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OFFICE OF NUCLEAR REACTOR REGULATION

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Licensee: Pacific Gas and Electric Company

Facility Name: Diablo Canyon Unit 1

Inspection Conducted: August 24 through October 30, 1992

Inspection Team: Jeffrey B. Jacobson, Team Leader, NRR
John D. Wilcox, Jr., Assistant Team Leader
Peter S. Koltay, NRR
Hai-Boh Wang, NRR
Daniel O'Neal, NRR
Steven Sanchez, NRR
Ronaldo V. Jenkins, NRR
Alan Madison, AEOD
Michael Royack, Region V
Christopher Myers, Region V

Prepared by: [signature] 12/2/92
Jeffrey B. Jacobson, Team Leader
Team Inspection Development Section A
Special Inspection Branch
Division of Reactor Inspection
and Licensee Performance
Office of Nuclear Reactor Regulation
Date

Reviewed by: EV Imbro 12/3/92
Eugene V. Imbro, Chief
Special Inspection Branch
Division of Reactor Inspection
and Licensee Performance
Office of Nuclear Reactor Regulation
Date

Approved by: RP Zimmerman for 12/8/92
Charles E. Rossi, Director
Division of Reactor Inspection
and Licensee Performance
Office of Nuclear Reactor Regulation
Date

EXECUTIVE SUMMARY

For two periods between August 24 and October 30, 1992 (August 24 through 28 for phase one and October 22 through 30, 1992 for phase 2), the Nuclear Regulatory Commission (NRC) staff conducted a pilot inspection of shutdown risk and outage management at Diablo Canyon Power Plant Unit 1. The intent of the inspection was to assess the quality and implementation of the licensee's outage planning with regard to minimizing the risk of accident sequences during shutdown conditions. During the first phase, conducted before the 1992 refueling outage, the team assessed the following attributes: (1) management involvement and oversight of the outage planning; (2) outage scheduling, focusing on coordination of significant work activities and the availability of electrical power supplies, decay heat removal systems, reactor coolant inventory control systems, and containment; and (3) operator response procedures, contingency plans, and training for mitigation of events involving shutdown risk. During the second phase, conducted during the outage, the team observed overall control of ongoing outage work activities and testing to assess the following attributes: (1) the controls, procedures, and training related to the performance of plant activities during shutdown conditions; (2) the working relationships and communication channels between operations, maintenance, and other plant support personnel; (3) outage planning activities for potential impact on shutdown risk, including the scheduling and supervision of work activities and control of changes to the outage schedule; (4) control room evolutions before and during mid-loop operations; and (5) the degree of management involvement and oversight in the conduct of the outage. The team also completed NRC Temporary Instruction 2515/113, "Reliable Decay Heat Removal During Outages."

PG&E had developed and implemented an effective risk-sensitive outage plan for the fifth Diablo Canyon Unit 1 refueling outage. Specific strengths were identified in the following areas:

- training - Both licensed operators and other personnel received specific training on plant operations and high risk evolutions during shutdown conditions.

- scheduling - The concept of defense-in-depth and risk minimization was well integrated into a controlled scheduling process.

- self-assessments - PG&E completed several indepth self-assessments designed to evaluate the outage from a risk perspective.

- control room operators - The control room operators appeared knowledgeable, well trained, and attuned to shutdown risk concerns.

- outage safety plan - PG&E's overall outage safety plan including the outage safety schedule, the outage safety checklist, and associated procedures formed the basic framework for minimizing risk during shutdown.

- equipment/material control - PG&E's policies and procedures ensured effective control over tools, equipment and material.

The following deficiencies were identified:

- drawing control - Three instances of drawings not being up to date were identified in the control room.

- inadequate procedures - No procedure existed for ensuring foreign material exclusion on disconnected instrument lines. In addition, the procedure that controlled the addition of unborated water to the spent fuel pool inappropriately left it up to personnel discretion as to when water additions were expected to exceed 100 gallons and needed to be monitored.

- failure to follow procedures - Maintenance workers failed to tag a disconnected instrument line for a spare steam generator level instrument.

- overtime control - There were several instances in which licensed operators and maintenance personnel had exceeded overtime guidelines without the required pre-approval.

The team identified several weaknesses or areas where safety enhancements could be made. These are identified in the report as Observations. One observation concerned inconsistencies in the definition and control of equipment deemed "available" by operations personnel. Another observation concerned conflicting guidance on the conditions during mid-loop operations when reactor water level data would be recorded. Additional observations included the lack of a dedicated power supply to the reactor level standpipe television camera, and the incomplete implementation of self-assessment recommendations.

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1.0 INTRODUCTION

The Nuclear Regulatory Commission (NRC) staff conducted an announced pilot inspection of shutdown risk and outage management at the Diablo Canyon Power Plant Unit 1 in two phases. Phase 1 was conducted on August 24 through 28, 1992; phase 2 was conducted on October 22 through 30, 1992. The primary objective of this inspection was to assess the quality and implementation of the licensee's outage planning with regard to minimizing the risk of accident sequences during shutdown conditions. A secondary objective was to assess the licensee's ability to cope with events that could arise during shutdown conditions. To achieve these objectives, the team conducted the inspection in two phases: (1) during pre-outage planning and (2) during the outage.

During phase 1, the team assessed:

- management's involvement and oversight of the outage planning

- the outage schedule, focusing on coordination of significant work activities and the availability of electrical power supplies, decay heat removal systems, reactor coolant system (RCS) inventory control, and containment control

- operator response procedures, contingency plans, and training for mitigation of events involving a loss of decay heat removal capability, loss of RCS inventory, and loss of electrical power sources during shutdown conditions

During phase 2, the team assessed:

- the controls, procedures, and training related to the performance of plant activities during shutdown conditions

- the working relationships and communication channels between operations, maintenance, and other plant support organizations

- outage planning activities, including the scheduling and supervision of work activities and control of changes to the outage schedule

- management involvement and oversight of the conduct of the outage

- the adequacy of selected modifications packages and post-maintenance testing

The team has characterized the negative findings in this report as deficiencies. Deficiencies are either (1) the apparent failure of the licensee to comply with a requirement or (2) the apparent failure of the licensee to comply with a written commitment, or the provisions of applicable codes, standards, guides, or other accepted industry practices. Observations are items for which safety enhancements could be made, although these items had no apparent direct regulatory basis. Each deficiency is summarized in Appendix A to this report; observations are listed in Appendix B.

2.0 PHASE 1 - OUTAGE PLANNING AND SCHEDULING

The team placed particular emphasis on determining if the licensee incorporated risk management considerations into the outage scheduling process and how the planning and scheduling process to control work activities relevant to shutdown risk was used. The team reviewed the process for planning and preparation of modification and work packages scheduled for the outage and reviewed training and procedures related to shutdown risk to ensure that adequate considerations were implemented before and during the outage.

2.1 Outage Risk Assessment Plan

The team reviewed the licensee's pre-outage planning process for the Unit 1 refueling outage designated 1R5 with emphasis on shutdown risk considerations. The team found that extensive measures were being taken by the licensee to identify and schedule significant maintenance and construction tasks that could impact plant risk.

The licensee administratively controls outage management through Program Directive AD8, Revision 0, "Outage Planning and Management." The licensee planned to issue three additional procedures that were in draft format. These draft procedures could enhance the outage and shutdown risk program during future outages.

The team noted a number of quality attributes associated with outage planning. For example, Program Directive AD8 required that the licensee evaluate plant configurations and outage activities to determine if any safety functions could be adversely affected. Another quality attribute, Interdepartment Administrative Procedure AD8.ID1, specified that an outage safety plan be developed to describe the systems, structures, and components needed to provide a defense in depth assurance for key safety functions. These key safety functions are: (1) decay heat removal, (2) inventory control, (3) power availability, (4) reactivity control, and (5) containment closure. The outage safety plan identified those outage activities that represent higher risk evolutions and included associated contingency plans and infrequently performed tests and evolutions.

The licensee used an outage safety schedule to indicate and control the availability, logic, and sequence of events for those plant safety systems and vital electrical power supplies deemed necessary to maintain the desired level of defense in depth for key safety functions. The safety schedules received the required procedural review by the outage safety coordinator (OSC) and an independent review by a senior reactor operator (SRO) who was not involved in the creation of the schedule.

The licensee had the nuclear excellence team (NET) perform a pre-outage safety assessment of the schedule. The NET report, dated August 24, 1992 included recommendations to perform contingency planning for required maintenance activities during higher risk periods. One finding from this independent review was an extension of the availability of the auxiliary feedwater pump 1-1 to support a steam generator filling operation.

The Unit 1 pre-outage safety schedule showed the licensee's efforts to integrate related work activities to the shutdown safety equipment logic diagrams in Station Procedure AD8.DC55, "Outage Safety Scheduling." This procedure had been initiated to maintain the defense-in-depth approach with respect to the key safety functions.

Overall, the scheduling of maintenance activities reflected explicit planning with respect to the minimization of shutdown risks. The licensee posted the plan of the day, safety schedule, and safety checklist in appropriate locations throughout the plant. These documents were current, accurate, and were administratively controlled by applicable procedures and/or policies.

The licensee also instituted the 12 outage risk assessment and management (ORAM) improvements resulting from a probablistic risk assessment that Westinghouse and the Electric Power Research Institute (EPRI) had performed for the outage. At the beginning of the 1R5 outage, only one of the 12 improvements had not been completed. This incomplete improvement was associated with the alarm set point for the reactor vessel refueling level indication system (RVRLIS). The licensee indicated that incorporating the ORAM risk insights into outage practices reduced the boiling risk by about a factor of 2.5 and the core uncovery risk by about a factor of 4.

The team concluded that the outage risk assessment plan that implemented and controlled the risks associated with the 1R5 outage was a strength.

2.2 Planning, Scheduling, and Preparation of Modifications and Work Packages

In response to Generic Letter 88-17, "Loss of Decay Heat Removal," the licensee committed to implement procedures and/or administrative controls to reasonably minimize the likelihood of a loss of decay heat removal. The team examined the licensee's process for outage planning and scheduling to determine if shutdown risk management considerations were incorporated and how related work activities were controlled. The team reviewed the licensee's process for planning and preparing plant modifications and work packages for activities scheduled during the outage to determine if shutdown risk had been adequately considered.

2.2.1 Scheduling and Planning

The licensee's shutdown risk management program was well established and documented in formal procedures. In addition, checklists had been formally established for the 1R5 outage so that operations personnel could track the status and availability of systems and equipment. The licensee's procedures established shutdown risk considerations as goals for planning and scheduling purposes rather than as requirements for the control of work activities.

The licensee had developed a safety plan in accordance with procedure AD8.ID1. The pre-outage safety plan contained a written description of the equipment and systems that the licensee considered to be required to minimize risk by maximizing equipment and system availability.

The safety schedule reflected the licensee's safety plan and identified the planned status of equipment and systems on a daily basis throughout the outage. The safety schedule graphically correlated the availability of key safety functions (decay heat removal, inventory control, electric power, reactivity control and containment closure) to critical periods of plant vulnerability, such as during reduced RCS inventory and fuel movement. The safety schedule had been reviewed and approved as required by the licensee's procedure.

Extensive interviews with licensee personnel and review of licensee procedures showed the licensee had implemented effective outage planning and administrative controls to generally avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or to systems considered necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition. The licensee personnel involved in managing risk and maintaining safety functions during outage activities had a clear understanding of the safety plan. The personnel maintained awareness of high shutdown risk periods during the outage and adequately communicated the status of plant equipment to meet the safety plan.

The licensee procedures incorporated the recommendations of the Nuclear Utilities Management and Resources Council (NUMARC) and the Institute for Nuclear Power Operations (INPO), along with industry experience and plant-specific lessons learned.

The team concluded that the licensee had taken extensive measures in developing the outage plan for the fifth refueling outage for Unit 1 to identify and schedule potentially significant outage tasks that could affect shutdown risk. The licensee's scheduling and planning activities were a strength in the licensee's program for managing shutdown risk.

2.2.2 Planning and Preparation of Modifications and Work Packages

The planning and scheduling group utilized a computer scheduling program (PREMIS) to implement the safety plan and develop the safety schedule. Milestones were assigned to the start and completion of key outage activities, such as maintenance on one train of decay heat removal. The lead scheduler provided input to the computer program to create logic ties between milestones to satisfy the logic diagrams of safety scheduling procedure AD8.DC55. Each modification and work package for the outage was scheduled through PREMIS into an appropriate window between milestones. Using the computer program with safety plan logic ties, the licensee planned all outage work activities and supervised activities during the outage to implement their outage safety plan.

The licensee tracked the status of outage work activities using a computerized tracking system (PIMS). The status of each work activity was updated in PIMS to identify completion of milestones for PREMIS. PREMIS was updated twice daily. The licensee utilized the PREMIS scheduling program for all outages involving either planned or forced entry into Mode 5 or 6 and for emergent work identified during the outage.

The licensee established a goal in procedure AD8.ID1 to complete the preparation of all refueling outage work packages before the start of the outage. However, they were unable to meet this goal for the 1R5 outage and revised planning priorities to ensure that all work packages scheduled for the first two weeks of the outage were issued 30 days before the start of the outage. The team reviewed selected modifications and work packages and found that the individual packages had been prepared in accordance with licensee procedures. The safety evaluations for the modifications were thorough and complete.

The team concluded that the licensee's process for planning and preparation of modifications and work packages was a strength in its program for managing shutdown risk.

2.3 Training

The licensee's response of January 6, 1989, to Generic Letter 88-17 provided an extensive outline of licensed operator training related to loss of decay heat removal, reduced inventory, and lowered loop operations. The response identified when the training was completed, that procedure update training would be provided during the requalification training program, and that required operator briefings of concerns and procedures associated with mid-loop conditions would be conducted before a unit was brought to a mid-loop condition.

The team reviewed the licensee's "Licensed Requalification Training Session 92-1," simulator scenarios and training records for licensed operators, non-licensed operators, maintenance and technical staff, and supervisors to determine if personnel were being trained in shutdown risk.

In the operator requalification training session, the licensee provided classroom and simulator (where applicable) training for NRC licensed operators in:

- recent industry events related to shutdown risk
- procedure changes related to shutdown
- shutdown emergency procedures
- problem identification and resolution
- the outage safety plan

Training applicable to shutdown conditions was scheduled and given within 3 months of the shutdown. Simulator shutdown scenarios were developed to include multiple failures and the shutdown emergency procedures.

Of the 70 NRC-licensed SROs and reactor operators, and 5 shift technical assistants, all but 3 had completed all of the training sessions that could impact shutdown. As of the close of the inspection, these 3 were in the process of completing the training.

Non-licensed operators had training in shutdown operations and in potential problems and consequences which could result from a loss of decay heat removal during high risk periods of operation. The team's review of training records and interviews with non-licensed operators confirmed that training was

completed and effective. Maintenance personnel were trained in specific operations associated with high risk shutdown/refueling operations. Technical and supervisory personnel were trained in problem identification and resolution for evaluating degraded plant conditions.

The team concluded that the licensee had met its commitments for training personnel in response to Generic Letter 88-17.

2.4 Procedures

The team reviewed the technical content of the licensee's procedures for responding to events during shutdown conditions and walked through selected procedures to verify they could be physically implemented within the timeframe required. The team reviewed normal, emergency, and abnormal operating procedures to determine the extent to which the procedures contained appropriate cautions and warnings related to required actions. Areas addressed included the potential to cause perturbations in RCS inventory, decay heat removal, instrument air, service water, or component cooling water (CCW) system, and the availability of onsite or offsite power sources.

The 500 kV and 230 kV switchyard areas were under administrative control of an external Pacific Gas and Electric Company (PG&E) organization, High Voltage Transmission and Substations (HVT&S). Station Procedure AD8.DC51, "Control Of Offsite Power Supplies to Vital Buses," states that "when only one offsite power supply is available, i.e. power is only being supplied via the 230 kV system or only being back fed through the 500 kV system, no routine work shall be performed in the operating switchyard." The team raised one concern about the lack of an approved procedure controlling work activities within the switchyard areas when the unit has only one single source of offsite power. The licensee responded that a proposed procedure in HVT&S memorandum dated August 20, 1992, will control work activities when only one offsite supply is available. This procedure was implemented on September 18, 1992.

In addition, to ensure more positive control of shutdown operations, drain down, and mid-loop operating activities, the licensee instituted enhancements as described below.

- Operators were expected to complete an outage safety checklist as part of shift turnover activities. However, operators requested that this checklist also be used as a status board in the control room during the outage. During phase 1 of the inspection, the team recommended that the licensee incorporate this checklist into the normal operating procedures and comply with the operator's request for status boards. Before the start of the outage, the outage safety checklist was issued as Operations Department Policy D.8, "Outage Safety Checklist," and was effectively used as a status board in the control room. The checklist and status boards provided a clear and readily available reference for the operators to ensure compliance with the defense-in-depth policies developed in the outage safety plan and were considered a strength by the team.

- Information regarding time to core uncovery was not originally planned to be made available to the operators. In response to concerns raised by the team, the licensee did develop this information and provided it to operators before drain down.

- Boron dilution paths had not originally been identified for each planned shutdown configuration. Subsequent to concerns raised by the team, the licensee reviewed procedures related to shutdown operations and revised these procedures to identify boron dilution paths and require that these be isolated and tagged out of service.

The licensee indicated it would include these enhancements in future procedure revisions to ensure continued positive control of safe shutdown operations.

To assess procedure capabilities, the team selected several hypothetical events and walked through the procedures that would be used to mitigate these events with licensed operators. The licensee had developed several procedures to address events occurring during shutdown, including SD-0, "Loss of, or Inadequate Heat Removal"; SD-1, "Loss of Vital AC Power"; SD-2, "Loss of RCS Inventory"; SD-3, "Loss of Auxiliary Salt Water"; SD-4, Loss of Component Cooling Water"; and SD-5, "Loss of Residual Heat Removal." These procedures were well prepared with adequate guidance to achieve the desired results. No problems were identified during the walkdowns and the operators selected for the walkdowns were adequately trained and familiar with using the procedures.

The licensee had administrative procedures and directives in place to ensure that technically accurate and correct procedures were provided and maintained. New procedures and revisions to procedures were subjected to independent peer reviews, including operator walkdowns of procedures. Additionally, applicable procedures were reviewed for lessons learned following unusual incidents and modifications. Periodic reviews of all procedures were required, and personnel were informed of procedural errors. It was an administrative policy that tolerating procedural errors was unacceptable and, when found, such errors would be corrected. Several methods were available for personnel to report and correct procedural errors and deficiencies. The licensee appeared to have adequate controls for ensuring procedures were updated and improved when necessary.

2.5 Review of Electric Power Availability

The team interviewed operations personnel who stated that it is station policy to maintain at least one offsite and one onsite power source to each required shutdown load. Procedure AD8.ID1 requires that when ac power system availability drops below the planned defense in depth, specific contingency plans shall be developed and implemented as required by AD8.DC55. A review of the August 26, 1992, safety outage schedule indicated that at least one offsite power source and one onsite power source would be available to each required shutdown load.

The licensee planned to perform battery testing and replacement work on battery 12 by removing only one vital dc power source at a time. The dc power system design permits dc power to be available to the required loads through the use of crosstie connections to the alternate dc charger/battery.

Interviews with licensee personnel indicated that no temporary power modifications were planned for the outage other than those identified in the outage safety plan. The licensee planned to install jumpers for the various bus outages for preventive maintenance on the breaker and the replacement of battery 12. The licensee planned to use a high impact team (HIT) to organize and implement controls over the above nonstandard electrical configurations. Other non-standard electrical lineups for temporary power for welding and lighting and test support purposes were controlled under approved procedures and originated from a power service that was not safety related.

Operating personnel said they were trained on the use of emergency operating procedures (EOPs) and applicable Abnormal Operating Procedures (AOPs) that provided for manual control of electric power systems as needed. The safety outage schedule of August 26, 1992, indicated that a maximum number of electric power sources would be available during the reduced inventory period when the fuel was in the vessel. The team concluded that the planned electric power availability was adequate for the outage.

2.6 Industry Event Review

The team reviewed the program for evaluation of industry information used by the operations experience assessment (OEA) group as well as evaluations of NRC information notices (INs) and bulletins and the Institute of Nuclear Power Operations (INPO) significant operating event reports (SOERs) and significant event reports (SERs) related to the loss of decay heat removal and shutdown/outage risks. This program is administratively controlled by PG&E Company Procedure NPAP C-14/NPG-8.2, Revision 11, "Nuclear Plant Administrative Procedure Processing of Industry Operating Experience." The team reviewed OEA evaluations pertaining to two bulletins, six INs, six SOERs, and two SERs were included in the review. The team found the evaluations of INPO and NRC documents to be technically adequate and thorough, with appropriate recommendations for plant actions to address concerns identified in the documents.

The team concluded that industry events related to shutdown risk were being properly evaluated and implemented in the plant where appropriate.

3.0 PHASE 2 - OUTAGE IMPLEMENTATION

During phase 2 of the inspection, the team assessed the quality of the outage activities and management involvement and oversight of the outage. The team also observed plant evolutions during mid-loop operations that occurred during the outage. The team emphasized the direct observation of operations, maintenance, and surveillance activities. Particular attention was given to the control and coordination of activities from the main control room. Team members attended daily status briefings, observed shift turnovers, and conducted numerous tours of plant areas during both day and back shifts to

assess the adequacy of maintenance and surveillance activities, housekeeping, and work practices. The team also reviewed the license's self-assessment programs.

3.1 Control of Plant Operations and Work Activities

Shift supervisors and shift foremen were adequately monitoring activities for which they were responsible. The high level of experience among these personnel was obvious. There was good communication between operations and outage management, maintenance, and other groups. The assignment of several experienced operators to the outage management group appeared to benefit communication between outage management and operations personnel.

Operations management participated in daily outage status and planning meetings and kept the shifts informed of outage activities. Shift turnover briefings were very thorough and emphasized plant status, areas of increased risk, activities involving the crew, as well as significant outage activities. Outage coordinators provided special briefings for shift supervisors and shift foremen of crews reporting back to work after days off. This extra effort provided added assurance of operations personnel awareness and control of shutdown activities.

Control room activities were well managed and operators were aware of activities that affected control room indicators and alarms. Work that would cause annunciators to alarm or changes in control room instrumentation was discussed before it commenced. In general, the team observed that control room activities were conducted in a professional manner.

Shutdown logs and shift turnover forms were properly maintained and completed. In addition, the use of the outage safety checklist enhanced the operator's awareness and control of equipment important to shutdown safety. Further, the usage of the checklist as a status board to identify operable and available equipment enhanced the shift's ability to ensure compliance with the defense-in-depth approach of the outage safety plan and schedule. Operators were required to complete the checklist each shift as part of the turnover process and update the status board when necessary. The operators and their supervisors were positive about using these checklists.

Night orders addressed significant items of interest to the shift. All shift supervisors and shift foremen were required to read and initial the night orders.

The auxiliary operators completed their rounds in an orderly fashion. Equipment was checked for leaks and excessive vibration. Observed temperatures, pressures, and levels were noted in a log. The control room or responsible individual was contacted when questions arose. Radiation safety procedures were met. In addition to their set rounds, the auxiliary operators performed tasks assigned by the control room. During tagging out of equipment and when returning it to service, the auxiliary operators double checked identification numbers, used the correct tools, labeled and secured fuses and breakers that were pulled, and contacted the control room when assigned tasks were completed.

The team identified three instances where controlled plant drawings did not have the correct revision number. These drawings were operating valve identification drawing (OVID) 106717, Revision 36, sheet 7; 106717, Revision 39, sheet 7; and 106704, Revision 36, sheet 2. According to Nuclear Plant Administrative Procedure NPAP E-9, "Development and Control of Plant Operating Valve Identification Diagrams and Instrument Prints (OVIDIPs)," when a revision is made, the OVID office will send the original signed revised drawing to Document Services, who will then route controlled copies to the various stations (e.g. the control room, technical support center (TSC), and emergency operation facility (EOF)). Also, according to Administrative Procedure (AP) E-55, "Control of Posted Plant Signs and Information," the OVID office was responsible for verifying the correct revision of OVIDs/OVIDIPs before posting the drawings and for ensuring that posted plant drawings were updated upon revision to the OVIDs/OVIDIPs.

All of the drawings located under a plastic covering on the control room center console were compared with the master copy in Document Services. Drawing 106717, Revision 39, sheet 7, appeared in the control room but did not appear in the master copy file. The licensee concluded that this particular drawing was overlooked when the time came for replacing the old revision with the current revision in the master copy file. The licensee investigated the replacement of the revisions that occurred before and after the revision date on drawing 106717, Revision 39, sheet 7, to determine whether or not other revisions had been replaced. The licensee concluded that only this drawing had been overlooked in the replacement process.

In addition, control room personnel indicated that some other drawings had been copied and placed in a location convenient for operator use. This location was unknown to the person responsible for updating the drawings and, therefore, was overlooked when the time came to replace the drawings with the current revision. Consequently, the team identified that drawings 106704, Revision 36, sheet 2, and 106717, Revision 36, sheet 7, were available in the control room but had not been updated with the latest revisions.

The team also identified discrepancies in a second drawing used in the control room: the "Fed From List." This document is considered a controlled document and is part of the PIMs data base in accordance with NECS-E3.7, "As Builts and Corrections," and AP E-53sl, "Change Control for NECS Engineering Entries in the PIMS Component Data Base," respectively. This document is used by operations personnel to verify and investigate work clearances and operational problems.

While the team observed licensed operators researching clearances, it discovered that the Fed From List listing for instrument ac panel feeder breaker 52-PY17 did not include breakers 52-PY1713, 52-PY1722, 52-PY1736, and 52-PY17-40. These breakers were described in controlled electrical drawings that also were available in the control room and supplied various fire protection loads. Further, breaker 52-PY1729 was listed as "DC Power Supply" in the Fed From List, but as "Condition Monitor" on controlled electrical drawing 437549. The operators conservatively verified listings in the Fed From List with the controlled electrical drawings thereby eliminating the possibility of errors caused by the discrepancies in the Fed From List.

However, this was a second indication of a lack of control over operator aids and controlled documents. The licensee indicated it would review the Fed From List for additional discrepancies and revise it as appropriate. The instances of improper drawing control are identified as Deficiency 92-201-01 in Appendix A to this report.

The team observed operations involving cleaning of a fuel handling tool in the spent fuel pool area. Personnel were washing this tool with unborated, demineralized water over the pool. The team was concerned with the amount of demineralized water being added to the pool during this operation without the usage of a device to measure the amount because this could result in an unmonitored and uncontrolled dilution of spent fuel pool boron concentration. Radiation Control Procedure (RCP) D-216, "Addition of Unborated Rinse Water to the Spent Fuel Pool," appeared to require the usage of a flow totalizer when additions of greater than 100 gallons were expected. However, the "Scope" section of this procedure states, in part: "It is not intended to control the rinsing of a few tools or an underwater light which may be occasionally removed from the pool." The personnel involved in cleaning the tool had elected to not use the flow totalizer because they did not expect to exceed 100 gallons of unborated water into the pool. The team raised the concern that the cleaning may have resulted in the 100 gallon criteria being exceeded and that the procedure left it up to the individuals judgement as to whether a particular work evolution could be expected to exceed the 100 gallon criteria. The licensee indicated it would revise the procedure to require usage of the flow totalizer whenever unborated water is added to the spent fuel pool. The procedural weakness concerning the unborated water addition to the spent fuel pool is identified as part of Deficiency 92-201-02 in Appendix A to this report.

In addition, the team was concerned that the person handling the demineralized water hose and the radiation technician standing next to her were not wearing protective face shields. This was discussed with the personnel involved and their management. Licensee management noted that occurrences of personnel contamination had increased during this outage and that increased awareness and controls were warranted. The licensee agreed to consider the team's concerns when reviewing and revising procedures and policies related to personnel contamination control.

3.1.1 Control of Special Tests

As part of the team's review of shutdown risk, a review was conducted of infrequently performed and high risk tests conducted during the outage. An infrequently performed test that could affect core cooling and a test in which natural circulation was relied on to provide core cooling for 1 minute were reviewed during the inspection in accordance with NRC Temporary Instruction (TI) 2515/113 3.01 a and b, respectively.

The licensee had identified Test Procedure TB-9206, "MOV Flow Test - Miscellaneous ECCS Valves in Post-LOCA Recirculation Configuration," Revision 0, as an infrequently performed test that required special management attention. This test involved differential pressure testing on emergency core cooling system (ECCS) motor-operator valves with fuel in the reactor vessel. The team

found one residual heat removal (RHR) train remained in operation at all times during the test. The test was structured so that if the RHR train in operation became inoperable, the other RHR train could provide core cooling. The test appeared to be organized, and the operators' communication appeared to be good.

The team also reviewed STP M-15, Revision 17, "Integrated Test of Engineered Safeguards and Diesel Generator," which was performed in Mode 6. Mode 6 is defined in the technical specifications (TS) as the following state of the plant: "k-effective less than or equal to 0.95, percent rated thermal power =0, average coolant temperature less than or equal to 140°F, and fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed." As part of the test, both RHR pumps were shutdown, per the procedure, for one minute during the test. The refueling cavity was flooded above the reactor vessel flange, and the water in the refueling cavity was used as a heat sink. The rate of temperature increase for the water in the refueling canal and RCS was about 14°F per hour during the time of the test, with temperature monitoring taking place in the control room. The team noted no abnormalities in its review.

The licensee planned the outage safety schedule such that both RHR trains were available to provide core cooling while in Modes 5 and 6. The licensee also maintained a set of emergency procedures that addresses loss of or inadequate decay heat removal while the plant is in Mode 5 and 6. OP AP SD-0, "Loss of, or Inadequate Decay Heat Removal," Revision 3, provides entry conditions to use another abnormal operating procedure in this set, or to use an alternate decay heat removal method.

3.1.2 Mid-Loop Operations

The team reviewed the licensee's commitments to Generic Letter 88-17, performed walk downs of in-plant and control room instrumentation, and observed control room operations during reduced inventory and mid-loop operations.

3.1.2.1 Instrumentation

The licensee had in place and operating at least two independent RCS level indications, a wide range and a narrow range level indication with associated alarms, and an independent standpipe level indication. The standpipe level was monitored by video camera, which provided the level to several locations including the control room. The team confirmed the correct installation of temporary level instrumentation and operability of the following instrumentation:

- at least two independent core exit temperature indications with associated alarms
- RHR pump current indications and associated alarms
- plant process computer to monitor, trend, and provide alarm signals for the above indications

- RHR system heat exchanger inlet and outlet temperature indications and trending

- RHR system flow indication

- RCS wide range hot leg temperature indication and trending

3.1.2.2 Control Room Observations

The team observed control room operations for formality and control during reduced inventory and mid-loop operations. Control room supervisory personnel ensured that reactor operators maintained an elevated awareness of plant conditions during the reduced inventory and mid-loop operations. Plant maintenance or evolutions that could cause a loss of or affect RHR capabilities were not performed during reduced inventory or mid-loop operations.

During mid-loop operations a mid-loop trouble alarm was received. Operators responded to the alarm and determined that there was an invalid input signal from an uncoupled core exit thermocouple. The input from the thermocouple was removed and the alarm cleared. The operators response to the alarm and subsequent actions indicated an understanding of the systems and procedures.

During mid-loop operations the control room operators noted that the video display of the standpipe level indication was lost. The operators verified their control room RCS level indications and confirmed the standpipe level indication with the dedicated operator at the standpipe. The operators determined the cause of the loss of display to be the unplugging of the camera power supply by maintenance personnel. Operations personnel had the power re-established to the video camera and continued monitoring standpipe levels. The licensee was considering providing a dedicated source of power for the standpipe video camera for future outages. The team identified the lack of a dedicated source of power to the video camera as Observation 92-901-05.

3.1.2.3 Procedures

The team reviewed procedures OP B-2:VI, "Draining the Refueling Cavity"; OP A-2:II, "Draining the RCS to the Vessel Flange-With Fuel in Vessel"; and OP A-2:III, "Draining to Half Loop/Half Loop Operations with Fuel in Vessel." The team noted that OP B-2:VI was used to pump down the refueling cavity from 121-foot to the 111-foot elevation, and that OP A-2:III was used to drain down to the mid-loop (half loop) condition (about 107-foot 6-inches). The 121-foot elevation is the elevation at the top of the reactor vessel. The 111-foot elevation is the elevation at 3 feet below the reactor vessel flange or the point at which a reduced inventory condition is entered.

The team found that OP B-2:VI did not require the operator to read and record reactor coolant levels while draining down from 121-foot to 111-foot elevation. However, OP A-2:II and OP A-2:III require the operator to read and record RCS levels while draining down from 121-foot to mid-loop elevation (107-foot 6-inches) and below. Additionally, Attachment 9.7, "Control Operator RVRLIS Log Sheet," to OP A-2:II indicated that once reactor coolant level has been reduced below the reactor vessel head (121-foot elevation), the

control operator should read and log RVRLIS values every 4 hours. Attachment 9.7 did not provide operator guidance as to what specific instrument channels should be read, did not provide a "Date" requirement on the sheet, and did not reference the body of OP A-2:II. Operators recorded RCS levels on Attachment 9.7 to OP A-2:II while draining down the RCS to mid-loop conditions from the 111-foot elevation; however, recordings were not taken in between the 121-foot and 111-foot elevation.

Although the team identified no specific NRC guidance that addressed recording reactor coolant levels during the drain down period before entering reduced inventory conditions, the licensee indicated they would review and enhance the above procedures to provide consistency. The lack of consistency in the drain down and mid-loop procedures is identified as Observation 92-201-06.

3.1.3 Overtime Control

The team reviewed overtime controls and practices for the period from January 1 through October 23, 1992. The following departments were inspected: Operations, Rad Protection, Electrical Maintenance, Mechanical Maintenance, and Instrumentation and Control.

The licensee's administrative control of overtime was addressed in TS Section 6.2.2.f and in procedure OM14.Id1, Revision 0, "Overtime Restrictions."

Restrictions on overtime included the following:

- An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.
- An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time.
- A break of at least 8 hours should be allowed between work periods, including shift turnover time.
- Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

The overtime restrictions were the same in both documents, with any deviation from the overtime restrictions requiring authorization from the Plant Manager.

The licensee maintained overtime records on a computer data base that tracked hours on periods of 24 consecutive hours, 48 consecutive hours, and 7 consecutive days. The team identified several instances where personnel had exceeded working 72 hours in 7 consecutive days without prior approval. One operator had worked 75 hours from September 7, 1992 through September 13, 1992, and one operator had worked 77 hours from September 8, 1992 through September 14, 1992. One mechanical maintenance helper put in 80 hours from September 21, 1992 through September 27, 1992 and 82 hours from September 22, 1992 through

September 28, 1992. During the period September 20, 1992 through September 26, 1992, two electrical maintenance personnel worked 74 hours and 73 hours, respectively.

These instances of exceeding overtime guidelines without pre-approval are identified as Deficiency 92-201-03 in Appendix A to this report.

3.2 Control of Maintenance and Surveillance Activities

The team reviewed modification packages, work activities, schedule changes, equipment isolation, station procedures, and post modification testing to determine whether those activities had been conducted safely and in accordance with approved procedures.

3.2.1 Review of Modification Packages

The team reviewed 17 modification packages containing a variety of subjects. The selection also included packages that required post-modification testing (PMT). The packages generally were prepared in accordance with the licensee's established procedures and appropriate job planning information was included. Appropriate permits, clearances and safety precautions were identified along with quality control (QC) hold points. The work activities were prescribed in detailed written procedures.

DCP N-47406, Revision 0, "Resistance Temperature Detector Bypass Elimination (RTDBE) Project (DCP M-43425)," contained instructions to modify rupture restraint 7-4RR and declare restraints 7-4RR and 7-1RR as inactive. The safety evaluation (Attachment 1 of the DCP) for cutting the notch into the 2-inch thick web of the lower frame main member showed that the maximum stresses were 72 percent of the allowable stresses per FSAR criteria. The safety evaluation for cutting of the 14-inch holes was prepared by Westinghouse and was considered proprietary information and could not be released. However, the team reviewed a summary of the evaluation that Westinghouse provided and found it acceptable.

DCP N-47450, Revision 1, "Containment Penetration Modifications to Support Steam Generator Maintenance Activities," modified two spare electrical penetrations (45E and 47E) into mini-equipment hatches. The penetrations were to be used to pass hoses and cables during refueling operations. The DCP also temporarily converted containment penetration #63 into a mini-equipment hatch. After refueling operations are complete, this penetration will be restored to its original configuration.

Two calculations were performed to support this DCP. Calculation 2151C-3 performed the seismic qualification of the penetrations, while calculation 900411 evaluated the design conditions (pressure, temperature, etc.). The only PMT required for this DCP was the local leak rate test, which only could be performed when the reactor is in mode 1 through 4. The team determined that the overall package was well prepared, and noted no deficiencies in the corresponding calculations.

DCP E-47281, Revision 0, "Replacement of Battery 12," replaced the existing LC-25 batteries with LCUN-33 batteries that have a higher ampere-hour capacity. The modification also added feeder circuit termination details to reduce strain on the battery terminals, modified three of the four existing battery racks, and replaced one existing rack with a new two-step rack. Battery 12 is one of three vital station batteries that supply 125-vdc power to two of the nuclear instrument invertors 12 and 14.

A couple of concerns were identified by the team regarding the vital station battery rooms. One of the three rooms (Room 103) did not display any torque marks on the bolts holding the battery racks together. These racks are seismically qualified and therefore, the bolts are required to be torqued. After some discussion with the licensee, it was determined that these marks are displayed in accordance with procedures to assist the QC inspector in determining what bolts have been torqued. The marks are not required to remain visible over any period of time and may be covered when the racks are routinely painted.

The eye wash basins appeared to be located in close proximity to the batteries and the team was concerned with the possibility of a break in the piping and the resultant spraying of water onto the batteries. The licensee's written response stated that seismically analyzed bilateral supports had been installed on 3/4-inch copper water lines to preclude support failure and/or piping failure in a seismic event.

The team concluded the modification packages were adequate.

3.2.2 Coordinating of Work Activities/Schedule Changes

During the 1R5 outage, the team observed that the licensee consistently worked to ensure that work groups remained focused on pending or current work priorities. The outage director conducted morning and afternoon meetings on the outage status, emphasizing alertness during periods of high risk. The work organizations were appropriately represented at the meetings. Those emergent issues discussed appeared to be clearly focused and resolved.

Changes to the outage schedule were controlled under the licensee's procedure AD8.DC55. Emergent work and/or schedule changes during the outage were required to be reviewed by the OSC and an independent SRO to determine if the work/change would affect any of the key safety functions. If the defense-in-depth condition of the key safety function was reduced by the change, then approval by the outage director was required.

The team reviewed 15 changes to the safety schedule and one change to the safety plan that had occurred during the 1R5 outage. In all but one case, the changes had been reviewed and approved in accordance with licensee procedures.

The team noted one instance in which the safety schedule had apparently been changed subsequent to an actual change in work sequencing. The licensee's pre-outage safety schedule had identified that the personnel hatch would be

closed during mid-loop operations. However, the team found that, during the high risk period of mid-loop operations, the personnel hatch was not maintained in the status identified in the safety schedule.

In response to the team's observation, the licensee identified that the key safety function had been maintained as required by their safety plan during the high risk period; that is, the capability to close containment within an appropriate time had been maintained. The licensee further identified that a work order to open the personnel hatch had been authorized by operations personnel because it did not affect the required containment closure status. The safety schedule was subsequently revised after the fact when outage scheduling became aware of the change in the status of the personnel hatch. The licensee said that improvements have been identified and planned for their computer program to flag out-of-sequence work activities for more timely review. The team found that the licensee was aware of the weakness and that their proposed actions appeared to be adequate.

The team concluded that the licensee had established appropriate coordination of work activities and control of emergent work and schedule changes to maintain the safety plan during the outage.

3.2.3 Equipment Isolation

The licensee's process for identifying non-conforming equipment, and for isolating equipment and systems to facilitate maintenance, modifications, and for the protection of personnel, was detailed in Administrative Procedure NPAP-C-12, "Identification and Resolution of Problem and Non-Conformance," Revision 21; NPAP-C-6, "Clearance Request/Job Assignments, Revision 10; and AP-C6S2, "Clearance Procedure-System Dispatchers Clearance," Revision 2.

The procedures provide detailed instructions to plant personnel in the use of tags to identify a variety of non-conforming equipment and system conditions in the plant. Action request (AR) tags, as described in NPAP-C-12, can be placed by any plant employee upon identifying a non-conforming condition. "Man On Line" tags were designed for the protection of personnel and are used to identify equipment removed from service for maintenance, modification, or testing activities. Caution tags provide administrative controls over equipment that may not be operable or equipment awaiting final testing that could be placed in service during an emergency. Such caution tags are hung on the control room switch of the affected equipment.

All equipment isolation clearance packages required for outage activities were generated and issued by the Operations Coordination Department. All clearance packages of safety-related equipment received an independent verification by a clearance coordinator from a designated review group that includes several operator licensed personnel. Equipment isolation boundaries were established by a work planning group on the basis of the scope of the scheduled activities. All isolation and clearance tags were tracked on the plant computer, providing the capability for equipment status verification on all shifts.

The procedures, including applicable drawings used by plant personnel for equipment tagging, were the latest revision. Isolation tags on the residual heat removal, safety injection, and component cooling water systems were properly placed and controlled. The Man On Line and caution tags associated with testing of the high-head safety injection system motor-operated valve and with the RHR system containment sump suction valve 8802B were located in the safety injection flow path and designated the equipment as available to the operators during an emergency. Although the valve was not required to be operable it did meet the licensee's definition of available equipment because operators would be able to control the valve position and initiate SI flow as needed.

3.2.4 Post-Modification Testing

The team reviewed eight modification packages that required PMT. The modification packages specified appropriate PMT requirements. The approved test procedures established appropriate test controls and included provisions for data recording. The PMT requirements specified in the design change package (DCP) for the modifications were incorporated in scheduled test activities. In most cases, the licensee had not performed the PMTs because the tests required that the systems first reach certain operational conditions. Some of the modification packages reviewed are discussed below.

- DC1-EP-45955, Revision 0, "Modify Disc's For RHR Mini Flow Valve"

  For the two post modification tests listed, the attachment did not indicate how to perform the first PMT for RHR flow to the four RCS cold legs. The licensee said that either STP V-4A or PMT 10.06 would fulfill this requirement. The PMT 10.06 test showed that the measured flow was above the required rate.

- DC1-EJ-47188, Revision 1, "Replacing Feedwater Bypass Valves"

  This DCP replaces the feedwater bypass valves SV-1510A, SV-1010B, SV-1520A, and SV-1502B. Two PMTs were required: valve closure time (closure trip test) and valve modulation time (modulation time for opening and closing). The closure trip test was tracked on the computer, but the modulation test could not be found. Upon further investigation, the licensee found that the modulation test was part of a loop test (LT). Appendix 10.5 (Valve Timing Tests) of LT 4-44B, Selection 8.6.1, performs the trip closed timing test and Sections 8.6.2 and 8.6.3, perform the open modulation timing tests and the closed modulation timing test, respectively.

- DC1-EN-47241, Revision 0, "Replace 2" and Smaller Nozzles and Skirt Couplings Cracking due to IGSCC"

  This DCN replaced the 2-inch and smaller accumulator nozzles and skirt couplings in Unit 1 that exhibited inter-granular stress corrosion cracking (IGSCC). Numerous nozzles and skirt couplings already had been replaced in Unit 2 (DCP N-48204 and P-38343.) The new nozzles were made of 304L or 316L stainless steel and the original nozzles were made of

304 stainless steel. The PMTs included hydrostatic testing each vessel that had a nozzle replaced, a leak test for each vessel that had a nozzle replaced with a pipe size (nominal) of 1-inch or less, and applicable functional tests.

The team concluded that the licensee's control of PMT was adequate to ensure that the maintenance had been performed properly and that the functional capability of the equipment had been restored.

3.2.5 Status of Available Equipment

All PMT was not necessarily performed at the completion of the specific maintenance work activity. In some cases, the PMT was incorporated into later scheduled surveillance testing. The team sampled selected work activities with deferred PMT and found that all required testing was tracked to completion.

However, the team noted that equipment was considered by the licensee to be "available" for service within their safety schedule at the completion of the maintenance work activity itself when all work clearances were removed from the equipment. According to the licensee, the functional status of the affected equipment and system was ensured by the routine maintenance verification testing performed as part of the maintenance work activity. The team noted that the component level verification testing conducted as part of the maintenance work did not appear to specifically establish a functional capability commensurate with the high reliability status intended within the licensee's safety plan.

Generic Letter 88-17, program enhancement 3(a), recommended equipment enhancements "to assure that adequate operating, operable, and/or available equipment of high reliability is provided for cooling the RCS and for avoiding a loss of RCS cooling." Enclosure 3 to the generic letter further defined "reliable" as "the condition of having a high, but reasonable, expectation of being able to perform the intended function."

However, the licensee did not specifically evaluate the reliability or the intended function of equipment or systems before considering them to be available for service in the safety plan. The licensee's safety plan appeared to rely on the routine maintenance work controls to establish adequate functional capability of the equipment at the time all work clearances were removed. While the team found no instances in which deferred post maintenance testing identified deficiencies that would have affected the interim available status of the equipment, the team considered that the inferred availability of equipment before the completion of functional PMT was a weakness in the licensee's program to ensure the high reliability of available equipment.

Furthermore, licensee procedure AD8.ID1, "Outage Planning and Management," paragraph 3.25, defined "Available" as, "the status of a system, structure or component that is in service or can be put in service in a FUNCTIONAL or OPERABLE state by immediate manual or automatic actuation."

The team sampled the status of the systems and equipment considered by the control room operations personnel to be available. Several systems were not capable of immediate manual or automatic actuation. Discussions with operations personnel revealed that Operations considered equipment available if it could be made functional within a reasonably short period of time consistent with its intended service. The team considered the Operations Department interpretation to be consistent with the definition of available provided in Enclosure 3 of Generic Letter 88-17. However, the Operations Department interpretation was contrary to the licensee's definition of "available" in procedure AD8.Id1.

The team discussed the reliability of available equipment and the inconsistency observed in the definition of available status with outage management personnel. The licensee acknowledged the need for additional clarification and enhancement of its procedures to address the intended status of available equipment and systems within its program for shutdown risk management. The weaknesses in the licensee's definition and control of "available" equipment was identified by the team as Observation 92-201-07.

3.3 System and General Plant Walkdowns

The team conducted pre-outage walkdowns of the normal and emergency power supply components and switchyard areas. These walkdowns included the vital dc batteries and battery chargers, the vital 480-Volt/4 kV switchgear, the EDGs, the auxiliary and startup power transformers, the vital inverter power supplies and the 230 kV and 500 kV switchyard areas. Housekeeping of the subject areas was acceptable and switchyard areas were not judged to be vulnerable to vehicular hazards. On the basis of its review of AP D-758, "Control of Activities Near Plant High Voltage Lines and Equipment," the team determined that adequate controls were in place to minimize the potential for damage.

During the second phase of the inspection, the team performed independent walkdowns of several safety-related systems and accompanied licensee personnel during their walkdowns. Systems selected included the RHR, component cooling water, spent fuel pool cooling, emergency diesel generators, dc power supplies, and electrical distribution. The labeling and piping configurations matched the plant drawings and the sampled valves and breakers were correctly aligned in accordance with operating orders for the normal plant lineup or in accordance with clearances in effect.

During a walkdown of systems piping in containment, the team noted that the instrument tubing for spare steam generator level instrument PX-452 was disconnected and a temporary, tygon tubing line was attached for temporary monitoring equipment in support of maintenance activities. The disconnected instrument tubing was not tagged for identification and was not covered to prevent entry of foreign material. Discussions with licensee personnel revealed that AP C-453, "Control of Lifted Circuitry, Process Tubing and Jumpers During Maintenance," required identification of this disconnected tubing. However, maintenance personnel involved in the installation of the temporary monitoring equipment had failed to follow this procedure. The licensee agreed to counsel all maintenance personnel regarding strict

compliance with all station procedures. The failure to tag the disconnected instrument lines .is identified as Deficiency 92-201-04 in Appendix A to this report.

The licensee had no procedures existed to control the entry of foreign material into disconnected process or instrument tubing. The American National Standards Institute (ANSI) Standard 3.2, "Administrative Controls and Quality Assurance For the Operational Phase of Nuclear Power Plants," Section 5.2.6, "Equipment Control," states, in part: "When entry into a closed system is required, control measures shall be established to prevent entry of extraneous material and to assure that foreign material is removed before the system is reclosed." The licensee stated that tubing had been overlooked when procedures were established to control the entry of foreign material and agreed to revise procedures to incorporate requirements to preclude the entry of foreign material into disconnected tubing and to require that disconnected tubing be adequately covered. The lack of a procedure for maintaining foreign material exclusion (FME) on instrument lines is identified as part of Deficiency 92-201-02 in Appendix A to this report.

Aside from the above deficiency, the team concluded that the material conditions and housekeeping throughout the plant and the licensee's policies and procedures regarding housekeeping, tool control, and equipment/material control as implemented were a strength.

3.4 Self-Assessment Activities

The team reviewed two of the licensee's self-assessment initiatives conducted within the past year: "2R4 Outage Risk Management Assessment - SOSLOG 1851," dated December 23, 1991, and "1R5 Pre-Outage Safety Assessment," dated August 24, 1992. The self-assessment of December 23, 1991 was generally positive and identified 7 strengths and 13 recommendations. The self-assessment of August 24, 1992, identified three strengths and five weaknesses.

The team's review concluded that both assessments were detailed and thorough, and performed by qualified individuals. The assessment of December 23, 1991 included a team member from another licensee. This team composition appeared to enhance the results of the assessment in giving it a more objective viewpoint. Overall, the implementation of the two assessments and their conclusions were considered a strength.

The team identified several items that had not been resolved before the 1R5 refueling outage. Although the primary recommendations and improvements had been implemented, the following items had yet to be implemented:

1. Recommendation 6 of the self-assessment dated December 23, 1991, specified that Engineering Work Request (EWR) A249793 was written to request an evaluation of the reactor vessel refueling level instrumentation system (RVRLIS) alarms to determine if increasing or decreasing levels could be provided to warn the operators of changing conditions. This EWR A249793 was canceled on October 25, 1991, and a new AR written in October 1992.

2. Recommendation 8 of the self-assessment dated December 23, 1991 specified that a communications mechanism between outage management and the 500 kV switchyard operator be established. At the beginning of the 1R5 outage, as a result of E-Mail problems, this communication link had not been finalized.

3. Recommendation 9 of the self-assessment dated December 23, 1991, specified that spent fuel pool temperature indication should be made available to control room operators. At the beginning of the 1R5 outage, AT EWR A241881 had been written to request such a modification. However, other than approving the performance of this modification in the 1995 budget, no further action had been accomplished.

5. Weakness 1 of the self-assessment dated August 24, 1992, resulted in a recommendation that all Diablo Canyon Power Plant (DCPP) maintenance engineers, maintenance foremen, planners and schedulers, HIT team leaders, etc., take Technical Staff Continuing Training (Lesson TU9234). At the beginning of the 1R5 outage, several maintenance and planning and scheduling personnel had not completed this training.

6. Weakness 3 of the self-assessment dated August 24, 1992, resulted in a recommendation that procedure MP 7.7A provide direction to shop foremen for a RCCA or fuel assembly being stuck to the upper internals during lifting of upper internals. At the beginning of the 1R5 outage, the procedures had not been revised to incorporate the recommendation.

The team concluded that the licensee had conducted two meaningful self-assessments and identified noteworthy weaknesses and/or recommendations. The incomplete implementation of the self-assessment recommendations was identified by the team as Observation 92-201-08.

4.0 EXIT MEETING

At the conclusion of the inspection an exit meeting was held where the team's findings were discussed with PG&E management and staff. The following people were in attendance:

NRC

Name	Title
Imbro, Eugene V.	NRC/NRR
Jacobson, Jeffrey B.	NRC/NRR
Koltay, Peter S.	NRR/RSIB
Madison, Alan L.	NRC/AEOD
Miller, Lew	NRC/RV
Miller, Mary	NRC/SRI
Myers, Christopher	NRC/RV
O'Neal, Dan	NRC/NRR
Royack, Michael	NRC/RV
Sanchez, Steven P.	NRC/NRR
Wang, Hai-Boh	NRC/NRR
Wilcox, Jr., John D.	NRC/NRR

PG&E	Title
Banton, Steven	Director/Plant Engineering
Burgess, McCoy	Director/System Engineering
Collins, L. R.	Senior Supervisor/QA
Crocuett, Bill	Manager Tech Services
Doss, Ken	Human Performance Evaluation System
Gisclon, John	Manager/Nuclear Operations Support
Giffin, B.	Manager/Maintenance Services
Grebel, Terry	Regulatory Compliance
McKnight, Terry	QC Engineer
McLane, William	Unit 1 Outage Director
Miklush, Dave	Acting Plant Manager
Molden, Jim	I&C Director
Moon, Dale	Regulatory Compliance Engineer
Newman, C. E.	Staff Forman
Taggart, David	QA/Director QP&A
Patton, Bruce	Director/Reliability Engineering
Phillips, Harry	Director/Electrical Maintenance
Sarafian, Peter	Senior Engineer/Onsite Safety Review Group
Stolz, Craig	Planning and Scheduling
Vosburg, David	Director/Work Planning

APPENDIX A

SUMMARY OF INSPECTION FINDINGS

DEFICIENCY 92-201-01

TITLE: Lack of Control Over Operator Aids and Controlled Documents (Section 3.1)

DESCRIPTION OF CONDITION:

The licensee failed to adequately control the use of operator aids and controlled drawings, as discussed below.

1. The team identified three instances during which controlled plant drawings did not have the correct revision number. These drawings were operating valve identification drawings OVIDs 106717, Revision 36, sheet 7; 106717, Revision 39, sheet 7; and 106704, Revision 36, sheet 2. These drawings pertained to the circulating water pumps (non-safety related) and steam generators (safety related), respectively. Drawing 106717, Revision 39, sheet 7, appeared in the control room but did not appear in the master copy file, which is located in Document Services. The licensee concluded that this particular drawing was overlooked when the time came for replacing the old revision with the current revision in the master copy file. The licensee investigated the replacement of the revisions that occurred before and after the revision date on drawing 106717, Revision 39, sheet 7, to determine whether other revisions had been replaced. The licensee concluded that only drawing 106717, Revision 39, sheet 7, had been overlooked in the replacement process.

   Control room personnel indicated that some drawings had been copied and placed in a location convenient for operator use. This location was unknown to the person responsible for updating the drawings and, therefore, was overlooked when the time came to replace the drawings with the current revision. Thus, drawings 106704, Revision 36, sheet 2, and 106717, Revision 36, sheet 7, were not replaced with the updated copies.

2. The team also identified discrepancies in a second operator aid: the "Fed From List." This document was used by operations personnel to verify and investigate clearances and operational problems. While observing licensed operators researching clearances for operational irregularities, the team discovered that the listings for instrument ac panel feeder breaker 52-PY17 did not include breakers 52-PY1713, 52-PY1722, 52-PY1732, 52-PY1736, or 52-PY1740. Further, breaker 52-PY1729 was listed as "DC Power Supply" in the Fed From List but as "Condition Monitor" on controlled electrical drawing 437549. The operators conservatively verified listings in the Fed From List with the controlled electrical drawings thereby eliminating the possibility of errors caused by the discrepancies in the Fed From List.

REQUIREMENT:

10 CFR Part 50, Appendix B, Criterion VI states, in part, that measures shall be established to control the issuance of documents, including changes.

REFERENCES:

Nuclear Plant Administrative Procedure NPAP E-9, "Development and Control of Plant Operating Valve Identification Diagrams and Instrument Prints."

Administrative Procedure AP E-55, "Control of Posted Plant Signs and Information."

Administrative Procedure AP E-53S1, "Change Control for NECS Engineering Entries in the PIMS Component Database."

Nuclear Engineering and Construction Services Procedure NECS-E3.7 "As-Builts and Corrections," Appendix 6.1.

DEFICIENCY 92-201-02

FINDING TITLE: Inadequate Procedures (Sections 3.1 and 3.3)

DESCRIPTION OF CONDITION:

The licensee failed in two instances to have an adequate procedure as discussed below.

1. Radiation Control Procedure RCP D-216, Revision 0, "Addition of Unborated Rinse Water to the Spent Fuel Pool" was intended to control the addition of unborated rinse water to the spent fuel pool by requiring the use of a flow totalizer. However, the procedure states, in part: "It is not intended to control the rinsing of a few tools or an underwater light which may be occasionally removed from the pool." The team was concerned that this discretionary guidance can be interpreted such as to lead to the unmonitored addition of unborated rinse water to the spent fuel pool. When informed of this concern, the licensee agreed to revise the procedure to require the flow totalizer during all unborated rinse water additions to the spent fuel pool.

2. The team identified inadequacies in AP C-10S4, Revision 5, "Foreign Material Exclusion Program." Specifically, this procedure did not address instrument or process tubing. Therefore, the licensee did not require measures to prevent the entry of foreign material into disconnected instrument or process tubing. During a walkdown inspection the team identified that the piping to a spare steam generator water level instrument (PX-452) had been disconnected and not covered. When informed of this concern, the licensee agreed to revise AP C-10S4 appropriately.

REQUIREMENT:

ANSI Standard 3.2, "Administrative Controls and Quality Assurance For the Operational Phase of Nuclear Power Plants," Section 5.2.6, "Equipment Control" states that measures shall be established to prevent the entry of foreign material into closed systems.

10 CFR Part 50, Appendix B, Criterion V states, in part, that quality-related activities be conducted in accordance with appropriate procedures.

REFERENCES:

Radiation Control Procedure RCP D-216, Revision 0, "Addition of Unborated Rinse Water to the Spent Fuel Pool."

Administrative Procedure AP C-10S4, Revision 5, "Foreign Material Exclusion Program."

ANSI Standard 3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants."

DEFICIENCY 92-201-03

FINDING TITLE: Overtime Control (Section 3.1.3)

DESCRIPTION OF CONDITION:

The licensee failed to adequately follow their administrative procedure and technical specification (TS). Technical Specification 6.2.2.f and procedure OM14.ID1, Revision 0, "Overtime Restrictions," required in part that an individual should not be permitted to work more than 72 hours in any 7 day period, excluding shift turnover time, unless preapproval has been given. Several deficiencies were found in the licensee's compliance to the overtime restriction stated above. Two operators had exceeded working 72 hours in 7 consecutive days without prior approval. One operator had worked 75 hours from September 7, 1992 through September 13, 1992, and one operator had worked 77 hours from September 8, 1992 through September 14, 1992. One mechanical maintenance helper put in 80 hours from September 21, 1992 through September 27, 1992 and 82 hours from September 22, 1992 through September 28, 1992. During the period September 20, 1992 through September 26, 1992, two electrical maintenance personnel worked 74 hours and 73 hours, respectively.

REQUIREMENTS:

TS 6.2.2.f and procedure OM14.ID1, Revision 0, "Overtime Restrictions," require, in part, that an individual should not be permitted to work more than 72 hours in any 7-day period without prior approval.

REFERENCES:

TS 6.2.2.f and procedure OM14.ID1, Revision 0, "Overtime Restrictions."

DEFICIENCY 92-201-04

FINDING TITLE: Failure To Follow Procedures (Section 3.3)

DESCRIPTION OF CONDITION:

Administrative Procedure (AP) C-4S3, Revision 4, "Control of Lifted Circuitry, Process Tubing and Jumpers During Maintenance," requires that all disconnected process tubing be tagged for identification. Contrary to this requirement, the team found one instance where disconnected process tubing was not tagged for identification. Specifically, steam generator level instrument PX-452 tubing was disconnected to facilitate connection of temporary instrument lines and was not properly tagged for identification. When notified of this concern, the licensee agreed to tag the disconnected instrument tubing and provide additional training for maintenance personnel to ensure continued compliance.

REQUIREMENT:

10 CFR 50, Appendix B, Criterion V, states, in part, that activities affecting quality are required to be prescribed by documented procedures of a type appropriate to the circumstances and accomplished in accordance with these procedures.

REFERENCE:

Administrative Procedure AP C-4S3, Revision 4, "Control of Lifted Circuitry, Process Tubing and Jumpers During Maintenance."

APPENDIX B

List of Observations

92-201-05	Lack of a Dedicated Power Source for Standpipe TV Camera (Section 3.1.2.2)
92-201-06	Inconsistency in Drain down and Mid-loop Procedures (Section 3.1.2.3)
92-201-07	Definition and Control of "Available" Equipment (Section 3.2.5)
92-201-08	Incomplete Implementation of Self-Assessment Recommendations (Section 3.4)