UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-348/88-05 and 50-364/88-05

Licensee: Alabama Power Company
600 North 18th Street
Birmingham, AL 35291

Docket Nos.: 50-348 and 50-364 License Nos.: NPF-2 and NPF-8

Facility Name: Farley 1 and 2

Inspection Conducted: February 22-26 and March 7-11, 1988

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SUMMARY

Scope: This was a special announced Operational Performance Assessment Inspection (OPA). The OPA evaluated the licensee's current level of performance in the area of plant operations. The inspection included an evaluation of the effectiveness of various plant groups including Operations, Maintenance, Quality Assurance, Engineering and Training, in supporting safe plant operations. Plant management awareness of, involvement in, and support of safe plant operation were also evaluated.

The inspection was divided into three major areas including Operations, Maintenance Support of Operations, and Management Controls. Emphasis was placed on numerous interviews of personnel at all levels, observation of plant activities and meetings, extended control room observations, plant tours and system walkdowns. The inspectors reviewed plant incident reports and licensee event reports (LERs) for the current Systematic Assessment of Licensee Performance (SALP) evaluation period, and evaluated the effectiveness of the licensee's root cause identification; short term and programmatic corrective actions; repetitive failure trending and related corrective actions; and, reportability.

In general, the licensee's programs in the areas inspected were found to be complete and effective. However, three violations and one unresolved item were identified. Also a number of particularly strong features were noted along with some potentially weak aspects of the licensee's programs. Strengths and weaknesses are summarized below:

Strengths

In the area of Operations, strengths included:

- Control room operators were professional and maintained good awareness of plant status.

- Communication and interface among the operating shift crew were good.

- Rotation of senior reactor operators (SROs) through the training organization enhanced operator training.

- Conduct of and checksheet data for shift turnovers were excellent.

- Shift logs were well maintained.

- The Operations staff had a low turnover rate resulting in a high level of experience in most of the operating staff positions.

- Operating crews attended requalification and simulator training as a crew, enhancing interface and teamwork within the crew.

- Operators had a positive attitude towards Operations and plant management and indicated that management interface with the crews was improving.

- Shift crews were composed of degreed and non-degreed individuals resulting in a good balance of engineering expertise and plant experience.

- Control room drawings were easily accessible, very legible, and in very good condition with a mylar protective coating.

- Color coding of unit access doors and procedures to indicate Unit 1 and 2 was an asset. Color coding of instrumentation in the control room and plant was good.

- Housekeeping in the control room was good.

The following strengths were identified in the area of Maintenance Support of Operations:

- Maintenance and Operations had a single manager allowing smoother coordination between groups.

- An aggressive program to reduce the maintenance work request backlog had been established and the practice of keeping plant personnel aware of performance in this area was good.

Strengths in the area of Management Controls included:

- The licensee had recently completed a comprehensive Self-Assessment of various plant programs and had targeted weak areas for corrective action.

- The working relationship between the corporate and site engineering groups and the dedicated consultant personnel was good.

- Management control of and member participation in the Plant Operations Review Committee were good.

- Good management control and interface was noted at status meetings.

- The Safety Audit and Engineering Review Group conducted aggressive audits and was staffed with well qualified personnel.

- Upper level management was well qualified and many of the managers held current SRO licenses.

Weaknesses

Weaknesses in Operations included:

- Additional guidance and controls should be established for post-maintenance testing.

- Control of fluid system fill and vent processes should be proceduralized.

- The fire protection administrative workload was heavy and detracted from other Shift Supervisor duties.

- Repetitive errors in tagging should be examined for appropriate corrective action.

- Individuals filling the Shift Foreman Inspecting position needed additional training in preparation of tag out orders in the electrical area.

- The inspectors found scaffolding attached to safety-related and fire protection piping and supports.

- The inspectors found several locked valves in rooms which would be inaccessible during accident conditions.

Weaknesses in Maintenance Support of Operations included:

- Control of calibration stickers was weak.

  Vendor manuals were used in lieu of detailed maintenance procedures.

- In some cases, detailed maintenance procedures were not written for safety-related maintenance.

- A backlog of preventive maintenance work existed and a lack of coordination in scheduling between different disciplines was noted.

- Maintenance task planning sheets were not well controlled and did not include detailed requirements for post-maintenance testing.

- Independent verification of jumper removal and lifted lead restoration was not always performed.

- The valve lubrication schedule was not adequate and did not specify acceptable grace periods.

- The work planning group did not develop complete work packages.

- A lack of control over torquing was noted.

Weaknesses in Management Controls Area included:

- Peer QC review was weak.

- An ineffective procedure and drawing control system existed.

- I&E Notices recommending corrective action were not closed out in a timely manner.

- Review and documentation of root cause determinations for equipment failures and documentation of corrective actions in Incident Reports and LERs were weak.

- Events were not trended to determine programmatic corrective actions for personnel errors or repetitive equipment failures.

REPORT DETAILS

1. Licensee Employees Contacted

*R. Berryhill, Systems Performance Manager
*S. Fulmer, Supervisor, Safety Audit and Engineering Review Group
*R. Hill, Operations Manager
*D. Morey, Assistant General Manager - Operations
*C. Nesbitt, Technical Manager
*L. Shinson, Manager, Plant Modifications
*W. Shipman, Assistant General Manager - Plant Support
*J. Thomas, Maintenance Manager
*J. Woodard, General Manager, Farley Nuclear Plant

NRC Representatives

*W. Bradford, Senior Resident Inspector
*A. Gibson, Director, Division of Reactor Safety
*C. Hehl, Deputy Director, Division of Reactor Projects
*W. Miller, Resident Inspector
*E. Reeves, Senior Project Manager
*M. Shymlock, Chief, Operational Programs Section

Other licensee employees contacted included technicians, Operation's personnel, maintenance and instrumentation and controls personnel, security force members, and office personnel.

*Attended exit interview.

2. Exit Interview (30703)

The inspection scope and findings were summarized on March 11, 1988, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspector during this inspection.

Note: A list of acronyms used in this report is contained in paragraph 9.

Item Number	Status	Description / Reference Paragraph
348, 364/87-35-02	Closed	URI - Control of Maintenance and Tagging Activities. (paragraph 3)

348, 364/87-11-03	Open	VIOLATION - Failure to control and evaluate the use of nonconforming material. This inspection identified an additional example which involved a failure to take adequate corrective action to ensure that nonconforming coupling bolts in the 1A and 1B charging pumps were replaced in a timely manner. This item will be tracked as part of EA 87-142. (paragraph 6.1)
348, 364/88-05-01	Open	VIOLATION - Failure to follow procedure and take adequate corrective action to assure (1) control of procedures and drawings, and (2) that Supervisor Check Points are signed by the appropriate Maintenance Foreman. (paragraphs 7.e and 7.g, respectively)
348, 364/88-05-02	Open	VIOLATION - Failure to take adequate and timely corrective actions to known safety-related system design deficiencies, test results, and equipment failures. (paragraph 8.d)
348, 364/88-05-03	Open	URI - Applicability of TS 6.5.3.1.b, specifically General Manager approval requirements, to minor departures. (paragraph 7.a)

3. Licensee Action on Previous Enforcement Matters (92701)

   (Closed) Unresolved Item 348, 364/87-35-02. Control of Maintenance and Tagging Activities. The inspectors reviewed plant incident reports and licensee event reports generated during the current SALP period. The evaluations of the indicators of weak performance taken from this review are discussed in numerous areas throughout this report. In particular, maintenance activities are discussed in paragraph 6 and tagging errors are discussed in paragraph 5.n. The review of incident report quality is documented in paragraph 7.k. Based on these reviews, this unresolved item is closed.

4. Unresolved Items

   Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. An unresolved item identified during this inspection is discussed in paragraph 7.a.

5. Operations (71707, 71710)

The inspectors performed extended observation of control room operations including backshift and weekend activities and shift turnovers. The inspectors monitored Operations personnel performance, awareness of plant status, use of procedures, and the maintenance of required unit logs and status boards. Interviews were conducted with Operations management, Shift Supervisors (SSs), control room operators, senior reactor operators (SROs), shift technical advisors (STAs), SROs filling the Shift Foreman Inspecting (SFI) and Shift Foreman Operating (SFO) positions, and system operators. Interviews were conducted with control room operators and system operators during system walkdowns, plant tours, observations of surveillance and post-maintenance testing, and tagging and removal of equipment from service.

a. Control Room and Local Plant Operations

(1) Control Room Demeanor

During sustained control room observations by the inspectors, the operators maintained a professional demeanor and directed their attention to the status of the control boards and plant evolutions. The responses to alarms were generally taken without delay. The response included reading, acknowledgement and appropriate corrective action to the alarms. The operators appeared to be well disciplined. The SSs were in control of the activities and appeared confident in performance of supervisory duties. Few instances were noted where attention was diverted to non-job related conversations. The conscientious attitude of the operators resulted in excellent attention to plant status. The control room crews appear to work together well and generally remain together as a crew through all shift work and training.

The control room appearance was clean and appropriate procedures and reference material were readily available. Gages and recorders were readable, indicated operating bands and setpoints and were kept in good condition. Two instances of outdated procedures and one instance of an outdated drawing were noted and brought to the licensee's attention as discussed in paragraph 7.e of this report.

During the inspection, the inspectors noted that turnovers for mid-shift reliefs of the licensed operator at the reactor controls were not always clear and the SS was not always aware of turnovers. Mid-shift turnovers should be conducted in a clear concise manner with acknowledgement of the assumption of the position. The SS on the unit should also be informed of position changes. The turnovers should include an appropriate discussion of the status of evolutions and board indications.

No violations or deviations were identified.

(2) Operations Procedure Compliance and Use

Observation of surveillances did not reveal any instances where procedures were not followed and procedures were observed to be in-hand during performance. The inspectors did not observe any instances where procedures were not used for testing. The licensee used Tagging Operations Orders (TOOs) to control tag-out of equipment and restoration to service. Use of TOOs for fill and vent of fluid systems was noted as a weakness since, in general, no specific system guidance or procedures were provided and, therefore, each tag-out order was generated anew at the time of need. Weaknesses in fill and vent methods were also observed as documented in NRC Inspection Report 348, 364/87-35. Inadequate fill and vent had contributed to plant events as detailed in paragraph 8. Proceduralized fill and vent instructions could eliminate this weakness.

No violations or deviations were identified.

(3) Procedure Terminology Versus Control Board Labeling

The inspectors noted that in Farley Nuclear Plant (FNP) procedure FNP-1-AOP-28.0, Control Room Inaccessibility, Rev. 1, procedural terms were not identical to remote shutdown panel labeling. Review of other procedures indicated that labeling was also not exact. Operators did not appear to have difficulty in identifying the appropriate controls with the terms used in the procedures, but human factors could be enhanced by providing exact equipment labeling in Operation's procedures.

A review of instrumentation unit labeling indicated examples where Technical Specification units were different from that used on the gage. A sample of surveillances indicated that steps were included to make the proper conversions and that a curve book to convert units was available.

No violations or deviations were identified.

(4) Status of Control Boards and Instrumentation

The inspectors reviewed the number and type of deficiency tags present on the Unit 2 control board equipment. The control board had few outstanding maintenance work requests/deficiency tags with only four of the tags reviewed over six months old. The Unit 1 board was reviewed in less detail, however, Unit 1 appeared to be in a similar condition. Interviews indicate that routine audits of the status of the boards are conducted by management. The licensee appears to place proper emphasis on maintenance of control board instrumentation.

Color coding of instrumentation in the control room and plant appeared to be good. The majority of piping was also labeled. The inspectors noted that addition of operating bands or setpoints to the remote shutdown panel gages could enhance the implementation of the control room inaccessibility procedure.

No violations or deviations were identified.

(5) Communications

The inspectors noted that although communication between the control room crew members is generally excellent, additional emphasis on mid-shift turnover practices was warranted. The control room crews appear to function well as a team. The establishment of the SFO, Shift Supervisor Support (SSS) and SFI positions have resulted in less administrative burden on the SS. These positions appear to interface well with the SS.

No violations or deviations were identified.

(6) Logs and Records

Shift records are comprised of the logs, data sheets, checklists, sign-off lists, recorder charts, and computer printouts that describe or record operating information or actions. Requirements for maintaining such records are contained in FNP-0-AP-16, Conduct of Operations - Operations Group, Rev. 17, Section 6.0. The inspectors reviewed the unit operators' log books, night order book entries, the method by which recorder charts are routinely checked, and the information contained on control room computer printouts. System operator logs and log sheets were also checked for content.

Logs and records were legible, accurate and understandable. Log sheets provided space to record readings on plant equipment which could then be easily compared to preprinted acceptance criteria on the log sheets. The inspectors observed that the Unit Operator does not log dilution and boration start and stop times, explanations for equipment start/stop, or entry times for performance of maintenance and surveillance tests which may affect unit operation. Such additional information in the Unit Operator logbook could be useful to the control room staff.

No violations or deviations were identified.

(7) Shift Turnover

The inspector reviewed shift turnover controls and observed numerous shift turnovers. Turnover forms were reviewed for all operating crew positions. Status sheets utilized to inform management of the unit status were also reviewed.

The operations staff conducted detailed shift turnovers using turnover forms and performed detailed control board walkthroughs with their respective watch reliefs. All important information appeared to be effectively transmitted to the oncoming shift personnel. The turnover forms appeared to be comprehensive and used routinely.

No violations or deviations were identified.

(8) Overtime

Technical Specification 6.2.2.f and FNP-0-AP-64, Work Schedule for Personnel Performing Safety-Related Functions, Rev. 2, were established to limit the working hours of unit staff who perform safety-related functions. Those personnel include SROs, reactor operators, health physics technicians, auxiliary operators, and key maintenance personnel.

The inspectors reviewed time sheets for Operations personnel for the period between December 12, 1987 through February 21, 1988. During that time frame both units were operational. Only one person was noted to have exceeded the overtime guidelines. That occurred when more than 72 hours were worked in a seven day period. The Emergency Director, as specified in FNP-0-AP-64, granted approval for that overtime. When the plant is operating at power, Operations personnel appear to work a nominal 40 hour week with occasional overtime required due to sickness or absences of other staff members.

The inspectors also reviewed time sheets for the last refueling outage. Numerous examples were noted of Operations personnel exceeding, with the Emergency Director's approval, 72 hours in a 7 day period. During outages, the Operation's staff rotates through two, seven day, 12 hours per day periods, i.e., two periods of 84 hours in seven days every 5 weeks. Although this exceeds the guidelines of Technical Specification 6.2.2.f.3 and FNP-0-AP-64, the benefits of this schedule are that when additional outage related overtime is required, the operating staff continues to receive the normal days off, resulting in 10 days off during the 5 week period. Operators also rotate on the same schedule as during normal operations. The change is that each person works either a 12 hour day or night shift in place of his normal 8 hour work period. The licensee has been able to maintain short outage durations in the past; therefore, it appears that the structure of approved overtime during outages is acceptable.

No violations or deviations were identified.

(9) Organization and Staffing

The organization of the staff, specifically use of the SFI and SFO positions, appeared to result in smooth functioning of shift activities. Also, the licensee attempts to maintain a blend of degreed and non-degreed members on each crew which provides a balance between plant experience and engineering expertise. It should be noted that in recent years, the Operations staff has had a low turnover rate which has resulted in a high experience level in the operating staff.

b. Control of Maintenance Work

Interviews and observations indicate that the SS is kept well informed of all maintenance work on his unit. A work authorization form is issued by the SFI and initialed by the SS. It does not appear, however, that the unit operator is always informed of all maintenance, although it does appear that he is informed of and logs major maintenance work. The operations staff could take a more direct role in tracking the start and completion of maintenance activities including ensuring that maintenance is being performed on the appropriate piece of equipment and correct train. The inspectors did note that Instrumentation and Control (I&C) technicians interfaced well to alert operators to alarms prior to system maintenance and testing.

Interviews indicate that Operations has some difficulties in obtaining and/or scheduling support from other sections, particularly for tagging equipment. The licensee has taken actions to alleviate these interface problems by assigning maintenance personnel to the tagging function during outages.

The inspectors observed one instance where an I&C technician brought a work request (MWR 175618, Repair and Calibrate H2 Regulator for VCT) to the SS, and the SS denied permission to perform the work since the work had not been planned or scheduled and no interface with Health Physics (HP) had been arranged. Enhancements could be made in this area to reduce the administrative burden on the SS by ensuring that work planning is completed prior to bringing a work authorization for approval.

Interviews indicate that, particularly in the area of mechanical maintenance, repetitive rework was often required. Operations appeared to be conscientious in not functionally accepting deficient equipment. Comments were made that system engineers were not available at the plant to assist Operations or Maintenance in identifying problems and appropriate maintenance. Discussions with management indicated that sufficient engineering support was available. The engineering support may not be fully utilized by the staff due to a reluctance to request engineering assistance.

The inspectors observed various maintenance activities to determine the adequacy of Operation's control of maintenance work and the adequacy of post-maintenance testing. Comments were provided to the licensee on the following maintenance activities:

The inspector observed MWR 163520. This work involved removal of a dedicated shutdown breaker from Unit 1 cubicle EE05, 1B battery charger, and installation of the breaker in cubicle EE04. The breaker from the Unit 1 polar crane cubicle ED04 was removed and taken to the electrical shop. The three current transformers and the amptectors were swapped between breakers EE05 and ED04. After the post-maintenance test (FNP-0-MP-28-12, Westinghouse 600V DS 206 and DS 416 Circuit Breaker and Amptector Type L1 and LS Electrical Maintenance, Rev. 12) was performed on breaker ED04, it was installed in cubicle EE05 to return the 1B battery charger to service. This swap out and exchange of equipment was documented under MWR 175643 to ensure that equipment would be eventually returned to its original location. The inspector noted that this maintenance was accomplished without inspection of the work being done on the DS-206 breaker pole shaft as required by IE Bulletin 88-01, Defects in Westinghouse Circuit Breakers, dated February 5, 1988. The Bulletin requires the inspection of pole shaft welds when DS-206 breakers are removed for maintenance. The licensee considered this changeout to be an emergency condition since they were in an LCO and these breaker inspections are required during routine maintenance. The licensee indicated that an inspection program for the breakers has been developed and those breakers that needed to be inspected have been identified. This breaker will be tested at the next maintenance or refueling outage.

The inspector observed work conducted under MWR 163515 which involved installation of reactor trip breaker E004ARTA for Unit 2 after performance of inspection and rework required by IE Bulletin 88-01. After the breaker was reinstalled in its cubicle, the inspector observed the performance of Surveillance Test Procedure FNP-2-STP-33.2A, Reactor Trip Breaker Train A Operability Test, Rev. 6. Difficulty was encountered in identifying the test point where the I&C technician would take electrical measurements required in the above STP since the test points were not adequately labeled.

The labeling consisted of marking on the cubicle door and terminal board with a magic marker. The licensee indicated that this labeling deficiency would be corrected and that a program is presently underway to improve plant labeling.

No violations or deviations were identified.

c. Surveillances

The inspectors observed surveillance testing and reviewed documentation for completed surveillance testing. Comments were provided to the licensee on the following surveillances:

FNP-1-STP-1, Operations Daily Shift Surveillance Requirements Modes 1,2 and 3, Rev. 18. The main control board meter indications for the boric acid tank, refueling water storage tank, spray additive tank and condensate storage tank did not have the same units as the Technical Specification units. Correlation could be made using the Unit Curve Book.

FNP-1-STP-605.3, Auxiliary Building Battery Weekly Verification (Electrical Maintenance), Rev. 8. No problems were observed with the actual performance of the STP. Procedural steps were followed. All measurements were within tolerances and calibration on equipment was current. Personnel appeared knowledgeable of test performance. The inspector observed that washers and bolts used to connect cells together and battery feeder cable appear to consist of various numbers of washers and have bolts of different lengths from that specified in FNP drawing U-176261-F. The licensee confirmed that the materials were correct and indicated that the configuration would be changed to be consistent among cells.

While observing the performance of FNP-1-STP-605.3 the inspectors requested information as to the temperatures that the battery could experience and still meet its design basis rating during an accident. The licensee did not have this information available and contacted Bechtel Eastern Power Company for the requested information. This information was provided in a letter from R. C. Gandhi, Project Engineer, to W. G. Hairston, Alabama Power Company, dated February 26, 1988. A review of this letter identified that the battery discharge capacity used in calculations for a design basis event loading was based on a temperature range of 45°F to 104°F. A review of the licensee's TS table 3.7-8 for Unit 2 indicated that the battery room containing the train A and B safety-related batteries has a maximum temperature limit of 120°F. The licensee provided information that indicated that a maximum temperature limit of 120°F would only affect battery life. Any shortening of the battery life should be detected by routine Technical Specification surveillance testing. This information resolved the question.

FNP-0-STP-55.0, Fire System Underground Piping Operability Test, Rev. 8. The portion of the test observed was performed satisfactorily. The inspector, however, observed that the procedure did not include information on a drain hole in the piping for draining of the fire hydrants. The operator performing the procedure, upon noting the leakage when flow was initiated, thought that the line was leaking and stopped the test. A second operator indicated that he had performed the test before and had also not known of the drain. The test was then restarted. The inspector noted that valve labeling and lack of definitive location markers for valves and hydrants resulted in delays in the test. The procedure could be enhanced by correcting these human factor deficiencies.

FNP-2-STP-227.2, Containment Air Particulate Monitor R11 Channel Check and Functional Test, Rev. 9. The inspector noted that the cover sheet of the test data package was labeled Rev. 8 when the current revision was Rev. 9. The test data package had not been changed in Rev. 9. The error appeared to be a typographical error in entering the test revision on the cover sheet.

No violations or deviations were identified.

d. Scaffolding

During plant walkdowns, the inspectors noted that scaffolding had been secured to safety-related equipment. Scaffolding was erected at elevation 83 in the Unit 2 containment spray pump room and on elevation 100 in front of the Unit 2 catalytic hydrogen recombiner. The scaffolding was attached to RHR suction piping from the RWST, fire main piping and various safety-related piping supports and cable trays. This equipment had not been declared inoperable and no analysis had been conducted to confirm operability. Upon being informed of this condition the licensee immediately removed the scaffolding and developed the procedure discussed below.

Sections 4.13 and 4.16 of procedure FNP-0-GMP-60, General Guidelines and Precautions for Erecting Scaffolding, Rev. 0, dated March 29, 1988, established guidelines on control of scaffolding. The procedure required a review of proposed scaffolding by Operation's personnel and labeling of the scaffolding. It did not, however, require that an analysis be performed to determine operability of equipment in the vicinity of the scaffolding. Also the procedure did not address what controls and documentation are required if the scaffolding makes the equipment inoperable. The licensee indicated that the procedure would be reviewed.

No violations or deviations were identified.

e. Restoration of Equipment and Post-Maintenance Testing

Interviews indicated that although the planning group provided a limited amount of direction for post-maintenance testing, Operations personnel (SS and SFI) were generally not provided with written guidance or procedures on testing requirements. The scope of the post-maintenance tests were generally developed through reliance on operator experience. Excessive reliance appears to be placed on the SFIs and SSs to determine the scope of the testing. The SSs are often busy which could affect their ability to ensure adequate post-maintenance testing, and in some cases, the SFIs did not appear to have adequate experience. To ensure consistent and adequate post-maintenance testing, procedural guidance should be provided. The licensee indicated that actions had been undertaken to improve guidance in this area.

No violations or deviations were identified.

f. Technical Specification Compliance

The inspector observed control room operations and reviewed active Limiting Conditions for Operation for both Units and historical files of mandatory, voluntary, and administrative LCOs. FNP-0-AP-16, Conduct of Operations - Operations Group, Rev. 17, indicated that mandatory LCOs were entered when plant equipment required by Technical Specifications (TS) was inoperable beyond the control of the SS. Furthermore, voluntary LCOs covered those instances where an LCO was entered to test or repair equipment and administrative LCOs were entered when TS equipment was out-of-service but was not required in the specific operational mode, or if it reduced the redundancy of the equipment, but not less than the TS requirement for the redundancy. For an administrative LCO, the required times for restoration and time limit were not used.

The inspectors determined that the licensee was utilizing an administrative LCO to cover entry into the Technical Specification action statement for an inoperable power operated relief valve (PORV) block valve. Interviews indicated that administrative LCOs are generally used when the TS action statement does not require a definite return to service time requirement, or repetitive TS surveillance. These action statements do, however, require continual surveillance to ensure compliance with the action statement and further actions, including shutdown requirements, in the event the action statement cannot be met. In the case of the PORV block valve, the "N/A" of the required TS action statement and tracking as an administrative LCO was not appropriate. The licensee agreed with this concern and indicated that PORV block valve inoperability would no longer be tracked as an administrative LCO.

In addition, the inspectors noted that the licensee did not treat room coolers as attendant equipment for safety-related pumps. These room coolers were considered as "support" equipment which could be removed from service without entering the Technical Specification action statement for the associated safety-related pumps. The licensee had not conducted and documented an evaluation to demonstrate that the pumps could perform their design functions without the room coolers. The inspectors indicated that the licensee should either treat the coolers as attendant equipment, or provide an analysis that indicated that the room coolers were not required for pump operability in accident conditions. The licensee committed that the room coolers would be treated as attendant equipment pending further evaluation and resolution of this concern. The inspectors did determine that administrative LCOs had been used to track inoperable room coolers and, therefore, action statements for safety-related equipment had not been exceeded when the associated room cooler was inoperable.

No violations or deviations were identified.

g. Temporary Procedure Changes

The inspector reviewed two temporary procedure changes. No problems were identified. No violations or deviations were identified.

h. Management Involvement

During control room observations, the inspectors noted that the General Manager, Assistant General Manager - Plant Operations, and Operations Manager conducted routine control room tours. Interviews indicated that upper management tours of the control room were conducted approximately monthly. The Operations Manager appears to conduct tours weekly and Unit Supervisors made daily visits to the control room.

Interviewees consistently stated that additional management presence in the plant was needed. It was indicated that the General Manager, Assistant General Manager-Operations and Operations Manager tours of the plant occurred on a very infrequent basis. They felt that these managers had a strong interest in plant activities and conditions, but that other administrative duties reduced the time available for plant tours. Interviews with plant managers confirmed that the administrative burden does severely limit managers' available time for control room and plant tours.

All personnel interviewed indicated that improvement was needed in communications between plant staff and management. They felt that management had recently placed additional emphasis in this area. The Plant Manager had initiated a series of question and answer meetings with shift personnel. In addition, the Operations Manager was conducting shift meetings to emphasize important areas and goals such as procedure compliance. Operations personnel indicated optimism for the success of the efforts, and desired to see the recent efforts continued.

No violations or deviations were identified.

i. Locked Valve Control and Locked Doors

The control of locked valves appeared adequate and included independent verification of lock installation in all cases observed. Several instances were noted where valves had been locked inside a pump room, specifically both Unit 1 and 2 charging pump rooms, when the valve was operated via a remote operator. Some of the remote operators had deficiency tags. Subsequent review the second week of the inspection indicated that the locks were still on the valves instead of the remote operators. These valves are positioned in the accident fail safe position but, due to the locks, could not be manipulated from outside the pump room to isolate ruptured lines during accidents. The licensee indicated that the locks would be relocated to the remote operators.

The inspectors observed that numerous doors in the plant were locked. Plant operators were issued appropriate keys for access, however, delays were noted during walkthroughs while searching for the appropriate key. The locking of many non-security access doors to pump rooms, switchgear rooms, etc., appears to be a carry-over from construction. This could potentially affect the timely response during emergency conditions and also required administrative controls for a large number of door keys. Since interviews indicated that these locked doors are often propped open for convenience, it would probably be of benefit for the licensee to review this policy on a door by door basis.

No violations or deviations were identified.

j. System Walkdowns

The inspectors walked down two safety-related systems, residual heat removal and service water system. Portions of the service water system (SWS) for the outside service water structures of Unit 1 and the SWS supply to the Unit 1 emergency diesel generators and the Unit 1 residual heat removal system (RHR) lineup from the pumps to the containment penetrations were inspected. As found valve and breaker positions were compared to the most recent valve and electrical lineups using FNP-1-SOP-24.0, Service Water System, Rev. 21, and FNP-1-SOP-7.0, Residual Heat Removal System, Rev. 24, respectively. All as found positions were correct for the current plant conditions and corresponded to the last lineup checklist. However, for the SWS, nine discrepancies were noted during the walkdown. A description of those discrepancies was provided to the Operations Manager. Included were examples of metal identification tags missing from valves, valves which were not listed in the SOP-24.0A checklist, and a valve which had an incorrect metal identification tag attached.

The inspectors noted the need for improved housekeeping in the service water pump house. Water was found standing on the floor and a general lack of cleanliness was observed. The licensee indicated that the SWS pump house was scheduled for a general cleanup effort.

No violations or deviations were identified.

k. Training

The majority of the operators interviewed indicated that both initial and requalification training were adequate and had improved substantially over the last two years. Interviews also indicated that the practice of operating crews attending requalification and simulator training as a crew enhanced the interface and teamwork within the crew.

Simulator training was highly praised and operators indicated that plant specific events and emergency operating procedures (EOPs) were well covered. Operators did indicate, however, that some initial and requalification training material contained incorrect information in relationship to the as-built and as-operated plant. Although the interviews indicated that these errors did not significantly detract from the effectiveness of training, the licensee should utilize a feedback mechanism to allow operations personnel to initiate necessary revisions to training material. A feedback program should include a method to notify the initiator that the material was revised, thus closing the loop and encouraging additional responses.

The licensee had a required reading program coordinated through the Training Department. A brief review of the training topics indicated that industry events, plant events, and plant modifications and procedure changes were incorporated. Each operator received a copy of the material and interviews indicate that tracking sheets are returned promptly to training to track the completion of the review.

The licensee rotates SROs through the Training Department. This practice enables a high experience level to be maintained among the instructional staff.

No violations or deviations were identified.

l. Operator Aids

The licensee has implemented an upgraded equipment labeling program. All equipment is being reviewed for adequate labeling and is being labeled by the Operations Group, as necessary, with appropriate equipment title and number. System walkdowns by inspectors indicated that most equipment was labeled, although there were several examples of missing or incorrect labels. All examples were pointed out to the licensee for corrective action. The inspectors also noted that in response to a previous event and violation, the licensee had color-coded and labeled access doors between Unit 1 and Unit 2. This operator aid should help prevent further similar personnel errors and events.

No violations or deviations were identified.

m. Fire Protection Administration

Responses obtained during interviews concerning areas that the SS and ROs felt were problem areas, revealed that the administrative workload associated with inoperable fire dampers, fire doors, and establishment of fire watches detracted from the other shift duties of the SS. This is considered a weakness.

No violations or deviations were identified.

n. Tagging

Procedure FNP-0-AP-14, Safety Clearance and Tagging Procedure, Rev. 8, established the safety tagging system as an administrative control to prevent operation of systems or components when such operation might cause personnel injury or equipment damage or when maintenance or testing is performed.

The inspection was conducted by direct observation of placement and removal of tagging orders, interviews with tagging officials and individuals who are responsible for placing tags, review of recent tagging related Incident Reports, and inspection of documents (prints, procedures, etc.) available for use by the tagging officials.

The following problems were identified by the inspectors and were supported by numerous licensee Incident Reports:

- additional in-plant training and experience were needed for the Shift Foreman Inspecting (SFI)
- SFIs needed additional training in the use of electrical prints
- hold tags lacked sufficient information to allow prompt reference to a specific clearance or to equipment tagged
- inadequate MWR details made tagging more difficult
- use of standard tag-outs was limited

- a comprehensive electrical load list was not available to the tagging officials
- microfiche drawings were difficult to read
- equipment list did not contain all Total Plant Numbering System (TPNS) numbers
- SFIs were sometimes called upon to complete complicated system tag-outs and restorations when their duties and working conditions do not allow concentration on large projects.

In the areas of safety clearance and tagging, interviewees consistently indicated that the SFI position had not been fully staffed and had been used as a training position for engineering personnel. Interviewees felt that as soon as a person was adequately trained to independently fill the position the individual would be transferred to a new position and management was slow in providing a replacement. The SFI, therefore, often depends heavily on the Shift Foreman Operating, the Shift Supervisor and other plant personnel to assist him in accomplishing assigned tagging tasks. The licensee believes that utilizing the Shift Technical Advisors as SFIs and tagging officials is an efficient use of personnel and increases the experience levels and credibility of the STAs. While this position has merit, it appears that additional management support will be required in the form of additional SFI/STA training and in providing complete electrical load lists and experienced personnel for assistance. Additionally, the Planning Group could assist by providing more complete MWR packages containing the latest procedures and drawings.

The inspectors observed that the red hold tag could be enhanced by including such information as the clearance number, position of equipment (open, closed, tripped, etc.) and date tag was placed. Such additional information would minimize tagging errors and permit a quick reference to the proper clearance thus enhancing efficiency, especially during outages. Interviewees indicated that the time required to coordinate between groups to place hold tags was a problem. The licensee should consider using only Operations personnel to perform the duties of the Designated Operator as described in FNP-O-AP-14. This could reduce time to place hold tags and, due to the increased training of Operations personnel, reduce errors. Finally, the licensee should review repetitive tagging errors for appropriate corrective actions. This failure to trend repetitive errors in tagging was noted as a weakness.

No violations or deviations were identified.

o. Independent Verification

Interviews with operators indicate that some misunderstand the independent verification requirements. Several interviewees, including supervisors, indicated that two people could, and often do, complete independent verification together as opposed to separately. This does not meet the intent of NUREG-0737 to independently verify the restoration for the proper position of safety-related valves, breakers, and systems. The licensee's management agreed that the personnel performing independent verification should do so separately. This position should be reemphasized through additional training and more specific wording in related administrative procedures.

No violations or deviations were identified.

p. Housekeeping, Cleanliness and Preservation of Equipment

The licensee had made improvements in the general condition of the plant. Contamination zones had been reduced significantly resulting in increased efficiency in Operations personnel tours and access to equipment. Provisions have been put in place to control leaks and spills. In general, the housekeeping of the plant was good. The inspectors did note that the housekeeping, cleanliness and preservation of equipment was poor in the service water building. Signs of trash in the auxiliary building indicate that the one time cleanup may not be supported by a long-term continuing program to maintain a high level of plant housekeeping.

The inspector noted that installed or portable ladders were not used consistently to access plant equipment resulting in damage to equipment and lagging due to climbing. Climbing on piping and supports also represents a personnel hazard.

No violations or deviations were identified.

q. Indicator Lamps

A listing of appropriate indicator lamps for the main control board indicator lamps was not available to the control room operators. Problems, including a plant trip, have occurred at other plants as a result of installing incorrect indicator lamps in the main control board. The inspectors recommended that a list be provided to operators.

No violations or deviations were identified.

6. Maintenance Support of Operations (62700, 62702, 92703)

The inspectors reviewed administrative procedures, completed work packages, work packages classed as ready to work, maintenance incident reports, LERs which were maintenance related, the maintenance planning process, and the maintenance backlog. The inspectors also observed maintenance and preventive maintenance in progress and interviewed managers, supervisors, foremen, journeymen, apprentices, and engineering technicians.

a. Qualifications and Training

The Maintenance Manager, supervisor and foremen qualifications generally exceeded the licensee's minimum administrative requirements. The Maintenance Manager was supported by a Mechanical Maintenance Supervisor, Electrical Maintenance Supervisor and an I&C Maintenance Supervisor. These managers and the Operations Manager report to the Assistant General Manager - Operations. A single manager over Operations and Maintenance appeared to improve coordination between these groups and was noted as a strength.

The Institute of Nuclear Power Operations (INPO) accredited maintenance training program had been implemented and a review of training records indicate approximately 95 percent of the mechanics had completed all training segments.

No violations or deviations were identified.

b. Licensee Self-Assessment

Previous NRC inspection reports indicated that maintenance errors involved failure to follow procedure, inadequate communications, and removal from service of the wrong equipment for maintenance. The errors appeared to be attributable to several root causes including a lack of specific maintenance procedures, inadequate direct field supervision, less that aggressive corrective actions to repetitive errors, and less than adequate Operations oversight in the actual removal of equipment from service for maintenance.

Maintenance management had recently completed a Self-Assessment and has established goals to upgrade and improve maintenance practices. This includes items such as: developing a maintenance procedure writers' guide, developing additional needed procedures and revising existing procedures, integrating corrective maintenance with required planned maintenance, developing performance teams to improve communications, and having work requests "packaged." The inspectors independently came to similar conclusions concerning deficient areas where attention needs to be applied.

c. Control of Calibration and Calibration Stickers

The inspector reviewed the licensee's procedure FNP-0-AP-11, Control and Calibration of Test Equipment, Test Instrumentation and Plant Instrumentation, Rev. 8. This procedure contains the following requirements. Calibration stickers are to be affixed to permanently installed process instrumentation. Instruments which are utilized for surveillance testing procedures (STP) or the preventative maintenance program (PM) shall have a green and white calibration sticker attached. These stickers, as a minimum, will indicate date of calibration and date next calibration is due. Instruments which are not covered under the STP or PM program shall have red and white caution stickers attached to indicate that the instrument is not routinely calibrated. If an instrument tagged with a red and white sticker should require calibration to support a test or other non-routine check, a green and white calibration sticker will also be attached, but the due date shall be left blank.

The inspector noted the following calibration sticker discrepancies while touring the plant on February 23 and 24, 1988.

Instrument	Discrepancy
NIN35PDI539	Red sticker required, not attached. Green sticker attached indicating due date of February 6, 1988, due date is required to be left blank. Instrument "pegged" high, no deficiency tag (DT) attached as specified in FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, Rev. 12.
N2P16PDI2925A	Red sticker required, not attached. Green stickers attached indicating due date of June 13, 1988, due date is required to be left blank. Instrument "pegged" high, no DT attached as specified in AP-52.
N2P16PDI2925C	Red sticker was attached. Green tag attached indicating due date June 16, 1987, due date is required to be left blank. Instrument "pegged" high, DT was attached but no Work Order (WR) number noted on the tag as required in FNP-0-AP-52.
N2C23PI507	Red sticker required, not attached. Green sticker attached indicating due date of November 20, 1988, due date is required to be left blank.
QIR43TI658	Green tag attached indicating due date of August 20, 1988. MWR 164869 dated February 17, 1988 issued to calibrate (18 months overdue) instrument; instrument was out of tolerance (OOT), not adjustable; new instrument was ordered and OOT instrument was reinstalled but DT was not attached to indicate instrument was OOT.
NIN21FT597	Green tag attached indicating due date of January 30, 1988
NIN21FT596	Green tag attached indicating due date of February 9, 1988

The above discrepancies were discussed with the licensee, noting that this was not an all inclusive list; the licensee acknowledged that this area needs improvement.

Adherence to the procedural guidelines for calibration stickers should be emphasized and a general plant walkdown conducted to establish a baseline of procedural compliance. In a telecon with the Region on March 21, 1988, the licensee indicated only one of the aforementioned instruments, QIR43TI658, was actually outside the 25% calibration allowance.

No violations or deviations were identified.

d. Use of Vendor Technical Manuals

Licensee procedure FNP-0-AP-15, Maintenance Conduct of Operations, Rev. 9, Section 5.4 states, "Most of the equipment installed at the plant was supplied with technical manuals. These manuals are controlled by Document Control and may be checked out for use during maintenance activities. During the work activity, these manuals are to be used for information only. If a step-by-step procedure is deemed necessary for a particular task, the technical manual will be used as guidance to develop a maintenance procedure."

Licensee procedure FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, Rev. 12, Section 7.5 states, "...provide a work sequence that includes an appropriate delineation of the activities to be performed either by reference to approved procedures and/or by inclusion of steps written into the body of the work sequence."

Approximately 60 Maintenance Work Requests (MWRs) on safety-related equipment were reviewed, and it was found that many work sequences stated, "Repair using vendor manual for guidance . . .". Instead of using the vendor manual for information only, or instead of incorporating steps from the vendor manuals into the MWR work sequences, the vendor manuals are used to provide the work sequence for the maintenance department.

Licensee procedure FNP-0-AP-04, Control of Plant Documents and Records, Rev. 12, Figure 1, Drawing/Manual - Revision Form, includes signature blocks for the applicable department supervisors and managers to review and approve new vendor manuals and revisions to vendor manuals for use at the plant site.

The inspector observed safety-related work being performed on the 1-B diesel generator and observed that procedures were not being utilized at the job site, but that Manual U184852, Rev. K was being used to guide the task. A review of the revision forms for this manual determined that the last revision that was approved by the department manager for use was Rev. F. Site personnel informed the inspectors that these forms were used only if the revision was generated on site. If the revision was generated by Bechtel or Southern Company Services it was assumed correct and no site technical review and approval was performed.

The use of manuals in place of approved procedures is a weakness in the licensee's control of work activities. This lack of specific maintenance procedures was also identified in the licensee's self-evaluation of maintenance activities. The licensee indicated that plans exist for developing new maintenance procedures, and revising existing procedures to incorporate vendor manual guidelines.

No violations or deviations were identified.

e. Maintenance Work Request (MWR) Backlog Reduction

The licensee recently established an aggressive program to reduce the number of active MWRs. Goals have been established based on INPO guidelines and the various maintenance departments are scheduling overtime as necessary to maintain the backlog below the established goals. The inspector noted that the number of active MWRs older than 90 days was significantly lower than the established goals. Graphs depicting the number of open MWRs were conspicuously displayed on bulletin boards leading into the turbine building and on plant information television monitors located at several points throughout the plant site.

The effort to reduce the number of backlogged MWRs, and the practice of keeping plant personnel aware of performance in this area, are noted as a strength in the maintenance area.

No violations or deviations were identified.

f. Motor-Operated Valve Common Mode Failure Correction Program

IE Bulletin No. 85-03, Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings, requested licensees to develop and implement a program to ensure that switch settings on certain safety-related motor-operated valves be selected, set, and maintained correctly to accommodate the maximum differential pressures expected on those valves during both normal and abnormal events within the design basis.

The inspector interviewed the coordinator for the program, reviewed the established program, and reviewed the results of several of the valves that have already been worked under this program. The licensee completed assessment and development of the required program, and initiated corrective actions on 37 valves (out of 104 targeted valves) during the latest Unit 2 refueling outage. During this effort, problems were encountered with insufficient numbers of spare parts, and in coordinating system removal with the Operations Department.

The licensee identified these initial problems and had modified the program in an attempt to eliminate them in the upcoming Unit 1 refueling outage. The inspector reviewed the new program and determined that it has the potential to improve performance in this area.

No violations or deviations were identified.

g. Emergency Diesel Generators

The inspector reviewed the lists for both active and historical MWRs for the period 1987 and 1988. During this period, there were approximately 500 MWRs written for work on the diesels. Of these, over 70 percent concerned corrective maintenance on the diesel generators and support systems.

System Performance Engineering identified the emergency diesel generators as one of the safety systems with the highest failure rate during the maintenance history review performed by that department. In a report dated December 1987, the failure rate was reported to the Maintenance Manager.

The inspector interviewed the sector supervisor responsible for emergency diesel generator maintenance, regarding the failure rate of the diesel generators. The supervisor has been the designated engineer for diesel maintenance for approximately six years. During the interview it was determined that the supervisor was aware of the number of problems with the diesel generators, but he believed that the majority of the repairs were minor in nature and did not impact the reliability of the system. After a review of the maintenance history for the period under consideration, the inspector determined that the majority of the repairs were minor. There are no reliability concerns at this time.

The inspectors observed maintenance being performed on the 1-B diesel generator during the course of inspection. The maintenance was being performed under the direction of a vendor representative and under the guidance of the vendor technical manual. Lack of specific maintenance procedures was a contributor to the events leading to the maintenance observed by the inspectors on the 1-B diesel generator, which is discussed later in this report. The Maintenance Manager stated that major work on the diesel generators is routinely performed using a vendor representative and technical manual in place of plant procedures, but that plans exist to develop site specific technical manuals and procedures. The licensee indicated that they felt that the maintenance performed was within the skill-of-the-craft. The inspector reviewed the Maintenance Training Program and determined that 64 hours of diesel engine training is included in the program.

No violations or deviations were identified.

h. Preventive Maintenance

Licensee procedures FNP-0-AP-53, Preventive Maintenance Program, Rev. 3, and FNP-0-GMP-1, Preventive Maintenance Procedure, Rev. 9, provide instructions for the requirements and implementation of the Preventive Maintenance (PM) Program. Reviews were conducted of the appropriate procedures, Task Planning Sheets (TPs) (FNP-0-GMP-1, Figure 4) for approximately 300 tasks, monthly schedules for each of the maintenance disciplines for January and February 1988, and the backlog history through November 1987. In addition, the PM coordinators for each of the maintenance disciplines were interviewed.

As of November 1987, there were in excess of 400 backlogged PM work authorizations. The supervisors of the various disciplines indicated that there were problems completing the PM tasks because of the volume of corrective maintenance being performed. One supervisor stated that one of the problems was the difficulty in coordinating PMs between the disciplines on the same systems.

The inspector determined, from the interviews with the PM coordinators, that each discipline controls the PM scheduling process differently, and that there was not an integrated coordination system. Monthly schedules are utilized to establish the dates for performance of PM tasks and document completion of the tasks. In Electrical Maintenance, the work planner maintains the schedule, allowing the completion of the records sooner than in the sections where the PM coordinator maintains the monthly schedule. In all three maintenance disciplines, the January monthly schedules were not completely signed off for completed PM tasks. The PM coordinators confirmed that a delay existed in the completion of the monthly schedule.

PM coordination problems were recognized in the licensee's maintenance self-evaluation, and plans exist to implement a computer-based repetitive task program to administer the PM program. The program will contain requirements for corrective and preventive maintenance from the various disciplines and will be utilized to schedule both types of maintenance.

The inspector also noted that the work authorization requires a review by the responsible maintenance foremen following functional acceptance. The inspector determined that, at times, completion of the post maintenance acceptance review takes several months.

The detail present for post-maintenance testing requirements varies greatly between the disciplines. Some maintenance task planning sheets, such as QSR43A501, contained vague post-maintenance testing requirements, requiring only that proper operability be verified and providing no instruction, references, or acceptance criteria for the performance of the post-maintenance testing.

The use of correction tape and fluid on numerous master copies of maintenance task planning sheets, which were maintained in work planning, was brought to licensee management attention for correction.

Additionally, the inspector reviewed FNP-0-AP-28, Plant Lubrication Program, and interviewed responsible personnel. The station lubrication program is not included in the preventive maintenance program, but is scheduled by the Systems Performance Group and implemented by Operations and Maintenance groups. During system walkdowns, numerous valves were observed with grease fittings painted over. The licensee explained that a large scale painting effort had recently been completed. Three valves, Q1P16V511, Q1P16V506, and Q1P16V507, located in the service water pump house, were determined by inspectors not to have been lubricated since March 1986 (two years) although they had been assigned an 18-month lubrication period. The licensee's program failed to flag the overdue lubrications. It was additionally noted by the inspectors that the licensee had not specified an acceptable grace period for overdue lubrications. The valve lubrication program is identified as a weakness.

No violations or deviations were identified.

i. Valve Maintenance

The inspector reviewed the listing of all active MWRs as of February 25, 1988, and determined that the Mechanical Maintenance Department had approximately 450 safety-related MWRs assigned to them. Approximately 34 percent of these were pertaining to corrective maintenance of valves. In the last six months, there have been approximately 250 safety-related MWRs completed on valve corrective maintenance. The Maintenance Manager indicated that he did not consider a problem to exist with an excessive number of leaking valves at the site.

The inspector conducted a tour of the auxiliary building for both units and noted a number of valves with problems, including leakage, missing handwheels, corrosion, etc. Examples were in the Unit 1 1A and 1C Safety Injection pump rooms where there are several catch basins hung under leaking valves. The majority of the problems identified by the inspector already had deficiency tags placed on them.

No violations or deviations were identified.

j. ASCO Solenoid Valve Problem

On January 18, 1987, three valves failed to stroke during the performance of a surveillance test. Valves HV-3376, HV-3377, and HV-3380 are ASCO solenoid valves. HV-3376 and HV-3377 are containment sump discharge isolation valves and HV-3380 is the containment sump recirculation valve on the liquid radwaste system. The three valves each failed to stroke during the two initial attempts. The next attempts on both HV-3380 and HV-3376 resulted in the valves stroking. HV-3377 failed on two more attempts. An operator who had been dispatched to HV-3377 reported that air was blowing by the solenoid when stroking of the valve was attempted. Approximately 40 minutes after the initial failure, the Shift Supervisor was informed that HV-3377 would not stroke. Approximately 60 to 90 minutes later, the Shift Supervisor was informed that the HV-3376 and HV-3380 valves had also failed to initially stroke. Due to the operator not notifying the shift supervisor of the initial valve problems, it was not recognized until after the event that the unit had entered Technical Specification 3.0.3. The unit was in TS 3.0.3 approximately 20 minutes, less than the allowable one-hour corrective time.

MWR 156924 was performed to repair the solenoid on HV-3377 and the valve successfully stroked following the work. MWR 134615 was written to check the air regulator and supply air line for rust or dirt for valve HV-3380. The mechanic reported under the "Maintenance Performed" section of the MWR that he "Found filter a little dirty and rusty, but not bad enough to be a real problem; blew air through a paper towel and got a small amount of rust in powder form." No evidence was found that any inspection was performed on the solenoid.

Licensee Event Report (LER) 87-005 stated, "HV-3376 will be inspected during the next outage of sufficient length." MWR 156929 was written to identify the problems with HV-3376. The work sequence, written on January 20, 1987, stated:

(1) Check air regulator filter for rust, dirt, etc. - install a new filter.
(2) Blow down air line thru a white cloth - check for rust, dirt, etc. - blowdown until clean.
(3) Reconnect air lines and install filter - check for air leaks, crimped tubing, etc.

This work sequence appeared to presuppose that the problem was a dirty air regulator filter, and did not require an inspection to determine the root cause. The MWR was worked on April 8, 1987, and the work performed was "Installed new regulator and checked air lines. Had operations stroke valve. Valve stroked fine." Since the valve was stroking satisfactorily following the initial two failures, changing the air regulator did not determine that the air regulator was the root cause of the valve failure.

On both HV-3376 and HV-3380 an adequate root cause evaluation was not performed. On HV-3380, the worker implied that the air regulator was not felt to be a problem. Inadequate evaluation of the potential root cause of failures is identified as a weakness.

No violations or deviations were identified.

k. Completed Maintenance Work Request/Review

Selected completed Maintenance Work Requests (MWR) were reviewed for completeness in documentation, post-maintenance testing, independent verification and root cause determination. The following MWRs were reviewed.

MWR 147294	1A Charging Pump Rotation Assembly Changeout
139135A	Failure of MOV 3019A to Stroke
169106	Torque Switch Setpoint Adjustment on MOV 8108
169112	Torque Switch Setpoint Adjustment of Q2E21LCV115B
145145	Fuel Oil Leak on #2 Cylinder Injector on 1-2A Diesel
138182	Investigate Indicating Limit Switch Failure of MOV 8701B
84306	Inspect 1B Charging Pump Speed Reducer
166525	Inspect Indication of MOV 3825B
163737A	HV 8149C Failed to Stroke
155718A	MOV 8884 Failed to Stroke
144663	Seismic Restraint Bolts on 7300 Card System

In general, MWRs were being completed in accordance with FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, Rev. 12. The inspector noted, however, that MWR 169106, which adjusted the close torque switch on a valve, did not require a local leak rate test (LLRT) of the valve. The requirement for LLRT was not documented as a retest on the MWR. Section 48 of the MWR should list the required post-maintenance test and indication of its satisfactory performance. The inspector verified that an acceptable LLRT was performed on the valve prior to the licensee declaring it operable. The inspector did not identify any cases of inadequate retesting.

It was noted that in some MWRs jumpers had been used for various troubleshooting activities but had not been independently verified as removed. Independent verification is not a requirement in FNP-0-AP-13, Control of Temporary Alterations. Technicians are required to document use of temporary alterations such as lifted leads, jumpers, and sliding links on a continuation sheet of the MWR. It would appear that during MWR review it is easy to miss an alteration that may have been inadvertently left, since independent verification is not required, and the documentation of the alteration could be entered anywhere on the MWR. In all cases reviewed, temporary alterations were documented as having been removed.

The inspector noted that documentation of root cause for component failures was not always clear or in some cases was missing completely. Failure descriptions, such as blown fuse, were observed on MWR 166525, 163737A, and 155718A however no determinations of causes were evaluated and documented. In one case on MWR 155718A, troubleshooting was performed twice on MOV 8884, B Train Hot Leg Injection, and in each case the same blown fuse was replaced, however, the root cause was not established. MOV 3019A, Service Water to 1A Containment Cooler, would not stroke, and maintenance was performed under MWR 139135A. No problems were found and the valve successfully operated during troubleshooting. Further evaluation was not conducted.

The inspector reviewed MWR 144663, which addressed the replacement of seismic restraint bolts in the 7300 card system. The documentation in the work order package did not indicate a seismic analysis had been performed for the as-found configuration of the 7300 cards, nor did it address the specific 7300 cards involved. Subsequent review of additional reports indicated that an adequate analysis was performed but not documented on the work order.

No violations or deviations were identified.

l. System Performance Group

Procedure FNP-0-AP-63, Conduct of Operations - System Performance Group, Rev. 2, Section 4, describes the use of problem reports. Problem reports are used to identify, document, and maintain accountability of recommendations and evaluations communicated to other groups. The originator maintains a copy for tracking and the applicable group supervisor receives a copy for action. Upon completion of these actions, the forms are to be returned to the System Performance Group.

Review of the Inservice Inspection Section (ISI) problem reports indicated that responses were not being sent back to the System Performance Group nor was the System Performance Group pursuing the closeout of the problem reports. ISI problem reports 002, 004, 018, 020, 021, 023, 026, which cover a period of May 1986 to February 1988 revealed high particulate and water levels in the lube oil samples taken from the Unit 1 and 2 steam generator feedwater pumps. ISI problem reports 002, 010, 019 revealed high copper content in the 2C DG lube oil sample indicating excessive wear problems. Further review indicated that the responsible groups had taken corrective action, but had failed to return their copy of the problem reports to the Systems Performance Group indicating that corrective actions had been taken.

The importance of not closing the problem report was clearly demonstrated in QC problem report 004. The report identified that nonconforming non-safety-related Code C coupling bolts had been installed in the 1A and 1B charging pumps. They had been installed in the 1B pump under MWR 84306 in September 1983 and on the 1A pump under MWR 147294 in August 1986. The coupling bolts are installed as a set of four due to balancing considerations. The nonconforming bolts were discovered when the licensee determined, after the August 1986 work, that nonconforming material had been ordered as replacement parts. The licensee then reordered safety-related Code A coupling bolts for installation in the pumps. The licensee failed to perform an evaluation or a justification for continued operation of the charging pumps with the installed nonconforming bolts.

The new safety-related bolts arrived on site on December 20, 1987, however, the licensee failed to install them since an MWR had not been written to track the nonconformance. This was pointed out by the inspectors and the licensee took prompt action to install the Code A coupling bolts.

In a telecon with the licensee on March 21, 1988, the licensee indicated that an evaluation had been completed that indicated that the non-safety Code C bolts had not rendered the charging pumps inoperable while installed. The licensee indicated that the determination was based on the following:

(1) The Code C bolts were obtained from the original pump manufacturers.
(2) Vibration data taken since the bolts were installed showed no signs of imbalance.
(3) Information from the bolt manufacturer indicated that the material in the Code A (safety-related) and Code C bolts is the same.
(4) A letter from the pump manufacturer which indicated that no additional testing would be required for Code A bolts. The only requirement would have been a Certificate of Conformance stating that the bolts met the requirements of the purchase order and that they were equal to or better than the original bolts.

The licensee provided the letters from the pump manufacturer and the bolt manufacturer for NRC review. The letters indicated that all Code A bolts are inspected for defects while only a sample of Code C bolts are inspected.

Appendix B of 10 CFR 50 requires, in Criterion XV and [illegible], that nonconforming material be controlled, reviewed for acceptability prior to use, and that the licensee establish controls to assure that nonconforming material is promptly identified and corrected.

The NRC Vendor Inspection Branch inspection, conducted in May and June of 1987, identified in NRC Inspection Report 50-348, 364/87-11 that a number of commercial grade components had been installed in safety-related equipment. A violation with a civil penalty was issued. The failure to perform an evaluation to accept the nonconforming bolts and/or determine pump operability and the failure to take corrective action to ensure that the Code C bolts were replaced in a timely manner is identified as an additional example of Item I.B of the Notice of Violation and Proposed Imposition of Civil Penalties (EA 87-142) associated with NRC Inspection Reports 348, 364/87-11 and 348, 364/87-14 dated November 3, 1987. Your response to this item is under review by the NRC.

m. Work Planning Process

FNP-0-AP-52, Equipment Status Control and Maintenance Authorization, Rev. 12, describes the Maintenance Work Request (MWR) System. The planning program is divided into two groups, daily planning and outage planning of which only daily planning was evaluated during this inspection. Daily planning is under the control of Operations and is supervised by an SRO licensed individual. The daily planning staff consists of two planners in each of the areas of mechanical, electrical and I&C maintenance. Additionally, two SRO licensed operators are assigned. Planning provides support seven days a week with 24-hour coverage on Monday, Wednesday and Friday.

Approximately 20 open or completed MWRs were reviewed for completeness. Discussions were held with four maintenance planners and the planning supervisor. Maintenance personnel were also asked for their perceptions on the planning program. The inspector walked through the preparation of one MWR with a planner. Daily planning meetings were attended to ascertain the effectiveness of job scheduling and departmental interface.

The daily planning meetings were observed to be used effectively in communicating station maintenance activities and in prioritizing work. The inclusion of SRO qualified individuals on the planning staff was observed to be an asset in maintenance planning. The planning program uses the Farley Nuclear Plant Information Management Computer System to keep track of current MWRs and the result of historical MWRs. Computer printouts of active MWRs are routed to maintenance sector supervisors and are used in the daily planning meetings.

The maintenance technician is required to obtain all references and drawings listed on an MWR. The MWRs, however, generally did not provide tool requirements, scaffolding requests, or torque values. FNP-0-AP-44, Cleanliness of Fluid System and Associated Components, Rev. 13, requires appropriate cleanliness controls be specified in the controlling procedure when opening a Class A, B, or C system. Generally, this requirement was not being met in that numerous MWRs reviewed included only a reference to FNP-0-OAP-44, but did not specify cleanliness controls.

Some maintenance personnel interviewed felt the quality of maintenance planning could be improved. Job foremen typically performed a lot of the planning, which impacted the time available for observing maintenance activities. This appeared to be due to the small number of planners allotted. Planners manually scheduled preventative maintenance (PM) items into the daily schedule of maintenance activities. It is required that PMs be extracted from various disciplines when a component is down for corrective maintenance. This has proven to be ineffective in the past. A new computer system scheduled to be installed will integrate PMs with other scheduled maintenance and be able to provide due dates and last date accomplished information. The system apparently has been promised for a while, but the implementation date had slipped. The planning staff appears adequately qualified. The planning supervisor expressed a desire to include more training for his planners, however, he recognized that with such a small staff and accounting for personnel absences (vacation, illness) he could not afford to lose planners for a significant amount of time.

No violations or deviations were identified.

n. Observation of Work in Progress

The inspectors observed portions of selected maintenance activities to ascertain that the activities were conducted in accordance with approved administrative and maintenance procedures.

On February 23, 1988, the inspector observed troubleshooting activities under MWR 175614 on the 1B Diesel Generator fuel racks. During the previous evening, operators were unable to shutdown the engine for approximately 30 minutes. One of the fuel racks apparently failed to cut off fuel to the number 12 cylinder. It was determined that the collar assembly on one fuel rack had been excessively tightened the week before when maintenance personnel were instructed to tighten up loose bolts. This activity was apparently conducted without the use of an approved MWR and caused the fuel rack to hang up.

During troubleshooting, it was observed by the inspectors, that the fuel rack shields and fasteners that were being remove[illegible] ere not being bagged and labeled as required by FNP-0-AP-15, [illegible]itenance Conduct of Operations, Rev. 9. This was corrected by [illegible] licensee after the inspectors pointed this out. It was then dec[illegible]ed by the licensee to remove the number 12 cylinder head and remove the piston for inspection. This activity was conducted without the use of a detailed step by step procedure. The inspectors were concerned that the licensee intended to use only the engine technical manual and the presence of the vendor to remove the piston. Station approved procedures were not available. FNP-0-AP-15, Rev. 9, specifies that technical manuals are to be used for information only.

The inspectors pointed out that teardown of a diesel engine certainly warrants written procedures and does not qualify as a skill normally possessed by maintenance personnel. The licensee has identified in its Maintenance Self-Assessment that written maintenance procedures do not exist on many safety-related components and are necessary. During the maintenance the technicians attempted to remove the connecting rod cap from the wrong side of the engine and dropped it into the sump. A better planned job could have prevented this.

The inspectors reviewed tag out order 88-302-1 for the maintenance. The tag-out incorrectly identified circuit breaker CB-4 as the power supply for the oil heater as opposed to the circulating oil pump. Conversely CB-3 was incorrectly identified as the power supply for the circulating oil pump versus the oil heater. While both components ended up being deenergized and tagged, the potential clearly existed for inadequate isolation of power supplies. Neither the person hanging the tag nor the verifier identified this problem until pointed out by the inspector at which time the licensee corrected it.

It was also noted that this tag-out was apparently a copy of a standard tag-out for the 1B Diesel Generator and had been used on numerous occasions. The inspectors later observed I&C technicians attempting to reconnect the Resistance Temperature Detector (RTD) for the generator bearing. The technicians were unable to accomplish this as the three leads had not been labeled or otherwise identified in the MWR, nor were electrical prints available at the job site to determine correct hookup.

On February 24, 1988, the inspectors observed maintenance on valve Q2P16V582, C Service Water Pump Discharge Valve Vacuum Breaker. The valve was being relapped. It was noted that the bonnet/cap to the valve was not bagged nor were other removed components labeled as required by FNP-0-AP-15. The job foreman was questioned, but was unable to explain if this was required. The procedure being used, FNP-0-GMP-27.0, Disassembly and Reassembly of Safety-Related Valves, was reviewed. It was observed that no body to bonnet torque value was specified although an entry existed for this task. The job foreman did not know the value and had to call the maintenance offices to obtain it.

On March 7, 1988, the inspectors observed reassembly of the 1C service water pump under MWR 150720. After replacement of the impeller bowl assembly, a flanged connection on cooling water to the motor was observed to be tightened without the use of a torque wrench. The maintenance technician was questioned and indicated he had forgotten the torque wrench. He also did not know the value to which the bolts were required to be torqued. The foreman assumed that the flange had been torqued correctly until informed otherwise by the inspector at which time he researched a standard for values based on bolt size and ensured the flange was properly torqued. The pump later had to be disassembled because the stuffing box was cocked. On March 8 the same flange was again tightened without a torque wrench. Further research by the licensee revealed that the flange was not required to be torqued because it was on a low pressure system.

The inspector was concerned that guidance for torquing bolts on some safety-related systems was unclear. Typically, values from drawings or technical manuals are used or a standard value is used from the licensee's Pipe Fitting Procedure, SS-1109-2, which specifies values for piping systems designed for greater than 600 psig. Maintenance personnel interviewed were aware of the reference, however, they were inconsistent in their understanding of its use. While some assumed the reference was applicable to all components, others felt that it applied to safety-related components and still others believed that unless a torque value is specified in the MWR or procedure, it was not important. It was noted that typically this reference is not included in the MWR nor readily available for use at job locations. Failure to provide guidance for torquing was noted as a weakness.

No violations or deviations were identified.

7. Management Controls (40700, 92700, 92701, 92720)

The organizational structure was reviewed to determine that it was as prescribed by corporate policy documents, that its functions were adequately defined by charter documents and procedures and that staffing and staffing plans appeared adequate to fulfill the chartered roles.

The status of implementation of major organizational functions was determined by review of procedures, review of records, interviews and discussions with licensee managers, supervisors, and staff personnel inside and outside the departments of interest.

a. Plant Modification Control

Plant modification control was reviewed to determine if this control was adequate to insure proper implementation of design changes to the facility. Plant modifications were controlled by FNP-0-AP-8, Design Modification Control, and FNP-0-AP-70, Conduct of Operations - Plant Modifications and Maintenance Support.

In addition to these procedures, the licensee had established a group of procedures entitled Plant Modification Procedures (PMPs). The PMPs provided generic instruction for such items as field running of pipe and were used in the performance of plant design changes. There were two types of plant design changes: Major plant design changes called Production Change Notices (PCNs) and minor plant design changes called Minor Departures (MDs). Major plant design changes were initiated via a Production Change Request (PCR) which, when approved, provided the justification for the design change. Following approval of the PCR, a PCN was developed and provides the controls for a plant design change when implemented.

PCN packages were complete and well documented. The modifications staff appears knowledgeable in their duties and the drawing correction backlog was acceptably small. The licensee has been able to maintain an outage modification completion rate of approximately 90 percent.

PMPs allow work to be inspected by "peer" review. This means that the worker, another worker, or his supervisor can provide the quality inspection for work performed. Deficiencies in the "peer" review process are discussed in paragraph 7.g.

The MDs are minor plant design changes that are very limited in scope and can be either permanent or temporary. MDs did not receive the same review and approval as a PCN and did not involve detailed engineering activities. MDs were required to receive PORC review prior to implementation if required by a pre-implementation check-list. Those that do not require PORC review prior to implementation, only received a lower level of plant supervision review and approval. In either case, all MDs received PORC review within after 60 days of implementation unless the General Manager - Nuclear Plant granted an extension.

To audit this area, the inspection consisted of a review of the controlling procedures and an interview with the Plant Modifications Manager. PORC meetings were attended by the inspector to observe the review and approval of PCNs and MDs. In addition the following completed design packages were reviewed:

PCN B87-2-4048	Replacement of Anchor/Darling Tilting Disc Check Valve
PCN B87-2-4340	Reactor Vessel Head Conoseal Modification
PCN SM81-1016	DG 1-2A and 1B Jacket Wtr. Sys. Flow Control Orifice
MD 88-1838	By Pass the S2 (Test Auto Short Trip Switch) Switch for the RTA Breaker Using a Temporary Jumper
MD 88-1812	Setpoint and Reset Change on Normal Receiver Air Pressure Switches and Compressor Control (on/off) Pressure Switches on 1C Diesel

MD 87-1786	Replacement of Existing ASCO Solenoid Valve Q2P17SV3045 With EQ ASCO Solenoid Valve
MD 87-1717	TDAFW Pump Start Train C Selector Switch Located on Hot Shutdown Panel

MDs were not approved by the General Manager - Nuclear Plant prior to implementation. The plant modification procedure, FNP-0-AP-8, allowed MDs to be implemented without PORC review and approval. While this procedure also required that MDs be reviewed within 60 days of implementation (unless extended by the General Manager - Nuclear Plant), this means that plant design changes could be in effect within the plant for 60 days or more before they were reviewed by the PORC. Since some MDs may be implemented with only specific discipline lower level supervisory review, the possibility exists that a design change could be made that was detrimental to plant operations, and the error would not be identified for 60 days or more. The inspectors did not identify any instances where a major design change was processed as an MD, but implementation of MDs without the approval of the General Manager appeared to be contrary to the requirements of Technical Specification 6.5.3.1.b. This TS requires approval of proposed modifications by the General Manager prior to implementation. The NRC is reviewing the applicability of TS 6.5.3.1.b to MDs and this item is identified as unresolved item 328, 364/88-05-03. In any event, lack of Plant Manager review and PORC review prior to implementation appears to be a weakness in the licensee's design change process.

The licensee appears to have an effective system to approve, develop, and implement major design changes via the PCN process. The plant modification staff appears to be capable of carrying out their intended tasks. The MD approval and review issue is considered to be a weakness that needs further resolution.

No violations or deviations were identified.

b. Onsite Engineering Group

A review of the activities of the licensee's onsite engineering group was conducted to determine the group's interface with both corporate and site operations and to determine if engineering issues were being adequately resolved.

The engineering functions at the site are divided among three groups; System Performance, Plant Modifications, and Plant Maintenance. The maintenance group had engineers on the staff with one engineer assigned to each maintenance discipline, i.e., instrumentation and control, electrical, and mechanical. Due to the diversity of the engineering staff, there was no one procedure governing the activities of the onsite engineering personnel. It appeared that the engineering activities are controlled by the following procedures:

FNP-0-AP-3	Plant Organization and Responsibilities
FNP-0-AP-18	Conduct of Operations - Technical Group
FNP-0-AP-63	Conduct of Operations - Systems Performance Group
FNP-0-AP-70	Conduct of Operations - Plant Modifications and and Maintenance Support.

The inspection consisted of a review of the controlling procedures and interviews with the various groups' supervisors and managers. In addition, the Vice President for Nuclear Operations was interviewed and a telephone interview was held with corporate engineering management.

There appeared to be a very good relationship between the site engineering groups and corporate engineering. While the corporate engineering staff appeared to be limited (there are approximately 35 engineers), the staff maintained personnel on 24 hour call and had personnel dedicated to the Farley plant at each of their consultants. This consultant staffing consisted of about 55 personnel fr m Southern Services, 50 personnel from Bechtel, and 10 personnel from Westinghouse. The relationship between the corporate and site engineering groups and the dedicated consultant personnel was considered to be a strength. It was noted that the licensee relied heavily on consultants, however, it did not appear at this time to be detrimental to the performance of the engineering functions.

No violations or deviations were identified.

c. Plant Operations Review Committee

The activities of the plant's onsite safety review committee, PORC, were reviewed to determine if the committee was functioning as required by the Technical Specifications (TS), was providing adequate interface with various plant disciplines, and was performing adequate safety evaluations.

The inspector attended PORC meetings, interviewed PORC members and the PORC secretary and reviewed administrative procedures, member assignment, meeting minutes and meeting agendas. In addition to the requirements delineated in the facility TS, the PORC activities are controlled by procedure FNP-0-AP-2, the PORC Charter, and a memorandum signed by the General Manager - Nuclear Plant that lists the PORC members and their alternates.

The PORC holds meetings on the order of twice a week. More frequent meetings or special meetings are held as needed. There is good member participation during the meetings and evidence of strong management control. These aspects were considered to be a strength of the PORC review process. Prior to each meeting members received a meeting agenda that delineated the subjects to be covered. The agenda also contained copies of procedures to be reviewed and copies of safety evaluations and/or plant event reports. The agenda could be further enhanced by providing advanced information regarding the design changes to be presented at the meeting. While the agenda indicates, in general, that design changes are to be reviewed, it does not specify the changes. The agenda should, as a minimum, specify the number and title of the design changes to be reviewed. In addition, minor design changes (minor departures) should be attached to the agenda (as procedure changes are) so that each member has a copy for review both before and during the meeting.

One other item noted involved the apparent inconsistency between TS 6.5.1.6.f, which required all safety related noncompliances to be reviewed, and the PORC Charter, which allowed the General Manager - Nuclear Plant to select the noncompliances for review. While there was no evidence that the PORC was not accomplishing the required reviews, this inconsistency could lead to a violation of the TS.

The PORC appeared to be accomplishing their mission and performing adequate reviews and safety evaluations. Implementation of a more complete meeting agenda and resolution of the inconsistency between the PORC Charter and the TS should strengthen the review process and ensure compliance with the TS.

No violations or deviations were identified.

d. Plant Status Meetings

Various plant status meetings were attended to determine whether day-to-day plant activities and planned future activities were being adequately disseminated to the applicable plant staff.

The inspector observed the SSS turnover which included discussions of all the ongoing and planned maintenance and testing activities for the shift. The inspector noted that during the subsequent control room operator turnover meeting, the SS, although briefed by the SSS on the ongoing and planned shift activities, did not inform the operating shift of all these activities. Interviews were conducted with operators to assess their knowledge of ongoing maintenance affecting control room indications. The interviews indicated that operators felt that they were not always fully briefed on pertinent maintenance activities. The licensee should review the level of detail in the briefings/notifications to operators of ongoing maintenance activities to assure that operators are fully informed of maintenance activities affecting control room indications.

In general, there appeared to be good interface between plant groups and good participation by personnel in plant status meetings. The various status meetings provide a discussion of plant conditions and ongoing or planned maintenance and/or testing activities. There was good management control at the meetings and adequate multi-discipline attendance including the security personnel.

No violations or deviations were identified.

e. Procedure and Drawing Control

Plant procedure and drawing control was reviewed to ensure that the correct procedure/drawing revisions had been issued to the field and that controls were sufficient to maintain the correct revisions. The inspector interviewed the document control supervisor and selected 6 plant drawings and 12 procedures for verification of proper revisions in the field. FNP-0-AP-4, Control of Plant Drawings and Records, Rev. 12, specifies requirements for controlling plant documents and records.

A computer system was used to control procedures and drawings. Rather than have a minimum number of areas where controlled documents are kept, the controlled documents appeared to be issued to many onsite and offsite locations and are signed out to both groups and individuals. One administrative procedure (FNP-0-AP-14) had 50 locations (including onsite and offsite locations).

The inspector's review of document control indicated that the following areas lacked proper control:

Plant Modifications Group - drawings stamped as uncontrolled, incorrect revision for procedure FNP-0-AP-14
Control Room - incorrect revision for procedure FNP-0-ECP-000, FNP-2-ARP-1.2 (Part B), FNP-2-ARP-1.2 (Part G) and drawing D200007
Turbine Building "A" Man - procedure FNP-2-SOP-002.1 missing
Maintenance Manager - Drawing stamped as "INFORMATION ONLY"
Maintenance Supervisor - incorrect revision on FNP-0-AP-014
Plant Manager - incorrect revisions on FNP-1-AOP-004 and FNP-0-AP-014
Materials Warehouse (individual) - incorrect revision on procedure FNP-0-AP-014

The failure to maintain procedure and drawing controls had been identified by the licensee's Safety Audit and Engineering Review (SAER) internal audit on two previous occasions. Licensee audit finding FNP-NC-62-86/9(18) identified a problem with document control. The problem was reportedly corrected and completed on June 25, 1987. During a subsequent audit (Audit Report No. 87-14 dated July 30, 1987) the SAER identified that the corrective action was inadequate in that four additional procedures that were in use in the control room were found to have incorrect revisions.

The failure to follow procedure FNP-0-AP-4 and the failure to implement adequate corrective action for procedure/drawing control activities as required by 10 CFR 50, Appendix B, Criteria V and XVI, respectfully, is identified as an example of violation 348, 364/88-05-01.

The licensee does not appear to have an effective document control system as evidenced by their own internal audit findings and the NRC findings. The practice of having controlled documents distributed throughout the site and offsite has made such control very difficult and appears to be the root cause of this weakness.

No violations or deviations were identified.

f. Licensee Action on NRC I&E Notices

The licensee's activities with regard to the processing of I&E Notices (IENs) was reviewed to determine if internal responses to these notices were timely and adequate.

Review, tracking, and final resolution of IENs is performed by the licensee's onsite licensing group in accordance with procedures FNP-0-AP-18, Conduct of Operations - Technical Group, and FNP-0-ETP-3673, Preparation and Processing of NRC Information Notice Responses.

To audit this area the inspector interviewed licensing personnel, reviewed procedures FNP-0-AP-18 and FNP-0-ETP-3673, and examined the licensee's activities and status on six selected IENs. The following IENs were selected for review:

IEN 84-58	Inadvertent Defeat of Safety Function Caused by Human Error Involving Wrong Unit, Wrong Train, or Wrong System
IEN 85-74	Station Battery Problems
IEN 85-75	Improperly Installed Instrumentation, Inadequate Quality Control and Inadequate Post-Modification Testing
IEN 86-57	Operating Problems with Solenoid Operated Valves at Nuclear Power Plants
IEN 87-34	Single Failures in Auxiliary Feedwater Systems
IEN 87-57	Loss of Emergency Boration Capability due to Nitrogen Gas Intrusion.

The inspector noted that the onsite licensing staff consisted of two personnel and a supervisor who had many other duties in addition to the tracking and resolution of IENs. Of the six IENs reviewed, the inspector noted that all had been reviewed and that four of the six had been adequately closed. The inspector also noted that these four did not require any corrective actions. IEN 85-74 had partial corrective action taken, however, one aspect of the corrective action had not been completed. This one corrective action item had been open for more than 1 and 1/2 years. IEN 86-57 was sent to the corporate engineering office for corrective action and as of the date of this inspection no action had been taken.

It appears that IENs that did not recommend correctiv_ actions were quickly closed out. Those that did recommend corrective action were not closed out in a timely manner. This had led to a backlog of approximately 78 incomplete IEN's with one IEN (83-56) dating back to 1983.

The licensee did appear to have an effective tracking system so that IEN status can be easily identified.

No violations or deviations were identified.

g. Quality Control

The NRC inspector reviewed the licensee's procedure on Quality Control Measures, FNP-0-AP-31, Rev. 8. This procedure established the responsibilities and controls by which quality will be controlled by utilizing "peer" review. Procedure steps which require independent inspection, notated as "I" were to be accomplished by certified inspectors within the discipline but who were not involved in the work activity nor worked for the foreman responsible for the task being accomplished. Section 6.1 of FNP-0-AP-31 requires the Quality Control Engineer to provide overall responsibility for verification of the adequacy and effectiveness of the quality control of inspections for which independent inspections apply. This was to be accomplished by observing selected independent inspections to ensure inspections are performed, evaluated, and documented in accordance with the requirements of FNP-0-AP-31.

Discussions with the QC Supervisor and review of documentation indicated that QC did not perform independent observations of "I" points in 1985, 1987, and none up to March 9, 1988. QC did observe three maintenance tasks in 1986. The licensee's performance of observing three independent observations of "I" events in 1986 and none since does not appear to be an adequate frequency for assessing the quality of "I" points. This is identified as a weakness.

The NRC inspector also reviewed SAER audits which revealed the licensee had an effective system for identifying problems but the corrective action seems ineffective. The following is a representative sample:

- SAER audit of May 16, 1986, issued a nonconformance (NC) NC-58-86/8(21), nonsupervisory personnel initialled "S" points, which are supervisor responsibilities, during the performance of surveillance test procedure FNP-0-STP-616. Additionally, special test procedure FNP-0-STP-611.1, Spillway Channel Structure Verification, was signed-off as accepted prior to completion.

- SAER audit of June 30, 1986, issued NC-65-86/12(15), day shift personnel signing for night shift work. Maintenance Procedure FNP-0-MP-61.2 was not followed step-by-step nor were steps adhered to as evidenced by the fact that oil samples from 2C Reactor Coolant Pump (RCP) were not analyzed. Additionally the "S" point was signed for clearances being set between the jackscrew and guide shoe to a specified tolerance when in fact the necessary equipment to measure the clearance was not available. Also, NC-70-86/12(15) was issued because the QC Supervisor made no direct observations of the 2C RCP five-year inspection effort.

- SAER audit of December 14, 1986, issued NC-157-86/24(15), "S" point for cleaning and testing reactor trip breaker was signed by a journeyman, however, "S" points require a foreman's signature. NC-158-86/25(15) noted that during the performance of maintenance procedure FNP-0-MP-28.193, Inspection, Maintenance, Cleaning and Testing of Reactor Trip Breaker Switchgear, individual steps were not signed-off. The SAER also noted that many procedures with data sheets did not have M, S, or I notations as required.

- SAER audit of March 24, 1987, issued NC-35-87/4(15) which indicated general maintenance procedure FNP-0-GMP-52.3, Replacement of Individual Battery Cells in Existing Batteries, was not followed, in that, the foreman did not sign "S" point. The audit also noted that maintenance procedure FNP-0-MP-28.109, Siemen-Allis 4.16 KV Circuit Breakers (for work under MWR 130283) had the "as found" data sheet N/A'd.

- SAER audit of May 26, 1987, issued NC-63-87/9(15) because an "S" point had been signed-off in maintenance procedure FNP-0-MP-53.2, Lifting of Main Turbine Rotor, as complete the day before the work was actually performed.

- SAER audit of June 10, 1987, noted in comment 4 that during the performance of maintenance procedure FNP-0-MP-14.1, Colt Diesel Engine, that step 5.7 was N/A'd. However, step 5.7 required the governor to be adjusted when an oil change has been accomplished.

- SAER audit of July 13, 1987, noted that nine previous NCs remained open from previous audits and this audit issued five additional NCs. All NCs were related to Control of Measuring and Test Equipment.

- SAER audit of August 4, 1987, issued NC-103-87/15(34) because, contrary to administrative procedure FNP-0-AP-5, the same individual performed and reviewed, the reactor safeguards response time testing procedure FNP-0-STP-256.1B.

- SAER audit of October 1, 1987, issued NC-136-87/20(34) because test results are required to be reviewed and signed-off by a level II certified individual. Two records indicate that FNP-0-STP-610.2 did not have this review performed.

The same deficiencies continue to reoccur. Foremen allow nonsupervisory personnel to sign "S" points and also fail to sign their own steps. The peer review process does not appear to be consistently working and the licensee's corrective actions have not prevented the above noted nonconformances from continuing.

10 CFR 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by documented instructions and shall be accomplished in accordance with these instructions. In addition, 10 CFR 50, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality are promptly corrected. The failure to provide adequate quality controls to prevent deficient Supervisor Check Point signoffs from reoccurring during the performance of maintenance activities is identified as an additional example of violation 348, 364/88-05-01.

During discussions with the licensee, the inspector was informed that the QC Supervisor position was established in 1981 and that the QC Supervisor reports to the System Performance and Planning Manager. The inspector noted that the QC Supervisor position was not listed in administrative procedure FNP-0-AP-3, Plant Organization and Responsibility, Rev. 7. A review of administrative procedure FNP-0-AP-63, Conduct of Operations - System Performance Group, Rev. 2, also did not list the QC Supervisor position, however, the inspector did note that a QC Engineer is listed, but reports to the Operating Experience Evaluation Section Supervisor. Further review indicated that the QC Supervisor was identified in two administrative procedures FNP-0-AP-65, Operating Experience Evaluation Program, Rev. 4, which requires the QC Supervisor to perform a program effectiveness review and FNP-0-AP-20, Receipt Inspection, Rev. 7, which requires the QC Supervisor to provide a dedication plan. Additionally, the QC Supervisor appears to have numerous responsibilities drawn from several procedures. FNP-0-AP-3 describes three responsibilities for a QC Engineer including monitoring plant QC measures, assigning and evaluating procurement QA requirements per FNP-0-AP-9, Procurement and Procurement Document Control, Rev. 13. and coordinating the EQ program. FNP-0-AP-22, Nonconformance Deficiency Reporting, Rev. 5, requires him to review nonconformance disposition reports.

The licensee's administrative procedures need to be updated to reflect the QC Supervisor's organizational position, responsibilities and qualifications. Additionally, the QC personnel assigned to assist the QC Supervisor need to have their roles delineated, i.e., guidance on authority to stop activities, how and when to stop activities and to whom findings are transmitted.

h. Management and Engineer Training

The inspector reviewed the training for managers and engineers with respect to management training, QA/QC inspector training, requalification training for SRO licensed managers, mitigation of core damage training, emergency director training, systems training and specialized training. The majority of upper level managers in technical positions had current SRO licenses with all appropriate requalifications completed. In the few cases where upper level managers did not have SRO licenses, the managers appeared more than adequately qualified for their position. The qualifications of upper level management were considered a strength. The personnel involved in all emergency positions, including Emergency Director, were adequately qualified. In all cases reviewed, personnel training records were complete and accurate.

No violations or deviations were identified.

i. Performance Monitoring

The inspector reviewed the Farley Nuclear Plant Performance Monitoring Report, Maintenance Department Trend Report and interviewed selected management personnel to determine parameters or indicators monitored, goals in each area, and the communication of performance goals within the organization.

The FNP Performance Monitoring Report provides a periodic summary of performance parameters which include:

- Inadvertent Partial or Total Inoperability of a Safety Feature or System
- Unplanned Safety Feature or System Actuation
- Safety System Unavailability
- Forced Power Reductions
- Unit Equivalent Availabilities and Capacity Factors
- Heat Rate
- Reactor Fuel Rod Reliability
- Liquid and Gaseous Radioactive Effluents
- Avoidance of Excessive Radiation Exposures
- Collective Personnel Radiation Exposures
- Low Level Solid Radioactive Waste
- Backlog of Total Work
- Requests/Backlog of PM Work Authorizations
- Minor Departures From Design
- Modification Status

This report was widely distributed within the licensee's organizations which permitted ready comparison between established goals and actual monitored performance parameters. The Senior Vice President is on distribution for the report. Additionally, the inspector reviewed the internal weekly Maintenance Trend Report, which is an informal tracking and trending aid used by the Maintenance Manager to help reduce the backlog of maintenance items and monitor performance within this group. The performance goals for reducing maintenance backlog are being met. Through the use of the trend report the Maintenance Manager is fully cognizant of the activities within the department.

No violations or deviations were identified.

j. Improvement Programs

The inspector interviewed the Senior Vice President and various members of plant management to determine the status of various plant improvement programs. The licensee conducted a Self-Assessment report which delineated eight specific problem areas. The report appeared to be an honest characterization of problems the licensee is either facing or can expect to face as the plant ages. The straight-forward approach to these problems and realistic solutions proposed, are evidence of sound forethought in the area of plant management. The Self-Assessment was considered a strength.

k. Licensee Event Reports and Incident Reports

The inspectors reviewed 37 Licensee Event Reports (LERs) to determine the adequacy of corrective actions, root cause determination, and trending and tracking of similar events. Twenty-two of the LERs were attributed to personnel error. The documented corrective action for these events generally involved counseling the individual involved. The corrective actions, which were documented on the LER and the associated Incident Reports, were not indicative of all the corrective actions that actually took place. In some cases the corrective actions included retraining for all or part of the operations or maintenance staff, PORC review or procedural or policy changes. Additionally, although not specifically documented, a more detailed root cause analysis was generally performed. The failure to adequately document corrective actions, is considered a weakness. With the exception of the above comment, the LERs appeared to adequately comply with 10 CFR 50.73 and NUREG-1022.

The inspector reviewed Unit 1 and 2 Incident Reports generated during the current SALP period and in some cases conducted more detailed reviews including review of associated maintenance work requests. IRs were reviewed for equipment deficiency trends, personnel error trends, reportability, root cause determination, and corrective actions.

The sample selected indicated a high threshold of reportability, but appeared to be within the minimum guidelines of interpretations of reporting requirements provided to the licensee by the NRC in NUREG-1022, and applicable supplements. However, the documentation for reportability, root cause, and corrective actions was generally cursory, and not indicative of the actual work performed or corrective actions taken. Also, the licensee did not appear to have an effective program to trend personnel errors or repetitive equipment failures. This deficiency was also noted in NRC Inspection Report 328, 364/87-35. The lack of documented corrective actions in IRs and the failure to trend events were identified as weaknesses.

Interviews indicated that little or no feedback was provided to operators involved in events as to the results of the investigation of the Incident Reports (IRs). It also appeared that the administrative burden on Unit Supervisors was heavy due to the requirements involved in preparation and review of IRs.

No violations or deviations were identified.

l. Safety Audit and Engineering Review Group

The inspector reviewed the Safety Audit and Engineering Review Group (SAER) and found their audits to be both performance based and effective. SAER is tasked only with determining noncompliances (N/C), but is purposely not tasked with providing the solution to N/Cs. SAER reviews the proposed Corrective Action Reports (CAR) and provides input to the Senior Vice President on the appropriateness of the CAR. SAER reaudits the N/C when the CAR is complete, and verifies that the noncompliant condition is corrected.

SAER staffing is derived from selected licensee existing job positions. Licensed personnel and personnel with desired specific skills are selected. Personnel are routinely rotated through the SAER organization. The normal time period for assignment is three to five years. This provides personnel to SAER who have first hand knowledge of plant activities and current work practices, and rotates personnel back to the plant with in-depth Quality Assurance knowledge and experience.

SAER routinely audits both safety-related and non-safety-related areas, and is encouraged to audit any area of the plant site where a problem may exist. The SAER is a non-voting member of the Plant Operations Review Committee (PORC) and in this capacity provides systematic engineering reviews of plant performance, and these review results are reported directly to the manager of the SAER.

SAER reviews the following items and adds areas to their audit checklists as appropriate:

- Procedure Safety Evaluations
- Design Changes
- Minor Departures
- LERs
- PERs
- NRC Violations and Corrective Actions
- Other Nuclear Plant NRC Violations
- INPO Nuclear Network Entries

The number, scope, and depth of SAER audits are demonstrative of maximum program effectiveness as evidenced by the number of significant technical findings identified in these audits. All audit finding corrective actions are approved at the Senior Vice President level. Late or delayed corrective actions may be escalated to the Senior Vice President at the discretion of the SAER Manager. The SAER program is considered a strength, however, corrective action to SAER audits did not appear to always be prompt as discussed in paragraphs 7.e and 7.g.

The inspector reviewed the Operations Quality Assurance Policy Manual, Revision 25,18 CARs and the SAER audits listed below. No discrepancies were noted.

SAER Audit No.	Report Date	Areas Audited
87-02	02/10/87	Plant Administration
87-19	09/15/87	Fire Protection
87-21	11/20/87	Corrective Action
87-10	05/28/87	Corrective Action
87-17	08/19/87	Radiation Controls
87-03	02/19/87	Plant Operations

During the inspection a question concerning the storage of safeguards audits was turned over to the Region II security staff.

No violations or deviations were identified.

8. Hydrogen Entrapment in RHR to Charging Pump Crossover Piping (93702)

a. Initial Conditions and Sequence of Events

On the morning of February 26, 1988, operators were involved in a troubleshooting effort in an attempt to determine the source of suspected boron inleakage to the reactor coolant system (RCS). Unit 1 was at 100 percent power with the "1B" charging pump in service. Isolation valves 1-8706 "A" and "B" in the Residual Heat

Removal System (RHR) to charging pump crossover piping had been stroke tested on February 23, 1988, and were the suspected source of the leakage. The valves had been cycled under surveillance test procedure (STP) 11.6, RHR Valves Inservice Test, and were believed not to have fully reseated. Following the valve testing, the operators observed a slight decrease in Tave and experienced unusually high dilution rates of approximately 3000 gallons per day versus the expected rate of 1500 gallons per day. These valves were recycled to improve seating and a maintenance work request (MWR) was written to check the torque switch settings. The troubleshooting evolution on February 26, 1988 consisted of venting a series of high point vents in the RHR to charging crossovers to sample and attempt to pinpoint the source of leakage. These troubleshooting efforts were controlled by an MWR.

When the operator opened valve Q1E21V483, the high point vent valve on the "A" train crossover for Unit 1, gas instead of the expected water sample was emitted. The system operator (non-licensed) and health physics technician vented gas from the vent valve for approximately one hour before achieving water flow and obtaining a sample. This gas, which would later be determined to be hydrogen, was vented to the penetration room. The control room operator (licensed) had assumed the venting of valve V483 had been completed shortly after it was started, and discontinued monitoring of the Volume Control Tank (VCT) level in support of the evolution. When the control room operator became aware of the automatic makeup to the VCT, he directed the operator in the plant to close the vent valve. This direction was given after approximately one hour of venting, and water was observed at the vent prior to closing the valve. The venting evolution had resulted in 30 percent change in VCT level. A 30 percent change in VCT level equates to approximately 420 gallons of water which in turn represents about 56 cubic feet of gas displacement in the RHR to charging pump train A crossover line. This crossover piping was later calculated by the licensee to have sufficient volume to contain approximately 800 gallons of water. These calculations would indicate that the "A" train piping was filled with approximately 50 percent gas on the morning of February 26, 1988.

The Unit Supervisor who initially investigated the source of the train "A" gas on February 26, 1988, believed that the gas was air trapped in the lines following the previous refueling outage. The event was also believed to be similar to an RHR event that had occurred on November 27, 1987 (NRC Inspection Report 50-348, 364/87-35).

In that event, air had been trapped between the RHR containment sump suction isolation valves following a local leak rate test and a failure to fill and vent. When the valves were stroked with the RHR system in operation, the trapped air and resultant pressure surge lifted the RHR suction relief valve. The suction relief valve stuck open resulting in the discharge of approximately 2200 gallons of water through a pressurizer relief tank rupture disc. It was initially believed that the stroking of valves 1-8706 "A" and "B" on February 26, 1988, may have moved a void resulting in a similar occurrence.

On February 28, 1988, operators were directed to vent the Unit 1 "B" train crossover line to check for air. No gas was detected during this venting evolution. On February 29, 1988, Operations management decided to vent the Unit 2 RHR to charging pump crossover lines. Venting of the "2B" charging pump prior to pump start had been necessary for several years due to a gas accumulation problem. As a result, the "2B" pump had been left running most of the time to prevent this necessity. The venting of the Unit 2 "A" train on February 29, 1988 resulted in a net VCT level change of approximately 20 percent or 310 gallons of water. This VCT level change equated to a gas void of about 41 cubic feet. This gas was still believed to be air and no gas sample was taken. The venting of Unit 2 train "B" did not result in any gas discharge.

On March 1, 1988, operators re-vented Unit 1 train "A" with a net VCT level change of approximately 152 gallons or 18 cubic feet of gas. At this time, the gas was sampled and determined to be 98 percent hydrogen instead of air as originally believed. Following this apparent reaccumulation of gas in the Unit 1 "A" train crossover, the licensee contacted Westinghouse for assistance in determining the source of the hydrogen, the potential effect of gas on the charging pumps, and whether venting could result in pump problems. The Westinghouse response indicated that a gas "slug" of greater than six cubic feet entering a charging pump could result in a loss of pump water lubrication, an increase in vibration, internal rubbing and possibly seizure or shaft breakage. The response indicated that venting of the crossover lines to ensure less than six cubic feet of hydrogen accumulation should prevent the catastrophic failure of a charging pump. Due to the configuration of Unit 1 and 2 "A" train crossover piping and the suction configuration to the Unit 2, "2B" charging pump, it was also recommended that the "B" pumps on both units be utilized for normal charging service. This alignment, according to Westinghouse should prevent gas accumulation in the high points of the "A" trains due to running the "A" charging pumps and also prevent hydrogen accumulation in the suction of the "2B" pump.

On March 3, 1988, in response to the problems experienced and the Westinghouse response, the licensee revised System Operating Procedure (SOP) 7.0, Residual Heat Removal System, to add Appendix I. Appendix I provided directions for venting non-condensable gases from the "A" train RHR to the charging pump suction line on both units. Appendix I also provided precautions for preventing hydrogen accumulation and explosion while venting. The licensee was utilizing this procedure to vent the "A" crossover piping once per eight hours as an interim preventive measure.

In response to the Westinghouse recommendations, the licensee also secured the "1A" charging pump which had been placed in service on February 29, 1988, and placed the "1B" pump in service. With the "1B" and "2B" pumps in service, subsequent ventings of the "A" trains indicated a substantial reduction in gas accumulation with VCT net changes of 5, 28, and 14 gallons and then unmeasurable VCT level changes with only a few seconds of gas venting on Unit 1 "A" train.

A chronological list of events, taken from control room logs and interviews, is provided in Appendix A.

b. System Design

Each operating unit at Farley is provided with three centrifugal charging pumps. Under normal operation one charging pump is in service on each unit, taking suction from the volume control tank (VCT) and returning the water to the reactor coolant system (RCS) via the regenerative heat exchangers. An overpressure of hydrogen gas is maintained in the VCT in order to maintain a hydrogen concentration in the reactor coolant of 25 to 35 cc per kg of water. The charging pumps also serve as emergency core cooling system (ECCS) pumps following an accident in both the injection and recirculation cooling modes. In the injection mode, the charging pumps act as high head safety injection (HHSI) pumps supplying water to the RCS from the refueling water storage tank (RWST) at high pressure. This mode of operation is completely automatic and continues until low level is reached in the RWST in about one-half hour.

Following the injection mode and depletion of the RWST, the operators take manual action to enter the long-term cold leg recirculation mode. In the cold leg recirculation mode, the RHR pumps are aligned to take suction on the containment sump and deliver the water to the RCS cold legs. A portion of the RHR pump discharge flow is diverted to the suction of two operating charging pumps which would also deliver directly to the RCS cold legs but at a high pressure. The charging pump pressure ensures flow in the event that depressurization proceeds slowly and RCS pressure is still in excess of the RHR pump shutoff head. The cold leg recirculation mode would be in effect for approximately 20 hours, at which time the hot leg recirculation mode would be entered.

In the cold leg recirculation mode the RHR system is aligned for a portion of the RHR flow to be directed to the charging pumps. The connection between RHR and the charging pumps suctions is through two crossover lines, "A" and "B", which are connected to the discharge side of the RHR heat exchangers. The "A" and "B" crossover lines are isolated by two isolation valves (one per line), 8706 "A" and "B". When entering the cold leg recirculation mode, operators open these valves to supply a portion of the RHR flow to the suction of the charging pumps. The "A" crossover lines on both Units 1 and 2 have an unusual configuration when compared to the "B" crossover lines. The "1A" and "2A" charging pump suctions have an inverted loop seal piping configuration with the highest elevation of the loop at approximately the 110 foot elevation of the plant. The "A" crossover lines from RHR also have an inverted loop seal which rises to approximately a level of 133 feet or about 23 feet higher than the pump suction loop seal and the "B" train crossovers. This high point geometry provides a trap for hydrogen which has disassociated from the reactor coolant at the suction of the charging pumps. The vent which was utilized to vent trapped gas on February 26, 1988, is located at the top of the "A" train crossover piping loop. Trapping of hydrogen at the highest point of the "A" train loops is believed by Westinghouse to occur when the "A" charging pumps are utilized for normal plant operations. With the "A" pump running, the suction flow from the VCT must pass by the "A" crossover line allowing gas to rise into the top of the loop. There is no flow of coolant through the crossover lines during normal operations, and the 8706 valves are closed.

The Unit 2 "B" charging pump suction configuration also provides a gas trap for hydrogen which disassociates from the reactor coolant. The suction line from the VCT is connected to a vertical section of piping with the "B" charging pump above this connection point, and the "A" and "C" pumps below. As a result, when the "2B" pump is not in operation, hydrogen gas may accumulate in this riser in the suction to this pump. For a number of years the licensee had to vent this pump locally when starting the pump and, therefore, had elected to operate this pump for normal charging service.

c. Charging Pump Gas Accumulation History

The licensee first experienced problems with gas binding in the charging pumps on both units during testing and startup in 1979. As a result of these problems, an engineer wrote an Operations Change Request (OCR 2-3514) dated November 6, 1979. This OCR indicated that "the layout of the suction piping to the charging/HHSI pumps is such that gas pockets can accumulate in the suction lines to these pumps," and that "running gas through these pumps can lead to pump damage." The OCR also indicated that at least one other plant, Connecticut Yankee, had experienced similar problems including the vapor binding of charging pumps and elected to install continuous vents from the pump suctions back to the VCT.

In the OCR, the engineer proposed providing continuous vents from the suctions of the "B" and "C" charging pumps back to the VCT. Due to the different configuration of the "A" pump suction, with the high point above the VCT, the OCR proposed a different solution to gas accumulation in the "A" piping. In this case the proposal was to pipe the high point vent on the "A" crossover to a site glass and then to a drainage piping. This arrangement would allow periodic venting of gas accumulation to prevent gas binding of the pumps supplied by the "A" RHR to charging pump crossover. OCR 2-3514 included isometric drawings of the existing RHR to charging pump piping and the proposed modifications. An outline of the history that followed these initial gas problems and proposed modifications is as follows:

- The "1B" charging pump shaft failed early in 1980 and a replacement shaft was installed. Westinghouse conducted special tests on this pump to determine if gas voids were contributing to the failure. A letter from Westinghouse dated June 11, 1982, indicated that tests were conducted on April 1 and 2, 1980, which demonstrated that gas was passing through the "1B" pump and could have contributed to the failure. Following the April tests, the shaft was removed, straightened, and reinstalled.

- In August 1980, the test was repeated, and although problems were experienced with test equipment, the tests again indicated that gas was passing through the pump. The test also indicated that the pump suction pressure dropped to "0" PSIG while on mini-flow which could cause gas to come out of solution and damage the pump. The letter indicated that additional tests would be conducted during startup from the refueling outage. These tests were to evaluate the effect of changes in suction source, system temperature changes, and VCT level changes. These additional tests or similar tests of the other charging pumps were apparently never conducted.

- June 10, 1981 - Plant Change Request (PCR) 81-2064FA was written to correct the design of the "2B" charging pump suction to prevent gas binding. The PCR indicated significant amounts of gas had been found in the "2B" suction and requested an engineering design correction.

- August 7, 1981 - A letter from Engineering to the plant indicated that Bechtel could not determine a temporary solution to the "2B" pump gas problem except to run the pump continuously. The letter indicated that a permanent solution would be to install vents from the pump suction back to the VCT.

- March 22, 1982 - A letter from Westinghouse contained proposals for installing vents on Units 1 and 2 to prevent accumulation of gases in the charging pump lines and damage to the pumps.

- April 15, 1982 - An internal letter requested the issuance of a purchase order for Unit 2 modifications (vents) only. Since the modification was planned for the refueling outage, it was requested that the supporting design be issued by July 15, 1982. This letter also requested a 60 day extension to allow for additional evaluation of the necessity to install the modifications on Unit 1.

- April 28, 1982 - A letter from Engineering to the plant requested a confirmation of whether or not gas accumulation was a problem on Unit 1.

- June 28, 1982 - An internal letter indicated that testing performed on the "1B" charging pump under PCN-79-0077 in 1980 had demonstrated gas accumulation on Unit 1. This letter requested that the plant initiate a Unit 1 PCR, similar to PCR 81-2064FA, for venting the charging pump suctions.

- March 2, 1987 - The "1A" charging pump failed to pump twice due to gas binding and had to be vented to restore operability. Incident Report 1-87-88, Section 13 - Permanent Corrective Action, indicated that a PCR would be submitted for Unit 1 charging pumps similar to 81-2064 for Unit 2 and as recommended in 1982.

  NOTE: This Unit 1 PCR, recommended in June 1982 and again in March 1987, was apparently never written.

- January 25, 1988 - Plant management cancelled PCR 2-81-2064 on the Unit 2 "B" charging pump modifications as written in 1981. The justification stated, "The PCR was cancelled due to the cost of the proposal (both installation and maintenance) plus the added risk of faulty automatic valve operations did not appear to be justified for the benefits gained. The potential for gassing is being controlled by system alignments." Running the "2B" charging pump for normal service or venting before starting the "2B" pump was utilized.

d. Event Analysis and Conclusions

The Westinghouse letter dated March 4, 1988, (ALA-88-596, Rev. 1) indicated that six cubic feet of gas passing through a charging pump as a slug could result in catastrophic failure of the pump. The letter states, "The consequences on the pump are highly dependent on how the gas is mixed with the fluid prior to entering the pump. If the gas is not mixed and passes as a slug, the pump could experience a relatively long period of time (approximately 40-seconds) during which no water would be available for pump lubrication. Given this worse case scenario, pump vibration could significantly increase and cause rotating element internal rubbing and possibly seizure or shaft breakage."

The amount of gas vented from the Unit 1 "A" crossover line on February 26, 1988 was 56 cubic feet or over nine times the amount which could cause seizure and catastrophic failure of a charging pump. The 41 cubic feet vented from the "A" train of unit 2 on February 29, 1988 was nearly seven times the amount necessary to cause similar failures of one or more charging pumps.

The "A" trains were inoperable in that on entering the cold leg recirculation mode following an accident, this gas accumulation could be sufficient to destroy one or more charging pumps aligned for "A" train service ("A" and/or "B" charging pumps). If the gas was mixed with the water instead of in a slug form, the Westinghouse letter indicates the pump failure might occur slower, even a matter of days, depending on the amount of gas in the mixture. Considering, however, that the "A" crossover lines were approximately one-half full of gas, it appears that on entering recirculation that the RHR pump pressure would have pushed a slug of gas into the operating "A" train pump leading to pump failure.

The history of this system would also indicate that large amounts of gas may have been trapped in the "A" train crossover lines for several years. Interviews with operators and managers indicated that the operation of the loop high point vents during troubleshooting on February 26, 1988, was probably the first time these vents had been utilized since startup in the 1979-1980 time frame. SOP 2.1, Chemical and Volume Control System Plant Startup and Operation, Section 4.10, contains directions for fill and vent of this system. Step 4.10.5 specifically lists the vent points that were utilized to vent the trapped hydrogen during this event. There are no sign-offs for use of these vents, however, and it could not be determined that they had been utilized in recent years.

According to Table 6.3-3 in the FSAR, when entering the cold leg recirculation mode operators separate the "A" and "B" trains of RHR to charging flow by closing isolation valves which isolate the "B" charging pump and align "A" train to the "A" charging pump and "B" train to the "C" charging pump. The licensee's emergency procedures, however, have been revised to allow operators the flexibility of utilizing the "B" charging pump for either "A" or "C" train recirculation service. Table 1 of Event Specific Procedure (ESP) 1.3, Transfer to Cold Leg Recirculation, provides the operator with directions for valving operations which separate the "A" and "B" trains depending on which two charging pumps are utilized.

A gas slug could have caused failure of either the "A" or "B" pump or both making the "A" train inoperable for post-accident recirculation operation. In the event of an "A" train failure, total reliance would be placed on the "B" train to supply containment sump water from RHR to either the "C" or "B" charging pump. A single failure in the "B" train crossover line could cause a loss of the charging system for cold leg recirculation, a condition which is outside the design basis.

The Westinghouse letter also indicated that Westinghouse and Pacific Pump believe that in addition to the catastrophic failure mode already discussed, that any amount of gas accumulation can be detrimental to the charging pump on a long term basis. Since gas is believed to have accumulated in the "A" trains of both units for several years and in the suction to the "2B" pump since 1979, the long-term gas effect on the operability of these pumps is also a concern. Adding to this concern is that the gas effect tests conducted on the "1B" charging pump in 1980 by Westinghouse were apparently never completed, and the other charging pumps never tested.

As indicated in paragraph 7.a., the licensee first became aware of gas binding problems in the charging pump during testing and startup in 1979. An engineer recognized the potential for the trapping of gas in the "A" crossover piping and in the suction of the "2B" charging pump and proposed installation of permanent vents to alleviate this potential and prevent damage to the charging pumps. The proposal indicated that the vents would be "a simple, inexpensive and safe system for venting the pump and seals." In 1980, the licensee experienced shaft failure on the "1B" charging pump and had Westinghouse perform special tests which indicated gas intrusion may have contributed to the shaft alignment problems and failures. These tests were apparently never completed as recommended and the other charging pumps were not tested. In 1981, PCR 2-81-2064 was written to design a modification to solve the gas problems on the suction of the "2B" charging pump. In 1982, Westinghouse designed a modification to vent Unit 2 and Unit 1. Alabama Power Company (APCO) Engineering appears to have recommended the installation of the modification on both units and the issuance of purchase orders for the materials. The modifications, however, were never installed, the materials were never ordered, and the actual PCR, as recommended in a letter dated June 28, 1982, was never written.

Plant management indicated to the inspectors that they had doubts that venting back to the VCT would work and that continuous operation of the "2B" pump with venting before starting, adequately resolved the problems with Unit 2. Similar venting back to the VCT at Connecticut Yankee in 1979 and more recently at Commanche Peak, had apparently resolved this gas accumulation problem. The

Assistant Plant Manager - Operations indicated that he could not recall the part of the March 22, 1982 letter that proposed a loop seal modification to the "A" pump suction lines. No formal evaluations were performed or documented to justify not implementing the proposed modifications to Units 1 and 2 and to ensure continued operability of the charging pumps. There is also no indication that any venting and sampling was performed to assess whether hydrogen was accumulating at the crossover loop high points.

On March 2, 1987, the "1A" charging pump failed to start twice due to gas binding and cavitation. The permanent corrective action section of the associated incident report indicated that a "PCR will be submitted for Unit 1 charging pump suction similar to 81-2064 for Unit 2, and as recommended in 1982 by Nuclear Engineering and Technical Support (NETS) letter 82-0769." The PCR was never written, and a formal analysis of the source of the gas and the effect on pump operability was not performed; and, the decision not to implement a modification was not evaluated. There did not appear to be any venting of the high point vent and sampling to determine if gas trapping was occurring. Plant management indicated that they had not previously experienced problems with the "1A" pump and considered this failure to be a "first data point".

As indicated in paragraph 7.a, when the large amount of gas was vented from the "A" crossover line of Unit 1 on February 26, 1988, operations personnel initially diagnosed the gas as air which was probably trapped from the last outage. The hydrogen was vented to the room without explosive precautions and no gas sample was taken. The belief that the vented gas was air was probably promoted by several circumstances. Although these vents were in the CVCS operating procedure, it appears that they may have not actually been utilized since plant startup. During interviews, the Operations personnel indicated that they recognized that fill and vent was an area of weakness, and that there was a chance air had been left in the system since the last outage. The event was also related back to the event which occurred on November 27, 1987, where the failure to fill and vent had trapped air between the RHR containment sump suction isolation valves following a local leak rate test. This trapped air subsequently contributed to the opening and failure of the RHR pump suction relief valve, and loss of approximately 2200 gallons of RCS water through the PRT rupture disc. Since the Operations Unit Supervisor believed the gas was air, and that it had all been vented off, no action was taken at that time to check the "A" loop of Unit 2 or to request assistance from engineering or Westinghouse. The Unit Supervisor was apparently not aware of the previous gas problems and proposals associated with the charging pump suctions. February 28, 1988 the Unit Supervisor did initiate actions to vent the "B" train of Unit 1.

On February 29, 1988, the event was discussed at the morning meeting and plant management made a decision to vent Unit 2 to also check for trapped air. The Assistant Plant Manager - Operations indicated that he was aware of the history of gas problems and suspected hydrogen at this time. This information, however, was apparently not transmitted to the operators who once again vented without sampling or explosive precautions. Also on February 29, 1988, the operators placed the "1A" charging pump in service which may have caused the reaccumulation of hydrogen in Unit 1 "A" train. Unit 1 "A" train was vented and finally sampled for hydrogen on March 1, 1988 and assistance was requested from Westinghouse.

This history indicates that the licensee's management had not adequately performed and documented an engineering/safety analysis related to the design deficiencies, equipment failures, system operability and decisions not to implement corrective system modifications. The licensee has also been ineffective in implementing adequate venting and sampling associated with an RHR to charging pump configuration problem known (since 1979) to contribute to hydrogen accumulation and potential charging pump damage or failure. As a result, in the post-accident cold-leg recirculation mode, the "A" RHR-charging pump suction trains on both units may have been effectively inoperable for several years with the potential to cause catastrophic failure of the "A" and/or "B" charging pump. This "A" train inoperability may have resulted in single train vulnerability of the "B" train crossover, the only remaining RHR to charging pump interface. The gas accumulation may have also contributed to long term deterioration of the charging pump, an area that should be further evaluated by the licensee. The history also indicates that the licensee's management had not been aggressive or effective in pursuing corrective actions associated with safety related design deficiencies and equipment failures.

The failure to adequately perform and document an engineering/safety analysis related to the design deficiencies, equipment failures, and system operability; the decision not to implement corrective system modifications; and, the failure to take adequate and timely corrective actions to known safety-related system design deficiencies, test results, and equipment failures, is a violation (348, 364/88-05-02).

9. List of Acronyms

AOP	Abnormal Operating Procedure
AP	Administrative Procedure
APCO	Alabama Power Company
CAR	Corrective Action Report
CVCS	Chemical Volume Control System
DG	Diesel Generator
DT	Deficiency Tag
ECCS	Emergency Core Cooling System
EOP	Emergency Operating Procedures
ESP	Event Specific Procedure

FNP Farley Nuclear Plant
FSAR Final Safety Analysis Report
GMP General Maintenance Procedure
HHSI High Head Safety Injection
HP Health Physics
IEB NRC Office of Inspection and Enforcement Bulletin
IEN NRC Office of Inspection and Enforcement Notice
IR Incident Report
ISI Inservice Inspection Section
LER Licensee Event Report
LCO Limiting Condition for Operation
LLRT Local Leak Rate Test
MD Minor Departure
MOV Motor Operated Valve
MP Maintenance Procedure
MWR Maintenance Work Request
N/A Not Applicable
NETS Nuclear Engineering and Technical Support
NRC Nuclear Regulatory Commission
OAI Operational Assessment Inspection
OCR Operations Change Request
PCN Production Change Notice
PCR Plant Change Request
PORC Plant Operations Review Committee
PORV Power Operated Relief Valve
PM Preventive Maintenance
PMP Plant Modification Procedure
PRT Pressurizer Relief Tank
QA Quality Assurance
QC Quality Control
RCS Reactor Coolant System
RHR Residual Heat Removal System
RTD Resistance Temperature Detector
RWST Refueling Water Storage Tank
SAER Safety Audit and Engineering Review Group
SALP Systematic Assessment of Licensee Performance
SFI Shift Foreman Inspecting
SFO Shift Foreman Operating
SGFP Steam Generator Feed Pump
SO System Operator
SOP System Operating Procedure
SRO Senior Reactor Operator
SS Shift Supervisor
SSS Shift Support Supervisor
STA Shift Technical Advisor
STP Surveillance Test Procedure
SWS Service Water System
TOO Tagging Operations Order
TS Technical Specification
URI Unresolved Item
VCT Volume Control Tank

APPENDIX A

SEQUENCE OF EVENTS

February 23, 1988 - March 3, 1988

February 23 1530 hours	Stroke time valves 1-8706 "A" and "B", RHR to charging pump isolations to obtain stroke times utilizing surveillance test procedure (STP) 11.6, RHR Valves Inservice Test. Operators experienced a slight decrease in Tave and abnormally high rates of dilution following the stroking of the valves.
February 23-26	High dilution rates were believed to be an indication of borated water leakage through valves 1-8706 "A" and "B". Operators recycled the valves and wrote maintenance work requests on valve torque settings.
February 26 0315 hours	In the process of troubleshooting the source of suspected boration on Unit 1, the operators opened a series of high point vents for sampling. Unit 1 was at 100 percent power during these evolutions with the "B" charging pump in service. When the vent on the "A" train suction from the RHR to the charging pump (valve Q1E21V0[illegible]) was opened, gas instead of water was emitted. Venting of the gas resulted in a 30 percent net change in volume control tank (VCT) level. This level decrease equated to 420 gallons of water which indicated that the gas void had occupied approximately 56 cubic feet of piping.
February 28 1430 hours	Operators vented the "B" train connection between RHR and the charging pump suction. No gas was detected.
February 29 1321 hours	Operators placed the "1A" charging pump in service and secured the "1B" pump.
February 29 2000-2018 hours	Operators vented Unit 2 "A" train suction loop from RHR to the charging pumps. This venting evolution resulted in a release of gas and a 20 percent net change in VCT level. This drop in VCT level equated to 310 gallons of water which indicated a gas void of approximately 40 cubic feet. Operators also vented the Unit 2 "B" train but did not detect any gas.
March 1 0440 hours	Operators vented the Unit 1 "A" train suction loop from RHR to the charging pumps. This venting resulted in approximately a 10 percent net change in VCT level. This drop equated to 152 gallons of water which indicated a gas void of approximately 20 cubic feet. This gas was sampled and determined to be 98 percent hydrogen.

March 2 0330 hours — Operators vented Unit 2 "A" train suction loop from RHR to charging pumps. No gas was detected.

0736 hours — Started and secured the "1B" charging pump.

1620 hours — Operators vented Unit 1 "A" train suction loop from RHR to charging pumps. Gas equivalent to 5 gallons of water was obtained.

2055 hours — Operators vented train "A" of Unit 2 and no gas was detected.

March 3 0035 hours — Operators vented train "A" of Unit 1 with a resultant 28-gallon decrease in VCT level equivalent to approximately 4 cubic feet of gas.

0650 hours — Operators vented train "A" of Unit 2. No gas was detected.

1055 hours — Operators vented train "A" of Unit 1 with a resultant decrease of 14 gallons of water or approximately 2 cubic feet of gas.

1405 hours — Operators vented train "A" of Unit 2. No gas was detected.

1659 hours — Placed the "1B" charging pump in service and secured the "1A" charging pump.

2045 hours — Operators vented "A" train of Unit 1 with a 5-second discharge of gas.

2145 hours — Vented "A" train of Unit 2. No gas was detected.

Operators continued to vent the "A" trains of both units every 8 hours under system operating procedure (SOP) 7.0, Residual Heat Removal System, Appendix I.