

APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION V

Report Nos: 50-275/94-03
50-323/94-03

License Nos: DPR-80
DPR-82


Licensee: Pacific Gas and Electric Company
Nuclear Power Generation, B14A
77 Beale Street, Room 1451
P. O. Box 770000
San Francisco, California 94177

Facility Name: Diablo Canyon Units 1 and 2

Inspection at: Diablo Canyon Site, San Luis Obispo County, California

Inspection Conducted: January 11 through February 16, 1994

Inspectors: M. Miller, Senior Resident Inspector
M. Tschiltz, Resident Inspector
J. Winton, NRR Intern

Approved: 
D. F. Kirsch, Chief
Reactor Projects Branch 1

3/16/94
Date Signed

Inspection Summary:

Areas Inspected (Units 1 and 2): Routine, announced, resident inspection of plant operations; maintenance and surveillance activities; followup of onsite events, open items, and licensee event reports (LERs); and selected independent inspection activities. Inspection Procedures 40500, 51332, 62703, 61726, 71707, 90712, 92701, and 93702 were used as guidance during this inspection.

Results (Units 1 and 2):

Strengths:

- Diablo Canyon was placed on the NRC good-performing plant list for the fifth consecutive time since January, 1992.
- The licensee's audit of design changes, which are scheduled to be installed during the next Unit 1 (1R6) outage, was both probing and effective. Several issues were identified involving both Westinghouse design and plant engineering support involved with the changes (Paragraph 6).



Weaknesses:

- Personnel performing a surveillance test failed to issue an Action Request to document a quality problem. Additionally, the use of performance comments to revise procedures is not being utilized in cases where procedure improvements could be made. This issue is receiving management involvement as a part of the ongoing process for improving procedural compliance (Paragraph 7 and 11).

Summary of Inspection Findings:

- A non-cited violation was identified (Paragraph 7).
- Inspection Followup Item 323/93-24-04 was closed (Paragraph 10).
- Inspection Followup Item 323/93-07-04 was closed (Paragraph 10).
- Inspection Followup Item 275/92-20-01 was closed (Paragraph 10).
- Inspection Followup Item 275/93-03-04 was closed (Paragraph 10).
- Inspection Followup Item 275/92-22-03 was closed (Paragraph 10).
- Inspection Followup Item 275/91-40-01 was closed (Paragraph 10).
- Violation 275/92-17-02 was closed (Paragraph 10).
- Unit 1 Licensee Event Reports 94-001, Revision 0; LER 93-011, Revision 0; LER 93-001, Revision 0; LER 93-003, Revision 0 and LER 93-010, Revision 0 were closed (Paragraph 9).

Attachments

- Attachment 1 - Persons Contacted and Exit Meeting



DETAILS

1. PLANT STATUS

During this inspection period, Unit 1 operated at 100 percent power for the entire report period.

Unit 2 operated at 100 percent power except for a period from January 14-15, 1994, when power was reduced to 20 percent for a leak repair of Moisture Separator Reheater (MSR) 2-2C shell drain line check valve.

2. ONSITE RESPONSE TO EVENTS (93702)

2.1 Centrifugal Charging Pump Discharge Flow Control Valve (CVCS-FCV-128) Position Outside of Design Basis (Units 1 and 2)

On January 28, 1994, a 1-hour non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B) to report that both Units 1 and 2 were operating in a configuration that could lead to loss of reactor coolant pump (RCP) seal injection flow under certain accident conditions. The preliminary assessment by the licensee concluded that RCP seal injection flow would be lost during certain design basis events without operator action if the positive displacement charging pump (PDP) was running with CVCS-FCV-128 closed and its controller in manual. A Westinghouse analysis had shown that the sustained loss of RCP seal injection flow (i.e., 12 to 16 minutes) combined with the loss of component cooling water to the RCP thermal barrier would result in the failure of the RCP seal package. For several events, this configuration could potentially be outside of the design basis for plant operation. In order to be consistent with design basis requirements, the licensee has placed the controller for CVCS-FCV-128 on each unit in automatic to ensure the CVCS-FCV-128 will open while further review of the issue is ongoing.

The inspector noted during a tour that the valve stem for CVCS-1-FCV-128 was bent approximately 0.35 inches. This condition had been previously documented on an Action Request (AR) and evaluated as being acceptable for continued operation by the licensee. The inspector also noted that the valve stem for the same valve in Unit 2, CVCS-2-FCV-128, was not bent. During the last Unit 2 refueling outage, the licensee installed a different design trim set with a customized plug which prevents valve flow instabilities at high differential pressures, which are believed to have caused the change to the Unit 1 valve stem. The licensee has scheduled the replacement of the Unit 1 CVCS-1-FCV-128 trim set during refueling outage IR6.

Additional issues identified by inspectors and the licensee involved the operation of the positive displacement pump (PDP). Although the pump is a nonsafety-related pump and the Final Safety Analysis Report (FSAR) accident analyses do not credit its contribution of cooling water for core cooling purposes, the inspector was concerned that the pump may continue to operate during a design basis event. This may be a non-conservative situation for two design basis-events.

In the first example involving a potential large break loss-of-coolant-accident (LOCA), the inspector was concerned that the contribution of the volume of cooling water injected by the PDP would be assumed to flash to steam, along with cooling water from other injection systems, and contribute



to the peak containment pressure. The inspector was also concerned that the peak containment pressure analysis currently has very little margin. After further analysis and discussion with Westinghouse, the licensee confirmed that the contribution of the PDP had not been included in the Westinghouse peak containment pressure analysis. However, Westinghouse concluded that the contribution of the PDP would not result in exceeding peak containment pressure, and planned to provide a detailed analysis to the licensee.

In the second example involving a potential steam generator tube rupture event, the inspector was concerned that the contribution of the PDP may result in overflow of the ruptured steam generator before pressure equalization occurs between the RCS and steam side of the steam generator. After further discussions with Westinghouse, the licensee determined that adequate margin was available in the steam generator to accommodate contribution of the PDP charging flow. Detailed documentation of the analysis will be provided to the licensee by Westinghouse.

The inspector concluded that the licensee's actions in dealing with these concerns was acceptable.

2.2 Repair of Moisture Separator Reheater Drain Line Check Valve

On January 14, 1994, during a repair of a leak on a secondary plant 150 psi steam line (turbine cold reheat line), a gasket failed resulting in a steam leak at the affected flange. Since the leak was not isolable from the main turbine, reactor power was reduced to approximately 20 percent to reduce steam pressure in the line and limit steam leakage to assist continuation of the repair. The leak was repaired at the reduced power level, and power returned to 100 percent within about six hours. No leakage at that gasket has been observed to date.

The licensee inspected the plant equipment which were wetted by the leakage. The licensee determined that no damage had occurred. The inspector concluded that the licensee's actions in dealing with this situation were acceptable.

2.3 Inoperable Fire Barrier Penetration Seals Due to Improper Installation

On January 28, 1994, a 1-hour non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B) to report that certain fire barrier penetration seals may not meet the 3-hour fire rating. The fire barriers were degraded because damming boards were not properly installed on the ends of the seals. The seals in question are constructed of Promatec RTV foam. The penetration installation details require that damming boards be installed.

The licensee established fire watches as required in accordance with licensee Equipment Control Guidelines (formerly a part of fire protection Technical Specifications). This issue was identified by the licensee Design Engineering Organization and is believed to have existed since initial construction. Repair activities are being planned by the licensee. This item will be followed by the review of the associated Licensee Event Report (LER). The inspector concluded that the licensee's actions were acceptable.

No violations or deviations were identified.



3. OPERATIONAL SAFETY VERIFICATION (71707)

During the inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly or monthly basis. On a daily basis, the inspectors observed control room activities to verify compliance with selected Limiting Conditions for Operation (LCOs) as prescribed in the facility Technical Specifications (TS). Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions and to evaluate trends. This operational information was then evaluated to determine whether regulatory requirements were satisfied. Shift turnovers were observed on a sampling basis to verify that all pertinent information on plant status was relayed to the oncoming crew. During each week, the inspectors toured accessible areas of the facility. The inspectors talked with control room operators and other plant personnel. The discussions centered on pertinent topics of general plant conditions, procedures, security, training, and other aspects of the work activities.

No violations or deviations were identified.

4. MAINTENANCE (62703)

During the inspection period, the inspectors observed portions of, and reviewed records on, selected maintenance activities to assure compliance with approved procedures, Technical Specifications, and appropriate industry codes and standards. Furthermore, the inspectors verified that maintenance activities were performed by qualified personnel, in accordance with fire protection and housekeeping controls, and that replacement parts were appropriately certified.

The inspectors observed portions of the following maintenance activities:

<u>Description</u>	<u>Dates Performed</u>
RHR Pump 2-1 Overcurrent Trip Relay Calibration (W/O R011124)	February 2, 1994
Diesel Fuel Oil Piping Modifications (Units 1 and 2) (W/O C0116150)	January 13, 1994
Battery Charger 1-2 Troubleshooting (W/O C0122926)	February 10, 1994
Uninterruptable Power Supply Troubleshooting (W/O C0122804)	February 10, 1994
Main Steam Safety Relief Valve Testing (Unit 1) (MP M-4.18)	February 8, 1994

The results of setpoint verification testing of the Main Steam Safety Reliefs (MSRs) for Unit 1 indicated that 13 of the 20 Unit 1 valves did not lift within ± 1 percent of their associated setpoint. All the valves were reset to within the ± 1 percent of their setpoint tolerance, and the lift setpoints



verified by two consecutive lifts without adjustment within the ± 1 percent setpoint tolerance.

Of the 13 valves that did not lift within the ± 1 percent tolerance, 7 of the valves had greater than 3 percent deviation and 3 of the valves had greater than 5 percent deviation. Of the 20 valves tested, fifteen of the valves had been refurbished and tested during the last refueling outage. Nonconformance Report (NCR) DC1-89-TN-N098 described the licensee actions on this problem based on the results of prior MSR testing and remains open for further investigation of the issue.

No violations or deviations were identified.

5. QUALITY ASSURANCE AUDIT OF DESIGN CHANGES (40500)

The inspector reviewed a recent audit by the licensee of the acceptability of engineering involvement in the design changes to be installed during the next refueling outage. The inspector reviewed the report to determine whether the audit was of an appropriate depth and scope and if the auditors had effectively implemented the audit plan.

The licensee's Quality Assurance (QA) organization audited several of the design changes. Some of the findings included: (1) design data which was not the most recent revision of design analysis; and (2) inadequate coordination between the licensee and vendors in performing design calculations. Additionally, in analyzing a new plant protection system feature to be installed, (i.e., the negative steam line pressure rate trip) the audit found a lack of consideration of the time allowed for operators to depressurize the reactor coolant system in response to a steam generator tube rupture. Although Westinghouse had considered time constraints without offsite power and without availability of a condenser for steam dumps, the vendor had not considered the time constraints to avoid steam generator overfill if the condensers were available. Subsequent analysis and other corrective action by the licensee resolved the QA Audit finding concerns.

The inspector concluded that the licensee's audit was an effective assessment of the engineering role in the design change process.

No violations or deviations were identified.

6. SURVEILLANCE (61726)

The inspectors reviewed a sampling of Technical Specifications (TS) surveillance tests and verified that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned. The inspectors observed portions of the following surveillance tests on the dates shown:

<u>Procedure</u>	<u>Description</u>	<u>Dates Performed</u>
STP R-25	QPTR Calculation (Unit 2)	February 3, 1994



STP R-3A	Full Core Flux Map (Unit 1)	February 7, 1994
STP I-2D	Nuclear Power Range Incore/Excore Calibration (Unit 1)	February 10, 1994
STP I-2C3	Reinstatement of Power Range Channel to Service (Unit 1)	February 10, 1994
STP M-16P1	Continuity Testing of Train A/B Slave Relays (Unit 1)	January 19, 1994

On January 19, 1994, the NRC inspector observed the performance of Surveillance Test Procedure STP M-16P1, Revision 10, "Continuity Testing of Train A/B Slave Relays." This STP checks Engineered Safety Features (ESF) equipment circuit continuity. The inspector noted that both the instrumentation and controls (I&C) technician and the operations personnel were familiar with both the procedure and the equipment. During the performance of the surveillance test, the I&C and operations personnel understood and anticipated the results of their actions. Communications were established and maintained with the control room as required by the procedure. This procedure was performed on both Trains A and B. During the performance of the procedure, the inspector observed that Step 11.1, which required verification of the output mode selector switch for each train, was not performed for Train B. The inspector called this to the attention of the personnel performing the STP at which point the I&C technician and the operator reviewed the procedure and performed the required verification for Train B.

The inspector discussed this deficiency with the involved I&C and operations personnel as well as the Unit 1 Shift Foreman. The licensee evaluated the safety significance of having improperly performed the step, and concluded that the significance was negligible, since control room alarms would have been actuated had the switch been in the incorrect position. Involved I&C, engineering and operations personnel agreed that the surveillance procedure, and similar procedures, could be improved with some minor changes.

Upon recognition of improper performance of the procedure, the inspectors noted that the licensee had not documented the improper procedure performance in an Action Request, the licensee's method of documenting quality problems. The failure to document the improper performance of a procedure in a quality problem identification document, (i.e., Action Request), was a violation of 10 CFR 50, Appendix B, Criterion XVI, as implemented by licensee procedure OM7.ID1, Revision 2, "Problem Identification and Resolution - Action Requests," Step 5.2.2.a.2, which requires that problems adverse to quality, specifically improper performance of a procedure, be documented in an Action Request.

After discussions with licensee management, in which the inspectors pointed out the violation, the licensee immediately initiated an Action Request, pointed out that corrective action to clarify this and similar procedure steps had been already initiated despite the lack of a formal documentation, and identified that this specific instance would be used as a lesson learned for future training in proper performance of procedures.



The inspector evaluated corrective actions taken as a result of the deficiency noted. The inspector observed that the licensee was in the process of implementing a corrective action program for past occurrences of failure to properly follow plant procedures. This program is in process and went into effect on March 8, 1994. The licensee stated that this specific observation will be addressed in the corrective action.

The inspector concluded that the safety significance of the licensee's failure to formally document a quality problem with an Action Request was low. In addition, the licensee had initiated corrective actions, and later formally documented the problem after further discussions with the inspectors. Since the criteria of 10 CFR 2, Appendix C, Section VII.B.(1) of the enforcement policy was met, this violation was not cited (NCV 50-275/94-03-01, closed).

The inspectors also informed licensee management that, during NRC observations of licensee personnel using procedures, and inspector review of completed procedures, the inspectors had not noticed any occasions in which procedure comment/feedback forms (included with all procedures and work orders) had been used by licensee staff to recommend enhancements or clarifications to procedures. Since the licensee is implementing procedure enhancements in response to lack of procedure compliance, it appeared that lack of licensee staff feedback was counter to this effort. The licensee acknowledged this observation, and responded that comment forms were being used more frequently, and the corrective action program for procedure compliance would address lack of use of feedback forms.

One non-cited violation was identified.

7. PARTICIPATION IN LICENSEE EMERGENCY DRILL (51332)

On February 2, 1994, the licensee conducted a quarterly emergency preparedness exercise. The NRC inspector participated in the drill and observed operations in the simulator. The drill simulated a fire in a main transformer bank and a subsequent steam generator tube rupture. Licensee response observed by the inspector appeared appropriate and in accordance with emergency response procedures.

No violations or deviations were identified.

8. ONSITE REVIEW OF LICENSEE EVENT REPORTS (90712)

The inspector performed an in-office review of the following LERs associated with operating events. Based on the information provided in the report, the inspectors concluded that the licensee had met the reporting requirements, had identified root causes, and had taken appropriate corrective actions. The following LERs are closed:

Unit 1:

94-001, Revision 0, Inadequate Fire Barrier Penetration Seals Due to Lack of Damming Boards.

93-011, Revision 0, Turbine and Reactor Trip Due to a Generator Excitation Protection Transducer Failure.



93-001, Revision 0, Component Cooling Water Potentially Outside Its Design Basis Due to Non-Conservatism in the Design Basis Analysis.

93-003, Revision 0, Low Temperature Overpressure Protection Setpoint Analysis Non-Conservatism Due to Miscommunication.

93-010, Revision 0, Violation of Technical Specification 3.2.6.3 due to Inadequate Incorporation of Plant Design Basis and Operating Configuration in Technical Specifications.

No violations or deviations were identified.

9. FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

9.1 (Closed) Enforcement Item 50-275/92-17-02: Reverse Rotation of CFCUs

This enforcement item involved a failure of the licensee to identify and correct reverse rotation of the CFCU fans due to open backdraft dampers. The licensee implemented Surveillance Test Procedure STP M-51A to check for reverse CFCU fan rotation--an indication of open CFCU backdraft dampers. After Mechanical Maintenance had implemented final corrective actions to assure that all backdraft damper components were properly arranged, the surveillance test consistently showed that no backdraft dampers were open for several months on both units. The licensee corrective actions appeared to have been effective.

10. FOLLOWUP (92701)

10.1 (Closed) Open Item 50-323/93-24-04: Installation of a Temporary Component Cooling Water (CCW) Gage

This issue involved the installation of a test gage on the discharge of CCW pump 2-2 where plant procedures for the installation of test equipment were not followed. The licensee has reviewed the maintenance and test equipment logs and determined that no other test equipment had been left installed on safety-related equipment without proper documentation. The cause of this event has been attributed to personnel error due to inadequate knowledge of plant policies and procedures for installing temporary test equipment. The licensee was in process of changing the administrative control processes for providing technical assistance to more clearly specify the documentation and verifications required for the installation and removal of test equipment. A lessons-learned memorandum summarizing this event has been developed and training is being conducted with licensee personnel involved with this type of evolution. Based on the above, this item is closed.

10.2 (Closed) Open Item 50-323/93-07-04: Incorrect Dowel Dimension in Safety Related Check Valves

This issue involved the licensee's corrective actions for check valve dowel pins that were of incorrect dimensions. The dowel pins, as found during a outage check valve inspection, were too short to perform their design function of holding the hinge ring in place during a seismic event. Maintaining the hinge ring in the correct position prevents improper disc reseating and the



potential for reverse flow. Investigation revealed that the valve drawing for the valve in question (8" Anchor Darling Swing Check Valve) listed the incorrect dimension for these pins. Other similar valve design drawings were found that listed incorrect dowel pin dimensions (4" Anchor Darling Swing Check Valve). The licensee identified all valves in each unit that were potentially affected. Sixteen of the valves were installed in safety-related systems.

The licensee submitted LER No. 2-93-06, Revision 0, regarding the discovery of dowel pins of insufficient length in Anchor-Darling check valves. The licensee has completed inspection of all safety-related valves in Unit 2 and identified one additional dowel pin of insufficient length. Valves which were identified as being deficient were returned to the vendor. The licensee also identified that none of the potentially affected valves were installed in an orientation other than the recommended horizontal orientation.

In addition, the licensee performed an operability evaluation for this condition, which revealed that licensee procedures were in effect that required that the Unit be brought to Cold Shutdown following a seismic event with a ground acceleration of 0.2g or greater. In the event of a 0.2g or greater earthquake an evaluation of all potentially affected plant equipment would be performed. This would include an inspection of all the 4" and 8" Anchor Darling swing check valves installed in safety-related systems for the short dowel pin condition. Calculations by the licensee indicated that an upward seismic force of greater than 1.0 g would be required to cause hinge ring movement since the valves were oriented correctly. For a seismic event of 0.2g or less all suspect valves were oriented in lines such that less than 1.0g vertical acceleration would be experienced at the valves.

10.3 (Closed) Open Item 50-275/92-20-01: Corrosion of Diesel Fuel Oil Piping and Cardox Piping

This item involved the licensee's identification of unexpected corrosion of the diesel fuel oil and Cardox piping located in a trench outside the turbine building. The licensee's corrective action was to replace all of the piping and perform periodic inspections to assess whether corrosion was occurring.

The inspectors verified that the licensee has replaced all diesel fuel oil piping in the trench with new, corrosion-resistant, coated piping. The Cardox system piping has been removed from the trench and rerouted through the turbine building. The licensee has scheduled inspections of the Diesel Fuel Oil and Auxiliary Salt Water Annubar Piping in the trenches at one year intervals to determine if corrosion is occurring.

10.4 (Closed) Open Item 50-275/93-03-04: Post-LOCA Profile Not Conservative

The licensee identified in a nonconformance report (NCR) that several of the equipment qualification materials and components required reanalysis when the licensee determined that the peak Westinghouse Post-LOCA temperatures would be maintained for a longer time period (i.e., a few hours vice a few minutes). This reanalysis concluded that all equipment would remain qualified despite the longer time at the peak temperature. The inspector reviewed several of the summaries of the equipment analysis, and concluded that, given the conservative test data available which qualified the equipment, no inconsistencies with the licensee's conclusions were identified.



10.5 (Closed) Open Item 50-275/93-22-03: Hydrogen Purge System Not properly described in the FSAR

This item involved the inspector's identification that the external hydrogen (H₂) purge system was not installed as documented in the FSAR, in that the connections to install an external recombiner were not the T-type, but were the elbow-type. The licensee pointed out that all license commitments were fulfilled by both of the redundant trains of the internal H₂ recombiner system installed in containment, and the external H₂ system was not credited for any design basis accident. Nevertheless, the licensee agreed to update the FSAR, as appropriate.

10.6 (Closed) Open Item 50-275/91-40-01: Vulnerability of Unit 1 Centrifugal Charging Pump and Safety Injection Pump to Runout

This item involved a Westinghouse-identified concern that some Emergency Core Cooling System (ECCS) pumps may experience runout. The licensee determined that this may occur after a LOCA when hot leg recirculation is initiated and higher suction pressure is provided to the pumps by the RHR pumps, rather than the gravity head of the refueling water storage tank. The licensee's Operability Evaluation (OE) 91-14R0 concluded that piping friction losses would provide enough back pressure to prevent runout conditions for all the ECCS pumps, except Unit 1 safety injection pumps and centrifugal charging pump 1-1. The licensee concluded that operation at runout conditions had been previously tested during startup, and the pump vendors and Westinghouse analysis concluded that, based on acceptable vibration levels, no adverse effects would be expected under these conditions. The inspector identified four concerns, which the licensee adequately addressed, as discussed below.

Operation at Degraded Voltage Conditions: The inspector identified that degraded voltage conditions may cause higher currents for the pumps in runout, and may result in a safety concern. The licensee responded that electrical loads were not expected to change at that performance level, since the brake horsepower curve is flat at flow rates beyond the design runout flow.

Continued Assurance of Operability at Runout Conditions: Since the last validation of acceptable performance at runout conditions was during plant startup, the inspector questioned whether continued operability at runout conditions for those pumps was assured. The licensee stated that pump performance during surveillance testing (STP V-15) over several refueling outages had shown test results consistent with earlier tests, indicating that the pump performance had not degraded with time. The inspector questioned the assurance of future pump operability, since the acceptance criteria for the STP was based on pump performance at below runout flow. The licensee stated that pump flow balancing during the following outage (1R5, March 1993) would be performed to reduce flows to below runout. The licensee also discussed ASME Section XI pump testing which would result in placing the pump in alert status if performance dropped, and concluded that this testing was adequate. Since the flow balance had been reset to avoid runout conditions, the concern was resolved.

Effects of Runout On The Motor: The inspector was concerned about the potential for motor degradation at runout and motor breaker settings. The licensee indicated that based on past testing the motor was not affected by operation at runout conditions, and that operation at safeguard bus design



undervoltage would not affect motor breaker settings.

Applicability of Technical Specifications: The inspector noted that the Technical Specification 4.5.2.h. requirements for ECCS flow balance did not appear to have been met, since the pumps would operate at runout flow rates. In a document dated June 25, 1992, the licensee concluded that the Technical Specification requirements for ECCS flow balance referred to the injection phase only.

No violations or deviations were identified.



ATTACHMENT 1

DETAILS

1. Persons Contacted

Pacific Gas and Electric Company

- G. M. Rueger, Senior Vice President and General Manager,
Nuclear Power Generation Business Unit
- J. D. Townsend, Vice President and Plant Manager, Diablo
Canyon Operations
- W. H. Fujimoto, Vice President, Nuclear Technical Services
- *R. P. Powers, Manager, Nuclear Quality Services
- J. S. Bard, Director, Mechanical Maintenance
- D. H. Behnke, Senior Engineer, Regulatory Compliance
- *G. M. Burgess, Director, Systems Engineering
- S. G. Chesnut, Reactor Engineer Supervisor
- *W. G. Crockett, Manager, Technical and Support Services
- *S. R. Fridley, Director, Operations
- *B. W. Giffin, Manager, Maintenance Services
- C. R. Groff, Director, Plant Engineering
- J. A. Hays, Director, Onsite Quality Control
- *J. R. Hinds, Director, Nuclear Safety Engineering
- *K. A. Hubbard, Engineer, Regulatory Compliance
- *D. B. Miklush, Manager, Operations Services
- J. E. Molden, Director, Instrumentation and Controls
- S. R. Ortore, Director, Electrical Maintenance
- D. V. Pierce, Senior Engineer, Mechanical Maintenance
- P. G. Sarafian, Senior Engineer, Nuclear Quality Services
- *J. A. Shoulders, Director, Onsite Nuclear Engineering Services
- D. R. Stupi, Engineer, Mechanical Maintenance
- *D. A. Taggart, Director, Onsite Quality Assurance
- R. C. Washington, Senior Engineer, Instrument Maintenance

*Denotes those attending the exit interview.

The inspectors interviewed other licensee employees including shift supervisors, shift foremen, reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, and quality assurance personnel.

2. **EXIT MEETING**

An exit meeting was conducted on February 23, 1994. During this meeting, the inspectors summarized the scope and findings of the inspection as described in this report. The licensee did not identify as proprietary any of the materials reviewed by or discussed with the inspectors during this inspection.

