U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Commonwealth Edison Company
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EXECUTIVE SUMMARY

LaSalle County Station, Units 1 and 2
NRC Inspection Report 50-373/98019(DRP); 50-374/98019(DRP)

This inspection report included aspects of licensee operations, maintenance, engineering and plant support. The report covers a 6-week period of inspection conducted by the resident staff and other inspectors supporting startup inspections.

Plant Operations

- Operators performed well during the startup of Unit 1. Operators controlled Unit 1 startup activities and performed their duties in a deliberate manner. Operators maintained a questioning attitude, conducted professional shift briefings, and for the most part, met management expectations for communication and log keeping. Senior reactor operators ensured a professional atmosphere was maintained in the control room. (Sections O1.2 and O4.1)

- Several equipment problems required operator attention and operators responded appropriately to the problems. In particular, the licensee took appropriate, conservative action in shutting down the plant to address intermediate range monitor failures, failures during testing of the reactor core isolation cooling (RCIC) pump mechanical overspeed trip function, and flow control valve circuitry noise problems in the reactor recirculation system. (Section 01.2)

- Operators followed procedures in taking manual control of feedwater during a transient caused by a feedwater control system failure. Operators also appropriately initiated a manual reactor scram when a pre-established reactor vessel water level limit was reached during the transient. (Section O1.3)

- Inadequate command and control by the Unit Supervisor, poor communications between operations control room personnel, and incomplete work planning resulted in the unexpected start of the 1B emergency diesel generator. The response of operations personnel to the emergency diesel generator start was appropriate and the corrective actions were adequate for the associated Non-Cited Violation. (Section O1.4)

- Operations personnel responded appropriately to the trip of a reactor recirculation pump during a reactor vessel hydrostatic test, the failure of the other reactor recirculation pump to start, and the subsequent excessive reactor coolant system cooldown. The cooldown had minimal safety significance because the operators restored the cooldown rate to within acceptable limits in accordance with the applicable Technical Specification limiting condition for operations action statement. (Section O1.5)

- The RCIC system testing during the Unit 1 startup was performed in a controlled manner by operators. The pre-job brief for the RCIC testing was thorough and operators used three-way communication consistently in the control room. Operators accurately followed procedures and were attentive during RCIC pump performance testing. (Section O1.6)

- The quality of three-way communication between control room operators and field personnel during RCIC system testing was not consistent. (Section 1.6)

- Housekeeping was acceptable. The inspectors identified fewer housekeeping deficiencies during this inspection period, indicating that housekeeping improved from the previous inspection period. The equipment in the drywell was in acceptable condition for operations and the drywell was clean and generally free of debris. Deficiencies that were identified by the inspectors were minor and corrected by the licensee. (Section O2.1)

- Some configuration control issues continued to challenge station personnel such as an open main steam line drain valve during reactor vessel hydrostatic testing and closed instrument air isolation valves to the high radiation sample system. None of the instances of deficient configuration control were safety significant. The licensee was cognizant of the configuration control problems and implemented corrective actions to address the concerns. (Section O2.2)

- The inspectors identified an improperly installed lock and chain on a low pressure core spray system manual isolation valve which would not have prevented repositioning of the valve. The licensee implemented immediate corrective actions to properly secure the lock and chain. However, the licensee did not perform a review of the cause of the inappropriately locked valve until the inspectors requested the results of the licensee's review. This issue will remain an unresolved item pending a root cause determination. (Section O2.3)

- A licensed reactor operator became overly focused on control rod movements to support a plant heatup. Although he performed the appropriate surveillance, he failed to properly record the data or mark associated charts for reactor temperature and pressure data which was contrary to procedural requirements. The licensee identified the issue and operations management initiated prompt and conservative corrective action for this minor violation. (Section O4.2)

Maintenance

- In general, the licensee's performance of maintenance and surveillance activities was satisfactory. For example, troubleshooting and repair of the control system for the turbine driven reactor feedpumps was well implemented with a comprehensive plan and knowledgeable personnel. (Section M1.1)

- The licensee's approach to troubleshooting of the 1A reactor recirculation pump slow speed breaker and problems encountered during RCIC overspeed testing was initially narrow in scope and not well planned. Although the licensee eventually resolved the issues, the licensee's approach unnecessarily protracted the repair process and resulted in additional failed tests. The licensee recognized this problem and was taking additional actions to improve the implementation of troubleshooting activities. (Sections M1.1 and M8.1)

- The overall amount of maintenance rework was just slightly above the licensee's goal but most recently was on an increasing trend. Associated deficiencies, with only a couple of recent exceptions such as a failed intermediate range monitor, were typically of minor significance. (Section M4.1)

Engineering

- The licensee identified that the source range monitor neutron count rate required by Technical Specifications for withdrawal of control rods during startup was not conservative with respect the current plant design. The licensee took interim actions to ensure an appropriate count rate during Unit 1 startup and planned to submit a Technical Specification amendment request to resolve the issue. The licensee's failure in 1990 to derive the associated Technical Specification requirement from the analyses and evaluation included in the Updated Final Safety Analysis Report is a Non-Cited Violation. (Section E2.1)

- In one instance, involving reactor recirculation flow control valve hydraulic lines, the licensee's resolution to Generic Letter 96-06 issues was not timely due to the deficient communications between a contractor and licensee personnel. In another instance, involving residual heat removal shutdown cooling suction piping, the licensee identified that calculations for a modification associated with Generic Letter 96-06 assumed an incorrect piping configuration. This is an unresolved item pending NRC review of the licensee's operability evaluation for the second issue. (Section E4.1)

- The inspectors identified that operators relied upon an unofficial control room file of operability evaluations which was not maintained current. (Section E4.1)

- The licensee identified that a Qualified Nuclear Engineer had provided an incorrect flow value used to establish the setpoints for the average power range monitor flow biased scram and rod block and the rod block monitor rod block. The licensee's response to this Non-Cited Violation was timely and appropriate and the safety significance of the incorrect setpoints was minimal. (Section E4.2)

- The inspectors identified that during the performance of pressure regulation system startup testing, the test director directed an operator to place a switch in the OFF position which was out-of-sequence with the governing procedure steps. The test procedure was designated as a continuous use procedure; however, the test director and the operator failed to adhere to the licensee's requirement to perform continuous use procedural steps in the sequence written and did not obtain a temporary procedure change. There was no actual consequence to this action. (Section E4.3)

Plant Support

- Radiation protection (RP) personnel performed well during routine RP support activities. Technicians provided oversight for various maintenance and surveillance activities and ensured that plant personnel were cognizant of the radiological conditions while performing work in the plant. (Section R4.1)

- The inspectors identified one instance in which RP technicians were slow in posting a radiologically contaminated area and did not ensure formal control of the area to prevent personnel contaminations in the interim. (Section R4.1)

Report Details

Summary of Plant Status

During this inspection period, the licensee maintained Unit 1 in cold shutdown (Operational Condition 4) until August 1, 1998, in support of outage activities and final surveillance tests which were required to be completed prior to restart. On July 24, 1998, the NRC completed a review of licensee actions taken to resolve the issues identified in the April 1997 Confirmatory Action Letter (CAL) No. RIII-98-008B and issued a closure letter for that CAL. Issues identified in the CAL included problems with human performance, the corrective action program, plant material condition, engineering support and design deficiencies. Following final preparations, operators commenced startup of the Unit 1 reactor on August 1, 1998. The licensee subsequently shut down the unit on August 4, 1998, to address equipment problems. On August 6, 1998, the licensee again commenced a startup of Unit 1 after completing repairs and the turbine generator was synchronized to the electrical grid on August 12, 1998. The licensee shut down Unit 1 again on August 19, 1998, due to a feedwater level transient and on August 20, 1998, the licensee again commenced a startup. The turbine generator was synchronized to the grid on August 21, 1998. Unit 2 remained shut down for a refueling outage with all fuel removed from the reactor.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations and observed the Unit 1 startup activities on a 24-hour basis. Licensee oversight of startup activities was extensive and included 24-hour coverage by plant management, Nuclear Oversight personnel, and offsite representatives.

O1.2 Unit 1 Startup Observations

a. Inspection Scope (71707)

The inspectors observed Unit 1 startup activities continuously from initial control rod withdrawal on August 1, 1998, until the turbine generator was synchronized to the electrical grid on August 12, 1998. The inspectors observed activities in the control room and in the plant. Observed activities included control rod withdrawal to reactor criticality, reactor core isolation cooling (RCIC) system and automatic depressurization system testing, main generator synchronization to the grid, and other testing which occurred during power ascension.

b. Observations and Findings

Operators commenced reactor startup on August 1, 1998. However, equipment problems resulted in a decision by licensee management to shut down to repair the deficiencies on August 4, 1998. Equipment problems leading to the shutdown included:

- Two intermediate range neutron monitoring (IRM) detector failures.

- Reactor core isolation cooling (RCIC) system turbine mechanical overspeed trip failures.

- Reactor recirculation (RR) system flow control valve control circuitry noise problems.

The licensee addressed each of the equipment problems and commenced startup of Unit 1 on August 6, 1998. The main generator was synchronized to the electrical grid on August 12, 1998. Operators performed well during the restart of LaSalle Unit 1 and the conduct of startup activities was careful and controlled. Senior management and the Nuclear Oversight organization provided continuous oversight in the control room.

The operators maintained a questioning attitude. In one instance, maintenance personnel were planning to calibrate a main steam line instrument. The control room Unit Supervisor (US) questioned the technicians as to the effect the calibration would have on the main steam line high flow signal and the potential to cause the main steam isolation valves (MSIVs) to close. The US reviewed applicable drawings with the maintenance personnel to determine the effects of the calibration activity.

During control room turnover activities, control room supervision and reactor operators were thorough during the conduct of board walkdowns, was well as when discussing individual annunciators that were in the alarm condition, current system lineups, and equipment status. Control room personnel also reviewed and discussed the operating procedures that were currently being used. Control room decorum was very professional with minimal background noise level and with conversations limited to work related topics and control room supervisors controlled access to the control room. Also, shift turnover meetings conducted by the Shift Manager (SM) were performed in a professional manner and overall plant status and planned activities were clearly communicated. In addition, operators promptly responded to alarms and informed the US of alarms and the reason for the alarms. The operators normally used three-way communications, although the inspectors identified a few isolated instances where three-way communications were not used. Licensee management also identified communication problems when they occurred and addressed the issue with the operators.

Briefings for "high impact activities," such as the reactor startup and the pre-criticality briefing, were good. Operations personnel discussed expected plant response and policies concerning various plant conditions. During one briefing observed by the inspectors, the Operations Manager discussed lessons learned from various plant startup events at LaSalle and other plants. At the end of the briefings, operations personnel restated their titles and responsibilities for the activities.

The control room logs were generally accurate and complete. The logs referenced specific Technical Specification Limiting Conditions for Operations (LCO) and associated time limits. However, the inspectors identified some errors during reviews of the logs. For example, in one instance, the Operational Condition for Unit 1 was listed as Cold Shutdown when it was actually Startup. The inspectors notified operations personnel who corrected the incorrect log entry.

During the course of the startup, several equipment problems occurred which delayed startup activities, although the licensee appropriately addressed the problems. A partial list of the problems which required operator attention during the startup included:

- Control rods were difficult to withdraw from the full-in position during the initial reactor startup and had been a problem in the past. Operators used various proceduralized methods in the effort to get them to move correctly. Once operators were able to withdraw the control rods from the full-in position, the rods operated normally.

- The RCIC system turbine mechanical overspeed trip mechanism did not operate properly and required a significant amount of work by maintenance and engineering personnel to resolve the problems (see Section M1.1).

- A temperature measuring device in the drywell indicated that the temperature near a main steam isolation valve was high although no indication of leaks was identified by the licensee during a drywell inspection.

- One train of the instrument nitrogen system (IN) could not maintain the required system pressure. The licensee investigated the problem and repaired the IN compressor. However, the licensee considered the repair to be rework as maintenance was performed on the system during the extended shutdown (see Section M4.1).

- An unplanned half-scram resulted from a spiking local power range monitor and when changing the range of the "H" IRM from 6 to 7.

These problems were sufficiently resolved by the licensee, including repairs and evaluations which appropriately considered equipment operability and safety, to continue startup in a safe manner.

c. Conclusions

Operators performed well during the startup of Unit 1. Operators controlled Unit 1 startup activities and performed their duties in a deliberate manner. Operators maintained a questioning attitude, conducted professional shift briefings, and for the most part, met management expectations for communication and log keeping. Several equipment problems required operator attention and operators responded appropriately to the problems. In particular, the licensee took appropriate, conservative action in shutting down the plant to address IRM failures, failures during testing of the RCIC pump mechanical overspeed trip function, and flow control valve circuitry noise problems in the reactor recirculation system.

O1.3 Unit 1 Manual Reactor Scram

a. Inspection Scope (71707, 92901)

The inspectors reviewed the circumstances, alarm response procedures, and operating procedures pertaining to a manual reactor scram. In addition, the inspectors discussed the manual scram with plant personnel.

b. Observations and Findings

On August 19, 1998, operators initiated a manual reactor scram on Unit 1 during a reactor water level transient which resulted from the failure of the automatic feedwater level control system on the 1A turbine-driven reactor feedwater pump (TDRFP). Unit 1 was operating at 65% power and operators were performing feedwater system testing at the time of the scram. After operators placed the 1A TDRFP in service using manual control, they attempted to place the feedwater control system in automatic. When the 1A TDRFP was placed in automatic, the pump speed decreased and the reactor water level decreased. The 1B TDRFP automatically increased speed and flow output to compensate for the lower 1A TDRFP flow rate. An operator followed plant procedures and took manual control of the TDRFPs, but was unable to maintain the appropriate reactor water level. Another operator manually scrammed the reactor when the water level reached 50 inches, one of the manual scram criterion established for the feedwater system testing. Following the reactor scram, the plant operated as designed and no safety-related equipment problems occurred.

The licensee subsequently determined that the failure of the 1A TDRFP resulted from a defective flow controller card in the feedwater control system. The licensee replaced the defective card and tested the replacement after installation. Licensee management indicated that a quicker response from the operators in responding to the event could possibly have allowed operators to gain control of reactor water level before a manual scram was required. The licensee enhanced the feedwater system operating and testing procedures to include actions to prevent conditions which would necessitate a manual reactor scram. The licensee also provided operators with training on the TDRFP control system, the procedure enhancement, and the relationship between the reactor power level and the capacity of the feedwater pumps.

c. Conclusions

Operators followed procedures in taking manual control of feedwater during a transient caused by a feedwater control system failure. Operators also appropriately initiated a manual reactor scram when a pre-established reactor vessel water level limit was reached during the transient.

O1.4 Unexpected Emergency Diesel Generator (EDG) Start During System Auxiliary Transformer (SAT) Deenergization

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to the unexpected start of the 1B EDG during the deenergization of the Unit 1 SAT. The inspectors reviewed operator logs, applicable operating procedures, and interviewed operating department personnel.

b. Observations and Findings

On July 21, 1998, an operator failed to use the correct procedure when removing the Unit 1 SAT from service to repair degraded cables in an associated control cabinet. The US and a Unit 1 NSO verified that all loads had been removed from the SAT. The US then directed a Unit 2 NSO to complete the evolution because the Unit 1 NSOs were involved with other testing on Unit 1. The Unit 2 NSO referenced LaSalle Operating Procedure (LOP)-MP-08, "Removing a 345kV Bus From Service," Revision 2, which directed the SAT circuit breakers be opened, but did not require any additional equipment lineup changes on Unit 1. The NSO failed to reference a more specific and appropriate procedure for the evolution, LOP-AP-08, "Removing System Auxiliary Transformer (SAT) 142(242) From Service with Unit 1(2) in Shutdown," Revision 20. Section E.2 of this procedure required operators to disable the Division III EDG undervoltage automatic start relay. Because this action was not performed, when the NSO de-energized the SAT, the Division III EDG automatic start circuitry sensed an undervoltage on Bus 143. The EDG subsequently started and provided power to Bus 143, and all safety-related equipment responded as designed.

Several factors contributed to the personnel error which included:

- Poor communication between the personnel involved in the SAT deenergization. Operators had not performed a pre-job brief for infrequent evolutions.
- Inadequate direction by the US to the NSO on which procedure was to be used to perform the task.
- Several concurrent activities were in progress in the Control Room (CR) including scram time testing and shift turnover.
- Use of a Unit 2 NSO to perform a Unit 1 task.
- Perceived schedule pressure by the US.
- The SAT repair was emergent work and the schedule used by the licensee to implement the work did not include the procedure to be used for SAT deenergization.

Operations department management implemented corrective actions which included a 24-hour operations department standdown to review the event and to discuss expectations and lessons learned from the event. Also, the licensee evaluated scheduled Unit 1 startup work activities to provide additional planning where necessary to reduce the work load of the control room supervisors and operators.

The licensee's failure to use a procedure appropriate to the circumstance during deenergization of the SAT is a violation of 10 CFR Part 50, Appendix B, Criterion V (50-373/98019-01(DRP)). However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

Inadequate command and control by the US, poor communications between operations control room personnel, and incomplete work planning resulted in the unexpected start of the 1B EDG. The response of operations personnel to the EDG start was appropriate and the corrective actions were adequate for the associated Non-Cited Violation.

O1.5 Loss of RR Pumps During the Unit 1 Vessel Hydrostatic Test

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to the 1B RR pump failure during a reactor vessel hydrostatic test and the subsequent reactor coolant system (RCS) cooldown. The inspectors reviewed control room operator logs, applicable procedures including LOP-NB-01, "Reactor Vessel Leakage Test," Revision 29, and interviewed operations department personnel on shift during the event.

b. Observations and Findings

On July 16, 1998, during a reactor vessel hydrostatic test with an RR pump running in fast speed and the RCS pressurized to approximately 600 psig at a temperature of 197 degrees F, the NSOs secured the 1B RR pump in response to an indication of low upper motor bearing oil level. Subsequently, the operators attempted to start the 1A RR pump in slow speed to reinitiate forced circulation, but the pump failed to start due to unresolved issues from a previous failure to start (see Section M1.1). As a result, with the plant cooling by natural circulation, operations personnel depressurized the reactor coolant system and started the shutdown cooling system to provide forced circulation and control RCS temperature.

Due to little decay heat from the reactor core, the RCS experienced a rapid cooldown after the RR pump was secured. The NSOs monitored the bulk RCS temperature in accordance with LOP-NB-01 to ensure that the Technical Specification 3.4.6.1 cooldown limit of 20 degrees F in any one hour was not exceeded. However, engineering department personnel subsequently identified that the Technical Specification also applied to the bottom head drain metal temperature which had cooled at 25 degrees F per hour and had exceeded the 20 degree F Technical Specification value. Operator actions had restored within 30 minutes the cooldown rate to less than 20 degrees F in an hour as required by the corresponding Technical Specification LCO action statement. The licensee also performed an engineering evaluation as required by the Technical Specifications and determined that the excessive cooldown rate did not challenge the integrity of the RCS. The licensee revised LOP-NB-01 to include the appropriate RCS cooldown monitoring points. The inspectors reviewed the engineering evaluation and procedure revision and had no comments.

c. Conclusions

Operations personnel responded appropriately to the loss of a RR pump during a reactor vessel hydrostatic test, the failure of the other RR pump to start, and the subsequent reactor coolant system cooldown. The cooldown had minimal safety significance because the operators restored the cooldown rate to within acceptable limits in accordance with the applicable Technical Specification LCO action statement.

O1.6 Unit 1 RCIC Operation and Pump Test

a. Inspection Scope (71707, 61726)

During startup of Unit 1, the inspectors observed the licensee's activities regarding the operation and testing of the RCIC system which was a risk-significant system at LaSalle. These activities included several attempts by the licensee to perform LaSalle Operating Surveillance (LOS)-RI-R1, "Unit 1 RCIC Turbine Overspeed Test," Revision 13.

b. Observations and Findings

Operations personnel conducted a pre-job brief with all personnel participating in the RCIC testing, including supervisory personnel from the maintenance departments and the Nuclear Oversight organization. The US discussed the test acceptance criteria and Technical Specification limits for the suppression pool temperature, as well as other RCIC shutdown criteria. Each RCIC testing team member discussed their roles and responsibilities and participants exhibited a questioning attitude.

Operators performed the testing in accordance with approved procedures and closely monitored turbine speed and additional pump parameters during testing. The operators used three-way communication (repeat-back) consistently in the control room. However, during communication between the control room operators and field personnel (by radio or phone), three-way communication was not used consistently.

Several equipment problems occurred primarily with the mechanical overspeed trip mechanism during the testing which required resolution and additional testing. These are discussed in Section M1.1.

Following the troubleshooting activities and repairs of the RCIC system problems, the licensee performed three satisfactory turbine mechanical overspeed trip tests without a failure to ensure the turbine would properly respond to an overspeed condition. Operators satisfactorily performed pump flow testing at various reactor coolant system pressures once the turbine and pump were connected and determined the RCIC system to be operable.

c. Conclusions

The RCIC system testing during the Unit 1 startup was performed in a controlled manner by operators. The pre-job brief for the RCIC testing was thorough and operators used three-way communication consistently in the control room. However, the quality of communication between control room operators and field personnel was not consistent. Operators accurately followed procedures and were attentive during RCIC pump performance testing.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Features (ESF) System Walkdowns

a. Inspection Scope (71707)

The inspectors performed a walkdown of accessible portions of various ESF systems and the drywell. Also, the inspectors performed a walkdown of the 1A and 1B low pressure coolant injection (LPCI) systems which were identified as key equipment in the LaSalle Probabilistic Risk Assessment. Areas inspected included various levels of the respective reactor building corner rooms for the LPCI system and other areas of the reactor building.

b. Observations and Findings

The areas of the reactor building including the residual heat removal (RHR) corner room areas were clean with minimal debris during the majority of the inspection period and the inspectors identified fewer housekeeping deficiencies during this inspection period. Some housekeeping deficiencies are discussed below.

Drywell Inspection

The inspectors evaluated the drywell housekeeping and material condition, including various system configurations in the drywell, prior to restart of Unit 1. For the most part, the equipment in the drywell was in acceptable condition for operations and the drywell was clean and free of debris. The inspectors identified some maintenance debris during the walkdown (approximately 1 cubic foot) and the licensee removed the debris. In addition, some equipment deficiencies identified by the inspectors included loose electrical conduit, an instrumentation housing which was rubbing against its support, and a manual valve with a lock which was not locked appropriately. (The lock would not prevent operation of the valve) (See Section O2.3). The licensee corrected the deficiencies or provided appropriate justification for the deficiencies.

Reactor Building Corner Room Area Housekeeping

The inspectors did not identify any safety significant material condition or equipment configuration deficiencies. Although housekeeping improved from ESF walkdowns performed during previous inspection periods, the inspectors continued to identify minor housekeeping deficiencies. Specifically, the inspectors found various construction materials such as a putty knife below the Unit 1B RHR heat exchanger, welding rods, and pipe caps stored in pipe supports. The inspectors also found trash such as a pack of cigarettes, obsolete tags, and old stickers used to identify radiological conditions. In addition, the inspectors identified two completely illegible radiation survey tags, an unattached floor grating above safety-related components, and a valve room door alarming erratically. Also, a plastic sign which was posted in the lowest elevations of the reactor building was found unattached to the wall (apparently removed during painting). An emergency operating procedure required this sign to indicate acceptable water levels during an event. Thus, the sign would not be a dependable indicator of safe water level in the room since it would displace with rising room water level. All deficiencies noted by the inspectors were corrected by the licensee in an appropriate and timely manner.

c. Conclusions

Housekeeping was acceptable. The inspectors identified fewer housekeeping deficiencies during this inspection period, indicating that housekeeping improved from the previous inspection period. The equipment in the drywell was in acceptable condition for operations and the drywell was clean and generally free of debris. Deficiencies that were identified by the inspectors were minor and corrected by the licensee.

O2.2 Equipment Configuration Control Issues

a. Inspection Scope (71707)

The inspectors performed reviews of plant records, conducted plant walkdowns, and observed equipment testing. The inspectors reviewed the circumstances surrounding a main steam drain valve which was not in its required position during the reactor vessel hydrostatic test and additional equipment configuration control issues.

b. Observations and Findings

On July 16, 1998, the licensee was performing a reactor vessel leakage test in accordance with LOP-NB-01, "Reactor Vessel Leakage Test," Revision 1. During the test, unidentified leakage from the reactor vessel was occurring at approximately 50 gallons per minute. Using a thermal detector to inspect main steam piping, a plant operator found that a main steam drain valve, 1E12-F068, was not closed. An operator closed the valve and the test continued with the source of leakage stopped.

The licensee subsequently determined that LOP-NB-01 contained conflicting prerequisite positions for the drain valve. Because of ongoing maintenance, the licensee could not perform the procedure in the original order specified. Since the procedure specifically allowed operators to perform the procedure in a different order, operators placed the valve in the open position prior to commencing the vessel leakage test. As written, LOP-NB-01 did not return the valve to the correct position required to perform the test. No adverse consequences resulted from the valve being open, only delays in completing the test. The licensee indicated their intent to complete a revision to simplify the procedure and resolve the issue.

On August 18, 1998, while attempting to obtain a reactor coolant sample from the high radiation sample system (HRSS), the licensee found that the air operated valve which supplies reactor coolant to the HRSS would not open. The licensee subsequently determined that the instrument air isolation valves to two air operated valves associated with the HRSS were closed. Although operations personnel expected the instrument air supply valves to be open, the valves were not on a valve lineup checklist to ensure proper configuration. Also, no equipment part numbers were assigned to the instrument air valves, nor were they labeled. The licensee investigated the issue and concluded that the most probable cause of the valves being closed was inadvertent manipulation of the instrument air isolation valves during maintenance performed in the area. The licensee's long term corrective actions included assigning equipment part numbers to the valves and labeling air supply valves to all air operated valves by December 1999. The safety significance of this problem was minimal because alternate methods to obtain reactor coolant samples during normal and accident conditions were available.

The licensee's nuclear oversight organization identified that configuration control remains an issue at the station. Furthermore, senior station management had been emphasizing configuration control with station personnel and stated their intention to implement a new corporate procedure for configuration control.

c. Conclusions

Some configuration control issues continued to challenge station personnel such as an open main steam line drain valve during reactor vessel hydrostatic testing and closed instrument air isolation valves to the HRSS. None of the instances of deficient configuration control were safety significant. The licensee was cognizant of the configuration control problems and implemented corrective actions to address the concerns.

O2.3 Improperly Locked Valve

a. Inspection Scope (71707)

The inspectors evaluated the licensee's actions to address a valve that was not adequately locked to prevent opening. The inspectors interviewed operations and engineering personnel and reviewed documentation which included LaSalle Administrative Procedure (LAP)-200-3, "Conduct of Operations - Shift Operations," Section 26, "Locked Valves," Revision 30, and LOP-DW-01M, "Drywell Manual Valve Mechanical Checklist," Revision 20.

b. Observations and Findings

On July 22, 1998, the inspectors performed a walkdown of the drywell and portions of systems accessible in the drywell and identified that the locking mechanism for the low pressure core spray (LPCS) manual isolation valve, 1E51-F051, was not properly secured. The valve was in the required closed position with a lock and chain installed. However, the chain was not appropriately attached and would allow the valve handle to be turned. Operations personnel corrected the deficiency by securing the lock in a manner which would prevent movement of the valve handwheel. The safety-significance was minimal as the valve was in the correct position and position indication was available to operators. However, at some time in the past, operators had incorrectly fastened the lock in a manner which still allowed the valve to be operated.

The licensee did not initially investigate the root cause of the problem until the inspectors requested the results of the licensee's review. The failure of the licensee to perform an investigation was because the issue was not explicitly identified on a the Problem Identification Form (PIF) that the licensee had generated for the inspectors' drywell inspection results. The inspectors had communicated the issue to the licensee.

A similar issue regarding the locked valve program at LaSalle was identified in a previous inspection report. The licensee planned to perform an apparent cause evaluation to review the issue. The issue will remain an Unresolved Item pending further review of the root cause for the inappropriately locked valve (50-373/98019-02(DRP)).

c. <u>Conclusions</u>

The inspectors identified an improperly installed lock and chain on a LPCS manual isolation valve which would not have prevented repositioning of the valve. The licensee implemented immediate corrective actions to properly secure the lock and chain. However, the licensee did not perform a review of the cause of the inappropriately locked valve until the inspectors requested the results of the licensee's review. This issue will remain an unresolved item pending a root cause determination.

O4 Operator Knowledge and Performance

O4.1 <u>Senior Reactor Operator Knowledge of Plant Status During Reactor Startup</u>

a. <u>Inspection Scope (71707)</u>

The inspectors observed the performance of control room operators throughout the initial startup and power ascension of Unit 1. The inspectors frequently questioned the main control room operations personnel regarding the configuration of plant equipment and the status of plant testing activities in progress.

b. <u>Observations and Findings</u>

Senior reactor operators enforced strict communications standards and maintained a focused and professional atmosphere in the main control room throughout the Unit 1 startup and power ascension. In general, the US displayed an adequate knowledge of plant activities in progress. However, two instances of the US not fully understanding plant configuration were noted by the inspectors.

In one instance, the US did not know that the reactor water level was required to be maintained 32-38 inches above reference zero in accordance with LaSalle Special Procedure (LLP)-98-002, "L1F35 Power Ascension Special Procedure," Revision 1. At one point during the startup when the indicated reactor water level in the main control room was 39.5 inches, the US incorrectly stated that the control band was 30-40 inches when questioned by the inspector. An NSO was taking action to return the reactor water level to within the procedurally specified limits.

Another instance of inadequate US knowledge was noted by the inspectors when the US was asked about the status of the RR flow control valves (FCVs). The US indicated that the FCVs were being controlled manually and that the valves would respond normally to an automatic positioning signal. The inspectors then asked why the RR FCVs' trouble alarm was illuminated on the alarm panel in the control room and the US indicated that he did not know. The US subsequently was informed that the RR FCVs were in a locked condition as required by startup procedures and that they were not prevented from being repositioned.

c. Conclusions

Senior reactor operator knowledge and performance was, in general, good during the Unit 1 startup. Communication standards were enforced and a professional atmosphere was maintained in the main control room. Inspectors noted two instances of inadequate US knowledge of plant and equipment status. These instances appeared to be isolated.

O4.2 Reactor Parameters Not Recorded as Required During Changing Plant Conditions

a. Inspection Scope (71707)

The inspectors reviewed the response of operations department supervision following the licensee's identification that the reactor pressure and temperature data required to be verified in accordance with Technical Specification Surveillance Requirement 4.4.6.1.1 was not recorded as required by the plant startup special procedure.

b. Observations and Findings

On August 8, 1998, while the operators were withdrawing control rods in accordance with LLP-98-002, the operators discovered that reactor pressure and temperature data that was required to be verified by Technical Specification Surveillance Requirement 3.4.6.2 every 30 minutes, was not annotated as prescribed in the plant startup special procedure. Step E.1.9.6 of LLP-98-002 required verification of appropriate reactor pressure and temperature in accordance with Technical Specifications, and Step E.1.9.7 required the pressure and temperature chart recorders to be marked at the same interval.

Operations department shift management response to the discovery that the required reactor parameters were not properly annotated was appropriate and conservative. Specifically, the US halted rod movement to cease raising reactor temperature and pressure. The SM did not authorize further rod movement until controls were in place to ensure that the pressure and temperature readings were appropriately taken and documented. In addition, operators verified that reactor temperature and pressure were within the Technical Specifications limits. Also, the SM reviewed the appropriate LCO requirement for failing to meet a Technical Specification Surveillance Requirement.

The licensee initiated an accelerated investigation of the incident and found that the readings were taken as required by Technical Specifications. However, the NSO who took the readings did not record the data or mark the charts because he became distracted with control rod movements. The licensee obtained a timer to assist operators in the performance of repetitive recording of plant parameters during a heatup or cooldown. In addition, operations management emphasized to shift supervision the importance of reviewing NSO activities throughout the shift. The NSO's failure to perform the log entry and chart annotation in accordance with LLP-98-002 is a violation of Technical Specifications 6.2.A.a. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

An NSO became overly focused on rod movements to support a plant heatup. Although he performed the appropriate surveillance, he failed to properly record the data or mark associated charts for reactor temperature and pressure data which was contrary to procedural requirements. The licensee identified the issue and operations management initiated prompt and conservative corrective action for this minor violation.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-373/97-006-00: Diesel Generator Testing Did Not Meet Surveillance Requirement Due to Misinterpretation of Technical Specification.

On February 12, 1997, during performance of system functional reviews, engineering department personnel identified that some CR ventilation and auxiliary electrical equipment room (AEER) ventilation components were not verified to start every 18 months on a loss of coolant accident (LOCA) EDG electrical loading sequence as required by Technical Specification Surveillance Requirement 4.8.1.1.2.d.4.a.2. The licensee determined that a misinterpretation of the term "auto-connected loads" used in the surveillance requirement, but not defined in the Technical Specifications, had resulted in procedures being developed prior to initial licensing of Unit 1 in 1982 in which three CR ventilation fans and three AEER ventilation fans in train A and B were not tested. The 1A EDG powered the A train and 2A EDG powered the B train of the emergency ventilation systems, and therefore, operators declared EDGs 1A and 2A inoperable for the failure to test the fans. However, the applicable EDGs had previously been declared inoperable for unrelated reasons.

The licensee completed corrective actions which included revising the procedures to test the fans and reviewing EDG LOCA electrical load sequence surveillance procedures to ensure all items required by Technical Specifications were tested. The licensee also performed testing to ensure EDG load sequencing operated as designed. In addition, the licensee initiated two programs, the System Functional Performance Review program and the Updated Final Safety Analysis Report (UFSAR) validation program, to ensure that selected systems demonstrated performance consistent with the design basis and that the design basis information contained in the UFSAR was accurate. The licensee completed the System Functional Performance Review program without identifying any additional problems with EDG load testing and scheduled the UFSAR validation to be complete on May 30, 1999.

The licensee's failure to verify the load sequencing of "auto-connected loads" in a procedure generated in 1982, contrary to Technical Specification Surveillance Requirement 4.8.1.1.2.d.4.a.2, is a violation (50-373/98019-03(DRP); 50-374/98019-03(DRP)). However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This LER is closed.

O8.2 <u>(Closed) LER 50-373/98-009-00</u>: Division III Emergency Diesel Generator Actuated During Removal of the System Auxiliary Transformer From Service Due to Human Performance Error in Failing To Use an Operating Procedure.

This event is discussed in Section O1.4. This LER is closed.

<u>II. Maintenance</u>

M1 Conduct of Maintenance

M1.1 <u>General Maintenance</u>

a. <u>Inspection Scope (62707, 61726)</u>

The inspectors interviewed maintenance and engineering personnel and observed or reviewed all or portions of several maintenance and surveillance activities including:

- LaSalle Instrument Surveillance (LIS)-NB-115B, "Unit 1 High Pressure Excess Flow Check Valve Operability Test (Panels 1H22-P004, 1H22-P005, 1H22-P026, 1H22-P027,)" Revision 1.
- LOP-NB-01, "Reactor Vessel Leakage Test," Revision 29.
- Work Request No. 980072907, "Breaker Failed to Remain Closed During End of Cycle-Recirculation Pump Trip (EOC-RPT) Testing."
- LOS-MS-R6, "Main Steam Relief Valve Manual Cycling Test," Revision 0.
- LOS-RI-R1, "Reactor Core Isolation Cooling Turbine Overspeed Test," Revision 13.

b. Observations and Findings

In general, maintenance personnel performed work in accordance with work procedures and were well trained and knowledgeable of work activities assigned. For example, on August 26, 1998, the licensee performed troubleshooting and repairs on the 1A and 1B TDRFP. The work included replacement of a turbine control system electrical component on the 1B pump and adjustment of the speed control circuit on the 1A pump. The licensee developed a comprehensive work plan, implemented the plan, and completed the repairs. The reactor feedwater pumps responded as designed once the repairs were completed.

However, in the two instances discussed below, inspectors noted deficiencies in the licensee's approach to the troubleshooting and repair process:

- On July 16, 1998, during EOC-RPT testing, the Unit 1 RR pump motor slow-speed breaker failed to remain closed following receipt of a closure signal during a transfer from fast to slow speed. The operators observed that the breaker closed but immediately reopened and the pump coasted to a stop.

  During initial troubleshooting, electrical maintenance department (EMD) personnel did not adequately follow up on identified abnormal conditions. Technicians identified that the pump start was electrically coupled to the trip circuitry, but did not pursue the problem and did not identify the source of the electrical coupling.

  The maintenance personnel subsequently released the pump to the control room operators to perform a pump start in slow speed in an attempt to recreate the problem. Later on July 16, 1997, operations department personnel attempted to start the 1A RR pump in slow speed in response to a loss of the 1B RR pump (see Section O1.5). Again, the slow-speed breaker closed but immediately reopened. The licensee subsequently identified that a small sliver of metal was connecting two terminals of a test switch in the lower portion of the breaker. The sliver caused the breaker to open with each closure attempt. The EMD personnel removed the metal and subsequently tested the breaker satisfactorily. The licensee was not able to identify the source of the metal sliver.

- Several equipment problems occurred during the RCIC overspeed testing which required resolution and additional testing. These problems included a loose setscrew on the overspeed trip mechanism, trip and throttle valve latch mechanism binding, overspeed tappet bushing galling due to a degraded spring, the trip linkage not tripping due to the tappet screw being too long, and the failure of the DC trip solenoid due to binding from interference from an installed washer.

  The licensee failed to develo) and implement a comprehensive troubleshooting plan which methodically evaluated all possible causes of the RCIC overspeed mechanical trip mechanism failure. Instead, the licensee individually evaluated each possible cause, implemented repair, retested, and upon test failure, evaluated the next possible cause and solutions. This troubleshooting method resulted in additional failed overspeed tests. In addition, the failure to plan ahead and identify the next steps to be taken, in case the current actions did not fix the problem, resulted in additional delays in correcting the problem.

c. Conclusions

In general, the licensee's performance of maintenance and surveillance activities was satisfactory. For example, troubleshooting and repair of the control system for the TDRFPs was well implemented with a comprehensive plan and knowledgeable personnel. On the other hand, the licensee's approach to troubleshooting of the 1A RR pump slow speed breaker and problems encountered during RCIC overspeed testing was initially narrow in scope and not well planned. Although the licensee eventually resolved the issues, the licensee's approach unnecessarily protracted the repair process and resulted in additional failed tests. The licensee recognized this problem and was taking additional actions to improve the implementation of troubleshooting activities as described in Section M8.1 of this report.

M4 Maintenance Staff Knowledge and Performance

M4.1 Review of Maintenance Rework

a. Inspection Scope (62707)

The inspectors reviewed several maintenance activities which the licensee classified as rework items.

b. Observations and Findings

The licensee provided a listing of 24 maintenance activities designated as rework. The inspectors reviewed the specific rework items and found that most were of a minor nature and were not related to nuclear safety. The rework percentage for July 1998 was 2.1 percent, slightly above the licensee's goal of 2 percent, but increased during August 1998 to 2.7 percent. The inspectors did note two rework items that were of more than minor significance:

- On August 2, 1998, the B intermediate range neutron monitor (IRM) failed downscale and the US declared the IRM inoperable. Subsequently, on August 3, 1998, the D IRM failed and was declared inoperable by operations personnel. The licensee decided on August 4, 1998, to shut down the reactor to effect repairs of both IRMs. On August 5, 1998, maintenance department personnel completed replacement of the B IRM. Later that day, during reactor startup surveillances, a failure of the B IRM occurred again resulting in a half scram. The licensee appropriately declared the B IRM inoperable and placed it in the bypass condition. The licensee completed a subsequent replacement of the B IRM and the detector performed satisfactorily throughout the remainder of Unit 1 startup.

The licensee classified the second B IRM failure as rework and initiated a rework investigation. Senior licensee maintenance management indicated that the failure of the B IRM was due to the mishandling of the detector during replacement by the instrument maintenance technicians. The technicians indicated that there had been difficulty inserting the detector and several attempts were made before it could be fully inserted into the drive tube. As a result, the licensee intended to revise the appropriate work procedure to include specific provisions for determining the potential for detector damage as a result of any difficulty in inserting the detector into the drive tube.

The inspectors also noted that the post maintenance testing (PMT) performed after the initial repair did not include any provision for testing of the detector during or following a detector withdrawal. The PMT had not identified any detector abnormalities. Engineering personnel were reviewing the PMT to determine if additional testing during or following detector withdrawal but prior to reactor startup should be implemented.

- The licensee found that a valve had been incorrectly installed on the instrument nitrogen compressor when it was overhauled during the L1F35 outage. As a result, the licensee was having problems maintaining nitrogen pressure to instrumentation in the drywell. The licensee subsequently replaced the valve and restored the compressor to service.

c. Conclusions

The overall amount of maintenance rework was just slightly above the licensee's goal but most recently was on an increasing trend. Associated deficiencies, with only a couple of recent exceptions such as a failed intermediate range monitor, were typically of minor significance.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) URI 50-373/374-97006-06: Review of licensee troubleshooting practices.

The inspectors reviewed the licensee's processes and procedures to ensure that the licensee was evaluating equipment failures appropriately through the use of their maintenance and corrective action systems. The inspectors verified that the licensee implemented procedures governing troubleshooting and evaluation of equipment failures. However, the licensee continued to identify instances in which troubleshooting was initially narrow in scope and not well planned as discussed in Section M1.1 of this report. As a result, the licensee implemented additional actions to improve technical problem solving at the station, which included defining roles and responsibilities, reviewing the system engineering troubleshooting guide, and evaluating the need and availability of technical troubleshooting training. In addition, the licensee planned to review four events which occurred during the startup, including the RCIC turbine overspeed trip problems, and incorporate the results of the review as applicable. This item is closed.

<u>III. Engineering</u>

E2 Engineering Support of Facilities and Equipment

E2.1 Changes in Source Range Neutron Monitoring (SRM) System Design Information Not Incorporated Into the Technical Specifications

a. Inspection Scope (37551)

The inspectors reviewed LLP-98-002, and LaSalle General Procedure (LGP)-1-1, "Normal Unit Startup," Revision 57. In addition, the inspectors interviewed engineering and regulatory assurance personnel.

b. Observations and Findings

On July 22, 1998, the inspectors identified that Technical Specification 3.3.7.6.c regarding the SRM neutron count rate required for withdrawal of control rods during startup was not conservative with respect the current plant design. The note in Step E.1.6.1 of LLP-98-002 explained that a signal to noise (S/N) ratio of 20 to 1 (20:1) was administratively required when the SRM count rate decreased below 3 counts per second (cps) to the minimum SRM count rate of 0.7 cps. A neutron count rate below 3 cps could occur following an extended outage where fewer decay neutrons would be detected by the SRMs. Technical Specification 3.3.7.6.c only required a S/N ratio of 2:1 when using 0.7 cps as the minimum counts required for withdrawal of control rods. As explained below, the licensee had already identified this as an issue during a Safety System Functional Review and was taking appropriate action.

On December 16, 1988, General Electric (GE) issued Service Information Letter (SIL) No. 478 which described the design basis for GE's SRM system and the effects of reducing the SRM Technical Specification minimum count value from 3 cps to 0.7 cps. General Electric engineering personnel had assumed a S/N ratio of 2:1 when the 3 cps minimum SRM count rate was developed and the 2:1 S/N ratio provided a statistical neutron monitoring confidence of 95 percent that the indicated SRM signal was correct. A S/N ratio of at least 20:1 was required to maintain the original level of uncertainty when using 0.7 cps as the minimum SRM count rate. In April 1990, the licensee revised UFSAR Section 7.7.6.1.1.a, "Source Range Monitoring System - Design Bases," to state that a signal to noise ratio of 20:1 was required to reduce the minimum SRM count rate below 3 cps to 0.7 cps for control rod movement. However, the licensee did not revise Technical Specification 3.3.7.6.c which continued to require that the S/N ratio be greater than or equal to 2:1 to reduce the SRM count rate to as low as 0.7 cps.

On February 26, 1997, during a System Functional Performance Review, the licensee identified the S/N ratio discrepancy between Technical Specifications 3.3.7.6.c and 3.9.2 and UFSAR Section 7.7.6.1.1.a and determined that the Technical Specifications were not conservative as written. The licensee revised plant procedures to incorporate the 20:1 S/N ratio requirement. The licensee initially planned to either couple a corresponding Technical Specification revision with the Improved Standard Technical Specifications, or to submit a separate amendment request by the Fall of 1998.

The licensee more recently decided on the second option. In addition, during 1998 the licensee discovered two additional UFSAR items that had not been incorporated in the Technical Specifications. The licensee determined that the items had been tested as required by Technical Specifications, initiated Administrative Technical Requirements to control the items, and planned to submit applicable Technical Specification revision requests in the Fall of 1998. The inspectors determined that the corrective actions were appropriate.

The licensee's failure to derive the Technical Specifications from the analyses and evaluation included in the UFSAR, including amendments, as required by 10 CFR 50.36(b) is a violation (50-373/98019-04(DRP); 50-374/98019-04(DRP)). However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The licensee identified that the SRM neutron count rate required by Technical Specifications for withdrawal of control rods during startup was not conservative with respect the current plant design. The licensee took interim actions to ensure an appropriate count rate during Unit 1 startup and planned to submit a Technical Specification amendment request to resolve the issue. The licensee's failure in 1990 to derive the associated Technical Specification requirement from the analyses and evaluation included in the UFSAR is a Non-Cited Violation.

E4 Engineering Staff Knowledge and Performance

E4.1 Generic Letter 96-06 Issues Remaining at Unit 1 Startup

a. Inspection Scope (37551)

The inspectors reviewed aspects of the licensee's response to Generic Letter (GL) 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," dated September 30, 1996. The inspectors reviewed an operability evaluation related to GL 96-06. In addition, the inspectors also interviewed senior engineering management regarding the timeliness and communication of the resolution of the RR FCV hydraulic line penetrations which had been identified by the licensee as requiring a modification prior to Unit 1 startup in their original GL 96-06 response.

b. Observations and Findings

In a June 4, 1997, letter to the NRC, the licensee committed to implement changes prior to Unit 1 restart regarding the design of RR FCV hydraulic piping to address the potential overpressurization condition described in GL 96-06. The licensee subsequently decided to use an American Society of Mechanical Engineers (ASME) Code, Section III, Appendix F, analysis as a permanent resolution to the potential overpressurization condition. A licensee contractor later determined that the analysis did not meet the requirements of Appendix F because of the physical arrangement of the RR FCV hydraulic lines. However, the contractor did not adequately communicate this information to appropriate licensee personnel, and therefore these personnel were not initially aware of the need to take additional action regarding this issue.

As a result, these additional actions were not completed until July 28, 1998, just three days before Unit 1 restart. Specifically, the licensee completed operability evaluation (OE) No. OE98024, Revision 1, using provisions in ASME Code, Section III, Appendix F, and a fracture mechanics assessment (calculation L-001897, Revision 2) to justify Unit 1 restart without performing FCV hydraulic piping penetration modifications.

The inspectors reviewed the technical justification of OE98024 and did not identify any problems with the calculation itself. However, the licensee's process allowed an operability assessment to be performed using LAP-220-5, Revision 7, Attachment B, "Concern Screening Form," instead of the more rigorous Attachment C, "Operability Assessment Process Form," which required additional reviews. The licensee's management recognized the inspectors' concerns and indicated that a new ComEd corporate procedure would be implemented which would clarify the OE requirements and would ensure adequate reviews of all operability assessments.

In addition, on August 24, 1998, the inspectors identified that a copy of OE No. OE98024, Revision 1, was not maintained in the control room. Although the licensee had removed the requirement to maintain operability evaluations in the control room from their administrative procedures, a file containing several OEs was in the control room which operators thought was being maintained and updated with all current OEs. The inspectors were concerned that the practice of maintaining an unofficial control room file of operability evaluations could lead to incorrect assessments of the operability status of equipment.

On August 28, 1998, during a revision of calculation L-001436, Revision 0, to support a Unit 2 design change, the licensee discovered that the calculation incorrectly assumed a uniform piping configuration for the Unit 1 RHR shutdown cooling suction piping primary containment penetration. The calculation had been performed in support of a design change to install a relief valve to address the potential overpressurization condition identified in GL 96-06. The calculation used carbon steel pipe with a nominal pipe wall thickness of 1.281 inches. However, the pipe transitioned from the carbon steel piping to a stainless steel piping segment with a nominal pipe wall thickness of 0.900 inches within the boundaries of the containment isolation valves. The licensee commenced an evaluation to determine the operability of the Unit 1 RHR shutdown cooling suction piping primary containment penetration and initiated a review to determine the extent of the condition with regards to other penetrations with similar piping transitions. This item is an unresolved item pending the inspector's review of the licensee's operability determination and determination of the extent of the condition (50-373/98019-05(DRP); 50-374/98019-05(DRP)).

c. Conclusions

In one instance, involving RR FCV hydraulic lines, the licensee's resolution to GL 96-06 issues was not timely due to the deficient communications between a contractor and licensee personnel. In another instance, involving RHR shutdown cooling suction piping, the licensee identified that calculations associated with a modification associated with GL 96-06 assumed an incorrect piping configuration. The licensee completed OEs as an initial response to these issues. In addition, the inspectors identified that operators relied upon an unofficial control room file of OEs which was not maintained current.

E4.2 Incorrect Calculation Results in Non-Conservative Flow Biased Scram and Rod Block Setpoints

a. Inspection Scope (37551)

The inspectors reviewed the impact of the licensee's August 22, 1998, incorrect adjustment of the Unit 1 Average Power Range Monitor (APRM) and Rod Block Monitor (RBM) flow converter. The inspectors reviewed plant procedures including LIS-NR-107, "Unit 1 APRM/RBM Flow Converter to Total Core Flow Adjustment," Revision 8, and reference documentation such as the LaSalle Unit 1 Technical Specifications, the UFSAR, and the results from the Unit 1 Cycle 8 Core Operating Limits Report and Reload Transient Analysis.

b. Observations and Findings

On August 22, 1998, instrument maintenance personnel performed a calibration of the APRM/RBM flow converter which provided an input to the APRM flow biased scram, RBM rod block, and APRM flow biased rod block in accordance with LIS-NR-107. On August 23, 1998, a qualified nuclear engineer (QNE) noted that rod block alarms appeared to be set abnormally high and determined that the APRM flow biased rod block and scram setpoints and the RBM setpoints were incorrect. The US entered Technical Specifications LCO action statements and initiated the performance of LIS-NR-107 to establish the correct setpoints.

The licensee subsequently determined that when performing Step E.1.10 of LIS-NR-107, a different QNE failed to provide an accurate core flow value to be used by instrument maintenance personnel to set the output voltage of the flow converter. Also, the licensee did not require independent verification of the QNE's flow value.

The safety significance of the incorrect setpoints for the flow biased APRM scram, RBM rod block, and flow biased APRM rod block was minimal. While in Operational Condition 1, the Technical Specifications required the RBM at or above 30 percent of rated thermal power and the flow biased APRM rod blocks and scram with setpoints in accordance with Technical Specifications Table 3.3-6.2. However, the results from Reload Transient Analysis indicated that an unblocked setting for the RBM rod block was appropriate. Also, the licensee indicated that the flow biased APRM scram was not credited for in the Unit 1 cycle 8 transient and accident analysis.

The inspectors noted that initial corrective actions were appropriate and completed in a timely fashion following identification of the condition. Long term corrective actions planned by the licensee included a review of Technical Specification surveillance procedures used to establish equipment settings to determine if any instances existed of engineering calculations being used which did not require an independent verification. Other actions will be evaluated by the inspectors as part of the associated LER concerning this issue which is due in September 1998.

The licensee's failure to correctly set the RBM setpoints and APRM flow biased rod blocks and scram setpoints within the limits of the Technical Specifications is a violation of Technical Specifications 3.3.6 and 2.2.1, respectively. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII. B.1 of the NRC Enforcement Policy (50-373/98019-06(DRP)).

c. Conclusions

The licensee identified that a QNE had provided an incorrect flow value used to establish the setpoints for the APRM flow biased scram and rod block and the RBM rod block. The licensee's response to this Non-Cited Violation was timely and appropriate and the safety significance of the incorrect setpoints was minimal.

E4.3 Test Director Directs Procedural Steps To Be Performed Out Of Order

a. Inspection Scope (37551)

On August 11, 1998, the inspectors observed the performance of LaSalle Special Test (LST)-97-547, "Unit 1 Pressure Regulation System Startup Test Procedure," Revision 0.

b. Observations and Findings

On August 11, 1998, the inspectors identified that an operator performed a procedural step out of sequence during LST-97-547. Step F.2.9.2 of the procedure required an operator to place a switch on panel 1PA01J to the TEST A position. At the completion of step F.2.14, the inspectors observed that the test director directed the operator to place the switch in the OFF position. This direction did not match the procedure as written. The switch was required to be repositioned to OFF as part of the procedure in a subsequent step, F.2.32. The procedure was a continuous use procedure and Step C.1 of LST-97-547 required that the steps within each subsection be performed by the operators in the order written. In addition, LAP-100-40, "Procedure Use and Adherence Expectations," Revision 14, Step B.3.1 required users of continuous use procedures to perform each step in the sequence specified. In addition, the inspectors noted that the operator did not question the direction to perform the steps out of sequence. However, there were no actual consequences associated with the operator's actions. This failure to follow procedure was not a violation of NRC requirements because it involved non-safety related equipment.

c. Conclusions

The inspectors identified that during the performance of pressure regulation system startup testing, the test director directed an operator to place a switch in the OFF position which was out-of-sequence with the governing procedure steps. The test procedure was designated as a continuous use procedure; however, the test director and the operator failed to adhere to the licensee's requirement to perform continuous use procedural steps in the sequence written and did not obtain a temporary procedure change. There was no actual consequence to this action.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiation Protection (RP) and Chemistry

R4.1 Inadequate Control of Contaminated Area

a. Inspection Scope (71750)

The inspectors observed RP technicians during routine activities. In addition, inspectors observed RP technicians' performance in support of testing activities.

b. Observations and Findings

The inspectors observed the RP technicians verifying that individuals entering the radiologically protected area (RPA) were aware of radiation work requirements and radiological conditions in the plant. Radiation protection technicians challenged individuals entering the RPA regarding the individual's work locations, the work scope, and what radiation work permit (RWP) was being used. The RP technicians also questioned plant workers about the radiation exposure limits based on the RWP and RWP requirements. Technicians also were present at work locations to provide oversight and monitor for changing radiological conditions. On several occasions, RP technicians identified areas with higher dose rates, reminded workers of the high dose areas, and reminded workers to move to areas of lower dose.

However, inspectors identified one instance in which RP technicians did not meet licensee performance expectations. On August 10, 1998, the inspectors observed the performance of LOS-RI-Q3, "Reactor Core Isolation Cooling System Pump Operability and Valve Inservice Tests in Conditions 1, 2, and 3," Revision 29. During the test, a small steam leak developed in a drain line from the RCIC turbine trip/throttle valve at a strainer mechanical joint. The Operations Department field supervisor notified an RP technician of the leakage, and the RP technician arrived and performed contamination surveys of the floor beneath the leaking strainer. The results of the surveys indicated a smearable contamination level of approximately 10,000 disintegrations per minute (dpm) per 100 square centimeters which met procedural requirements for posting as a contaminated area.

The RP technician left the RCIC room without designating another person to control the contaminated area, and turned over to a second RP technician, instructing him to return to the RCIC room to post the area. There were between six and ten people working in the RCIC room throughout the performance of LOS-RI-Q3. The second RP technician returned to the RCIC room, was directed to the leak by the field supervisor, and posted the area around the leak, approximately 1.25 hours after the initial survey. As the second RP technician was leaving, the field supervisor asked if additional contamination surveys were performed to ensure that the extent of the contamination area was determined and that the correct location was posted. The RP technician replied that additional surveys had not been performed. The RP technician then performed additional surveys verifying that the area had been properly posted.

The inspectors were concerned with RP technician performance with regard to the unjustifiable delay in posting the contaminated area and the failure to formally control the area in the interim. The inspectors were also concerned by the lack of thoroughness of the second RP technician in not re-surveying the area to ensure the extent of the contamination area until questioned by the field supervisor. However, individuals in the room were aware of the leak and no personnel were contaminated.

c. Conclusions

Radiation protection (RP) personnel performed well during routine RP support activities. Technicians provided oversight for various maintenance and surveillance activities and ensured that plant personnel were cognizant of the radiological conditions while performing work in the plant. The inspectors identified one instance in which RP technicians were slow in posting a radiologically contaminated area and did not ensure formal control of the area to prevent personnel contaminations in the interim.

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 August 31, 1998. The licensee acknowledged the findings presented and the licensee did not identify that any materials examined during the inspection should be considered proprietary.

PARTIAL LIST OF PERSONS CONTACTED

ComEd

F. Dacimo, Site Vice President
*T. O'Connor, Plant Manager
*G. Campbell, Unit 1 Engineering Manager
*W. Riffer, Nuclear Oversight Manager
*G. Heisterman, Unit 1 Maintenance Manager
D. Sanchez, Site Training Manager
D. Boone, Site Support Manager
*D. Farr, Unit 1 Operations Manager
*P. Barnes, Regulatory Assurance Manager
R. Palmieri, System Engineering Supervisor
*J. Pollock, Support Engineering Supervisor
*E. Connell, Design Engineering Supervisor
*G. Putt, Work Control Supervisor
T. Halliday, Unit 1 Health Physics Supervisor
D. Bowman, Chemistry Supervisor
*R. Stachniak, Nuclear Oversight assessment Manager

* Present at exit meeting on August 31, 1998.

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

Open

50-373/98019-01	NCV	Failure of the licensee to use a procedure appropriate to the circumstance during deenergization of the SAT.
50-373/98019-02	URI	NRC review of inappropriately locked LPCS valve.
50-373/374-98019-03	NCV	Failure of the licensee to verify the load sequencing of "auto-connected loads" as required by Technical Specification Surveillance Requirement 4.8.1.1.2.d.4.a.2.
50-373/374-98019-04	NCV	Failure of the licensee to derive the Technical Specifications from the analyses and evaluation included in the UFSAR, including amendments, as required by 10 CFR 50.36(b).
50-373/374-98019-05	URI	NRC review of engineering calculations related to GL 96-06 response.
50-373/98019-06	NCV	Failure to meet Technical Specifications related to various reactor protection system setpoints.

Discussed or Closed

50-373/98019-01	NCV	Failure of the licensee to use a procedure appropriate to the circumstance during deenergization of the SAT.
50-373/374-98019-03	NCV	Failure of the licensee to verify the load sequencing of "auto-connected loads" as required by Technical Specification Surveillance Requirement 4.8.1.1.2.d.4.a.2.

50-373/374-98019-04	NCV	Failure of the licensee to derive the Technical Specifications from the analyses and evaluation included in the UFSAR, including amendments, as required by 10 CFR 50.36(b).
50-373/98019-06	NCV	Failure to meet Technical Specifications related to various reactor protection system setpoints.
50-373/97006-00	LER	Diesel Generator Testing Did Not Meet Surveillance Requirement Due to Misinterpretation of Technical Specification.
50-373/98009-00	LER	Division III Emergency Diesel Generator Actuated During Removal of the System Auxiliary Transformer From Service Due to Human Performance Error in Failing To Use an Operating Procedure.
50-373/97006-06	URI	Review of licensee troubleshooting practices.

LIST OF ACRONYMS USED

AEER	Auxiliary Electric Equipment Room
APRM	Average Power Range Monitor
ASME	American Society of Mechanical Engineers
CAL	Confirmatory Action Letter
CPS	Counts Per Second
CR	Control Room
DPM	Disintegrations Per Minute
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EMD	Electrical Maintenance Department
EOC-RPT	End of Cycle Recirculation Pump Trip
ESF	Engineered Safety Features
FCV	Flow Control Valve
GE	General Electric
GL	Generic Letter
HRSS	High Radiation Sample System
IRM	Intermediate Range Neutron Monitor
LAP	LaSalle Administrative Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LGP	LaSalle General Procedure
LIS	LaSalle Instrument Surveillance
LLP	LaSalle Special Procedure
LOCA	Loss-of-Coolant Accident
LOP	LaSalle Operating Procedure
LOS	LaSalle Operating Surveillance
LPCI	Low Pressure Coolant Injection System
LPCS	Low Pressure Core Spray
LRP	LaSalle Radiation Protection
LST	Special Test Procedure
MSIV	Main Steam Isolation Valve
NRC	Nuclear Regulatory Commission
NSO	Nuclear Station Operator
OE	Operability Evaluation
PDR	NRC Public Document Room
PIF	Problem Identification Form
PMT	Post Maintenance Test
QNE	Qualified Nuclear Engineer
RPA	Radiologically Protected Area
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling System
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RP	Radiation Protection
RR	Reactor Recirculation
RWP	Radiation Work Permit

SAT	System Auxiliary Transformer
SIL	Service Information Letter
SM	Shift Manager
SRM	Source Range Neutron Monitoring
TDRFP	Turbine-Driven Reactor Feedwater Pump
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
US	Unit Supervisor
VIO	Violation