U.S NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-373/89023(DRP); 50-374/89022(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, Illinois

Inspection Conducted: October 24 through December 7, 1989

Inspectors: R. Lanksbury
R. Kopriva

Approved By: J. M. Hinds, Jr., Chief
Reactor Projects Section 1B

01-05-90
Date

Inspection Summary

Inspection from October 24 through December 7, 1989 (Report No. 50-373/89023 (DRP); No. 50-374/89022(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of licensee action or previously identified items; operational safety; surveillance; maintenance; licensee event reports followup; ESF system walkdown; training; security; report review; cold weather preparation; and evaluation of licensee self assessment capability.

Results: Of the eleven areas inspected, no violations were identified in eight areas. In the remaining areas, six examples of a violation were identified. During this inspection period, the licensee was continuing with the Unit 1 refueling outage. Housekeeping in most areas was good. The number of Emergency Notification System calls had decreased from those identified in the last report period. Within this report period, violations were noted in the area of procedural adherence (refer to Paragraphs 3 c., e., g., 4 a., e., and 5 a.). In most cases, the safety significance was minimal, but the events caused considerable amounts of rework, clean up, and increased exposure to personnel. The items ranged from improperly erected scaffolding to several thousand gallons of water spilled in the drywell. The multiple examples of violations gives rise to a concern regarding potential programmatic problems pertaining to procedural adherence.

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DETAILS

1. Persons Contacted

   *G. J. Diederich, Manager, LaSalle Station
   *W. R. Huntington, Technical Superintendent
   *J. C. Renwick, Production Superintendent
   *J. V. Schmeltz, Assistant Superintendent, Operations
   J. Walkington, Services Director
   T. A. Hammerich, Regulatory Assurance Supervisor
   W. Betourne, Quality Assurance Supervisor
   *W. J. Marcis, Site BWR Engineering Supervisor
   *J. Roman, Resident Engineer, Illinois Department of Nuclear Safety
   *J. Borm, Quality Assurance
   *J. Thunstedt, Technical Staff
   *J. Ahlman, Regulatory Assurance
   *D. Crowl, Regulatory Assurance

   *Denotes personnel attending the exit interview on December 7, 1989.

   Additional licensee technical and administrative personnel were contacted by the inspectors during the course of the inspection.

2. Licensee Action of Previously Identified Items (92701)

   (Closed) Violation (No. 374/89019-01): This violation was issued for not adhering to administrative procedures pertaining to temporary system changes and control of contractors. The result was that a contractor cross-tied the station air system and clean condensate water system which resulted in flooding the Unit 2 main generator. The inspector has reviewed the licensee's corrective actions and finds these actions adequate. This item is closed.

   (Closed) Violation (No. 374/89019-03): This violation was for not having adequate procedures of a type appropriate to the tasks being performed and for the task(s) to be accomplished in accordance with those procedures. On August 13, 1989, the licensee attempted to line up the common Reactor Building Closed Cooling Water (RBCCW) heat exchanger from a Unit 2 line up to a Unit 1 line up without having an adequate or approved procedure. This resulted in overfilling the RBCCW expansion tank. The inspectors have reviewed the licensee's corrective actions and finds them adequate. This item is considered closed.

   (Closed) Violation (No. 373/88022-02; No. 374/88021-05): Failure to have adequate design control measures in place to verify the results of the contractor performed Unit 2, Cycle 2, stability decay ratio calculations. The licensee's corporate office committed to conduct detailed technical review meetings with the fuel vendors on each reload design. In addition, the licensee committed to having a technical reviewer participate in QA design control audits of the fuel vendors. Furthermore, the Office of Nuclear Reactor Regulation (NRR) has indicated that decay ratio calculations will no longer be used as a basis to determine the Technical Specification changes that are issued for each core reload. These items are closed.

(Closed) Violation (No. 373/88022-03A&B; No. 374/88021-06A&B): a) Procedure LOA-RR-07, Revision 5, did not include guidance to manually insert control rods to or below the 80 percent rod line using the plants prescribed control rod shutdown insertion sequence prior to attempting to restart a recirculation pump. b) Procedure LOA-RR-07, Revision 5, did not direct the operator to perform various required Technical Specification surveillances contained in Procedure LOS-RR-SR1 within the required time frame. The inspector reviewed the following procedures against NRC Bulletin 88-07, Supplement 1, Power Oscillations in Boiling Water Reactors (BWRs), and the Technical Specifications:

- LOA-RR-06, Revision 8, Loss of Recirculation Flow-Single Pump
- LOA-RR-07, Revision 8, Reduction of Recirculation Flow-Both Loops
- LOA-RR-09, Revision 2, Core Instability Protection
- LOS-RR-SR1, Revision 4, Thermal Hydraulic Stability Surveillance

The inspector also interviewed several Shift Engineers to determine their understanding of implementing these procedures. This review, as well as the interviews, indicated that the licensee had resolved the violations. These items are closed.

3. Operational Safety Verification (71707)

a. The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection period. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of Unit 1 and 2 reactor, auxiliary, and turbine buildings were conducted to observe plant equipment conditions. These tours included checking for potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for equipment in need of maintenance. The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan. This included verification that the appropriate number of security personnel were on site; access control barriers were operational; protected areas were well maintained; and vital area barriers were well maintained. The inspector verified the licensee's radiological protection program was implemented in accordance with the facility policies and programs and was in compliance with regulatory requirements.

b. The inspectors performed routine inspections of the control room during off-shift and weekend periods; these included inspections between the hours of 10:00 p.m. and 5:00 a.m. The inspections were conducted to assess overall crew performance and, specifically, control room operator attentiveness during night shifts. The inspectors also reviewed the licensee's administrative controls regarding "Conduct of Operations" and interviewed the licensee's security personnel, shift supervisors and operators to determine if shift personnel were notified of the inspectors' arrivals onsite during off-shifts.

The inspectors determined that both licensed and non-licensed operators were attentive to their duties, and that the inspectors' arrivals on site appeared to have been unannounced. The licensee has implemented appropriate administrative controls related to the conduct of operations. These include procedures which specify fitness for duty and operator attentiveness.

c. On October 19, 1989, at approximately 10:00 p.m. (CST), the Unit 1, Division 2, 125 volt DC battery was crosstied to Unit 2, Division 2, 125 volt DC battery in order to allow the Unit 1, Division 2, 125 volt DC battery charger to be de-energized and taken out-of-service. The Unit 1, Division 2, charger was being taken out-of-service to install a temporary system change to provide it a source of power while its normal power supply was de-energized. The Unit 1, Division 2, 4160 volt Engineered Safety Feature (ESF) Bus 142Y was being de-energized to install modifications. The temporary power source for the Unit 1, Division 2, 125 volt DC charger would prevent allowing the battery to discharge or having to leave the battery crosstied to Unit 2. This would allow a longer period of time to complete the modification work. At 10:25 p.m., the Unit 1, Division 2, 125 volt DC battery charger was taken out-of-service.

On October 20, 1989, at 12:30 a.m., Equipment Operators (EO's) were instructed to take Bus 142Y out-of-service. At 1:02 a.m., when Bus 142Y was de-energized the following occurred; (1) Unit 2, Division 2, battery charger amperage increased to approximately 80 amps; (2) a negative 125 volt DC ground occurred and; (3) Unit 1 Reactor Building Equipment Drain Tank (RBEDT) level indication was lost.

At this time the SE determined that LaSalle Operating Procedure LOP-DC-05, 125 Volt DC System Division 2 Ground Location and Isolation, was not completely applicable for the condition that the system was in at the time because the Division 2 DC buses were crosstied. The SE knew a negative 125 volt DC ground existed.

The SE and the Shift Control Room Engineer (SCRE) using a key diagram (a drawing identifying the loads fed from a particular bus) for Unit 1, Division 2, 125 volt DC bus 112Y, and the Technical Specifications, determined which DC breakers could be opened to isolate the ground.

An extra Shift Foreman (SF) instructed an equipment operator to open the breakers, including breaker No. 8. The Standby Gas Treatment System (SBGT) breaker No. 8 was not one of the breakers indicated to be opened on the key diagram. The extra SF determined that this breaker could be opened because Unit 1 SBGT was out-of-service and deenergized at this time. He failed to recognize that the logic for Unit 1 SBGT initiation also provides an initiation signal for Unit 2 SBGT system.

At 1:23 a.m., 125 volt DC Bus 112Y circuit breaker No. 20 (Primary Containment Isolation System (PCIS) was opened. This caused the Unit 2 Reactor Building Ventilation (VR) system isolation dampers to close, Unit 2 VR supply and exhaust fans to trip, and Unit 2 Standby Gas Treatment Train (SBGT) to start automatically. This was caused by de-energizing the DC power which feeds the Primary Containment Isolation system (PCIS) manual initiation logic. When circuit breaker No. 8 was opened, this de-energized the automatic initiation logic for SBGT system and provided an additional initiation signal.

The SE instructed the Unit 1 extra SF to have the Equipment Operators reclose the opened circuit breakers on Unit 1 Division 2 DC Bus 112Y. Once the breakers were reclosed, the Unit 1 PCIS and Unit 2 SBGT initiation logic was reset. SBGT was restarted in accordance with LOA-VR-04. At 2:00 a.m., the SE authorized a temporary return of AC Bus 142Y to service, this re-energized the Unit 1 Division 2 AC Distribution system and the negative 125 VDC ground cleared. The SE and the SCRE reviewed the electrical schematics and determined that the VR system isolation and SBGT system initiation occurred when DC Bus 112Y circuit breakers No. 20 and No. 8 were opened.

At 4:00 a.m., the temporary power supply installation for Unit 1, Division 2, 125 volt DC battery charger was completed. The Unit 1, Division 2, 125 volt DC battery charger was returned to service. The Unit 2, Division 2, and the Unit 1, Division 2, 125 volt DC distribution buses were uncrosstied. The negative 125 volt DC ground was the result of a bad power supply for the visual annunciator logic panel 1PA08J. When the AC electrical distribution Bus 142Y was de-energized, the normal AC power was lost, resulting in the automatic transfer to its backup power supply, which is fed from Unit 1, Division 2, 125 volt DC distribution Bus 112Y circuit breaker No. 15.

Technical Specification 6.2.A requires that the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 which includes operating and administrative procedures be adhered to. Operating Procedure LOP-DC-05 provides for a specific sequence to be followed when attempting to locate a ground. Contrary to the above on October 20, 1989, the Shift Engineer and Station Control Room Engineer failed to adhere to Operating Procedure LOP-DC-05, 125 Volt DC System Division 2 Ground Location and Isolation. The results for not adhering to this procedure resulted in a Group 4 PCIS isolation. The root cause for this violation was failure to adhere to procedures (No. 373/89023-01a; No. 374/89022-01a).

The safety significance of this event was minimal. When the DC power was de-energized to the Engineered Safety Feature systems (SBGT and PCIS), the systems actuated as designed to minimize the potential of any releases to the environment in the event an actual Design Basis Accident (DBA) were to occur.

d. On November 1, 1989, at 5:06 p.m. (CST), Unit 1 Bus 142Y tripped on undervoltage. Loss of the bus caused the loss of Unit 1 B Reactor Protection System (RPS), Unit 1 and 2 Reactor Building Ventilation Systems (RBVS), the RBVS and Fuel Pool Cooling System process radiation monitors, the SBGT Wide Range Gas Monitor (WRGM), the A Control Room and Auxiliary Building Ventilation system, and the Division II 125 volt DC battery charger. It also caused the auto starting of the Unit 2 Standby Gas Treatment (SBGT) system. The Unit 1 A Emergency Diesel Generator did not auto start because it was out-of-service. At the time of the event, Unit 1 was in cold shutdown and defueled as part of a refueling outage and Unit 2 was operating at approximately 100% power. At 5:08 p.m., the licensee started the B Control Room and Auxiliary Building Ventilation system. At 5:20 p.m., the Unit 1 B RPS was switched from normal power to alternate power and the isolation of the RBVS was reset and RBVS restarted.

The undervoltage relay tripped when the compartment door to which it was attached, closed. The door had some resistance to closure and as it was being pushed on, it suddenly slipped past the point of resistance causing the door and the relay to be jarred. At 5:45 p.m., the licensee had completed inspecting the 142Y compartment for damage, closed the door, and re-energized the bus. At 5:50 p.m., the A Control Room and Auxiliary Building Ventilation system was restarted and the B train secured. At 6:00 p.m., the SBGT WRGM was declared operable. At 7:23 p.m., the licensee made the required four hour Emergency Notification System (ENS) notification. At 9:50 p.m., the Unit 2 SGBT system was stopped and returned to standby.

e. On November 7, 1989, at approximately 6:10 a.m., water was noted to be running out of high point vent valves (1G33-F351 and 1G33-F352) on the Unit 1 Reactor Water Cleanup (RWCU) system onto a floor in the reactor building. At the time of this event, Unit 1 was shutdown and defueled as part of a scheduled refueling/maintenance outage and the RWCU system was shutdown for outage related work. In addition, the licensee was in the process of clearing the outage on the RWCU system and lining up the RWCU system, simultaneously, in preparation for performing a Local Leak Rate Test (LLRT) on the pump suction outboard isolation valve (1G33-F004). The licensee's investigation of the event indicated that the system was drained from the outlet of the inboard pump suction isolation valve (1G33-F001) to the inlet of the regenerative heat exchangers and that the LLRT required establishing a boundary upstream of 1G33-F001. The work was given to the Unit 1 Nuclear System Operator (NSO) (a licensed reactor operator) with instructions on performing both operations simultaneously. The NSO in turn distributed the portions of the work that were to be performed outside the control room to two Equipment Attendants (EAs). Because of poor communications by both the NSO and the EAs, the NSO believed that the steps of the LLRT procedure for 1G33-F004 (LTS 100-19, Reactor Water Cleanup Suction Local Leak Rate Test 1(2)G33-F001 and 1(2)G33-F004) necessary to allow opening of 1G33-F001, had been completed. When the NSO opened 1G33-F001, a flow path for reactor coolant was made from the bottom head drain to the RWCU system high point vents. Upon the leak being reported, the Unit 1 Shift Foreman directed the NSO to close 1G33-F001, thus terminating the leak.

Technical Specification 6.2.A requires that the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which includes administrative, surveillance, and operational procedures, be adhered to. LTS 100-19, step F.2.b requires that 1G33-F103, RWCU Suction From Reactor Vessel Bottom Bypass Stop, be closed. Step F.4 directs the opening of 1G33-F001. Contrary to the above on November 7, 1989, the Unit 1 NSO opened 1G33-F001 prior to 1G33-F103 being closed causing a loss of reactor coolant in the reactor building. The root cause for this violation was failure to adhere to procedures (No. 373/89023-01b).

f. On November 28, 1989, the licensee informed the resident inspectors that they had evidence of a small leak that had developed in the Unit 2 fuel pool. The leak was identified on November 17, 1989, by operation's personnel during their routine rounds of the reactor building which are performed each shift. The fuel pools have a leakage detection system to detect any degradation of the fuel pool liner. The detection system is separated into quadrants, each quadrant includes the walls and floor in that area. The leakage has been estimated at approximately 1/4 gallon per minute (GPM). The alarm on the leakage detection system is set at 1.92 GPM.

The leak appears to be located in the northeast quadrant of the fuel pool. The fuel pool does contain irradiated (spent) fuel assemblies from the previous outages.

During the summer of 1989, the licensee removed all of the old fuel racks from the Unit 2 fuel pool and replaced them with high density fuel racks allowing the licensee to store more spent fuel in the fuel pool. There was no degradation in the fuel pool liner identified during the time when the old racks were removed and the new racks installed or any time since completion of the rerack work.

The licensee's actions to date have been:

° Continue to monitor the leakage by the operation's personnel during normal routine rounds.

- A Technical Staff representative is monitoring the leakage once a day.

- General Electric (the vendor) has been contacted and is compiling methods on how to possibly locate the position of the leak.

- The licensee is pursuing the bases for the 1.92 GPM alarm setpoint of the leakage detection system.

The inspectors occasionally monitored the leakage.

g. During this inspection period, the inspectors noted during routine plant tours examples of scaffolding erected in the plant, including the control room and in the drywell (in the vicinity of safety-related equipment), that did not conform with the requirements of the licensee's administrative procedure for scaffolding erection (LAP 900-28, Erection, Inspection, and Use of Scaffolding and Ladders). As each example was identified by the inspectors, the location and specific concerns were provided to the licensee. In each case, the scaffolding was either corrected or dismantled by the licensee.

After several different examples had been identified to the licensee, the inspectors expressed the concern that the individuals authorized to erect and inspect the scaffolding and to verify compliance with LAP 900-28 were not performing their job. Licensee action appeared limited to only the specific examples provided by the inspectors with nothing being done to preclude repetition of the problem. Subsequent to this, additional examples of inadequate scaffolding were identified on November 3, 1989. The deviations from LAP 900-28 for the various scaffolding identified by the inspectors included failure to install midrails and guard rails for scaffolding in excess of 10 feet in height, vertical support members not plumb, failure to install toeboards (or installation of inadequate toeboards) on scaffolding over ten feet in height, lack of cross-bracing or cross-bracing not installed correctly, decking material installed incorrectly, failure to have a Scaffold Request Tag to indicate authorization for the scaffolding and to document its inspection, and failure to provide an access ladder to the work platform.

Subsequent to the inspectors identifying these deviations and informing the licensee that they would be the subject of a proposed Notice of Violation, the licensee took action to correct the scaffolding erection concerns on a generic basis. Actions taken by the licensee included an inspection and correction of all installed scaffolding for compliance with LAP 900-28, a revision to LAP 900-28 to better identify materials for scaffolding erection, erection techniques for awkward situations, and retraining of the personnel involved in erecting and inspecting scaffolding.

Technical Specification 6.2.A requires that the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which includes administrative, surveillance, and operational procedures be adhered to. LAP 900-28 provides numerous requirements for the erection of scaffolding. Contrary to the above on November 3, 1989, examples of deviations from LAP 900-28, as noted above, were identified for scaffolding installed in the reactor building and turbine building. The root cause of this violation was failure to adhere to procedures (No. 373/89023-01c; No. 374/89022-01b).

Three examples of a violation were identified and no deviations were identified in this area.

4. Monthly Surveillance Observation (61726)

The inspectors observed surveillance testing including required Technical Specification surveillance testing and verified that the testing was performed in accordance with adequate procedures. The inspectors also verified that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were accomplished and that test results conformed with Technical Specification and procedure requirements. Additionally, the inspectors ensured that the test results were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities:

LOS-DC-W1	Units 1 and 2 Weekly Surveillance for the Safety Related 250 VDC, 125 VDC, and Diesel Fire Pump Batteries
LOS-DC-W2	Units 1 and 2 Weekly Surveillance for the River Screen House 125 VDC, Technical Support Center 125 VDC, Relay House 125 VDC, and the Unit 24/48 VDC Batteries
LOS-DG-SA 2	(2A) Diesel Generator Operability Test With Response Time
LOS-RP-M1	Main Steam Isolation Valve Scram Functional Test
LOS-RP-M4	Turbine Control Monthly Surveillance

a. On October 30, 1989, at 6:00 p.m. (CST), the on duty Station Control Room Engineer (SCRE) reviewed a list of past due Technical Specification related surveillances and noted that LaSalle Operating Surveillance LOS-SC-Q1, Unit 2 B Standby Liquid Control (SBLC) Pump Operability Inservice Test and Explosive Continuity Check, was currently past its critical date. It was last performed on June 26, 1989, due September 29, 1989, and critical on October 22, 1989. The corresponding Unit 1 surveillance was determined to be similarly affected, but was not required since the reactor was defueled. The Unit 1 surveillance had last been performed on June 10, 1989, due September 10, 1989, and critical on October 3, 1989.

The Unit 2 B SBLC was declared inoperable and a 7-day Limiting Condition for Operation (LCO) time clock was commenced. LOS-SC-Q1, Attachment B, was performed, evaluated as acceptable, and the Unit 2 B SBLC declared operable at 8:00 p.m. on October 30, 1989. The root cause of the event was a clerical data entry error which caused the General Surveillance (GSRV) software to remove the surveillance from any normally published schedule.

A GSRV Change Request had been initiated to take the surveillance off an increased frequency status due to excessive vibration, and submitted to word processing on approximately July 14, 1989, to be incorporated into the GSRV. The scope operator inadvertently entered a 0 into both the increased frequency field and the critical count field rather than just the critical count field. The increased frequency field should have been blank. The Change Request form and resultant output reports were then returned to the Station GSRV Coordinator on July 18, 1989, for validation. It was found that all changes were made as requested, with no corrections needed. The surveillance schedules were issued to the departments on the same day. It was not noticed that the scope operator had made a change beyond that requested by the Change Request form.

Technical Specification 6.2.A requires that the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which includes administrative procedures be adhered to. Administrative procedure LAP 100-11, LaSalle County Station General Surveillance Program, step F.1.e, requires that the surveillance coordinator verify that the data has been entered correctly. Contrary to the above, on July 18, 1989, the surveillance coordinator failed to verify that all of the data entered by the scope operator was correct. It had not been noticed that the scope operator had made a change beyond that requested by the Change Request form which suppressed the surveillance from appearing on any normally published schedule. The root cause for this violation was failure to adhere to procedures (No. 373/89023-01d; No. 374/89022-01c).

b. On November 9, 1989, at 2:40 a.m. (CST), the Unit 2 Reactor Water Cleanup (RWCU) system isolated on a high heat exchanger room differential temperature signal. At the time of the event, Unit 2 was operating at approximately 100% power. The isolation occurred when a Instrument Mechanic (IM), while performing a routine functional test, placed the Division I Riley module toggle switch to the READ position. This was being done in order to compare the Division I module readout with the Division II module readout as required by procedure. When the toggle switch was moved, the Riley module indicated high causing the erroneous signal to be generated. The RWCU system pump suction valve isolated resulting in the two running RWCU system pumps tripping. The licensee made the required four hour Emergency Notification System (ENS) notification at 6:10 a.m. The licensee verified that there were no actual problems with the RWCU system and reset the isolation.

During investigation of the Riley module, the IM found a ground on the Division I thermocouple. This ground was not noticed during initial checks of the Division I thermocouple. The ground was cleared and the functional test completed.

c. On November 13, 1989, at approximately 6:00 p.m. (CST), with Unit 1 in a refueling outage, the licensee was performing instrument surveillance LIS-MS-107B, Unit 1 Reactor Vessel Low Water Level 1 and Level 2 Isolation Instrument Channels B and D Refuel Calibration. At 6:23 p.m., the instrument mechanic, per procedure, tripped channel B1 in preparation to calibrate the low water level detectors. Upon tripping channel B1, a Group I (Main Steam Isolation Valve) isolation was received. The isolation was received because channel 1A-A2 was already tripped and when channel B2 was tripped the isolation logic was completed. The licensee had taken the Unit 1 Division 1 electrical bus out of service for some repairs. Taking the bus out of service removed power from the channel 1A-A2 isolation logic which tripped that channel. The instrument mechanics, checking the control room annunciator panel, found the annunciators for channel 1A-A2 not lit or not tripped. The licensee's investigation found the annunciator lights to have been burned out. When the instrument mechanics checked the annunciator panel for channel 1A-A2 and found them not lit, they assumed that the channel was not tripped. The Main Steam Isolation Valves (MSIV) and the MSIV drain valves were already closed and out of service for other work. There was no valve movement. During the shift turnover at 3:00 p.m., the Nuclear Station Operator (NSO) had performed an annunciator check of all the Unit 1 control room annunciators. At that time the channel 1A-A2 annunciator light was lit. The licensee made the Emergency Notification System (ENS) phone call at 10:05 p.m. The resident inspector was also notified. All systems had functioned as expected.

d. On November 17, 1989, at 8:05 p.m. (CST) while performing LIS-HP-205, Unit 2 High Pressure Core Spray Minimum Flow Bypass Calibration, the instrument mechanics discovered Static-O-Ring (SOR) differential pressure flow switch 2E22-N006 out of its rejectable limits which rendered the High Pressure Core Spray (HPCS) minimum flow valve inoperable. The licensee commenced a four hour Limiting Condition for Operation (LCO) time clock pertaining to the Unit 2 primary containment and also declared the Unit 2 HPCS system inoperable. At 8:50 p.m., the licensee contacted the resident inspector informing him of the event and also made the Emergency Notification System (ENS) phone call. The HPCS minimum flow bypass switch was tripped and the valve closed at 9:20 p.m. in which the licensee exited the four hour LCO. A new SOR switch was installed by 5:00 a.m. on November 18, 1989, the switch was calibrated, and the HPCS system declared operable at 1:25 p.m.

e. On December 4, 1989, at 9:30 a.m. (CST), the licensee received an isolation of the Unit 1 Reactor Shutdown Cooling system. The licensee was performing instrument surveillance LIS-NB-111, Unit 1 Reactor High Pressure Shutdown Cooling Isolation Calibration. The instrument mechanic, per procedure, requested that breaker 135X-1 be de-energized prior to actuating the high pressure switch not knowing that the breaker had already been de-energized. The Nuclear Station Operator (NSO) believing that the instrument mechanic had indicated that he wanted the breaker energized, energized the breaker. When the instrument mechanic actuated the high pressure switch, the 1E12-F008 outboard isolation valve for the shutdown cooling system isolated. The shutdown cooling system had been in standby with no pumps running. Unit 1 was in a refueling outage and the licensee was approximately 60 percent complete in reloading fuel in the reactor core.

The cause of the actuation was a personnel error caused by poor communications. The licensee made the Emergency Notification System (ENS) phone call at 10:30 a.m. The shutdown cooling system had been returned to the standby mode by the time the ENS call was made. Technical Specification 6.2.A requires that the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which includes surveillance procedures be adhered to. Instrument surveillance procedure LIS-NB-111, Unit 1 Reactor High Pressure Shutdown Cooling Isolation Calibration, step F.3.A, requires that if the shutdown cooling mode is required to be in operation to have the operator de-energize the breakers for the RHR Shutdown Cooling Outboard Suction Isolation Valve, 1E12-F008. Contrary to the above, on December 4, 1989, during the performance of LIS-NB-111, step F.3.A, was not adhered to. The NSO, through poor communications with the instrument mechanic, energized the breaker controlling valve 1E12-F008 instead of de-energizing the breaker. When the instrument mechanics actuated the reactor high pressure switch, the valve isolated. The root cause for this violation was failure to adhere to procedures (No. 373/89023-01e).

Two examples of a violation of procedural adherence were identified in this area.

5. Monthly Maintenance Observation (62703)

Station maintenance activities affecting the safety-related systems and components listed below were observed/reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review: the Limiting Conditions for Operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance. Portions of the following maintenance items were observed during the inspection period:

Emergency Diesel Generator Modification
Repair of A Feedwater Turbine
Reassembly of the Main Turbine/Generator
Repair of the Unit 2 Motor Driven Feedwater Pump

a. On November 2, 1989, at approximately 4:00 p.m. (CST), the licensee was reflooding the Unit 1 reactor vessel with cycled condensate water. Reactor water level was being raised in order to continue with the next sequence of outage activities. During the flood-up process it was observed by personnel in the drywell that a blind flange cover was leaking from one of the main steam lines. The flange cover had been installed on the steam line after maintenance personnel had removed the N Safety Relief Valve (SRV) for repairs. The flange was held in place with two bolts/nuts. The licensee stopped flooding up and lowered water level in the reactor to just below the main steam lines. Mechanical maintenance was notified and a crew was sent to the location where the leak was observed to make repairs. Additional flange hold down bolts were installed and the leak stopped. The cause of the leakage was determined to be that the B main steam line plug which had lost its seal, and that the mechanical maintenance department had failed to properly install the required number of bolts in the blind flange cover as directed by procedure LMP-MS-06, Installation/Removal of Main Steam Safety Valves. As the licensee was filling the reactor vessel, the main steam line plug leaked allowing water to enter into the main steam line. This resulted in leakage through the main steam line drains and into the Main Steam Isolation Valve (MSIV) outboard room. The amount of water flowing past the main steam line plug exceeded the capacity of the MSIV drains which resulted in water backing up into the main steam line and out of the steam line where the SRV had been removed. An engineer in the drywell at the time was able to take pictures of the area as the water was spraying from the flange. The licensee has reviewed the pictures and are in the process of investigating the equipment that may have possibly been wetted. The immediate safety significance was minimal.

   The Unit 1 reactor was defueled and the leak was stopped within one hour after detection. The maintenance mechanics and the foreman believed that the purpose of the blind flange cover was for protecting the system from foreign material getting into the system. The personnel involved had removed the N SRV previous to this event while vessel level was above the main steam line plugs and no leakage was detected at that time. The longer term safety consequences potentially has more impact than the immediate safety significance.

The Reactor Recirculation (RR) pump discharge valve (1B33-F067B) was in the direct path of water leakage as was the B RR pump and flow control valve. The B RR pump motor was protected by scaffolding and welding blankets from activities in the area, and it was believed that no motor damage occurred. The B RR pump motor was meggered to ensure that no water made its way to the motor. The B RR pump instrumentation was checked for proper functioning. Additionally, the 1B33-F067B valve was meggered and inspected for any signs of water during the equipment qualification inspection.

Primary containment ventilation valves 113 and 114, as well as the RR pump suction valve, were in the path of water. However, no damage was apparent. Since these valves were in the path of the water, an inspection of the geared limit switch compartment was performed. An inspection was made of the cable trays and piping along the outer containment wall. No signs of any water was evident at any point from the B RR pump to the containment wall. An inspection was made of piping hangers and supports in the path of the water. No damage was evident to any components. Several junction boxes appeared to have had water on the boxes and were opened for inspection. The licensee estimated that approximately 2000-5000 gallons of water was spilled into the drywell.

Technical Specification 6.2.A requires that applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 which includes preventive and corrective maintenance operations be adhered to. Maintenance procedure LMP-MS-06, Installation/Removal of Main Steam Safety Valves, step F.2.13.1, requires that four bolts and nuts be installed and evenly tightened at 90 degree intervals around the blind flange. If the correct number of bolts had been installed in the flange cover, there is a possibility that water spill in the drywell would not have occurred. Contrary to the above, on November 2, 1989, maintenance procedure LMP-MS-06, step F.2.13.1 had not been adhered to in that the correct number of bolts had not been installed in the blind flange cover for the main steam line. The root cause for this violation was failure to adhere to procedures (No. 373/89023-01f).

b. On November 6, 1989, at approximately 7:19 p.m. (CST), with Unit 1 in a refueling/maintenance outage, the licensee was preparing to test the recently installed Rosemont level switches. These switches replaced the old Static-O-Ring switches used for indication of low (+ 12.5 inches) and low low (- 50.0 inches) reactor water level. As the switches were being calibrated, the unit received Groups 2, 6, and 7 isolations. The Primary Containment A chiller tripped when the primary containment ventilation isolation valves closed. These were the only valves that changed positions. All of the other isolation valves were in their correct positions. The resident inspector was notified at 10:15 p.m. and the Emergency Notification System (ENS) phone call made at 10:25 p.m. After the licensee confirmed that no actual low reactor water level condition existed they reset the isolations and restarted the primary containment ventilation.

During the licensee's investigation, they found two switches on the level switch instrument logic card in the wrong positions. The instrument mechanic placed the switches in the correct positions and the level functional test was reperformed satisfactorily. The level switches were then placed into service. A Licensee Event Report will be issued for this event.

One example of violating procedural adherence was identified in this area.

6. Licensee Event Reports Followup (90712, 92700)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports 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.

a. The following reports of non-routine events were reviewed by the inspectors. Based on this review it was determined that the events were of minor safety significance, did not represent program deficiencies, were properly reported, and were properly compensated for. These reports are closed:

   No. 373/89012-01 Reactor Core Isolation Cooling Hi Steam Flow Isolation Switch Failed Diaphragm

   No. 373/89018-01 Reactor Core Isolation During Warmup Due to Spurious High Steam Flow Signal

b. The following report of non-routine events involved violations of regulatory requirements. Event closure is being tracked by the associated violation. These reports are considered closed.

   No. 374/89015-00 Missed Technical Specification Surveillance on Standby Liquid Control System Due to Administrative Error. See Paragraph 4.a.

No violations or deviations were identified in this area.

7. ESF System Walkdown (71707)

The operability of selected engineered safety features was confirmed by the inspectors during walkdown of the accessible portions of the following systems. The following items were considered during the walkdowns: verification that procedures match the plant drawings, equipment conditions, housekeeping, instrumentation, valve and electrical breaker lineup status (per procedure checklist), and verification that items including locks, tags, and jumpers were properly attached and identifiable. The following systems were walked down this inspection period:

Unit 2 Division II 125V DC Batteries
Unit 1 A Emergency Diesel Generator

No violations or deviations were identified in this area.

8. Training (71707)

The inspector, through discussions with personnel, evaluated the licensee's training program for operations and maintenance personnel to determine whether the general knowledge of the individuals was sufficient for their assigned tasks.

In the areas examined by the inspector, no items of concern were identified.

No violations or deviations were identified in this area.

9. Security (71707)

The licensee's security activities were observed by the inspectors during routine facility tours and during the inspectors' site arrivals and departures. Observations included the security personnel's performance associated with access control, security checks, and surveillance activities, and focused on the adequacy of security staffing, the security response (compensatory measures), and the security staff's attentiveness and thoroughness. The security force's performance in these areas appeared satisfactory.

No violations or deviations were identified in this area.

10. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for November. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.5 and Regulatory Guide 1.16.

11. Cold Weather Preparation (71714)

The objective of this inspection was to determine whether the licensee had maintained effective implementation of the program of protective measures for extreme cold weather to which the licensee had committed in their response to IE Bulletin 79-24, Frozen Lines.

During this inspection period, the inspectors observed portions of operational surveillance LOS-ZZ-A2, Preparation for Winter Operation. The procedure encompasses the items noted in IE Bulletin 79-24. Upon completion of the procedure, the inspectors reviewed the surveillance procedure and results. The surveillance noted some equipment that was not functioning properly on which work requests were initiated to repair the equipment. The licensee completed the surveillance on October 19, 1989.

No violations or deviations were identified in this area.

12. Evaluation of Licensee Self Assessment Capability (40500)

On November 27, 1989, the resident inspector attended the licensee's regularly scheduled Nuclear Safety Onsite Quarterly Meeting. Site and corporate items of interest were discussed and reviewed during the meeting. The meeting was well organized such that the significant concerns could be addressed and then opened for discussions. The meeting was documented and the interactions between the different departments, both onsite and offsite, was good which provided for uninhibited discussion from the meeting members.

The meeting subjects pertained to the major/significant events, the licensee event reports, and trending of these events. Items requiring further actions were noted and resolutions addressed.

13. Exit Interview (30703)

The inspectors 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 inspectors 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.