U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-373, 50-374
License Nos:	NPF-11, NPF-18
Report Nos:	50-373/99012(DRP); 50-374/99012(DRP)
Licensee:	Commonwealth Edison Company
Facility:	LaSalle County Station, Units 1 and 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	June 23 - July 28, 1999
Inspectors:	K. Riemer, Acting Senior Resident Inspector J. Hansen, Resident Inspector R. Westberg, Acting Resident Inspector
Approved by:	Melvyn N. Leach, Chief Reactor Projects Branch 2 Division of Reactor Projects

EXECUTIVE SUMMARY

LaSalle County Station, Units 1 and 2
NRC Inspection Report 50-373/99012(DRP); 50-374/99012(DRP)

This inspection report included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 5-week period of inspection conducted by the resident staff.

Plant Operations

- The control room operators were knowledgeable of scheduled plant activities and system configurations, attentive to the main control room panels, and completed work activities in accordance with approved procedures. In addition, informational briefs conducted by operations shift management were thorough, although the inspectors identified that not all shift personnel were attentive during the shift briefs. The inattentiveness of the control room operators had been previously identified by Nuclear Oversight but was not corrected prior to the NRC observations (Section O1.1).

- The operators experienced increased equipment challenges due to long standing degraded equipment issues (Section O1.1).

- The Unit Supervisor performed a thorough review of the control room weekly surveillances and identified that invalid assumptions used during an earlier completion of surveillance steps had resulted in the failure to complete all required control rod cycling. The operators promptly completed the missed control rod surveillances. The licensee's root cause investigation and subsequent Licensee Event Report pertaining to the failure to complete rod cycling within the required Technical Specification surveillance interval were thorough (Section O1.2).

- While the individual reactivity management issues, which occurred during the reporting period, were of limited significance, collectively they represented a potential significant challenge to the operators. The licensee had initiated corrective actions for each event; however, management had not evaluated the collective effect of several reactivity management issues on the control room operators (Section O2.1).

- The licensee did not ensure the control room and auxiliary electric room ventilation train supporting safe plant operation was functioning satisfactorily prior to removing the other train from service for preplanned maintenance (Section O2.2).

- Operators performed well during the power reductions and subsequent power ascensions that were required to establish necessary plant conditions for the Unit 1 condenser cleaning activities (Section M2.2).

Maintenance

- The emergency diesel generator fast start surveillances were completed satisfactorily in accordance with plant procedures and in conformance with Technical Specifications (Section M1.1).

- Initial actions by instrument maintenance personnel and control room operators to the partial actuation of the reactor protection system during performance of a routine

surveillance test were prompt and in accordance with procedures. Actions initiated by the licensee to review recent similar occurrences for common initiators or problems were appropriate considering that corrective actions for two previous partial did not prevent recurrence (Section M1.2).

- The licensee's accelerated investigation was timely and effectively identified the root causes of the partial loss of Rod Position Indication System (RPIS) event. Operators and instrument technicians responded appropriately to the loss of control rod indication. Failure to consider this activity high risk, which resulted in the unexpected loss of part of the RPIS, presented a burden to control room operators (Section M1.3).

- The continued cycling of the Unit 2 D vacuum breaker in conjunction with inoperable position indication on the Unit 2 A vacuum breaker presented a repetitive challenge of long duration to the operators (Section M2.1).

- Station personnel have, on occasion, presented unnecessary challenges to control room operators during condenser cleaning activities. Inadequate condenser tube inspections also resulted in unnecessary additional radiation exposure to station personnel (Section M2.2).

- The licensee's investigation into the improperly re-assembled reactor water cleanup air-operated valves was sufficient to identify the contributing causes to the error (Section M4.1).

- The improperly performed maintenance on the reactor water cleanup air-operated valves represented a burden to operators attempting to perform a routine evolution. A contributing cause to the event was weak procedural guidance which illustrated a continuation of one of the concerns documented in the prior inspection period (IR 50-373/99004; 50-374/99004) (Section M4.1).

Engineering

- Engineers provided timely, accurate support to operations personnel in the revision to the Updated Final Safety Analysis Report and completion of the 10 CFR 50.59 Safety Evaluation Form for operation with elevated lake temperatures. However, the rapid response required by engineering personnel to the rising lake temperature was a direct result of not identifying and implementing corrective actions from the information discussed in a previously completed System Functional Performance Review (Section E2.1).

Plant Support

- Radiation Protection personnel performed thorough radiological monitoring during testing of a hydrogen water chemistry modification with a potentially significant impact on station radiation levels (Section R1.1).

Report Details

Summary of Plant Status

During this inspection period, the licensee maintained Unit 1 and Unit 2 near full power. The licensee completed several short power reductions on Unit 1 to perform condenser flushing and cleaning of the waterboxes.

I. Operations

O1 Conduct of Operations

O1.1 General

a. Inspection Scope (71707)

The inspectors evaluated operations personnel performance including monitoring control room activities such as routine turnovers and surveillances, attending shift briefings, reviewing shift logs, and interviewing operators regarding plant and equipment status. In addition, the inspectors reviewed Operating Abnormal Procedure (LOA)-EH-101, "Unit 1 EHC Abnormal," Revision 3.

b. Observations and Findings

Overall, the licensee operated safely and performed activities in accordance with procedures. The inspectors observed that the control room operators routinely monitored the panels and frequently scanned the panels when they were seated at the computers. When questioned by the inspectors, the Unit Supervisors (US) were able to provide a detailed discussion of work scheduled to be completed during the shift. The Shift Managers (SM) conducted pre-shift briefings for the upcoming shift personnel which effectively communicated plant operational status. However, the inspectors did note that control room personnel were not always attentive during the pre-shift briefs. Inspectors identified differences in operator conduct between the shift briefing office and main control room. In the control room, operators were sometimes distracted and/or engaged in other activities (i.e., phone calls, back panels logs, conversations, etc.). The inspectors informed operations management of the differences and noted improvement late in the inspection period. Licensee management presented information to the inspectors that a May 3, 1999, Nuclear Oversight audit documented similar observations regarding the activities of the control room operators during shift briefs but no changes had been implemented in the shift briefing process.

Several issues occurred during the inspection period which challenged the operators. These issues included several power excursions due to zebra muscles reducing flow through the Unit 1 condenser (see Section M2.2), high lake temperatures resulting from extreme weather conditions (see Section E2.1), and the failure of a main turbine electrohydraulic pressure controller (see below). The operators responded appropriately to these conditions and did not perform high risk activities during periods where the electrical grid was carrying significant loads.

One of the events that required significant operator response was the failure of one of the two controllers on the turbine electrohydraulic control (EHC) system. On July 25,

1999, the B EHC system pressure regulator took EHC system control when the steam pressure transmitter to the A EHC pressure regulator failed. The operators and system equipment responded to the minor system perturbation. The operators entered LaSalle LOA-EH-101 which identified operating with one EHC pressure regulator as an unanalyzed condition and required the operators to enter Technical Specification (TS) Action 3.2 3.a. The operators contacted the Nuclear Engineers and reduced reactor power as required. The engineers determined that a reduced Minimum Critical Power Ratio (MCPR) as discussed in the Core Operating Limits Report for a slow turbine control valve would ensure the thermal limits were met. The MCPR limits were reduced and the operators increased reactor power within the allowed limits.

While most degraded or failed equipment was repaired and returned to service in a timely fashion, some long standing degraded equipment issues identified and monitored in the Plan of the Day remained unresolved. The degraded equipment added additional compensatory actions and work for the operators which could impact their ability to focus on other important plant issues. In particular, the Unit 2 vacuum breaker problems (see Section M2.1) required the operators to take significant compensatory actions to minimize the possibility of a TS 3.0.3 entry during the routine monthly diesel generator testing.

c. Conclusions

The control room operators were knowledgeable of scheduled plant activities and system configurations, attentive to the main control room panels, and completed work activities in accordance with approved procedures. In addition, informational briefs conducted by operations shift management were thorough, although the inspectors identified that not all shift personnel were attentive during the shift briefs. The inattentiveness of the control room operators had been previously identified by Nuclear Oversight but was not corrected prior to the NRC observations.

O1.2 Missed Control Room (CR) Surveillance

a. Inspection Scope (71707)

The inspectors reviewed the licensee's root cause investigation, corrective actions, and NRC notification following identification of the failure to perform TS required control rod testing. Also, the inspectors interviewed Operations Department and Regulatory Assurance Department personnel. Some of the documents reviewed included:

- LOS-AA-W1, "Technical Specification Weekly Surveillances," Revision 39
- TS Surveillance Requirement 4.1.3.1.2.a
- TS 4.0.2.

b. Observations and Findings

On June 23, 1999, while completing documentation associated with operating surveillance LOS-AA-W1, the Unit 1 Control Room US identified that the control rod operability check performed on June 19, 1999, had not been fully completed. The licensee determined that on June 19, the shift US assumed that control rods had been cycled during a recent reduction in power and only cycled the four control rods in the vicinity of a leaking fuel assembly. The US documented acceptable completion of the

surveillance, noting that the other rods had been exercised previously. Subsequent review by the US on June 23 identified the incomplete surveillance and determined that control rods had not been cycled during the power reduction. The licensee immediately completed a rod operability check on the remaining rods and determined all rods were operable.

The rod operability check had last been completed on July 13, 1999. However, TS Surveillance Requirement 4.1.3.1.2.a required that operable withdrawn control rods be moved at least one notch every seven days plus an additional period of 25 percent allowed by TS 4.0.2. The licensee's failure to complete the rod operability check within the required time interval is a violation of TS 4.1.3.1.2.a (50-373/99012-01(DRP)). This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as Action Tracking Matrix No. 12850-16.

The licensee completed Licensee Event Report (LER) 373/99-002, "Missed TS Rod Operability Surveillance Due to Personnel Error," Revision 0. The inspectors identified that the LER incorrectly referenced TS Surveillance Requirement 4.4.1.3.1.1.b.

c. Conclusions

The US performed a thorough review of the weekly surveillance and identified that invalid assumptions used during an earlier completion of surveillance steps had resulted in the failure to complete all required control rod cycling. The operators promptly completed the missed control rod surveillances and determined the control rods operable. The licensee's root cause investigation and subsequent LER pertaining to the failure to complete rod cycling within the required TS surveillance interval were thorough.

O2 Operational Status of Facilities and Equipment

O2.1 Impacts on Reactivity and Reactivity Monitoring

a. Inspection Scope (71707)

The inspectors reviewed several licensee identified issues with potential impact on the ability of the operators to manage reactivity. Some of the documents reviewed included:

- Problem Identification Form (PIF) L1999-03301-unexpected partial actuation of the reactor protection system on average power range monitors
- PIFs L1999-03424, 02922-unexpected flow control valve movement causes actual change in reactor parameters
- PIF L 1999-03462-partial loss of control rod position indication
- PIFS (multiple)-trips of the reactor manual control system
- PIF L 1999-03506-wrong procedure revision used during TS surveillance on reactivity anomalies

b. Observations and Findings

Several events occurred during the inspection period which affected the operators ability to monitor and/or control reactor reactivity. The events included unexpected partial

actuation of the reactor protection system, unexpected flow control valve movement, a partial loss of control rod indication, several trips of the reactor manual control system, and the use of an incorrect surveillance procedure revision to provide reactivity anomaly information to the operators. In general, these events were of limited safety significance and the licensee performed investigations and implemented corrective actions. Two issues, the unexpected partial actuation of the reactor protection system and the partial loss of control rod position indication, were reviewed by the inspectors and are discussed in Sections M1.2 and M1.3, respectively.

c. Conclusions

While the individual reactivity issues were of limited significance, collectively they represented a potential significant challenge to the operators. The licensee had initiated corrective actions for each event; however, management had not evaluated the collective effect of several reactive management issues on the control room operators.

O2.2 Problems with Control Room (VC) / Auxiliary Electric Room (VE) Ventilation

a. Inspection Scope (71707)

The inspectors reviewed the licensee's actions in response to the unexpected trip of the A VC/VE compressor immediately after the start of the B VC/VE compressor which was being returned to service following routine maintenance.

b. Observations and Findings

On July 22, 1999, the operators returned the B VC/VE system to service following routine maintenance. The A train chiller compressor tripped on high oil temperature shortly after the B train was started. The licensee determined that a solenoid valve in the freon liquid line to the compressor oil cooler would not fully open and initiated a procedure change to allow operation with the solenoid opened manually. Operators utilized the procedure change to maintain the system operable until the work package was developed. Maintenance personnel repaired the solenoid and operators performed post-maintenance testing to ensure operability.

The inspectors identified that, on July 21, 1999, the plant operators had been monitoring the oil temperatures as being higher than normal on the A VC/VE chiller compressor. The compressor had been operating with oil temperatures about 4 degrees below the trip setpoint. The operators had informed operations shift management, system engineering, and maintenance personnel of the increased temperature a few days earlier. While possible causes for the increased temperature had been discussed, a formal trouble shooting plan or work request had not been generated. Operations personnel, in conjunction with the system engineer, decided that the compressor oil temperature was elevated but within the required range and proceeded with the planned maintenance on the B train.

c. Conclusions

The licensee did not ensure the VC/VE train supporting safe plant operation was functioning satisfactorily prior to removing the other train from service for preplanned maintenance.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-373/99001-00: Main Control Room, Auxiliary Electrical Equipment Room, and Switchgear Room Ventilation Systems Found Outside Design Basis Due to Inadequate Design.

On April 6, 1999, during review of Operability Determination No. OE99001, related to the Unit 2 switchgear ventilation (VX) back draft dampers, the licensee discovered that a single failure of motor operated damper VX22Y could block one of the exhaust air paths from all of the switchgear rooms. The dampers are normally open dampers which fail to the open position. A single failure of the damper to close would cause pressure to increase in the Division 1 and 2 switchgear and reactor protection system (RPS) motor generator rooms. This increase in pressure could result in a differential pressure less than the +0.125 in. w. g. minimum positive differential pressure required between the control room envelope and the adjacent Division 2 switchgear rooms and RPS motor generator set room. The licensee determined that the root cause was due to an inadequate initial design.

The inspectors reviewed the Operability Determination and the LER and verified that the corrective actions from the LER were in the licensee's corrective action tracking system via Action Request No. 6195. This issue is closed.

O8.2 (Closed) LER 50-373/99002-00: Missed TS Rod Operability Surveillance due to Personnel Error

This inspectors discussed this issue in O1.2 and verified that the corrective actions from the LER were in the licensee's corrective action program as ATM No. 12850-16. This issue is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Diesel Generator (DG) Surveillances

a. Inspection Scope (61726)

The inspectors observed the preparation for and conduct of portions of the 0 and 1A DG fast start surveillances and the 1A DG lube oil pressure shutdown switch calibration. The procedures reviewed included:

- LOS-DG-M2, "1A DG Fast Start 1A," Revision 41
- LaSalle Instrument Maintenance Procedure (LIP)-DG-505A, "1A Low Lube Oil Pressure Shutdown Switch Calibration," Revision 2
- LOS-DG-M1, "0 Diesel Generator Fast Start," Revision 38

In addition, the inspectors reviewed supporting test documentation and evaluated the test results.

b. Observations and Findings

On July 7, 1999, the inspectors observed the timed start of the 1A DG. The system engineer was present at the DG during the test and provided guidance to the operator regarding expected test results. Also, the Field Supervisor observed portions of the test. The operators completed the test satisfactorily.

During the surveillance, the inspectors observed instrument maintenance personnel purging air from the sensing line at the 1A DG low lube oil pressure shutdown pressure switch to complete the switch calibration. A 50-second delay exists from the startup until the low lube oil trip was initiated to allow sufficient time for oil pressure to reach its normal value and be sensed at the switch. The mechanics completed the venting within the 50-second period and did not impact the DG start time. In addition, the inspectors verified that local and control room DG parameters, including the start time and electrical load, were correctly indicated and within the test acceptance criteria.

On July 15, 1999, the inspectors locally observed operators start the 0 DG. The operators completed the test in accordance with LOS-DG-M1 and all acceptance criteria were satisfied. The inspectors noted that the SM, Field Supervisor, and System Engineer were present prior to and or during the test performance. Additionally, an operations department trainee was involved in performing portions of the test under the direction of a qualified Equipment Operator.

c. Conclusions

The DG surveillance tests were completed satisfactorily in accordance with plant procedures and in conformance with TS. The licensee provided good supervisory oversight during the tests and instrument maintenance personnel completed the instrument venting in a timely manner.

M1.2 Average Power Range Monitoring (APRM) Rod Block Monitor (RBM) Surveillance Testing

a. Inspection Scope (62707)

The inspectors reviewed the events pertaining to an actuation of a portion of the reactor protection system during the performance of LaSalle Instrument Maintenance Surveillance (LIS)-NR-107, "Unit 1 APRM/RBM Flow Converter to Total Core Flow Adjustments," Revision 9.

b. Observations and Findings

On July 26, 1999, instrument maintenance department (IMD) personnel were verifying the APRM flow bias adjustment following a recent control rod realignment on Unit 1. The IMD technicians were performing LIS-NR-107 and received a trip on one of two reactor protection systems. The technicians stopped the test, disconnected the test equipment, and informed the control room operators who reset the reactor protection system. A second such partial actuation was received shortly after the first had cleared.

The licensee's investigation did not identify procedure or personnel problems as factors in the partial actuation but determined that the power supply to the digital

multimeters used during the test may have initiated the actuation. Similar events had occurred on April 5, and June 17, 1999, with the root causes being attributed to faulty digital multimeters and loose or defective cards, respectively.

The inspectors reviewed the corrective action program history and identified several other instances where partial actuations of the reactor protection system had occurred since April 1999 in addition to the Unresolved Item (URI) from an unexpected partial actuation discussed in NRC Inspection Report 99004, Section M4.6 (See Section M8.1). In parallel, the licensee initiated an investigation to review the adverse trend. The inspectors will evaluate equipment actuations, procedure adequacy, human performance, and the licensee's response to this issue in the followup to the URI.

c. Conclusions

Initial action by IMD maintenance personnel and control room operators to the partial actuation of the reactor protection system were prompt and in accordance with procedures. Actions initiated by the licensee to review recent similar occurrences for common initiators or problems were appropriate considering that corrective actions for two previous partial actuations did not prevent recurrence.

M1.3 Partial Loss of Unit 2 Control Rod Indication

a. Inspection Scope (62707)

The inspectors reviewed PIF L1999-03462, "Unit 2 RPIS Module 2 PS1 5 Vdc power supply lost voltage during adjustment," and the subsequent accelerated investigation. The inspectors also interviewed instrument maintenance personnel.

b. Observations and Findings

On July 15, 1999, during performance of voltage checks and adjustments on Rod Position Indication System (RPIS) power supply, 2H13-P615-PS1-M3, in accordance with work request 990014120, task 01, the output voltage dropped from approximately 4.9 Vdc to approximately 0.9 Vdc. This caused the RPIS probe multiplexer cards fed by this power supply to become de-energized resulting in the loss of control rod position indication for approximately 40 rods. The control room operators entered TS Action 3.1.3.7.a for one or more inoperable control rod position indicators, which placed Unit 2 on an unexpected 12-hour requirement to repair the control rods or shutdown. Instrument technicians were able to restore output power from the power supply by removing its fuse, adjusting both the output voltage potentiometer and the over-voltage circuit potentiometer, then re-installing the fuse. These actions reset the over-voltage circuit and output power to within desired limits. Control rod position indication returned once the power supply was energized and the operators exited the TS Action. The duration of the event was approximately 20 minutes. The licensee determined the root cause of the event was an inherent design of the over-voltage protection circuit which, because of normal instrument drift, makes it hard to determine its trip point without actually generating a trip. As a result, the power supply may trip off even during small adjustments. The licensee determined that another contributing cause was failure to consider this activity high risk based on this know characteristic.

c. Conclusions

The licensee's accelerated investigation was timely and effectively identified the root causes of the partial loss of RPIS event. Operators and instrument technicians responded appropriately to the loss of control rod indication. Failure to consider this activity high risk, which resulted in the unexpected loss of part of the RPIS, presented a burden to control room operators.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Drywell to Suppression Pool Vacuum Breaker Issues

a. Inspection Scope (62707)

The inspectors reviewed the licensee's response to continued cycling of the Unit 2 D vacuum breaker identified during the last reporting period. In addition, the inspectors reviewed the licensee's corrective actions following the failure of one of two channels of position indication on the Unit 2 A vacuum breaker.

b. Observations and Findings

The inspectors discussed the cycling of the Unit 2 D vacuum breaker as a burden to the operators in Section O2.3 of Inspection Report (IR) 99004. The D vacuum breaker continued to cycle periodically during the current reporting period. Each valve cycling required the operators to declare the valve inoperable, enter TS Action 3.6.4.a, and ensure the valve closed within 4 hours or take additional actions. The engineers determined that the vacuum breaker was operable and opening to relieve a small differential between the suppression chamber and the drywell. In addition, the engineers developed possible causes for the buildup of pressure in the suppression chamber and the valve relieving at a lower than expected pressure. Corrective actions to eliminate the pressure buildup were implemented late in the inspection period. However, no corrective actions were implemented to repair the valve relieving at a lower than expected pressure.

Also, on June 17, 1999, during testing of the other vacuum breakers following the unexpected cycling of the D vacuum breaker, the operators identified that one of the two position indication trains on the Unit 2 A vacuum breaker failed to operate satisfactorily. The operators initiated a work request and, following trouble shooting by mechanical maintenance, satisfactorily cycled the valve and declared the valve operable. However, on June 30, 1999, during a routine surveillance, the A vacuum breaker Division 1 position indication failed again. The operators declared the position indication inoperable and commenced local verifications of valve position as required by TS Action 3.6.4.b. Engineering personnel determined potential causes of the position indication failure but no corrective actions were implemented. During routine monthly testing of the Division 2 emergency diesel generator, the operators were required to declare the Division 2 position indication to the valve inoperable. Significant compensatory actions were implemented to support a possible TS 3.0.3 entry should the D vacuum breaker cycle and be declared inoperable with A vacuum breaker indication inoperable. No TS 3.0.3 entries were necessary during the diesel generator testing.

c. Conclusions

The continued cycling of the Unit 2 D vacuum breaker in conjunction with inoperable position indication on the Unit 2 A vacuum breaker presented a repetitive challenge of long duration to the operators.

M2.2 Unit 1 Condenser Flushings and Cleanings

a. Inspection Scope (62707)

The inspectors monitored the performance of licensee personnel during Unit 1 condenser cleaning activities.

b. Observations and Findings

Licensee personnel performed several downpower evolutions to support valve cycling and waterbox cleaning activities on the Unit 1 main condenser. Operators reduced reactor power to establish the appropriate plant conditions required for the activities. The power reductions and subsequent power ascension activities were performed error free. However, the licensee committed some errors during the actual cleaning activities. Licensee actions resulted in leaks from the lower manway cover on three prior occasions (reference IR 50-373/99004; 50-374/99004). During this inspection period, inadequate condenser tube inspections following waterbox cleaning resulted in the need for licensee personnel to re-enter the waterbox and hydrolaze condenser tubes. Operators discovered the condition when the condenser was returned to service. Operators noted that the parameters associated with condenser flow and back pressure had not improved following the cleaning tasks. The operators were unnecessarily burdened by having to perform power reduction activities to support a re-entry into the waterbox. Additionally, station personnel received an extra, unnecessary 280 mrem during the second entry into the waterbox.

c. Conclusions

Operators performed well during the power reductions, and subsequent power ascensions that were required to establish necessary plant conditions for the Unit 1 condenser cleaning activities.

Station personnel have, on occasion, presented unnecessary challenges to control room operators. Inadequate condenser tube inspections also resulted in unnecessary additional dose exposure to station personnel.

M4 Maintenance Staff Knowledge and Performance

M4.1 Configuration Control Error Associated with Reactor Water Cleanup (RWCU) System

a. Inspection Scope (62703, 71707)

The inspectors monitored licensee response to an error associated with the RWCU system. The inspectors also reviewed PIF L1999-03225, "2C RWCU Air Operated Valves returned to service w/solenoids not installed."

b. Observations and Findings

On June 27, 1999, operators attempted to perform a routine precoat evolution on a RWCU filter demineralizer. Two remotely operated valves did not respond when personnel attempted to operate them. Operators backed out of the evolution and restored the system to a normal configuration.

The licensee determined that maintenance had been performed on the valves on June 18, 1999. The work performed on the valves involved both the mechanical and electrical maintenance departments. Written procedural guidance directed that solenoids be disconnected from the air-operated valves. When electrical maintenance personnel completed their tasks, mechanical maintenance personnel re-assembled the valves. The solenoids were not re-connected when the valves were re-assembled. The licensee's investigation revealed that the procedural guidance was weak in that it did not provide instructions directing that the solenoids be re-connected. Weak communication between the two maintenance departments contributed to the error.

c. Conclusions

The licensee's investigation into the improperly re-assembled air-operated valves was sufficient to identify the contributing causes to the error.

The improperly performed maintenance on the air-operated valves represented a burden to operators attempting to perform a routine evolution. Contributing causes to the event were weak procedural guidance which represented a continuation of one of the concerns documented in the prior inspection period (IR 50-373/99004; 50-374/99004) and weak communications between the two involved maintenance departments.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Open) URI 50-373/99004-01(DRP):50-374/99004-01(DRP): Unexpected Half Scram. The licensee completed the investigation which identified that a procedural error and instrument maintenance personnel's failure to question the procedure resulted in the half scram. The inspectors are reviewing this half scram in the context of several additional half scrams which occurred during the inspection period including multiple half scrams during Unit 1 average power range monitor flow bias adjustments (See Section M1.2).

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Response to Increasing Lake Temperatures

a. Inspection Scope (37551)

The inspectors reviewed engineering documents generated in response to increased lake temperatures. Documents reviewed included Updated Final Safety Analysis Report (UFSAR) UPDATE LU 1999-128, "UFSAR Change Regarding Increase

Maximum CW [circulating water] Inlet Temperature from 95° F to 97° F" and the supporting 10 CFR 50.59 Safety Evaluation Form. In addition, the inspectors reviewed System Functional Performance Review, Issue Resolution Sheet WS 004, concerning indications of lake temperature previously exceeding the service water system design maximum of 95° F.

b. Observations and Findings

During the inspection period, the LaSalle cooling lake temperature rose in response to meteorological conditions. As the temperature approached 95° F, the operators requested the engineers to review the UFSAR to determine the design cooling water temperatures of various equipment. The engineers determined that the fuel pool cooling system, the non-safety service water system, and the circulating water systems had cooling water design temperatures of 95° F. The engineers completed calculations and made UFSAR revisions to the appropriate sections raising the design temperature to 97° F. The 10 CFR 50.59 Safety Evaluation Form discussed and evaluated each UFSAR change. Engineering personnel continued to evaluate the possibility of raising the cooling water temperature above the approved 97° F should the lake temperature continue to rise. The maximum lake temperature reached during the inspection period was 96.5° F and the water temperature was decreasing at the end of the period due to changing meteorological conditions.

In 1997, during the completion of System Functional Performance Review, engineering personnel had identified that the lake had reached temperatures as high as 95.6° F for short periods of time in 1995. The information was evaluated as not safety significant and no corrective actions were identified in preparation for future occurrences.

c. Conclusions

Engineers provided timely, accurate support to operations personnel in the revision to the UFSAR and completion of the 10 CFR 50.59 Safety Evaluation Form for operation with elevated lake temperatures. However, the rapid response required by engineering personnel to the rising lake temperature was a direct result of not identifying and implementing corrective actions from the information discussed in a previously completed System Functional Performance Review.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radiological Protection (RP) Department Support of Unit 1 Hydrogen Water Chemistry (HWC) Testing

a. Inspection Scope (71750)

The inspectors observed and evaluated the support of the RP Department during testing of the HWC modification. Also, the inspectors interviewed operations, engineering, and RP personnel.

b. Observations and Findings

On July 18, 1999, the licensee implemented testing of the HWC modification on Unit 1. RP personnel were involved in pre-job briefings prior to beginning the testing and had evaluated areas for expected dose increases. As the test plan was implemented, RP personnel performed area surveys. Areas with increased dose rates were identified and, where radiological conditions warranted, reposted. The area survey maps were updated and personnel informed of the increased dose rates.

c. Conclusions

Radiation Protection personnel performed thorough radiological monitoring during testing of a hydrogen water chemistry modification with a potentially significant impact on station radiation levels.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of these inspections to licensee management listed below at an exit meeting on July 28, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee if any materials examined during the inspection should be considered proprietary. The licensee identified none.

X2 Pre-Decisional Enforcement Conference Summary

X3 Management Meeting Summary

Senior ComEd management met with senior Region III management in a public forum on June 30, 1999, to discuss ongoing utility actions in place to support improvements in plant performance. Licensee handouts used for the meeting were provided in separate, docketed correspondence.

PARTIAL LIST OF PERSONS CONTACTED

ComEd

*S. Barrett, Maintenance Manager
* J. Benjamin, Site Vice President
*C. Berry, Chief of Staff
*D. Bost, Site Engineering Manager
J. Burns, Chemistry Supervisor
C. Crane, Vice President, BWR Operations
D. Farr, Operations Manager
*T. Gierich, Work Control Manager
F. Gogliotti, Design Engineering Supervisor
*C. Howland, Radiation Protection Manager
*G. Kaegi, Site Training Manager
*P. Lucky, CAP Manager
*R. McConnaughay, Shift Operations Superintendent
*J. Meister, Station Manager
R. Palmieri, System Engineering Manager
J. Pollock, Support Engineering Supervisor
J. Place, Health Physics Supervisor
W. Riffer, Q & SA Manager
E. Shankle, Support Services Manager
*F. Spangenberg, Regulatory Assurance Manager
R. Stachniak, Nuclear Oversight Asessment Manager

* Present at exit meeting on July 28, 1999.

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observation
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Follow-up of Written Reports of Nonroutine Events
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-373/99012-01	NCV	Failure to complete rod operability check within the required time interval

Closed

50-373/99012-01	NCV	Failure to complete rod operability check within the required time interval
50-373/99001-00	LER	Main control room, auxiliary electrical equipment room, and switchgear room ventilation systems found outside design basis due to inadequate design
50-373/99002-00	LER	Missed TS rod operability surveillance due to personnel error

Discussed

50-373/374-99004-01	URI	Unexpected half scram

LIST OF ACRONYMS USED

APRM	Average Power Range Monitoring
CR	Control Room
CW	Circulating Water
DG	Diesel Generator
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EHC	Electrohydraulic Control
HWC	Hydrogen Water Chemistry
IDNS	Illinois Department of Nuclear Safety
IMD	Instrument Maintenance Department
IR	Inspection Report
LER	Licensee Event Report
LIP	LaSalle Instrument Maintenance Procedure
LIS	LaSalle Instrument Maintenance Surveillance
LOA	LaSalle Operating Abnormal Procedure
LOS	LaSalle Operating Surveillance
MCPR	Minimum Critical Power Ratio
MCR	Main Control Room
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PIF	Problem Identification Form
PDR	NRC Public Document Room
RBM	Rod Block Monitors
RP	Radiological Protection
RPIS	Rod Position Indication System
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup
SFPR	System Functional Performance Review
SM	Shift Manager
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
US	Unit Supervisor
VC/VE	Control Room Auxiliary Electric Room Ventilation