U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-373/82-55(DPRP); 50-374/82-23(DPRP)

Docket No. 50-373; 50-374 License No. NPF-11; CPPR-100

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: December 1 through 31, 1982

R. D. Walker for
Inspectors: W. Guldemond 2-10-83

R. D. Walker for
A. Madison 2-10-83

R. D. Walker
Approved By: R. D. Walker, Chief 2-10-83
Reactor Projects Section 2B

Inspection Summary

Inspection on December 1 through 31, 1982 (Report No. 50-373/82-55(DPRP); 50-374/82-23(DPRP))

Areas Inspected: Routine, unannounced inspection by resident inspectors of licensee actions on previous inspection findings; operational safety; surveillance; licensee event reports; plant trips; startup testing; and independent inspection of potential problems with agastat relays. The inspection involved a total of 241 inspector-hours onsite by two NRC inspectors including 40 inspector-hours onsite during off-shifts.

Results: Of the seven areas inspected, no items of noncompliance or deviations were identified in six areas; one item of noncompliance was identified in the remaining area (failure to follow procedures - Paragraph 3).

DETAILS

1. Persons Contacted

   *G. J. Diederich, Superintendent
   *R. D. Bishop, Administrative and Support Services Assistant Superintendent
   *J. G. Marshall, Operating Engineer
   *J. C. Renwick, Technical Staff Supervisor
   *R. Kyrouac, Quality Assurance Supervisor

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

   *Denotes personnel attending exit interviews.

2. Licensee Actions on Previous Inspection Findings

   (Closed) Noncompliance (373/82-45-01(DPRP)): Reactor Core Isolation Cooling System flow controller removed from the remote shutdown panel without informing operations personnel. The licensee has retrained instrument department personnel on communicating with operations personnel and on implementing the requirements for removing an instrument from its location.

   (Closed) Open Item (374/82-09-01(DPRP)): Differences in valve positions required by Unit 1 and Unit 2 Residual Heat Removal System valve lineups. The licensee has reviewed and appropriately revised these valve lineups to eliminate the differences.

   (Closed) Open Item (373/82-41-04(DPRP)): Problems encountered in NRC Regions IV and V with personnel air locks manufactured by Chicago Bridge and Iron. In October 1982 the licensee experienced a malfunction of the interlocks. Their investigation revealed that the problem was during the mechanical latching process door rebounding that resulted in the latching mechanism closing, but not engaging the door. This phenomenon and its resolution are addressed in the vendor's manual for the airlock. The licensee has made adjustments to the latching mechanism as specified in the vendor manual and successfully tested the interlocks.

   (Closed) Noncompliance (373/82-45-02(DPRP)): Event in which feedwater flushing valves were used to compensate for feedwater regulating valve leakage contrary to startup procedure requirements. Procedural compliance has been reemphasized to operations personnel. The feedwater regulating valve leakage was repaired on September 15, 1982.

   No items of noncompliance or deviations were identified.

3. Operational Safety Verification

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with plant operators during the month of December 1982. 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 Unit 2 reactor buildings and turbine buildings were conducted to observe plant equipment conditions, fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been expeditiously initiated and resolved for equipment in need of maintenance.

On December 13, 1982, the inspectors observed a fire drill involving the onsite and offsite fire brigades. Overall performance was judged excellent. Within two minutes of the time the simulated fire was reported to the Shift Engineer, the Shift Foreman was on location to investigate. Two minutes later, six members of the onsite fire brigade were on location fully dressed out. Twenty five minutes from the time outside assistance was requested, the Marseilles Fire Department was at the scene of the fire. No significant delays were encountered in processing the Marseilles Fire Department personnel on site. Radiological controls were implemented; however, they were implemented in a fashion which could have resulted in loss of contamination control. Specifically, a control point was established in a small area subject to significant personnel traffic. Boundaries were established using personnel rather than barriers. Personnel survey rates were excessive. These observations were also made by licensee observers and were incorporated into the drill critique.

The inspector, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan, and that radiation protection controls were being implemented.

During preparations for startup of Unit 1 on December 4, 1982, the licensee shut the "A" recirculation loop suction and discharge valves in order to facilitate warmup of that loop. When an attempt was later made to open the valves, it was discovered that the discharge valve would only open 80 percent. The valve would close normally; however, the amount the valve would open decreased on each subsequent cycle. This condition rendered the "A" recirculation loop inoperable and, in accordance with the Technical Specifications at that time, precluded plant startup.

In an effort to solve the problem with the valve, the licensee performed a boroscopic inspection inside the valve bonnet. This inspection revealed that the valve backseat, normally welded to the bonnet, had separated and attached itself to the valve stem. When attempts were made to open the valve, the backseat would contact the bonnet and prevent further movement in the open direction. Following this determination, the valve was closed and placed out-of-service.

In order to return Unit 1 to operation, the licensee submitted a technical specification change request along with technical justification requesting approval to operate Unit 1 with one recirculation loop out-of-service. While waiting for NRC approval of the change request, the licensee developed a repair procedure for the failed recirculation loop discharge valve. The procedure was tested on December 19, 1982, on a Unit 2 recirculation loop isolation valve identical to the failed Unit 1 valve. The inspector monitored this test and noted the following:

a. The test demonstrated that the procedure, as written, was workable.

b. The people involved in the test made several suggestions for improvement at various points during the test. The inspector verified that these comments were later incorporated into the repair procedure.

c. Representatives from three separate maintenance crews were involved in the test. This provided an adequate number of trained personnel and supervisors to ensure continuity in personnel familiar with the repair technique during actual repair efforts on Unit 1.

d. All of the special tools fabricated for the repair of the Unit 1 valve were tested. One of the tools, a valve disk capturing device, could not be used as designed. The tool was modified and successfully tested as verified by the inspector.

Additionally, the repair procedure was reviewed and commented on by a representative of the NRC Region III, Division of Engineering and Technical Programs. The Resident Inspector verified that all comments on the repair procedure were adequately resolved.

The licensee also developed operating procedures to support the repair effort on the Unit 1 recirculation loop "A" discharge valve. These procedures were reviewed and commented on by the Resident Inspector and the comments were appropriately resolved.

On December 17, 1982, the licensee received a license amendment authorizing operation of Unit 1 with one recirculation loop out-of-service for the first fuel cycle of plant operation. Among other requirements, the amendment restricted steady-state thermal power to 50% of the rated value.

At 12:30 P.M. on December 19, 1982, the licensee completed preparations for and commenced startup of Unit 1 with the "A" recirculation loop out-of-service. The reactor was declared critical at 2:20 P.M. on December 19. At 2:40 P.M., the licensee discovered that the high voltage power supply to the "B" intermediate range detector was disconnected. The "B" intermediate range monitor (IRM) had been assumed operable to this point in the startup and had not been bypassed. No scram signals or rod block signals had been generated by the "B" IRM, because the point of disconnect was electrically downstream of the circuit which monitors for high voltage power failure. The channel was immediately bypassed and startup was continued.

Upon review of this event, the inspector determined that Unit 1 Technical Specifications require only three of four IRMs to be operable in a given trip channel. As "B" IRM was the only inoperable IRM at this point, operation was in accordance with Technical Specification constraints. However, the event did represent an off-normal condition that the operating shift was not aware of. Had another IRM in the same trip channel as IRM "B" been bypassed, the Technical Specifications would have been violated.

It is this last consideration which is cause for concern. IE Inspection Report 50-373/82-41(DPRP) documents two Unit 1 reactor scrams which were due, in part, to operation personnel not being aware of off-normal conditions. IE Inspection Report 50-373/82-52(DPRP) documents two cases where plant operational modes were changed without verifying that all conditions for changing modes were satisfied. This latest event is viewed as another case in which operations were conducted without full cognizance of plant conditions.

The licensee currently has in place numerous procedural mechanisms to prevent this type of occurrence. These include LGP 1-S1, "Master Startup Checklist", which is required for each startup following shutdown lasting longer than 72 hours; LAP 200-3, "Shift Change"; LAP 220-2, "Unit Operators' Log"; LAP 240-6, "Temporary System Changes to Unit 1 Systems and Equipment and Common and Unit 2 Systems and Equipment Required for Unit 1 Operation"; LAP 900-12, "Caution Card Procedure"; LAP 1300-1, "Work Requests"; and LAP 200-3 (Attachment D), "Degraded Equipment Log".

A review of these procedures revealed the following deficiencies in content and implementation:

a. LGP 1-S1 requires that the Degraded Equipment Log be reviewed to make sure that no equipment is inoperable which would prevent plant startup. This was done for the startup performed on December 19, 1982. The Degraded Equipment Log did contain a reference to IRM "B"; however, detailed information apparently was not provided to the Unit 1 operator performing the reactor startup.

b. LGP 1-S1 does not require that a review of all outstanding Work Requests be performed to ensure that no open Work Requests adversely impact unit operations.

c. LGP 1-S1 does not require that the Caution Card Log be reviewed to ensure that there are no entries which adversely impact unit operations.

d. No requirement exists for all Nuclear Station Operators, Shift Foremen, Shift Control Room Engineers, and Shift Engineers involved in a reactor startup to review LGP 1-S1.

e. LAP 200-3 requires as part of shift change that any equipment in a degraded mode and/or that may require further action be logged in the Shift Engineer's log. This was not done for IRM "B". This same requirement exists for the Nuclear Station Operator. This also was not done for IRM "B".

f. LAP 200-3 requires as part of shift change that the oncoming and offgoing Shift Engineers, Shift Control Room Engineers, and Nuclear Station Operators review the Degraded Equipment Log. While there is no evidence to indicate that this was not done, the status of IRM "B" was not adequately turned over.

g. LAP 220-2 requires the Nuclear Station Operator to log surveillance tests that are in progress. No entry is required for corrective maintenance in progress.

h. LAP 240-6 establishes administrative controls for temporary system changes that may involve electrical jumpers, lifted leads, fuses, relays, relay blocks, spool pieces. This procedure requires that the desired change be reviewed pursuant to 10 CFR 50.59, if applicable, and then reviewed by the Shift Engineer who assigns and logs control numbers to the change. Although required, this procedure was not employed for the high voltage power supply cable for the "B" IRM detector.

i. LAP 900-12 is designed to call attention to temporary information relating to equipment performance that is not normal. This procedure was employed to identify that the connector on the high voltage power lead to IRM "B" was defective. The installed Caution Card did not identify the fact that the lead was disconnected. The card was hung on the cable itself. No provisions were made to directly alert operations personnel of the problem.

j. LAP 1300-1 was employed to identify that "B" IRM had erratic indications and to control the work performed to resolve the problem; however, this procedure does not require that control room personnel be appraised of when work is to be started or the status of work in progress. Further, it does not contain provisions for controlling conditions when work is to be suspended for an extended period.

These deficiencies fall into two categories. The first is a failure of existing administrative controls to adequately identify and control an off-normal condition. This failure is due, in part, to procedural deficiencies noted above. These deficiencies have been provided to the licensee for disposition. This disposition is being tracked as an open item (373/82-55-01(DPRP)).

The second category of deficiency is failure to comply with existing procedural requirements. Two examples of this were noted. The first is failure to log degraded equipment in the Shift Engineer's and Nuclear Station Operator's logs as required by LAP 200-3. The second is failure to identify the lifted lead as required by LAP 240-6. This failure to comply with procedures is an item of noncompliance (373/82-55-02(DPRP)).

It should be noted that operator response to this event was excellent given that there was no foreknowledge of the status of IRM "B". Shortly after the other IRM channels came on scale the operator noted that the

"B" IRM was not indicating properly. Within ten minutes it was discovered that the high voltage lead was disconnected. Before continuing with startup, the "B" IRM was bypassed.

At midnight on December 19, it was noted that the "B" narrow range reactor vessel water level instrument was indicating at the top end of its range. At the time, the reactor was in Mode 2 at 1% power. Investigation revealed that all of the level instruments connected to the reference leg for Division 2 level instruments were also reading high upscale. Efforts were undertaken to fill and vent the reference leg using water from the discharge of the CRD hydraulic pumps. These efforts caused the instruments to yield what appeared to be normal values; however, after a short period, the instruments would start drifting upscale. At 1:00 A.M., with the instruments still indicating abnormally, a channel "B" RPS half scram was manually initiated, the methods for safely tripping the other safety-related level instrumentation without causing unwarranted ECCS and containment isolation actuations were investigated, and a reactor shutdown was commenced. At 2:00 A.M., the licensee discovered fitting and packing leaks on the channel "B" fuel zone level indicating switch valve manifold. These leaks were allowing the subject reference leg to drain, resulting in the upscale indications. The leaks were repaired, the reference leg was satisfactorily filled, the half scram was reset, and recovery was commenced.

The inspector was in the control room monitoring licensee activities during this event. Based on these observations and subsequent review of the event the following conclusions were reached:

a. The problem with the level instruments was not discovered by the previous shift even though sufficient information was available. The previous station operator had noted that the "B" channel narrow range level indicator was indicating upscale; however, it was not noted that the wide range indicator was likewise upscale and none of the local instrument racks were checked. The problem was attributed to a single instrument reading incorrectly. A review of the alarm typer printout revealed that the "B" channel alarmed at 9:12 P.M. and that the alarm did not clear until the next shift took actions to fill the reference leg.

b. Review of the piping and instrument drawings revealed that several protection, actuation, and control systems receive inputs from the level instruments affected by the loss of the reference leg. These systems are Division 2 train "B" of the Automatic Depressurization System actuation logic, Division 2 Low Pressure Coolant Injection initiation logic, channel "B1" of the Reactor Protection System logic, channel "B" of the Primary Containment Isolation logic, channel "B" of the Reactor Core Isolation Cooling System initiation input, channel "B" of Standby Gas Treatment initiation logic, and Reactor Recirculation Flow Control logic including the Anticipated Transient Without Scram System.

c. Technical Specification requirements were reviewed to ascertain whether the licensee's actions taken in response to the event were appropriate. The following conclusions were reached. (1) Inserting the Reactor Protection System half scram on channel "B" satisfied the requirements of Technical Specification 3.3.1, "Reactor Protection System Instrumentation". (2) Beginning a reactor shutdown conservatively satisfied the Technical Specification requirements for the Automatic Depressurization System Division 2, train "B", Division 2, Low Pressure Coolant Injection, the Reactor Recirculation Flow Control System including the Anticipated Transient Without Scram System, the Reactor Core Isolation Cooling System, the Primary Containment Isolation System, and the Standby Gas Treatment System.

Thus, at all times following discovery of the reference leg problem, Unit 1 was operated within the bounds prescribed by the Technical Specifications.

The inspector also reviewed this event to determine if any Technical Specification violations occurred based on the first substantial indications of the problem at 9:12 P.M. Virtually all of the Specifications involved require that affected instrumentation channels be tripped in one hour or the systems they serve be declared inoperable and the applicable action statements be implemented. Neither of these actions were explicitly complied with by 10:12 P.M. However, the shutdown commenced at 1:00 A.M. on December 19 did satisfy the applicable Action Statements associated with the individual systems. Therefore, the plant was operated within the most limiting constraints in the technical specifications.

This event is viewed as another example of inadequate attention to plant conditions as originally described in IE Inspection Reports 373/82-41(DPRP) and 373/82-52(DPRP). It is fortuitous that the prompt and conservative corrective actions taken by the midshift operating crew avoided a serious violation of Technical Specifications. The inspector reiterated his concerns for this repetitive problem to licensee management and will continue to track licensee performance in this area under an open item (50-373/82-55-03(DPRP)).

On December 30, 1982, the licensee informed the inspectors that twice on December 29, 1982, the maximum allowable thermal power limit with one recirculation pump running was exceeded. This occurred while safety relief valves (SRV) were being operated as part of an approved test procedure. It was the licensee's contention that the events did not constitute a violation of a license condition as power exceeded 50% only briefly and that the 50% power limit was for steady state operation only.

The inspectors reviewed the events and made the following determinations:

a. Six computer performed thermal power determinations yielded results in excess of 50% power. These occurred at 8:26 P.M., 9:16 P.M., 9:22 P.M., 10:00 P.M., 10:24 P.M., and 10:55 P.M.

b. The highest calculated power reached was 51% at 10:55 P.M.

c. Computer thermal power determinations performed between 8:51 P.M. and 9:00 P.M. and again between 9:27 P.M. and 9:48 P.M. yielded results below 50% power.

d. The average power level during the shift was less than 50%.

e. In each case where power exceeded 50%, action was initiated to restore it to an acceptable value.

This information was discussed with NRC Region III management personnel in an effort to determine whether the licensee's contention was valid. The power excursions were evaluated against the current position on the definition of steady state power level. The conclusion was reached that operations during this period fell within the limits of the NRC position and that the licensee's contention was valid; thus, no items of noncompliance were identified. The inspector did express concern to station management over the performance of a test which would produce power variations in such close proximity to a power limit. These concerns were acknowledged. Concerns were also expressed over the poor quality of the Station Operator's and Shift Engineer's logs. Neither contained any reference to that fact that 50% power was exceeded, by how much, and what actions were taken to rectify the situation. These concerns were also acknowledged.

At 8:30 P.M. on December 28, 1982, a member of the licensee's staff noted excessive vibration in the shaft of the Unit 1 "B" Residual Heat Removal (RHR) pump. The pump was operating in the suppression pool cooling mode at the time of discovery. Pump discharge flow and pressure readings indicated normal performance. However, as a precautionary measure "B" RHR pump was secured. Suppression pool cooling was continued using the "A" RHR pump.

During the morning of December 29, 1982, the "B" RHR pump was operated so that members of the licensee Technical Staff and Maintenance Department could evaluate the reported vibration. Based on this evaluation, the pump was declared inoperable effective 8:30 P.M. on December 28. This placed the unit in a Technical Specification Action Statement for suppression pool cooling which allowed 72 hours of operation, an additional 12 hours to place the unit in hot shutdown and an additional 24 hours to place the unit in cold shutdown.

At 8:35 P.M. on December 30, 1982, the licensee commenced a normal controlled shutdown of Unit 1 in order to effect repairs to the "B" RHR pump and the "A" recirculation loop discharge valve which had failed on December 4, 1982. Even though the shutdown was being performed 24 hours before required by the Technical Specification Action Statement for suppression pool cooling, the licensee chose to declare an Unusual Event emergency classification as would have been required by emergency procedures had the allowed Action Statement time expired. At approximately 1:45 A.M. on December 31, the licensee received low pressure alarms on three of seven pneumatic accumulators serving seven Automatic Depressurization System (ADS) safety relief valves (SRV's). The normal drywell pneumatic system was supplemented by the instrument air system and the emergency nitrogen bottle banks available to the system.

Technical Specification 3.5.1 requires at least six operable ADS valves in Division 1 and 2 of the ECCS. The affected valves were in Division 2.

Action Statement "e" of this specification states, "For ECCS Divisions 1 and 2, provided that ECCS Division 3 is operable and Divisions 1 and 2 are otherwise operable . . . with two or more of the above required ADS valves inoperable, be in at least hot shutdown within 12 hours and reduce reactor steam dome pressure to ≤122 psig within the next 24 hours." The licensee recognized that the three ADS valves whose accumulators had low pressure alarms were inoperable. They also recognized that the "B" RHR pump, a Division 2 ECCS pump, was inoperable; thus, the Action Statement was not satisfied and action was required in accordance with Technical Specification 3.0.3. This specification requires that the unit be placed in startup within six hours, hot shutdown within the following six hours, and cold shutdown within the following 24 hours. The licensee's Emergency Plan requires that a Site Alert emergency classification be declared when this specification is entered. This was done at 3:00 A.M. on December 31, 1982.

At 3:50 A.M., Unit 1 was placed in startup. At 3:56 A.M., two of the three accumulator low pressure alarms cleared, technically taking the unit out of all Technical Specification Action Statements for ADS valves and out of the Site Alert. The licensee chose conservatively to remain in the Site Alert status until the cause of the accumulator low pressure alarms was conclusively established and corrected.

At 4:20 A.M., the licensee's Technical Support Center was manned and assumed control of the emergency status. At 5:00 A.M., the NRC Region III Incident Response Center was manned and communications with the station and NRC emergency response personnel were established. At 5:35 A.M., the Resident Inspector was onsite in the control room.

Normal plant shutdown was continued. At 6:18 A.M., the pressure at the outlet of one of the emergency nitrogen bottle banks was increased and the final accumulator low pressure alarm cleared. During this period, it was noted that the nitrogen usage rate on the bottle bank, whose discharge pressure was increased, was considerably greater than on the other bottle bank. Walkdowns of the drywell pneumatic system were commenced. At approximately 9:45 A.M., a drywell entry was performed to check for leaks on the drywell pneumatic system inside of the containment. At 10:32 A.M. it was reported that no significant drywell pneumatic system leaks were discovered inside of the containment. By 12:00 A.M. several leaks had been discovered outside containment on the "B" air dryer. These were repaired and at 12:13 P.M., with conditions stable, the Site Alert was terminated. This left Unit 1 in an Unusual Event status because of the ongoing shutdown to repair the "B" RHR pump.

During the course of this event, the inspector made the following observations that were provided to the licensee.

a. The licensee's response to the event was in accordance with the Emergency Plan.

b. Sound technical guidance was provided to the control room from the Technical Support Center.

c. Excessive time was required to perform the drywell entry to check for pneumatic system leaks. The decision to perform the entry was made at 7:21 A.M. The entry was not commenced until approximately 9:45 A.M.

Two additional items were identified. The first item concerned procedural compliance during the shutdown of Unit 1. Normal shutdown procedures were written tacitly assuming that the motor driven feedwater pump is available. This allows use of the feedwater regulating valve to control water level in the reactor vessel. At the time of the Unit 1 shutdown on December 30, the motor driven feedwater pump was out-of-service for repairs. This was recognized by the licensee's staff and direction was provided to the operating shifts in the December 30 night orders on the method for shutting the unit down without the motor driven feedwater pump.

Shortly before the time when the motor driven feedwater pump would normally be used, the operating shift took exception to the directions provided in the night orders. This forced them to develop an alternative method and prepare and implement accelerated procedure changes immediately before their use. While this was done successfully, it was done with an urgency which lead to some confusion on the part of the operating shift.

The preplanning for this shutdown is considered marginal based on this observation. The licensee had tentatively made the decision to shutdown on December 29. Yet time was not allotted for the operations shifts to review and comment on the revised shutdown guidance.

The second item identified concerns the interpretation of the times specified in Technical Specifiction Action Statements for changing plant conditions in response to a degraded mode. The licensee commenced the shutdown of Unit 1 on December 30 to comply with the Action Statement of Technical Specification 3.6.2.3. This Action Statement states, "With one suppression pool cooling loop inoperable, restore the inoperable loop to operable status within 72 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours."

The licensee interpreted this statement to allow a total of 84 hours to place Unit 1 in hot shutdown after declaring the "B" RHR pump inoperable; thus, they planned on placing Unit 1 in hot shutdown approximately 60 hours into the 84 hour period and staying in hot shutdown for the remaining 24 hours, then proceeding to cold shutdown.

At approximately 12:30 P.M. on December 31, 1982, the inspector presented this interpretation to the NRC Region III management personnel manning the Incident Response Center. The inspector also presented the alternative interpretation that once the plant achieved an operational mode called for by an Action Statement, the "timeclock" for reaching the next lower operational mode started immediately. This interpretation would not allow the licensee to remain in hot shutdown until the 84 hour period had expired and then proceed to cold shutdown. Rather, it would allow the licensee 24 hours from the time the plant reached hot shutdown to achieve cold shutdown. Region III management personnel informed the inspector that the latter interpretation was the correct interpretation and that 24 hours after achieving hot shutdown, the unit was to be in cold shutdown. This position was relayed to and complied with by the licensee.

4. Surveillance

LaSalle Administrative Procedure LAP 300-6, "LaSalle County Station Instrument Surveillance Program," Revision 0, controls periodic instrument calibrations. This procedure requires a weekly listing of instrumentation past due for calibration. In November 1982, the inspectors performed a partial review of the non-Technical Specification related portion of this listing. As a result of this review, the inspector identified two concerns to the licensee. These concerns were that the list was excessively long and that it appeared that some of the entries on the list might be Technical Specification related. The licensee performed a cursory review of the list and informed the inspectors that they did not believe that any of the instruments on the list were Technical Specification related, but that they would conduct a more detailed review in the future. The inspectors expressed misgivings over this approach and informed the licensee that the inspectors were undertaking a detailed review of the list.

On December 21, 1982, the inspectors identified that the past due for calibration list contained entries for area temperature monitoring instrumentation for the Auxiliary Equipment Room, the Switchgear Room, the Diesel Generator Rooms, and the Emergency Core Cooling System Corner Rooms. This instrumentation is used to perform temperature monitoring surveillances required by Technical Specification 4.4.7. An Instrument Foreman with whom the inspectors had been interfacing on the past due for calibration list was informed of the problem.

On December 23, 1982, the inspectors checked on the status of the apparently past due for calibration instrumentation. It was determined that all of the instruments with the exception of those serving the Auxiliary Equipment Room were not, in fact, past due for calibration. The Auxiliary Equipment Room instruments had been verified to be past their normal calibration frequency, but had not been calibrated.

After consultation with NRC Region III management on December 23, the inspectors adopted the position that as the Auxiliary Equipment Room temperature monitoring instrumentation was outside its normal calibration period, the Technical Specification surveillance testing this instrumentation had supported was invalid and that the licensee must comply with the Technical Specification Action Statements for area temperature monitoring. This position was conveyed to the Operating Assistant Superintendent.

Calibration of the three Auxiliary Equipment Room temperature instruments were performed during the afternoon of December 23, 1982, within the time constraints imposed by the applicable Technical Specification Action Statements. Two of the instruments were found to be within their calibration tolerances. One instrument was slightly outside the calibration tolerance but within Technical Specification tolerance. This instrument was adjusted to within its calibration tolerances.

The fact that the Auxiliary Equipment Room temperature instruments were past their normal calibration frequency was initially considered an item of noncompliance. However, the licensee noted that Technical Specification surveillance frequencies can be extended up to twenty five percent and requested to know if the same extension applied to calibrations. The inspectors discussed this with a representative of the Office of Nuclear Reactor Regulation. Based on these discussions, it was determined that this extension is allowable for calibrations. As the calibrations for the Auxiliary Equipment Room temperature monitors were due in October 1982, they technically were still within their calibration frequency when the issue was raised on December 21; thus, an item of noncompliance was not issued. The licensee was unable to provide assurances to the inspector that their current administrative procedures would have identified the problem in time to ensure that the calibrations would not become technically overdue.

Three concerns were identified as a result of the above event. First, the licensee has incorrectly incorporated instruments which support Technical Specification surveillance testing into a non-Technical Specification related calibration list. This compromises calibration controls for these instruments and raises questions concerning other potentially similar situations. Second, the licensee had taken little action in response to this issue which was first identified in November 1982. This lack of response to identified concerns is viewed as serious matter. Third, the situation was compounded by a breakdown in communications within the licensee's organization. A problem with respect to Technical Specification related calibrations was identified to the Instrument Department on December 21. It was not until the inspectors identified on December 23 that appropriate action had not been taken and informed the Operations Assistant Superintendent that the plant was in a Technical Specification Action Statement that calibration were performed.

These concerns were expressed to the licensee during an exit meeting on January 3, 1983. The licensee acknowledged these concerns and stated that the past due for calibration list was receiving a detailed review. However, no commitment could be obtained for completion of this review. The inspectors view this lack of specificity as significant and will track this as an open item (373/82-55-04(DPRP)).

On December 28, 1982, the "B" diesel fire pump (DFP) experienced an apparent failure of its weekly surveillance test. Personnel on shift deferred the question of pump operability pending an evaluation of the surveillance results by the Technical Staff. This review and additional testing on December 29, 1982 showed the pump to be operable.

The inspectors reviewed this event and determined that no Technical Specification time limits or operability constraints had been exceeded from the time the "B" DFP apparently failed its test until it was subsequently determined to be operable. Thus, no items of noncompliance were identified. However, two items of concern were identified and expressed to licensee management.

The first item was that several hours elapsed between the apparent failure of the surveillance test and establishing a position on the operability of the DFP. The position taken by the inspectors and expressed to the licensee was that if a component fails a Technical Specification required portion of a surveillance test, that component must be declared inoperable at the time of failure. It is acceptable to delay the declaration of inoperability for evaluation only during the normal time interval allowed for performing the surveillance test. It is unacceptable to delay a determination of operability pending review of surveillance results by other groups or organizations. The licensee acknowledged this position.

The second item was that the individual who performed the surveillance test was inexperienced. Efforts were not expended at the time of the test performance to ensure that the test was performed correctly. The licensee acknowledged this concern.

5. Licensee Event Reports Followup

Through direct observations, discussions with licensee personnel, and review of records, the following Event Reports (LER's) 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.

373/82-139/03L-0*	Inoperable Drywell Oxygen Monitoring Channel
373/82-129/03L-0	Defective Condensate System Weld
373/82-130/03L-0	Condensate System Leak
373/82-137/03L-0	Recirc Pump Shift Failure
373/82-134/03L-0	Stuck Damper In The Reactor Building Ventilation System
373/82-127/03L-0	Excessive Corrosion In The Radwaste System
373/82-136/03L-0**	Violation Of Containment Integrity Due To Access Door Interlock Problems
373/82-140/03L-0	Blocked Sample Line To The Offgas Pretreatment Radiation Monitor
373/82-141/03L-0	RCIC Testable Check Valve Failure To Close
373/82-143/03L-0	Blocked Sample Line To The Offgas Pretreatment Radiation Monitor
373/82-138/03L-0	Failed Reactor Vessel Level Switch
373/82-135/03L-0	Failed Reactor Building Ventilation Radiation Monitor
373/82-142/03L-0	Failure Of Radwaste Isolation Trip Valve To Close
373/82-119/03L-0*	Mode Change With An Inoperable Control Room Emergency Filtration Train
373/82-145/03L-0	Failed Control Room Ventilation Chlorine Detector
373/82-144/03L-0	Inoperable Battery Charger

*This LER was submitted late.

**This LER was submitted late. The inspector discussed this with the licensee and determined that personnel responsible for reporting requirements were not informed of the event in a timely fashion. The licensee has retrained the personnel involved in the necessity for timely transfer of information.

LER 373/82-124/03L-0 documents a failure of the lake blowdown flow monitor. In the LER it states, "The probe continues to plug up within a day from the time it is cleared." The inspector followed up on the problem and determined that the plugging is apparently due to debris from the bottom of the lake. Because of the continuing nature of the problem, the licensee is considering various modifications to the system. In the interim, operability of the monitor is being checked before and during discharges and actions prescribed in the Technical Specifications are being complied with. Thus, the LER is considered closed. However, ultimate resolution of the problem is being tracked as an open item (373/82-55-05(DPRP)).

6. Plant Trips/Safety System Challenges

On December 1, 1982, Unit 1 experienced an automatic reactor scram on low reactor vessel water level. The low level was the result of a control failure for the "A" turbine driven reactor feedwater pump (TDRFWP). The reactor operator attempted to maintain reactor vessel water level by starting the "B" TDRFWP and increasing the feed rate of the motor driven feedwater pump. However, the rapidity of the transient made his efforts unsuccessful. All systems functioned normally in response to the scram. No ECCS systems were challenged.

Subsequent investigation revealed that the loss of control of the "A" TDRFWP was caused by a malfunctioning control card. The card was replaced.

7. Startup Test Witnessing

On December 1, 1982, the inspector witnessed portions of the feedwater system testing performed in accordance with STP-27. Testing was performed in accordance with approved procedures.

On December 2, 1982, the inspectors witnessed the performance of STP-31, "Loss of Offsite Power." The test was performed in accordance with the approved procedure. A thorough pre-test briefing of all involved personnel was conducted. Operator actions during the test performance were appropriate with the exception that following the reactor scram, the mode switch was not placed in the shutdown position as called for by scram procedures. This was corrected immediately when pointed out by one of the inspectors. All systems functioned as expected on the scram with two exceptions. The "L" SRV actuated before either the "S" or "U" valves. This was attributed to setpoint tolerances. Difficulty was experienced in restoring primary containment ventilation. This was later attributed to a problem with a ventilation damper position limit switch which was subsequently repaired.

On December 27, 1982, the inspector witnessed portions of Technical Specification required SRV testing. The testing was required to verify the design adequacy of the Mark II containment. Test performance was well coordinated. Personnel were familiar with limitations and precautions. Equipment in use was calibrated. Approved procedures were adhered to. As noted in paragraph 3, later sections of this same test were conducted at a power level which resulted in a violation of the maximum power limit imposed at that time.

8. Independent Inspection Effort

In a letter dated October 15, 1982, the NRC Director, Division of Resident, Reactor Project and Engineering Programs appraised the NRC Director, Division of Engineering and Quality Assurance of a potentially generic issue relating to the use of commercial grade Agastat relays in safety-related applications. Nuclear grade Agastat relays were not manufactured until 1978. Thus, many Agastat relays employed in safety-related applications could be of commercial grade. The design of commercial grade relays is not fixed. If such relays were to be replaced in kind, there is no guarantee that the replacement relays would meet design requirements. This could lead to an unidentified degraded condition reportable pursuant to 10 CFR Part 21. The licensee was informed of this potential problem. Their actions are being tracked via open item (373/82-55-06(DPRP)).

9. 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 the licensee, or both. Open items disclosed during the inspection are discussed in Paragraphs 3, 4, 5, and 8.

10. 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.