U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-373/85019(DRP); 50-374/85021(DRP)

Docket Nos. 50-373; 50-374 Licenses No. NPF-11; NPF-18

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: LaSalle County Station, Units 1 and 2

Inspection At: LaSalle Site, Marseilles, IL

Inspection Conducted: June 20 through July 24, 1985

Inspectors: M. J. Jordan

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R. Kopriva

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Approved By: G. Wright, Chief
Reactor Projects Section 2A

8/13/85
Date

Inspection Summary

Inspection on June 20 through July 24, 1985 (Reports No. 50-373/85019(DRP); 50-374/85021(DRP))

Areas Inspected: Routine, unannounced inspection conducted by resident inspectors of licensee actions on previous inspection findings; operational safety; surveillance; maintenance; Licensee Event Reports; unit trips; annual emergency preparedness exercise; headquarters requests; organization and administration; design change and modification program; and followup of IE Bulletin 84-03. The inspection involved a total of 274 inspector-hours onsite by four NRC inspectors including 60 hours onsite during off-shifts.
Results: Of the twelve areas inspected, no deviations or violations were identified in ten areas; two violations of minimum safety significance were identified in the two remaining areas (Inadequate procedures - Paragraphs 3 and 4; failure to have procedures - Paragraph 7).

DETAILS

1. Persons Contacted

   *G. J. Diederich, Manager, LaSalle Station
   *R. D. Bishop, Services Superintendent
   C. E. Sargent, Production Superintendent
   *D. Berkman, Assistant Superintendent, Technical Services
   *W. Huntington, Assistant Superintendent, Operations
   *M. Jeisy, Quality Assurance

   The inspectors also talked with and interviewed members of the operations, maintenance, health physics, and instrument and control sections.

   *Denotes personnel attending the exit interview held on July 24, 1985.

2. Licensee Action on Previous Inspection Findings

   (Closed) Open Item (373/83046-01(DRS)): The licensee was to perform the Engineered Safety Feature reset controls test. The test was performed in November 1983. This subject is discussed in Reports 373/83052 and 373/83054.

   (Closed) Violation (373/83054-01; 374/83057-01(DRS)): The licensee failed to test all containment isolation valves that might reposition as a result of ESF reset signals. This followup testing was completed in February 1984.

   (Closed) Open Item (373/85-07-07(DRP)): The licensee was to revise LER 373/84-091 to clarify the reason for reporting. This revision has been received.

   (Closed) Violation (373/84-26-01(DRP)): Failure to post a Unit 1 Reactor Building high radiation area. Licensee corrective action was identified in Report 373/84-26.

   (Closed) Violation (373/84-26-02(DRP)): Failure to post a contaminated area. Licensee corrective action was identified in Report 373/84-26.

   (Closed) Violation (373/84-28-01; 374/84-36-01(DRP)): Operations problems resulting in the Standby Gas Treatment Systems being inoperable. The licensee's corrective actions as documented in a letter dated April 19, 1985 from Cordell Reed to James Taylor are considered adequate.

   (Closed) Violation (373/84-33-02; 374/84-40-02(DRP)): Failure to provide timely issuance of revised procedures and drawings for modifications. The licensee revised the administrative controls for modifications to improve document processing times.

(Open) Violation (373/84-23-03; 374/84-30-04(DRP)): The licensee was to take corrective actions for procedure problems with Reactor Protection System (RPS) bus transfers and performing surveillances. The inspector noted that the required procedure revisions are not completed.

(Closed) Violation (373/83052-01(DRP)): Failure to perform an adequate engineering review in the area of ESF reset controls. The action remaining on this item is to track completion of the valve control modifications which is being tracked by open item 373/84005-01.

No deviations or violations were identified in the review of this program area.

3. Operational Safety Verification

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the inspection period. The inspector verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of Units 1 and 2 reactor buildings and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance. The inspector by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspector observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls.

During the month of July 1985, the inspector walked down the accessible portions of the following systems to verify operability:

Unit 1 and 2 Standby Gas Treatment Systems
Unit 1 and 2 Standby Liquid Control Systems
Unit 1 and 2 RHR Service Water Pump Rooms
Unit 1 and 2 Emergency Diesel Generators
Unit 1 and 2 125 Volt and 250 Volt Batteries
Unit 1 and 2 Division I & II Switchgear and Auxiliary Electric Rooms

On June 19, 1985, at 10:50 a.m. (CDT), Unit 1 experienced a turbine trip at approximately 160 MWE from high reactor vessel water level. At 10:45 a.m. the "B" reactor vessel level indicator failed downscale while the "B" level indicator was providing inputs for level control. With reactor vessel level indication downscale, the motor driven feedwater pump tried to make up for (indicated) low reactor level. The unit was operating with one feedwater pump (motor driven) at the time because of the low power level. The feedwater pump increased water level and the main steam turbine and motor driven feedwater pump tripped on high level. Three (3) bypass

valves opened controlling reactor pressure. The operator inserted control rods to reduce reactor power. The reactor did not scram. No Emergency Core Cooling Systems (ECCS) initiated. All systems functioned as expected. The unit 1 generator was returned to the grid at approximately 12:00 p.m. on June 19, 1985.

On June 20, 1985 at 2:40 a.m. (CDT), the LaSalle Unit 1 turbine/generator was taken off line by normal shutdown procedure because the mainsteam turbine overspeed trip test failed to function properly. At 1:00 a.m. while at 160 MWE, the Unit 1 operators were performing a routine mainsteam turbine mechanical overspeed trip test. The turbine trip function failed to operate properly. To protect the mainsteam turbine, power was reduced and the turbine/generator taken off line. The reactor power was reduced to approximately 8% with one (1) bypass valve open controlling reactor pressure. A faulty solenoid was replaced in the turbine overspeed test line and the mechanical overspeed trip test performed satisfactorily at 8:30 a.m.. There were no ECCS system initiations. All systems functioned as expected. The unit generator was returned to the grid at approximately 10:15 a.m. on June 20, 1985.

On June 25, 1985, at 3:06 p.m. (CDT), with Unit 2 in Cold Shutdown, a Group I isolation and reactor building ventilation isolation signals were received. The 2A recirculation pump also tripped. The cause was determined to be a plant voltage dip caused by a failure of a non safety related 480 volt transformer that feeds cooling coils to the main turbine area ventilation (Bus 237x). The cause of the failure is believed to be a short between phases. No fire or damage to safety related equipment occurred. The licensee is replacing the transformer.

On June 27, 1985, as followup to the reverse piped Emergency Core Cooling System (ECCS) actuation switch problem (Inspection Report 373/85023; 374/85018), the inspector walked down the 1H22-P026 Division I instrumentation rack. The inspector checked the instrumentation piping and valve identification for proper connection and labeling. The inspector noted that the instruments appeared to be correctly piped but that various instrumentation connection points and the labeling of valves were confusing. Instruments were connected from the low side of the instrument to the high pressure labeled valves and piping and vice versa. A subsequent spot check of other instrumentation racks in the plant found this to be a typical problem. This concern was expressed to the licensee. The licensee plans to correct the instrument connection point and valve labeling problems. Completion of this action will be tracked as open items (373/85019-01; 374/85021-01(DRP)).

On July 1, 1985, at 2:42 p.m. (CDT) with Unit 2 in Cold Shutdown, a Division I Group VI primary containment isolation signal was received. This closed valves 2E12-F008 and 2E12-F053A which isolated the Shutdown Cooling System. A review of the event indicated that the licensee had initiated a system outage for correcting the mispiped Residual Heat Removal (RHR) System pump suction high flow isolation switches. The equipment outage failed, however, to include a jumper to bypass the

noted isolation function. The licensee issued a temporary system change (2-872-85) to install the required jumper. Shutdown cooling was reestablished at 4:30 p.m.. 10 CFR 50, Appendix B, Criterion XIV, as implemented by CECo Quality Assurance Program, Quality Procedure No. 14-51, requires, in part, that measures be established to indicate the operating status of systems or components to prevent inadvertent operation.

Contrary to the above, the Unit 2 shutdown cooling portion of the RHR System isolated on July 1, 1985 due to an inadequate procedure (equipment outage) not specifying the installation of a required jumper to remove the system high suction flow isolation switch from service. This is considered to be a violation (374/85021-02A(DRP)). During the review of the above event, the inspector noted that the Unit 2 Nuclear Station Operator's (NSO) log and the Shift Engineer's (SE) log failed to document whether or not the abnormal operating procedure for loss of shutdown cooling (LOA-RH-01) was utilized during the event. This example of poor log entries is considered an isolated case at this time. The licensee has been advised of this concern.

On July 17, 1985, at 5:35 p.m. (CDT), while performing a special test on Unit 1 to confirm the operability of ECCS instrumentation, the licensee found the four RHR shutdown cooling high suction flow isolation switches piped backwards. The special test was being performed on Unit 1 as followup to a recent event on Unit 2 that rendered all ECCS systems inoperable from June 5, 1985 to June 10, 1985. Both units were in Cold Shutdown. The piping problems occurred during the installation of environmentally qualified instrumentation. The installation was performed on Unit 1 during February and March of this year. Unit 1 had been operating since April 7, 1985 until shutdown for minor repairs on July 12, 1985. The licensee evaluated the remaining ECCS instrumentation and found no additional problems. This event will be addressed in a special inspection report (373/85023(DRP); 374/85018(DRP)).

Unit 2 went critical at 10:25 p.m. (CDT) on July 20, 1985 as part of a normal startup. The unit returned to service following a maintenance outage, which began on February 28, 1985, to install environmentally qualified instrumentation and conduct the 18 month surveillances required by Technical Specifications. As of July 24, 1985, the unit was holding at 55% power to perform control rod adjustments.

On July 22, 1985 Unit 1 received a low reactor water level scram and a Division II RHR shutdown cooling isolation after performing a hydrostatic test and valving the Standby Liquid Control System (SBLCS) back into service. The unit was in Cold Shutdown at the time. The licensee had performed an operational test of the squib valves on the SBLC system and tested the replacements. Upon opening the isolation valve too rapidly, the pressure surge in the injection line to the reactor vessel caused a perturbation to the reactor vessel level instrument line which taps off the SBLC injection line. This gave a false low level signal and caused the scram and isolation on low level. All systems functioned normally. The inspector expressed concern to the licensee about the continuing

problem of personnel causing plant perturbations of this type while returning equipment to service. A violation will not be issued for this event since the licensee's corrective actions will be followed with the actions being taken for violation 374/85017-04(DRP).

On July 23, 1985, with Unit 2 at approximately 35% power, the "E" and "N" mainsteam system safety relief valves went full open and then closed. The licensee was performing a Special Test (LST 85-103) with the assistance of the valve vendor representatives to test the valve setpoint monitoring equipment. The testing is intended to check the pressure setpoint of each safety relief valve by slightly opening the valve and is normally accomplished with reactor pressure between 850 to 900 psig. Due to ongoing Control Rod Scram Time Testing, the licensee elected to attempt the test at 955 psig. The testing of the first four valves was completed satisfactorily. The fifth and sixth valves ("E" and "N"), however, went full open when tested. Discussion between the licensee and the valve vendor representative determined that the flow dynamics upon initial lift caused the valves to fully open. The method used to eliminate the flow effect is to test at a lower vessel pressure. The licensee discontinued the testing and intends to complete it just prior to a future shutdown. This testing is utilized by the licensee to comply with Technical Specification testing requirements and as a means of determining which valves require maintenance.

No other deviations or violations were identified in this area.

4. Monthly Surveillance Observation

The inspector observed the Unit 1 Main Steam Isolation Valve monthly closure functional test per procedure LOS-RP-M1. The inspector also observed portions of a special test, LST 85-102, being performed on Unit 2 to evaluate an alternate method of decay heat removal. The inspector verified the use of technically adequate procedures, conformance to Technical Specifications, and satisfactory system performances.

The inspector observed the semi-annual operability test of the 1B diesel generator (LOS-DG-SA3). The inspector verified the use of technically adequate procedures, conformance to Technical Specifications, and satisfactory operation of the diesel generator.

The inspector observed the calibration of the low reactor vessel water level recirculation pump trip switch (2B21N036D) being performed in accordance with procedure LIS-NB-203. The inspector verified the use of technically adequate procedures, conformance to Technical Specifications, and the use of proper radiological controls. The inspector also noted that the test equipment calibration was current and that the instrument was found to be within allowed tolerances.

At 10:45 p.m. (CDT) on June 26, 1985 while performing a Drywell Floor Bypass Leakage Test (LTS-300-10) on Unit 2, the Reactor Building Closed Cooling Water System (RBCCW) and the Primary Containment Ventilation (PCV) System isolated due to high drywell pressure. The test procedure

was in error. The procedure intended to bypass all isolation logic as part of the test. The procedure failed, however, to bypass the isolation logic for the noted systems. The licensee was issuing a change to the procedure.

10 CFR 50, Appendix B, Criterion XIV as implemented by CECo's Quality Assurance Program, Quality Procedure No. 14-51, requires, in part, that measures be established to indicate the operating status of systems or components to prevent inadvertent operation.

Contrary to the above, the Unit 2 RBCCW and PCV systems were inadvertently isolated during a planned test because the System Test Procedure (LTS-300-10) failed to take out-of-service all the appropriate equipment. This is considered to be a violation (374/85021-02B(DRP)).

No other deviations or violations were identified in this program area.

5. Monthly Maintenance Observation

The inspector observed the repair of the limitorque operator for the Unit 1 suppression pool spray valve 1E12F027B (Work Request L50218). The inspector verified the use of technically adequate procedures, appropriate receiving inspection markings on replacement parts, and proper lubrication and reassembly of the operator.

The inspector also verified the safety precautions being implemented by the licensee for replacement of the vent valve for the Unit 2 hydraulic control unit for rod 50-31. This replacement required the use of a freeze seal per procedure LMP-GM-14. Due to the possibility of losing the ice plug and subsequent uncontrolled draining of the reactor vessel, the inspector was concerned about the backup means available to isolate a leak. After some discussion, the licensee staged a rubber plug to be inserted into the pipe in case of a leak. The inspector noted that the procedure, LMP-GM-14, did not contain a mandatory requirement for some form of emergency closure device when freeze seals are used as an isolation boundary. The licensee has agreed to revise the procedure. Completion of this action will be tracked as an open item (374/85021-03(DRP)).

Following replacement of the vent valve for the hydraulic control unit for Unit 2 control rod 34-35 (Work Request L50198), the inspector observed the inservice pressure test of the piping assembly. The inspector verified the use of technically adequate procedures, compliance with appropriate radiological controls, compliance with Technical Specifications and the ASME code, Section XI. The inspector noted appropriate Quality Control and ASME code (State of Illinois) inspectors witnessing the testing. The inspector noted satisfactory performance of the testing activities with the following weaknesses:

a. The testing equipment relief valve setting was not documented by a tag on the valve or documentation in the test documentation data sheets. The adequacy of test boundary protection could thus not be readily confirmed. This will be tracked as an open item (373/85019-02(DRP); 374/85021-04(DRP)).

b. The radiological controlled area access point did not have a frisking station. Accordingly, any contaminated personnel could easily spread the contamination to other plant locations. Review determined that the background radiation levels were too high to locate a frisker in the area. The Region III radiological controls inspector will evaluate any further action the licensee may need to take concerning this item.

These weaknesses were identified to licensee management for evaluation.

The inspector observed a modification made to the 2B21N036D reactor vessel level switch (Yarway) that removed three unused magnetic switches to improve instrument response (Work Request L47639). The three unused magnets caused the instrument to show a seven inch level error as the instrument indication mechanism passed each magnet. Removal of the magnets eliminated this problem.

The inspector verified the use of technically adequate procedures and proper radiological controls. The inspector noted a Quality Control hold point to verify final instrument wiring. The inspector also verified that the final instrument wiring agreed with the drawing requirements and that the instrument was satisfactorily returned to service. During a review of the work package, the inspector noted that the package contained a seismic evaluation for the modified instrument but that a formal change evaluation to the guidelines of 10 CFR 50.59 had not been performed. This concern was discussed with the licensee and corrective action was initiated. The licensee completed the appropriate 10 CFR 50.59 review.

On June 25, 1985 the licensee notified the inspector of a potential generic problem with the Crosby Main Steam System Relief Valves. Two valves had been replaced during the current Unit 2 outage. Upon disassembly, the nozzle ring set screw in each valve was found to be broken. The licensee subsequently replaced all of these set screws in the Unit 2 valves. Six additional valves were noted to have broken nozzle ring set screws. The nozzle ring had moved a maximum of three notches from the original setting on seven of the eight valves. The licensee conducted an evaluation to determine the safety significance of this problem as well as the root cause. The cause is believed to be a machining problem that created a notch sensitive area in the outer diameter of the set screw.

A sharp notch was created in lieu of a smooth radius that results in eventual failure of the set screw. The final 1 1/4 inch of the set screw breaks away which would allow free movement of the nozzle ring. The replacement set screws were received with a smooth radius that is expected to eliminate the failure problem. The set screws are tempered stainless steel, Grade 416.

The safety significance of the nozzle ring movement was determined to require the nozzle ring to move a sufficient number of notches such that it would act as a false valve seat and prevent the valve from closing fully. At LaSalle, this movement would have to be approximately eight

notches toward the seat. The maximum movement noted was three notches. Accordingly, the licensee considers the potential for a simmering valve to be minimal. The licensee inspected the Unit 1 valves during a July 1985 outage and found eight of the set screws broken. All set screws were replaced. The maximum number of notches moved on Unit 1 was noted to be five.

On July 7, 1985 at the completion of routine venting of the Hydraulic Control Unit (HCU) for the Control Rod Drives (CRD), the control room operator noticed that control rod 34-35 was drifting out of the full-in position "00" at a velocity of approximately 1 inch/second. An insert command was initiated when the drifting rod approached position "12" which resulted in a normal insertion of the rod to position "00". Once again, the drive drifted out after reaching the full-in position instead of staying at position "00". As the rod passed position "24", a normal withdrawal command was initiated.

The drive appeared to operate normally with the expected withdrawal velocity of approximately 2-3 inches/second. The rod was cycled several more times with similar results of the rod drifting. A full stroke single rod scram was initiated and no subsequent anomalies were detected.

The station contacted General Electric (GE) for potential causes and recommendations. Several tests were conducted and some valves replaced on the HCU. The conclusion, based on the tests, was that the most probable cause for the drifting rod was a stuck collet on the CRD due to foreign material in the collet assembly.

Recommendations for correcting the problem were as follows:

1. Flush all other CRDs in accordance with GE Service Information Letter (SIL) 310. The sustained withdrawal signal may be reduced to 15-30 seconds minimum.

2. Flush CRD 34-35 per SIL 310 for a total of 100 cycles. Conduct the collet friction test in accordance with GE's test procedure with the HCU valves V120 and V123 closed. Record both the delta-P traces and withdrawal stall flows.

3. Remove and inspect the HCU (34-35) transponder card and valve V122.

4. Remove CRD 34-35 at the next outage for inspection.

5. Procedures defined in SIL 292 and SIL 292 Supplement 1, should be followed in the unlikely event of inadvertent rod withdrawal.

The station completed the recommendations listed except for item 4 which will be completed during the next refueling outage and declared the rod operable.

The inspector observed portions of the flushing of the control rod drives being performed in accordance with procedures LLP 85-15 and LOS-RD-SR3. This flushing was performed as one of the corrective actions recommended by GE in their Service Information Letter (SIL) 310.

No deviations or violations were identified.

6. Licensee Event Reports

Through direct observations, discussions with licensee personnel, and review of records, the following Licensee Event Reports (LERs) were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications.

373/85043-00 - Chlorine Detector Actuation. The control room ventilation train which was in standby mode received a spurious isolation signal. Dampers were already closed so no ventilation change to the control room occurred. The signal was reset satisfactorily.

373/85039-00 - Ammonia Detector Actuation of Reactor Building Ventilation System. The ammonia detector was found out of calibration. Recalibration of the ammonia detector corrected the problem.

373/85044-00 - Chlorine Detector Actuation. The control room ventilation isolated due to a spurious chlorine detector actuation. The cause could not be determined. Potential cause was radio frequency interference which the licensee is investigating.

374/85028-00 - Scram on Low Control Rod Drive (CRD) Pressure. The procedure did not alert the operator of the condition of the plant so when the mode switch was moved to the startup position, a scram occurred. A violation was issued to the licensee in Inspection Report 374/85-17. The unit was in Cold Shutdown at the time.

374/85024-00 - Group I Isolation from Low Condenser Vacuum. The procedure did not alert the operator of the condition of the plant so when resetting the turbine, the isolation occurred. A violation was issued to the licensee in Inspection Report 374/85-17. The unit was in Cold Shutdown at the time.

No other deviations or violations were identified.

7. Unit Trips

On June 29, 1985, at 8:15 a.m. (CDT) the reactor operator manually scrammed Unit 1 from approximately 95% power by placing the mode switch in the shutdown position. While swapping Control Rod Drive (CRD) pumps, the CRD flow was lost and after two accumulator trouble lights came up in the control room, the unit was scrammed. The "B" pump was taken out of service for maintenance on an oil filter and the "A" pump tripped on low

suction pressure. The "B" pump was restarted but did not indicate flow and while trying to start either pump, the accumulator lights came up in the control room which required the manual scram to be initiated. All systems functioned as expected. A Group 6 and 7 isolation occurred when the reactor level got down to 12.5 inches. No other ESF actuations occurred. An Unusual Event was declared at 8:26 a.m. because Technical Specification 3.1.3.5.a required a shutdown. The Unusual Event was terminated at 9:06 a.m.. The licensee determined that the "A" pump was air bound which caused it to trip and that the "B" pump indication of no flow was due to a leaking check valve on the discharge of the pump. The unit was returned to power on June 30, 1985 at approximately 3:30 a.m. The licensee did not have a procedure for transferring CRD pumps while at power. Discussions of the difficulty of transferring CRD pumps with control room personnel indicated a procedure was needed. Transferring CRD pumps has been a problem in the past. This scram possibly could have been avoided if the past problems would have caused the licensee to prepare a procedure for proper transferring of the CRD pumps. Technical Specifications 6.2.A.3 requires detailed written procedures be "prepared, approved, and adhered to..... for actions to be taken to correct specific and foreseen potential malfunctions of systems or components...."

Contrary to the above, the licensee failed to prepare and issue a detailed procedure for shutting down one CRD pump and starting the other pump at full reactor power. This possibly could have prevented a reactor scram. This is considered a violation (373/85019-03(DRP)).

No other deviations or violations were identifed.

8. Annual Emergency Preparedness Exercise

On July 11, 1985 the licensee conducted the annual general station emergency preparedness exercise. The exercise was an unannounced emergency drill that included licensee personnel onsite as well as at the Emergency Offsite Facility (EOF) and the Corporate Command Center. A team of NRC observers witnessed the exercise. Due to the unannounced nature of the exercise, the Resident Inspectors participated in the drill for approximately four hours. An evaluation of the licensee's performance during the exercise will be documented in Inspection Report (373/85011; 374/85011).

9. Headquarters Requests

The inspector was requested to review the licensee's actions in response to several control rod movement errors at other power plants in the past year (TI 2515/67). The inspector reviewed the licensee's startup, shutdown, and power change procedures as well as the abnormal operating procedures for mispositioned control rods. This review was conducted to provide information to NRC headquarters regarding the adequacy of the licensee's controls for control rod movement. The inspector noted that the licensee's procedural controls and training program appear to be adequate with the exception of the guidance for use of the "Continuous Insert" mode of the Reactor Manual Control System. The inspector could

find no procedural guidance as to when this feature should be utilized. The Station Nuclear Engineering personnel were notified of this concern. The licensee considers that the general guidance in all rod movement procedures to strictly adhere to the approved sequence is adequate. Each specific rod pattern sequence provided to the operators also has restrictions on the use of the "Continuous Insert" function. The inspector has no further concern in this area at this time.

No deviations or violations were identified.

10. Organization and Administration

The inspector attended the meeting the licensee's management had with the first line supervisors to clarify their expectations of the first line supervisors. The meeting clearly defined the role of the first line supervisors and the actions expected of them. These included such items as accepting responsibility for the performance and conduct of workers; providing feedback to the supervisor; followup to ensure work gets accomplished; monitoring the performance of subordinates, including direct observation; and providing guidance as necessary, etc. The inspector attended this briefing for operations, technical staff supervisors, and the mechanical maintenance staff. The briefing was conducted by the department heads and attended by one of the senior site management personnel (Superintendent or above). These meetings were the result of a commitment made in an Enforcement Conference on June 24, 1985.

11. Design Change and Modification Program

On July 15, 1985 the inspectors held meetings with Commonwealth Edison Company's Station Nuclear Engineering Department (SNED) and Sargent and Lundy in reference to Engineering Change Notices (ECNs) for LaSalle Units 1 and 2. The meetings and review of the ECNs was prompted by a closed ECN No. 568 for Unit 1 pertaining to relocation of several safety related temperature sensors. As per a note on the ECN, the change applied to Unit 2 also and was never completed. This resulted in several Limiting Conditions for Operation (LCOs) being violated for Unit 2. The meetings and ECN review was intended to identify any other ECNs listing work to be performed on one particular unit with the change applicable to both units. Approximately one hundred mechanical and electrical ECNs were reviewed. Of those ECNs reviewed, none were found to contain similar application to both units. Preliminary results indicate that ECN No. 568 was a unique incident and not wide spread. Further results are pending. Documentation of the final results will be addressed in a future report.

12. Followup of IE Bulletin 84-03: Refueling Cavity Water Seal

On August 24, 1984, the NRC issued IE Bulletin (IEB) 84-03 to all power reactor facilities. The IEB, which described the events surrounding a refueling cavity water seal failure at the Haddam Neck facility, required licensees to evaluate the potential for and consequences of a seal failure and submit a summary report supporting their conclusions.

On November 19, 1984, the licensee submitted the required report. In this report, the licensee provided a description of the design of their seal system, their postulated worst case seal failure, the capacity of available makeup systems, an assessment of no fuel damage, and a description of alarms available. Procedures in place were indicated to be adequate to address seal failure concerns.

During the inspection, the inspector reviewed the licensee's response and discussed the bulletin and related issues with the licensee's staff with the following results:

a. The licensee does not use inflatable rubber seals to retain water in the reactor refueling cavity. A permanently installed bellows seal is used which, on total failure, will result in a small leak rate (185 gpm) limited by a backup seal arrangement. This allows ample time to put any fuel in the process of relocation to a safe place.

b. The spent fuel pit to reactor cavity gate is installed whenever channeling is being done in the fuel preparation machine. This is to assure that a reactor cavity drain down situation would not leave fuel exposed that is in the process of channeling.

c. With the fuel handling limitation in b., above, the relative elevations of the spent fuel pit, the reactor core, and the seal are such that with a seal failure and cavity draindown to the level of the seal, only fuel suspended from either the manipulator crane or the spent fuel handling crane could be uncovered. All remaining active fuel would remain covered to ensure adequate cooling.

d. Procedures are in place directing that fuel suspended from either of the aforementioned cranes be placed in an appropriate location to prevent uncovery. These actions could be completed before damage occurs or radiation levels become excessive as the refueling areas in containment and in the spent fuel pit are continuously manned whenever fuel is being transferred or suspended from a crane.

e. The spent fuel pit does not have any drains and potential siphons are defeated by anti-siphon valves such that no inadvertent valve opening or pipe failure can not result in draining the spent fuel pit below the level of active fuel.

f. A fuel pool level alarm and other alarms as well as direct observation are available to initiate mitigating actions on a loss of pool inventory. The abnormal operating procedure for loss of level appears to adequately address the necessary protective actions including (1) safe storage of fuel, (2) inventory makeup, and (3) evacuation of high radiation areas.

g. The licensee has also responded to INPO concerns in this area in a memorandum to B. B. Stephenson from G. J. Diederich, dated April 30, 1985. This included an evaluation of other possible drain paths. It appeared to the inspector that all items identified in the memorandum were adequately addressed.

Based on the above, the inspector concluded that the issue of loss of refueling system water inventory is adequately resolved.

No violations or deviations were identified.

13. Regulatory Improvement Program Meeting

On July 16, 1985, a meeting was conducted between CECo and Region III management. The purpose of the meeting was to discuss additional aspects of the licensee's Regulatory Improvement Program (RIP) which were identified during the June 24, 1985 RIP meeting. This meeting was part of the continuing series of management meetings aimed at improving licensee's regulatory performance and enhancing communications between the NRC and CECo.

14. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 3 and 5.

15. Exit Interview

The inspector met with licensee representatives (denoted in Paragraph 1) throughout the month and at the conclusion of the inspection period and summarized the scope and findings of the inspection activities. The licensee acknowledged these findings. The inspector also discussed the likely informational contents of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.