heating, Ventilation, and Air Conditioning (HVAC) Isolation Damper Surveillance, Smoke and Radiation Detection," licensee personnel identified that the 'B' control room area filtration (CRAF) subsystem was unable to maintain adequate positive pressure in the AEER.

Technical Specification Surveillance Requirement 3.7.4.5 requires that each CRAF subsystem maintain greater than or equal to 0.125 inches water gauge relative to adjacent areas during the pressurization mode of operation at an air flow of less than or equal to 4000 cubic feet per minute. The September 29, 2004, surveillance test results for the 'B' train pressurization indicated the AEER did not have a positive pressure of greater than or equal to 0.125 inches water gauge with respect to four plant areas:

- the Unit 2 cable room in the Unit 2 switchgear area;
- the Unit 2 Division 2 switchgear room;
- the Unit 1 cable spreading room; and
- the Unit 2 cable spreading room.

The 'B' CRAF subsystem was declared inoperable at 9:05 p.m. on September 29, 2004, and Technical Specification 3.7.4, Required Action A.1 was entered to restore the CRAF subsystem to an operable status within 7 days. On September 30, 2004, at approximately 4:30 a.m., licensee personnel investigating the CRAF subsystem failure discovered an 8 inch x 8 inch inspection port cover open in the suction ductwork associated with fire damper OVE39Y. The cover was lying on top of ductwork next to the inspection port access opening. When the cover was reinstalled, the Unit 2 AEER ventilation differential pressure increased by 0.21 inches water gauge.

On October 1, 2004, the 'B' CRAF subsystem was declared operable following successful surveillance testing. Because the licensee determined that the 'A' CRAF subsystem had probably been inoperable for routine maintenance during some of the same time as the inspection port cover was missing from the 'B' CRAF subsystem, the event was determined to be reportable under 10 CFR 50.73(a)(2)(i)(B), as a condition prohibited by the plant's Technical Specifications. The licensee further determined that the direct cause of the event was improperly secured latches on the inspection port cover. However, a root cause investigation by the licensee was unable to identify the specific root cause of the latches being improperly secured. The most probable root cause was determined to have been that the latch on the access door for the OVE39Y fire damper was bumped while a mechanic was climbing on the ductwork to inspect the OVE40Y fire damper during a routine surveillance inspection. The inadequately secured inspection port cover latch then permitted vibration and air flow from the system to have forced the cover off during system operation.

In reviewing this event, the inspectors determined that the 'B' CRAF subsystem failure constitutes a licensee-identified violation of regulatory requirements that is of very low safety significance. The details of this violation are discussed in Section 4OA7 of this report. The licensee had entered this issue into their corrective action program as CR 258287. Corrective actions planned and completed by the licensee include: installation of tape on access port cover latches via the safety-related modification process to prevent inadvertent or vibration-induced rotation; and enhancements to surveillance procedures that include inspection of ductwork to also inspect access port cover latches for material condition and excessive wear.

The inspectors' review and closure of this LER constituted a single inspection sample.

4OA4 Cross-Cutting Aspects of Findings

Cornerstones: Barrier Integrity and Mitigating Systems

Human Performance

One of the findings and one of the licensee-identified violations described elsewhere in this report had human performance deficiencies as their major causal elements.

- A Green finding and associated NCV described in Section 1R22 involved the failure of an operations non-licensed operator (NLO) to use an approved plant procedure for the backwashing of a safety-related RHRSW strainer. The unauthorized and improper backwashing evolution resulted in the depressurization of the 2B RHRSW train header, which rendered the Unit 2 Division 2 RHRSW system inoperable for several minutes. The licensee's apparent cause evaluation for the event identified inadequate human performance, specifically the failure to adhere to plant procedural guidance, as the primary cause for the event.

- A licensee-identified violation associated with an event described in Section 4OA3.3 involved the failure of licensee personnel to adequately secure latches holding an inspection port cover in place on a safety-related ventilation duct. The inadequately secured latches allowed vibration and/or system operating pressure to force the access cover open, rendering the associated safety-related ventilation train inoperable. The licensee's investigation into the root cause for the inadequately secured access port cover latches was indeterminate, but surmised that the most probable explanation for the inadequately secured latches was that they had been loosened by inadvertent contact, or bumped, by a station mechanic while conducting a visual inspection of a nearby fire damper.

4OA5 Other

Cornerstones: Initiating Events and Occupational Radiation Safety

.1 (Closed) Unresolved Item 05000373/2004002-01; 05000374/2004002-01: Discrepancies with Fire Watch Practices and Fire Watch Logs.

An Unresolved Item (URI) was opened to track the NRC's assessment of procedural noncompliance associated with compensatory fire watch patrols performed by the licensee to fulfill Technical Requirements Manual (TRM) action statements.

During routine quarterly fire protection inspections from February 5, 2004, through February 23, 2004, inspectors noted that logs documenting the performance of several licensee fire watch patrols recorded the performance of those patrols with unusual precision. Specifically, the inspectors noted that the times logged for the performance of each patrol were exactly 1 hour apart, with little or no variation seen over a period of days. It was further noted that these logs were not routinely carried by the fire watch during the performance of their rounds, thus requiring the logs to be filled in at the completion of each patrol. Direct observations by the inspectors identified that several fire watch patrols were logged at times the fire watch was not physically in the plant, contrary to licensee procedures that required the fire watch patrol logs to reflect the actual time of each patrol.

Direct observations by the inspectors also identified that fire watch patrols for some TRM fire door impairments were not routinely conducted by patrolling the fire zones on both sides of the affected barrier, as specified by written instructions for the impairment. The inspectors identified that certain fire watch patrols being performed by the licensee were, at times, merely a simple visual observation of the impaired doorway area only. Reviews of completed fire watch patrol logs and interviews with licensee personnel and contractors indicated that these practices have been ongoing for many months, despite multiple opportunities by licensee management to have identified the issues and taken corrective action.

The inspectors determined that these issues with compensatory fire watch patrols may have constituted licensee performance deficiencies and violations of regulatory requirements potentially involving willful aspects on the part of certain members of the licensee's staff. As a result, the issue was forwarded to the NRC Office of Investigations (OI) for further action. In September 2004, the NRC Office of Investigations completed their review of the issue (OI Case No. 2-2004-020), and determined that no actions on the part of any licensee staff member involving any degree of willfulness could be substantiated.

Subsequently, the inspectors determined that the various discrepancies with fire watch practices and fire watch logs constitutes a minor violation of Technical

Specification 5.4.1(c) that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. Specifically, the various discrepancies noted were minor noncompliances related to the licensee's fire protection program procedures and instructions that did not result in any actual adverse consequences or any potential consequences of significance. Per the licensee's apparent cause evaluation (CR 201611), the primary cause for this issue was "inadequate management oversight and control of the fire protection program."

The inspectors reviewed the licensee's corrective actions, both performed and planned, for the issue. These included: enhancements to the fire watch training program to emphasize fire watch responsibilities; fire watch procedure changes to remove identified weaknesses and inconsistencies; additional training for Operations Supervisors to ensure that fire watch briefing and tracking requirements are understood; review of old/completed fire watch logs for extent-of-condition; increased supervisory spot checks of fire watch patrol activities in the field; and a generic lessons-learned communication on the issue to all Exelon sites. The corrective actions reviewed appeared to be appropriate for the identified deficiencies.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to the Site Vice President, Ms. S. Landahl, and other members of licensee management on January 11, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- A Biennial Heat Sink Inspection, which was discussed with the Site Vice President, Mr. G. Barnes, and other members of licensee management on December 10, 2004.

- A periodic ALARA and Radiologically Controlled Area Access Inspection, which was discussed with the Site Vice President, Mr. G. Barnes, and other members of licensee management on December 17, 2004.

- An annual Licensed Operator Requalification examination, which was discussed via telephone with Mr. C. Dieckmann, LaSalle County Station Training Manager, on December 21, 2004.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCVs.

Cornerstone: Barrier Integrity

- Technical Specification 5.4.1(d) requires that the licensee establish, implement, and maintain written procedures for various Technical Specification required programs. The licensee's 10 CFR 50, Appendix J, local leak rate testing (LLRT) program is described in Technical Specification 5.5.13, and is one of the programs covered under Technical Specification 5.4.1(d). Contrary to the requirements of Technical Specification 5.4.1(d), the licensee failed to maintain adequate written procedures for the LLRTs associated with containment isolation check valves 1(2)E51-F028. Specifically, a procedurally required head correction factor used in calculating the test pressure applied to these valves was in error dating back to 1986, and because the error was in the non-conservative direction the test results had to be considered invalid and the valves declared inoperable.

  The inspectors determined the violation to be of very low safety significance and within the licensee's response band because the companion containment isolation valves in the same penetration, 1(2)E51-F069, were always available and operable, and thus, no open pathway between the primary containment interior and the environment was ever present. The licensee had entered the issue into their corrective action system as CR 253839. A detailed discussion of this issue is documented in Section 4OA3.2 of this report.

- Technical Specification 3.7.4 prohibits operation of either unit in Modes 1, 2, or 3 with both control room area filtration (CRAF) subsystems inoperable. Required Action D.1 of this specification mandates immediate entry into LCO 3.0.3 under this condition. Contrary to these requirements, the licensee operated both LaSalle units for various time periods with both CRAF subsystems inoperable, as discussed in LER 05000373/2004-002-00; 05000374/2004-002-00.

  The inspectors determined that the issue could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Under the Barrier Integrity Cornerstone, the inspectors determined the issue to be of very low safety significance and within the licensee's response band because it only involved the barrier function provided for the auxiliary electric equipment room (AEER). The licensee had entered the issue into their corrective action system as CR 258287. A detailed discussion of this issue is documented in Section 4OA3.3 of this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

G. Barnes, Site Vice President
S. Landahl, Plant Manager (Site Vice President as of 1/10/2005)
T. Connor, Maintenance Director
L. Coyle, Operations Director
D. Czufin, Site Engineering Director
C. Dieckmann, Training Manager
A. Ferko, Nuclear Oversight Manager
F. Gogliotti, System Engineering Manager
B. Kapellas, Radiation Protection Manager
W. Riffer, Emergency Planning Manager
T. Simpkin, Regulatory Assurance Manager
C. Wilson, Station Security Manager
M. Wolfe, Health Physicist

Nuclear Regulatory Commission

B. Burgess, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000373/2004005-01; 05000374/2004005-01	URI	RHR Pump Seal Operability with Elevated Seal Water Temperatures (Section 1R07)
05000373/2004005-02	NCV	Failure to Perform Effective Corrective Action on Degraded/Nonconforming Unit 1 RCIC F028 Containment Isolation Check Valve (Sections 1R12.2 and 4OA2.1)
05000373/2004005-03; 05000374/2004005-03	NCV	Inadequate VE System Test Procedure Causes Auxiliary Electric Equipment Room High Humidity Condition and Renders Multiple Control Room Annunciator Alarms Inoperable (Section 1R12.3)
05000373/2004005-04; 05000374/2004005-04	URI	SBLC Tank Level and Boron Solution Concentration Measurement Issues (Section 1R16)
05000374/2004005-05	NCV	Failure to Follow Applicable Operating Procedure For Strainer Backwashing Renders RHRSW Train Inoperable (Sections 1R22 and 4OA4)

Closed

05000373/2004004-01	URI	Unit 1 RCIC F028 Containment Isolation Check Valve Maintenance History Indicates Repeated Failures Since 1991 (Section 1R12.2)
05000373/2004005-02	NCV	Failure to Perform Effective Corrective Action on Degraded/Nonconforming Unit 1 RCIC F028 Containment Isolation Check Valve (Sections 1R12.2 and 4OA2.1)
05000373/2004004-02; 05000374/2004004-02	URI	‘A’ Train VE Compressor Tripped During Purge Mode Surveillance Testing Causing High Humidity Condition and Multiple Control Room Annunciator Alarms (Section 1R12.3)
05000373/2004005-03; 05000374/2004005-03	NCV	Inadequate VE System Test Procedure Causes Auxiliary Electric Equipment Room High Humidity Condition and Renders Multiple Control Room Annunciator Alarms Inoperable (Section 1R12.3)
05000374/2004005-05	NCV	Failure to Follow Applicable Operating Procedure For Strainer Backwashing Renders RHRSW Train Inoperable (Sections 1R22 and 4OA4)
05000374/2004-001-00	LER	Reactor Protection Bus ‘B’ Trip and Inoperable Automatic Depressurization Valves Due to Equipment Failure (Section 4OA3.1)
05000373/2004-001-00	LER	Invalid Containment Isolation Valve Local Leak Rate Test Due to Inadequate Procedure (Sections 4OA3.2 and 4OA7)
05000373/2004-002-00; 05000374/2004-002-00	LER	‘B’ Control Room Area Filtration Subsystem Inoperable Due to Unsecured Inspection Port Cover (Sections 4OA3.3, 4OA4, and 4OA7)
05000373/2004002-01; 05000374/2004002-01	URI	Discrepancies with Fire Watch Practices and Fire Watch Logs (Section 4OA5.1)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

Procedure:
-LOS-ZZ-A2; Preparation for Winter/Summer Operation; Revision 29

1R04 Equipment Alignment

Procedures:
- LOP-FP-01M; Unit 0 Fire Protection System Mechanical Checklist; Revision 16
- LV-FP1M; Unit 1 Fire Protection Locked Valve Position Checklist; Revision 2
- LOP-RI-01E; Unit 1 Reactor Core Isolation Cooling System Electrical Checklist; Revision 11
- LOP-RI-01M; Unit 1 Reactor Core Isolation Cooling System Mechanical Checklist; Revision 17
- LOP-FC-01M; Unit 1 Fuel Pool Cooling Filter and Demineralization Systems Mechanical Checklist; Revision 8
- LOP-FC-01E; Unit 1 Fuel Pool Cooling System Electrical Checklist; Revision 4
- LOP-DG-03E; Unit 0 Diesel Generator Electrical Checklist; Revision 9
- LOP-DG-03M; Unit 0 Diesel Generator Mechanical Checklist; Revision 8

Condition Reports:
- 271471; B DFP 0FP068B Packing Leak; 11/08/2004
- 271472; B DFP 0FP002B Packing Leak; 11/08/2004
- 282892; Misc Items Identified by NRC During Plant Walkdown; 12/15/2004
- 285239; NRC Identified Issues with Diesel Fuel Oil System; 12/22/2004

1R05 Fire Protection

Procedures:
- LMS-FP-15; TRM Fire Hose Stations Inspection; Revision 19
- OP-MW-201-007; Fire Protection System Impairment Control; Revision 0
- CC-AA-201; Plant Barrier Control Program; Revision 4
- LMS-ZZ-03; Inspection of Fire Doors Separating Safety Related Fire Areas; Revision 8
- OP-AA-201-003; Fire Drill Performance; Revision 6
- OP-AA-201-005; Fire Brigade Qualification; Revision 3
- OP-AA-201-008; Pre-Fire Plans; Revision 1
- RP-LA-825-1003; Maintenance Care and Inspection of the ISI Magnum Self-Contained Breathing Apparatus (SCBA); Revision 0

Condition Reports:
- 180973; SCBA Issues Identified During Fire Drill 03-Q4-01; 10/15/2003
- 259163; Recommendations from Fleetwide Fire Protection TRM Review; 10/01/2004
- 260493; SCBA Air Compressor 2nd Stage PI Would Not Get to 120-350 PS; 10/05/2004
- 265255; Fire Drill 04-Q4-04 Self Identified Item; 10/20/2004
- 266044; Station Fire Doors; 10/22/2004

- 265128; Door #218 Found Ajar; 10/19/2004
- 265122; Fire Protection Door #254 Found Ajar; 10/19/2004
- 265823; Fire Door Failure to Close; 10/21/2004
- 266299; Fire Door #233 Found Unsecured; 10/22/2004
- 267330; NRC Identified Issues; 10/26/2004
- 267328; ELBP 2LL199E Has a Burned Out Trickle Charge Light; 10/27/04

1R06 Flood Protection Measures

Procedures:
- LOA-FLD-001; Flooding; Revision 5
- LTS-1000-29; Water Tight Door and Penetration Inspection; Revision 10

Work Orders:
- 465469-01; EP Watertight Penetration Inspection Unit 1; 1/31/2004

Condition Reports:
- 267942; NRC Identified: Enhancements to LOA-FLD-001; 10/28/2004

1R07 Heat Sink Performance

10 CFR 50.59 Evaluations:
- L-02-0182; Inlet Water Temperature Raised to 104 Degrees; May 13, 2002
- L-02-0182; Revise Maximum Cooling Water Inlet Temperature From the Ultimate Heat Sink (UHS) to 102 F for Core Standby Cooling System (CSCS) and Service Water (WS), Circulating Water (CW) From 97.5F to 100F; Revision 0
- EC 33017, Revision 0, Updated Final Safety Analysis Report (UFSAR) Change No. LU2002-008; Calculation No. L-002457; Revision 4
- Activities Related to EC 334017; May 13, 2002

Safety Evaluation Screening; Seal Cooling is Not Required on the ‘C’ RHR Pumps; August 17, 1993

Evaluation of Thermal Performance Test Results for the 2A DG HX; December 8, 2004

Calculations:
- L-001212; Qualification of Replacement ECCS and RCIC Suction Strainers; Revision 0
- L-002404; CSCS Cooling Water System “Road Map” Calculation; Revision 2A
- 97-195; Thermal Model of LaSalle Station Unit 0, 1, and 2 Diesel Generator Jacket Water Coolers; Revision A
- L-000711; Evaluation of RHR Flow to RHR Pump Seal Coolers; Revision 4B
- L-002724; Change to Flow to RHR Seal Coolers 1(2)E12-C002A/B/C; Revision 0
- L-001780; RHR Heat Exchanger - Cooling Water Orifice E12-D304A/B; June 16, 2004
- Proto-Power Calculation 97-195; Revision A

Procedures:
- EN-LA-402-0005; Extreme Heat Implementation Plan - LaSalle; Revision 3
- LTS-200-9; Residual Heat Removal (RHR) Pump Seal Cooler Service Water Side Flowrate Test; Revision 12

- LTS-200-11; Diesel Generator Cooling Heat Exchanger Thermal Performance Monitoring; Revision 10
- LTS-200-17; RHR Heat Exchanger Thermal Performance Monitoring; Revision 6

Operability Determination OE02-014; Low Flow in RHR Pump Seal Cooler; dated December 9, 2002

LaSalle Station Generic Letter 89-13 Program Basis Document; Revision 3

Self-Assessment; Heat Sink Performance; October 15, 2004

Memorandums:
- Process Water Temperature Effect on Seal Performance RHR, LPCS, and HPCS Pumps; January 29, 1991
- John Crane 3-1/2" Type 8B1 Seal CFSP-38327-8; December 17, 2004
- Cooling Flow Rates for a 3.5 Inch Diameter T-8B1 Seal Installed at LaSalle County Station; September 17, 1996
- LaSalle Lake HEDP Reduction; August 12, 2004

Condition Reports:
- 280803; RHR Pump Seal Cooling Water Maximum Temperature (NRC Identified); December 8, 2004
- 280881; RHR SW Flow to RHR Seal Cooler Calculation Needs Revision (NRC Identified); December 9, 2004
- 2800366; Incorrect Information in Calculation L-000711 (NRC Identified); December 8, 2004
- 247227; LaSalle Lake Recommendation Changes; August 25, 2004
- 263535; Commitments for 89-13 Program Not Updated Per the Commitment Change Procedure; October 6, 2004
- 264985; Aggregate Review of Lake Conditions on Plant Systems; October 19, 2004
- 134065; 2A RHR Pump Seal Cooler Flow Rate Lower Than Acceptance Criteria; December 4, 2002
- 117929; RHR Surveillance Tube Side Flow Rate; August 1, 2002
- 251127; Thermal Model Calculations For RHR and FC Heat Exchangers Need Updating; September 8, 2004
- 138300; 2A RHR Pump Seal Cooler Service Water Flow Rate Degradation; January 6, 2003
- 145702; 2A RHR Pump Seal Cooler Flow Rate is Degraded; February 21, 2003
- 176163; Degrading Seal Cooler Flow; July 23, 2003
- 200828; RHR Seal Cooler Chemistry Conditions; February 10, 2004
- 225711; 2A RHR Seal Cooler Has Low Flow Found During LTS-200-9; June 3, 2004
- 098307; Backlog Issues Associated With 0, 1, 2 DG Cooler Calculations; March 7, 2002
- 239174; Exelon’s Cooling Lake Water Discussion; July 27, 2004
- 264985; Aggregate Review of Lake Conditions on Plant Systems; October 19, 2004
- 176163; Review Heat Transfer Calculations to Assess the Possible Decrease in Heat Transfer Coefficient Due to Scaling and its Effect on Operations; July 23, 2003

Work Orders:
- 465398; 1A RHR HX Visual Inspection; January 17, 2004
- 407585-01; 1A RHR HX Visual Inspection; April 28, 2003
- 465398; Eddy Current Test 1E12-B001A A RHR Heat Exchanger; March 11, 2004
- 465398; 1A RHR HX Inspection Data Sheet; January 17, 2004
- 99275462, LTS-200-17; A RHR Heat Transfer Test; January 23, 2002

<u>1R11</u> <u>Licensed Operator Requalification Program</u>

Licensed Operator Requalification Scenario Guides:
- ESG 37; Revision 2
- ESG 29; Revision 1

TQ-AA-106; Licensed Operator Requal Training Program; Revision 5

<u>1R12</u> <u>Maintenance Effectiveness</u>

Procedures:
- LOS-DG-SR5; 0 DG Cooling Water System Flow Test; Revision 0 & 1
- LTS-200-27; 0 DG Cooling Water Flow Test; Revision 11
- LTS-400-17; Control Room and Auxiliary Electric Equipment Room HVAC Isolation Damper Surveillance Smoke and Radiation Detection; Revision 15
- LOP-VC-01; Control Room HVAC Operation; Revision 19
- LOP-VE-01; Auxiliary Electric Equipment Room HVAC Operation; Revision 24
- MA-AA-733-1001; Guidance for Check Valve General Visual Inspection; Revision 3

Condition Reports:
- 195254; L1R10 LLRT on 1E51-F028 Exceed Alarm Limit; 1/15/2004
- 226097; IR 220248 Written on 6/11/04 But No WR or WO Created; 6/04/2004
- 241004; Incorrect Pressure Head Calculations Result in Leak Rate Test; 8/02/2004
- 246005; Oil Leak A VE Compressor; 8/20/2004
- 252847; ‘A’ VE Refer Compressor Tripped During LTS-400-17; 09/14/2004
- 252971; High D/P Noted on 1B DG Cooling Water Strainer After Pump Start; 9/15/2004
- 253839; 1E51-F028 Check Valve Local Leak Rate Failure; 9/09/2004
- 256534; NRC Questions Related to RCIC LLRTs Performed Sep. 2004; 9/23/2004
- 258873; Low VY Cooling Water Flow; 10/01/2004
- 260486; Unloader Not Working Correctly; 10/05/2004
- 261833; VC/VE Comp Oil to Suction Pressure Anomaly; 10/08/2004
- 261835; A VE Compressor Tripped on Low Oil Pressure; 10/08/2004
- 262747; Prefilter Torn on VE Supply Filter Unit; 10/12/2004
- 263159; Question of Procedure Adherence; 10/13/2004
- 265011; 1A RHR Room Cooler (1VY01A) DP; 10/19/2004
- 265975; Documented Trip Time Not Within Allowable Range; 10/22/2004
- 266400; High Disch Press Indicator Reads Low; 10/23/2004
- 266491; A VE Compressor Trip on High Oil Temperature; 10/23/2004
- 267074; Pressure Indicator 0PI-VE104 for 0VE04CA Refrigerant Machine; 10/26/2004
- 267235; Discharge Line Strainer Valve for A VE; 10/26/2004
- 267312; LTS-200-12, Procedure Revision is Necessary; 10/27/04

- 267332; Potential Lost Parts in VE/RG System; 10/26/2004
- 267663; ‘A’ VE Compressor Control Oil Screen Found 50 percent Plugged; 10/27/2004

Work Orders:
- 748389-06; EM Clean Discharge Strainer 0RG012M; 10/27/2004
- 748389-05; A VE Compressor Trip on High Oil Temperature; 10/28/2004
- 960008424-01; Failed to Close LLRT LTS-100-38 Leakage > 30 SCFM; 2/14/1996
- 970085284-01; 1E51-F028, Correct Valve Seat “Leak-By” (Failed LLRT); 11/16/1997
- 990013455-01; RCIC CNDSR Vacuum Pump Dsch Check Valve; 11/03/1999
- 990247031-01; RCIC CNDSR Vacuum Pump Dsch Check Valve; 1/11/2002
- 99071698-01; MM Disassemble and Repair Check Valve; 1/22/2004
- 99284182-01; L1R09C Contingency to Repair Valve is Local Leak Rate Fails; 9/17/2004

Maintenance and Performance History of 1E51-F028; 1996 to 2004

Adverse Condition Monitoring Plan; Unit 2 VY Cooler Flows; Revision 0

Maintenance Rule Performance Criteria and Data:
- VY-02; Cubicle Cooling System for the Reactor Building Corner Rooms (Division 1 & LPCS); October 2002 to October 2004
- DG-05; Diesel Cooling Water Pumps (Division 1); October 2002 to October 2004
- LP-02; Low Pressure Core Spray; October 2002 to October 2004

1R13 Maintenance Risk Assessments and Emergent Work Control

Condition Reports:
- 113218; Service Air Dryers Time Delay Relays 1TR Time Delay Values; 6/25/2002
- 129998; MSV-1 Failed to Return to Full Open Position; 11/02/2002
- 140286; MSV #2 As-Found RPS Limit Switch Reading > 8.9 percent; 1/21/2003
- 150074; Air Leak Found During RTS of U-1 SA Dryer; 3/20/2003
- 167247; "1PS-IN038, 'A' in Dryer Des Chamber PS OOT, B4"; 7/11/2003
- 167252; "1PS-IN040 'A' in Dryer Des Chamber PS OOT, B4"; 7/11/2003
- 176053; Potential Rework on U-1 Station Air Dryer Switching Work; 9/16/2003
- 218138; MSV #1 Limit Switch Fails to Close When Valve is Full Open; 5/01/2004
- 221433; SBLC Tank High Level Alarm; 5/16/2004
- 221474; U-1 SA Dryer Switching Failure Alarm; 5/16/2004
- 231614; U-1 SA Dryer Switching Failure Alarm; 6/25/2004
- 233673; Unit 1 Station Air Dryer Alarm Trend; 7/3/2004
- 241948; 0 SA Dryer Dessicant Missing; 8/5/2004
- 244446; U1 SA Dryer Switching Failure; 8/14/2004
- 261411; "OSA01D, 0 SA Dryer Switching Failure Alarms"; 10/7/2004
- 262062; Switching Failures; 10/10/2004
- 262240; U0 SA Dryer Switching Failure; 10/11/2004
- 262274; 0 SA Dryer Switching Failure Alarms And Press Fluctuations; 10/11/2004
- 262511; Unit 2 SA Dryer Timing Sequence Needs to Be Adjusted; 10/11/2004
- 262539; Station Air Dryer Troubleshooting; 10/11/2004
- 262576; Station Air Dryer Troubleshooting; 10/12/2004
- 262616; Common Station Air Dryer Switching Failure; 10/12/2004

- 262644; Unit 2 Station Air Dryer Blow Down; 10/12/2004
- 262965; New Micro Switch for 2SA02D; 10/13/2004
- 263342; Timer in Station Air Dryer 0SA02D Not Correct; 10/13/2004
- 263346; Timer in Station Air Dryer 2SA02D Not Correct; 10/13/2004
- 263409; U2 Station Air Dryer Would Not Operate After Maintenance.; 10/14/2004
- 263683; Unit 1 Dryer 1SA02D Timer Deficiency; 10/14/2004
- 264235; 0 SA Dryer Switching Failure Alarms And Humidity Monitor; 10/16/2004
- 268939; MSV-1 RPS/EOC-RPT Relay 1C71A-K010B Relay Remains De-Energ; 10/31/2004
- 270257; High Pressure Leak Rate Test Performed Outside Acceptance Band; 11/4/2004
- 273296; 1C71A-K10B Failed to Reset after Cycling the #1 TSV; 11/14/2004
- 275320; Alarm Window Still Initiated After Cleaning SBLC Bubbler; 11/19/2004
- 275584; Unplanned Technical Specification Entry Due to SBLC Concentration; 11/26/2004
- 276560; No Procedure Guidance for Sodium Pentaborate Addition Calc; 11/24/2004
- 276755; SBLC Concentration Outside TS Limits; 11/25/2004
- 276839; NRC Identified Point of Discovery for SBLC Inop; 11/26/2004
- 276881; 1C41-R601 Needs Calibration; 11/27/2004
- 277113; Unauthorized Operator Aid Found on SBLC Solution Tank; 11/26/2004
- 277439; NRC Identified Issue w/ Use of “T” Square for SC Tank Level; 11/29/2004
- 281238; Standby Liquid Control Solution Tank Volume Determination; 11/26/2004
- 281244; UFSAR Figure 9.3-1; 12/10/2004
- 281247; Chemistry Procedures PCR for SBLC Figures; 11/26/2004
- 283765; Sodium Pentaborate Concentration Outside Optimum Range; 12/16/2004

Procedures:
- LCP-310-09; Standby Liquid Control Solution Tank Sampling; Revision 8
- LES-EH-201; Unit 2 Turbine Stop Valve Limit Switch Calibration and Relay Test; Revision 14
- LOS-AA-S201; Unit 2 Shiftly Surveillance; Revision 29
- LOS-RP-Q2; Turbine Stop Valve Scram and EOC-RPT Functional Test; Revision 14

1R14 Operator Performance During Non-Routine Plant Evolutions and Events

Condition Reports:
- 198850; ‘B’ RPS Trip Caused Half Scram and PCIS Isolations; 2/2/2004
- 198871; ADS Accumulators ‘U’ and ‘E’ Low Pressure in Alarm; 2/2/2004
- 253839; Inspection Results, Check Valve 1E51-F028; 9/17/2004
- 258287; AEER Pressure Less Than 0.125 Inches with ‘B’ Train in Operation; 9/29/2004
- 259226; Installation of Non-Safety Tape on VC/VE Inspection Port Covers; 10/1/2004

1R15 Operability Evaluations

Operability Evaluations:
- OE 04-011; Jet Pump No. 19; Revisions 0 through 3
- OE 04-010; GE DuraLife 215 Control Rod Blades; Revisions 0 and 1
- OE 04-012; Scram Discharge Volume Vent & Drain Valves’ Fuse Block; Revision 0

Condition Reports:
- 254171; Cracks Observed in D215 Blades Discharged in the Spent Fuel Pool; 9/17/2004
- 258164; Determine Reportability of Removing 125V DC Breaker Access Covers Based on Information Provided by EMD; 10/29/2004

1R16 Operator Workarounds

Condition Reports:
- 221433; SBLC Tank High Level Alarm; 5/16/2004
- 275320; Alarm Window Still Initiated After Cleaning SBLC Bubbler; 11/19/2004
- 275584; Unplanned Technical Specification Entry Due to SBLC Concentration; 11/26/2004
- 276560; No Procedure Guidance for Sodium Pentaborate Addition Calc; 11/24/2004
- 276755; SBLC Concentration Outside TS Limits; 11/25/2004
- 276839; NRC Identified Point of Discovery for SBLC Inop; 11/26/2004
- 276881; 1C41-R601 Needs Calibration; 11/27/2004
- 277113; Unauthorized Operator Aid Found on SBLC Solution Tank; 11/26/2004
- 277439; NRC Identified Issue w/ Use of “T” Square for SC Tank Level; 11/29/2004
- 281238; Standby Liquid Control Solution Tank Volume Determination; 11/26/2004
- 281244; UFSAR Figure 9.3-1; 12/10/2004
- 281247; Chemistry Procedures PCR for SBLC Figures; 11/26/2004
- 283765; Sodium Pentaborate Concentration Outside Optimum Range; 12/16/2004

Engineering Evaluations:
- EC 338147; SBLC Tank Level; 11/20/2002

Sodium Pentaborate Sample Data:
- U2 SBLC Tank; 11/04/2004
- U2 SBLC Tank; 11/23/2004
- U2 SBLC Tank; 11/25/2004
- U2 SBLC Tank; 11/26/2004
- U1 SBLC Tank; 11/27/2004

Procedures:
- LCP-110-9; Determination of High Range Boron (Sodium Pentaborate); Revisions 20, 21, & 22
- LCP-310-09; Standby Liquid Control Solution Tank Sampling; Revision 8
- LOS-AA-S201; Unit 2 Shiftly Surveillance; Revision 29

1R19 Post-Maintenance Testing

Procedures:
- LCP-310-09; Standby Liquid Control Solution Tank Sampling; Revision 8
- LOS-AA-S201; Unit 2 Shiftly Surveillance; Revision 29
- LOS-FP-M6; Diesel Fire Pump Operational Check; Revision 5
- LOP-FP-02; Diesel Fire Pump Startup and Shutdown; Revision 15
- LOS-RP-Q2; Turbine Stop Valve Scram and EOC-RPT Functional Test; Revision 14

- LOS-RH-Q2; RHR (LPCI) and RHR Service Water Valve Inservice Test for Operating, Startup and Hot Shutdown Conditions; Revision 36
- MA-AA-723-301; Periodic Inspection of Limitorque Model SMB/SB/SBD-000 Through 5 Motor Operated Valves; Revision 1
- LEP-GM-102; Limitorque Valve Operator Electrical Maintenance; Revision 23
- LES-EH-201; Unit 2 Turbine Stop Valve Limit Switch Calibration and Relay Test; Revision 14

Work Orders:
- 722673-01; OP LOS-RP-Q2 TSV Scram Functional Att 1A; 11/14/2004
- 634326-01; 1E12-F049B EQ Inspection and VOTES Test; 11/22/2004
- 748389-05; A VE Compressor Trip on High Oil Temperature; 10/24/2004

Condition Reports:
- 125645; Equipment Apparent Cause Evaluation EACE to System Engineering to Investigate Cause of Trip; 11/22/2002
- 129998; MSV-1 Failed to Return to Full Open Position; 11/02/2002
- 218174; MSV #1 Limit Switch Fails to Close When Valve is Full Open; 5/01/2004
- 218138; MSV #1 Limit Switch Fails to Close When Valve is Full Open; 5/01/2004
- 221433; SBLC Tank High Level Alarm; 5/16/2004
- 246005; Oil Leak A VE Compressor; 8/20/2004
- 252847; ‘A’ VE Refer Compressor Tripped During LTS-400-17; 09/14/2004
- 261833; VC/VE Comp Oil to Suction Pressure Anomaly; 10/08/2004
- 261835; A VE Compressor Tripped on Low Oil Pressure; 10/08/2004
- 262747; Prefilter Torn on VE Supply Filter Unit; 10/12/2004
- 266491; A VE Compressor Trip on High Oil Temperature; 10/23/2004
- 267235; Discharge Line Strainer Valve for A VE; 10/26/2004
- 267332; Potential Lost Parts in VE/RG System; 10/26/2004
- 267663; ‘A’ VE Compressor Control Oil Screen Found 50 percent Plugged; 10/27/2004
- 268939; MSV-1 RPS/EOC-RPT Relay 1C71A-K010B Relay Remains De-Energ; 10/31/2004
- 273296; 1C71A-K10B Failed to Reset after Cycling the #1 TSV; 11/14/2004
- 275584; Unplanned Technical Specification Entry Due to SBLC Concentration; 11/26/2004
- 276010; Stem Lube Inadvertently Removed Prior to Test, 1E12-F049B; 11/22/2004
- 276560; No Procedure Guidance for Sodium Pentaborate Addition Calc; 11/24/2004
- 276755; SBLC Concentration Outside TS Limits; 11/25/2004
- 276839; NRC Identified Point of Discovery for SBLC Inop; 11/26/2004
- 276881; 1C41-R601 Needs Calibration; 11/27/2004
- 277113; Unauthorized Operator Aid Found on SBLC Solution Tank; 11/26/2004
- 277439; NRC Identified Issue w/ Use of “T” Square for SC Tank Level; 11/29/2004
- 281238; Standby Liquid Control Solution Tank Volume Determination; 11/26/2004
- 281244; UFSAR Figure 9.3-1; 12/10/2004
- 281247; Chemistry Procedures PCR for SBLC Figures; 11/26/2004
- 283765; Sodium Pentaborate Concentration Outside Optimum Range; 12/16/2004

1R22 Surveillance Testing

Procedures:
- LOS-DG-SR5; 0 DG Cooling Water System Flow Test; Revision 0 & 1
- LTS-200-27; 0 DG Cooling Water Flow Test; Revision 11
- LOS-DG-M3, Attachment 1B-Idle; 1B Diesel Generator Idle Start; Revision 57
- LIS-PC-312; Unit 1 Drywell Floor Drain Sump Fillup Rate Functional Test; Revision 6
- LOS-DG-M2, Attachment 2A-Idle; 2A Diesel Generator Operability Surveillance; Revision 56
- LOP-RH-14; Backwash of the Residual Heat Removal Service Water Strainers; Revision 11

Work Orders:
- 736290-01; OP LOS-DG-M3 U1 HPCS DG Surv Att 1B-Idle; 10/14/2004
- 748166-01; IM LIS-PC-312 U1 Drywell Floor Drain Sump Fillup Rate FT; 11/22/2004
- 734628-01; OP LOS-DG-Q5 ATT B5: 2A DG CWP Inservice Test; 12/09/2004

Condition Reports:
- 157016; DWEDS Totalizer Counting Without Pumping Down; 5/02/2003
- 173640; DWFDS Fillup Rate Increased From .1 gpm to .2/.3 gpm; 8/29/2003
- 188262; 1A DG Output Breaker Failure to Close; 11/26/2003
- 188681; ACB 1423 Failed to Close During LOP-DG-02; 12/2/2003
- 197534; Received 2PM13J B302 RB North/DW Flr Sump Trouble; 1/26/2004
- 206657; DWEDS PP Down Volume Erratic; 3/06/2004
- 207614; DWEDS Flow Transmitter 1FT-RE003, Trend Code B4; 3/11/2004
- 208340; U2 DWFDS Fill-Up Rate Decreased After VP Loop Swap; 3/15/2004
- 219742; Broken DWFDS High Level Switch; 5/08/2004
- 243379; Start Failure After DWEDS Pump Down; 8/11/2004
- 250060; Slow Steady Increase on DWFDS Fillup Rate Recorder 1UR-RF002; 9/03/2004
- 252415; Unit 2 Containment Monitoring Reliability Criteria; 9/13/2004
- 252971; High D/P Noted on 1B DG Cooling Water Strne After Pump Start; 9/15/2004
- 258873; Low VY Cooling Water Flow; 10/01/2004
- 262611; Division 2 RHR WS Pressure Low Alarm; 10/12/2004
- 263159; Question of Procedure Adherence; 10/13/2004
- 263581; Low Water Pressure Alarm for the 1B DG; 10/14/2004
- 265011; 1A RHR Room Cooler (1VY01A) DP; 10/19/2004
- 265917; NRC Identified - 1B DG Breaker Closed w/ Sync. Scope at 3 RPM; 10/21/2004
- 267312; LTS-200-12, Procedure Revision is Necessary; 10/27/04
- 275384; Receiving DWEDS Trouble Alarm During Pumpdowns; 11/20/2004
- 280973; LOS-DG-Q2 Attachment B5; 12/09/2004

1R23 Temporary Plant Modifications

Condition Reports:
- 278257; 2C11-F380 SDV Vent Valve Stroke Time Failure; 12/01/2004
- 278258; 2C11-F381 SDV Drain Valve Stroke Time Failure; 12/01/2004

Engineering Evaluations:
- EC345906; Evaluation of the Work Order to Provide Temporary Air Downstream of Valve 2C11-F379 for Online Repair (MR90 Eval); Revision 0

Work Orders:
- 760376-01; Install Temporary Air Downstream of Valve 2C11-F379 for Online Repair; 12/03/2004

1EP6 Drill Evaluation

LaSalle 2004 4th Quarter Drill Guide and Critique Sheets

12/9/04 and 12/16/04 Mini-Drills Findings and Observations Report; 12/30/2004

Condition Report:
- 286574; ERO Drill Results for December Mini-Drills; 12/30/2004
- 283601; EP ID'D - During EP Drill - Inaccurate NARS Form (TSC); 12/16/2004

Procedure:
- LS-AA-2120; Monthly Data Elements for NRC Drill/Exercise Performance; Revision 4

2OS1 Access Control to Radiologically Significant Areas

Focused Area Self Assessments:
- 194327; Access Control to Radiologically Significant Areas and Occupational Exposure Control Effectiveness Performance Indicator; September 30, 2004
- 231024; Radiation Worker Practices; June 15, 2004

LaSalle County Station Radiation Protection Program Improvement Plan Updates; November 27, 2004

Condition Reports:
- 224338; NSRB Executive Summary Radiation Protection Comments; May 28, 2004
- 224641; Nuclear Oversight Identified Unauthorized High Radiation Area Entry; May 29, 2004
- 227228; Nuclear Oversight Identified Improper Survey Ma Used for Radiation Protection Brief; June 9, 2004
- 237145; Human Performance Improvement Team Identified Issues; July 19, 2004
- 251693; Equipment Exceeding Direct Radiation Limit; September 10, 2004
- 253764; SAC Action: Ladder Guards Needed For Locked High Radiation Area Reduction Effort; September 14, 2004
- 255293; Worker Electronic Dosimeter Dose-Rate Alarms From Turbine Crane Surveillance; September 21, 2004
- 266019; Radiation Protection Access Control Focused Area Self-Assessment Comments for Consideration; October 22, 2004
- 261792; Access Control Focused Area Self-Assessment Deficiencies; October 8, 2004
- 245397; Quality Control Checks on Whole Body Counter; August 16, 2004
- 251134; Work Order and RWP Interface Breakdown; September 9, 2004
- 254176; New High Radiation Area Discovered; September 17, 2004

- 255170; Warehouse 1 Radioactive Material Control; September 21, 2004
- 255260; NRC Comments During Self-Contained Breathing Apparatus Inspection; August 17, 2004
- 264567; Nuclear Oversight Identified Inadequate High Efficiency Particulate Air Log/Record-keeping; October 15, 2004
- 264735; Nuclear Oversight Identified Requirements of Radiation Work Permit Not Followed; October 18, 2004
- 266019; Radiation Protection Access Control Focused Area Self-Assessment Comments For Consideration; October 22, 2004
- 190962; Extent of Condition Survey Map Missing; October 15, 2004

2OS2 As Low As Is Reasonably Achievable Planning And Controls (ALARA)

Condition Reports:
- 229141; Wrong Radiation Work Permit Assigned to Work Order; June 16, 2004
- 232068; Incorrect RWP Assigned to Work Order on Work Execution Day; August 19, 2004
- 252099; Electronic Dosimeter Dose-rate Alarms During U2 Down Power; September 12, 2004
- 257208; Work Orders Do Not Have ALARA Tasks; September 27, 2004

Radiation Work Permits (RWPs):
- 10003964; Install New Cameras in U-1 Low Pressure Heater Bay Work-In-Progress Review; December 5, 2004
- 10003962; 1HD032B Troubleshooting Work-In-Progress Review; December 5, 2004
- 10003965; Furmanite 1HD140A and Adjust Limits on 1HD-2SRDCV-HB Work-In-Progress Review; December 9, 2004
- 10004016; L2R10 Dry Well Control Rod Drive Pul/Puts and Support Activities
- 10004017; L2R10 Dry Well Under Vessel Sump Activities
- 10004020; L2R10, Dry Well Low Power Rate Meter Replacements
- 10004793; L2R10 Chemical Decontamination
- 10010889; U-1 Helium In-leakage Testing Work-In-Progress Review; July 2, 2004

Procedures:
- RP-AA-400; ALARA Program; Revision 3
- RP-AA-401; Operation ALARA Planing and Controls; Revision 4
- RP-AA-403; Administration of the Radiation Work Permit Program; Revision 1

4OA1 Performance Indicator Verification

LS-AA-2140; Monthly Data Elements for NRC Occupation Exposure Control Effectiveness; Revision 4

4OA2 Identification and Resolution of Problems

Condition Reports:
- 244804; LPCS/RHR ‘A’ Water Leg Pump Trips; 8/16/2004
- 244981; Current Reading Anomaly for LPCS Water Leg Pump; 8/17/2004

4OA3 Event Follow-up

Condition Reports:
- 198850; 'B' RPS Trip Caused Half Scram and PCIS Isolations; 2/2/2004
- 198871; ADS Accumulators 'U' and 'E' Low Pressure in Alarm; 2/2/2004
- 253839; Inspection Results, Check Valve 1E51-F028; 9/17/2004
- 258287; AEER Pressure Less Than 0.125 Inches with 'B' Train in Operation; 9/29/2004
- 259226; Installation of Non-Safety Tape on VC/VE Inspection Port Covers; 10/1/2004

4OA5 Other

Mechanical Maintenance Procedures:
- LMS-FP-15; TRM Fire Hose Stations Inspection; Revision 18

Exelon Procedures:
- OP-MW-201-007; Fire Protection System Impairment Control; Revision 0
- CC-AA-201; Plant Barrier Control Program; Revision 3

Surveillances:
- LMS-ZZ-03; Inspection of Fire Doors Separating Safety Related Fire Areas; Revision 7

Logs:
- Fire Watch Inspection Logs for Fire Doors 272, 417, 321, & 406; 2/1/2004 – 2/5/2004
- Fire Watch Inspection Logs for Fire Doors 231, 272, 256, 417, 406, Unit 1 Drywell, and Refuel Floor; 2/5/2004 – 2/6/2004
- Fire Watch Inspection Logs for Fire Door 272; 2/19/2004 – 2/21/2004
- Fire Watch Inspection Logs for Fire Door 256; 1/24/2004 – 2/5/2004
- Fire Watch Inspection Logs for Fire Impairment 1-03-132 TRM U1 DG Rooms; 1/17/2004 – 2/1/2004
- Fire Watch Inspection Logs for Fire Impairment 1-03-181 TRM U1 DG Corridor; 1/17/2004 – 1/28/2004
- Fire Watch Inspection Logs for Fire Door 471; 1/26/2004 –1/28/2004
- Fire Watch Inspection Logs for Fire Door 336; 1/24/2004 – 2/5/2004
- Fire Watch Inspection Logs for Fire Door 469; 1/13/2004 – 1/16/2004
- Fire Watch Inspection Logs for Fire Door 220; 1/17/2004 – 1/26/2004
- Fire Watch Inspection Logs for 2A EDG Room; 10/6/2003 – 10/9/2003
- Fire Watch Inspection Logs for Fire Door 469; 10/15/2003 – 10/16/2003
- Fire Watch Inspection Logs for Fire Door 351; 2/17/2003 – 2/17/2003
- Fire Watch Inspection Logs for Fire Door 256; 4/8/2003 – 4/10/2003
- Fire Watch Inspection Logs for Fire Door 503; 3/19/2003 – 3/19/2003
- Fire Watch Inspection Logs for Fire Door 128; 2/20/2003 – 2/22/2003
- Fire Watch Inspection Logs for Fire Door 731; 2/15/2003 – 2/19/2003
- Fire Watch Inspection Logs for Fire Door 406; 2/23/2003 – 2/27/2003
- Fire Watch Inspection Logs for Fire Door 615; 1/24/2003 – 2/19/2003
- Fire Watch Inspection Logs for U1 Drywell; 1/15/2004 – 2/6/2004

Condition Reports:
- 198921; Fire Barriers Exceeding 7 Day Time Clock; 1/31/2004

- 197970; Fire Watch was Inattentive to Duties; 1/28/2004
- 202427; Paper Work Not Maintained in the WEC; 2/18/2004
- 201611; NRC Concerns with Fire Protection System Impairment Control; 2/17/2004
- 200093; Hourly Fire Watch; 2/6/2004
- 201982; Fire Watch Inspection Log; 2/16/2004
- 192902; Workers Enter HRA Without Brief; 12/30/2003

Miscellaneous Documents:
- Memo from LaSalle Fire Marshall William Collins to Sun States Personnel; RE: Fire Protection Impairment Control; 2/6/2004
- Memo from LaSalle Fire Marshall William Collins to Sun States Personnel; RE: Door 272 Fire Watch Tour; 2/23/2004
- NRC Memorandum from B. Burgess, Chief, Branch 2, DRP, to B. Clayton, Team Leader, EICS; OI Investigation LaSalle County Station: (OI Case No. 2-2004-020) (AMS No. RIII-2004-A-0035); September 27, 2004
- NRC Memorandum from C. Pederson, Director, DRS, to J Heller, Senior Allegation Coordinator, EICS; OI Investigation LaSalle Nuclear Power Plant: (OI Case No. 3-2004-005) (AMS No. RIII-2004-A-0002); August 10, 2004

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADS	Automatic Depressurization System
AEER	Auxiliary Electric Equipment Room
CAP	Corrective Action Program
CAR	Corrective Action Request
CDF	Core Damage Frequency
CFR	Code of Federal Requirements
CR	Condition Report
CRAF	Control Room Area Filtration
CY	Calendar Year
DFP	Diesel Fire Pump
DG	Diesel Generator
DRP	Division of Reactor Projects
EACE	Equipment Apparent Cause Evaluation
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPMA	Electrical Power Monitoring Assembly
EPRI	Electric Power Research Institute
FOI	Follow-On Item
FSAR	Final Safety Analysis Report
GE	General Electric
HPCS	High Pressure Core Spray
HRA	High Radiation Area
HVAC	Heating, Ventilation, and Air Conditioning
IMC	Inspection Manual Chapter
IN	Instrument Nitrogen
IR	Inspection Report
JPM	Job Performance Measure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
LPCS	Low Pressure Core Spray
MCC	Motor Control Center
MG	Motor-Generator
MOV	Motor-Operated Valve
NCR	Non-Conformance Report
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-Licensed Operator
NRC	U.S. Nuclear Regulatory Commission
OI	Office of Investigations
OWA	Operator Workaround
PCIS	Primary Containment Isolation System
PI	Performance Indicator
PIV	Pressure Isolation Valve

PM	Planned or Preventative Maintenance
PMT	Post-Maintenance Testing
PRA	Probable Risk Assessment
RCIC	Reactor Core Isolation Cooling
RCR	Root Cause Report
RHRSW	Residual Heat Removal Service Water
RP	Radiation Protection
RPS	Radiation Protection Specialist
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SBGT	Standby Gas Treatment
SBLC	Standby Liquid Control
SCBA	Self-Contained Breathing Apparatus
SDP	Significance Determination Process
SDV	Scram Discharge Volume
SRI	Safety Review Item
SRV	Safety Relief Valve
SSC	Systems, Structures, and Components
TDRFD	Turbine-Driven Reactor Feedwater Pump
TOL	Thermal Overload
TRM	Technical Requirements Manual
TS	Technical Specification
TSV	Turbine Stop Valve
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
Vdc	Volts Direct Current