50-275/323-
CLA-2

14440

NOT ADMITTED

SAN LUIS OBISPO MOTHERS FOR PEACE'S
LIST OF EXHIBITS RELATED TO
CONTENTION I IN DIABLO CANYON
CONSTRUCTION PERMIT RECAPTURE HEARINGS

RELATED CORRESPONDENCE

'93 DEC 28

The following is a partial list of the documents which San Luis Obispo Mothers for Peace seeks to have admitted as exhibits to the record in the construction permit recapture case for the Diablo Canyon nuclear power plant. These documents relate to the scope of maintenance as understood by NRC and the nuclear industry; and to specific examples of maintenance and surveillance problems at DCNPP. SLOMFP also intends to introduce a limited number of other exhibits regarding Contention I; however, because of the large number of exhibits containing examples of maintenance and surveillance problems, we have provided a written list.

Exhibits 1-4 are documents which describe the scope of maintenance programs for nuclear power plants, as established by the NRC and INPO.

Exhibits 5 through 219 are documents which relate to specific examples of maintenance and surveillance problems at DCNPP. The documents are grouped under headings denoting the specific events or issues to which they relate. These groups in turn are ordered in descending chronological order, according to the date of the most recent document which discusses the event or issue. Unless otherwise noted, SLOMFP seeks the admission of each document in its entirety.

DOCUMENTS DISCUSSING SCOPE OF MAINTENANCE AND SURVEILLANCE, AGING

Exhibit 1: NRC Announcement Number 200, re: Revised Guidance on the Use of Performance Indicators (No-

vember 28, 1989]

Exhibit 2: NRC Draft Regulatory Guide DG-1001, Maintenance Programs for Nuclear Power Plants [August 1989]

Exhibit 3: Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants [June 1993]

Exhibit 4: INPO 90-008, Maintenance Programs in the Nuclear Industry [INPO: March 1990]

Exhibit 5: NUREG-1144, Nuclear Plant Aging Research [NPAR] Program Plant [Chapters 1-3] [NRC: September 1987].

CHECK VALVE SAFETY FUNCTION

Exhibit 6: NCR DCO-93-TP-N028 [7/29/93];

Exhibit 7: LER 1-84-047-00 [7/26/93];

Exhibit 8: NCR DCO-93-TP-N027 [7/8/93];

Exhibit 9: NCR DCO-93-TN-N011 [5/6/93];

Exhibit 10: NCR DCO-91-TN-N048 [2/7/92];

Exhibit 11: NCR DCO-91-TN-N026 [4/12/91]: In all of these documents, PG&E documents a failure to perform full stroke testing and/or reverse flow testing.

Exhibit 12: NUREG/CR-4302, Aging and Service Wear of Check Valves Used in Engineered Safety-Feature Systems of Nuclear Power Plants, ORNL-6193, Vol. 2 [NRC: April 1990]: Discusses determination

that current methods are inadequate for timely detection of degradation of check valves.

Exhibit 13: LER 1-92-001-00 [4/30/92]: Documents tech spec violation as a result of failure to include volume control tank outlet check valve CVCS-8440, which performs a safety function as a boundary valve during post-LOCA recirculation, in testing program.

CABLE FAILURES

Exhibit 14: NCR DC1-93-EM-N010 D3 [July 28, 1993]: Describes February 5, 1993, and March 12, 1993, 12kV cable failures and PG&E investigation into causation. Finds preliminary indication of long-term chemical attack, possible moisture intrusion.

Exhibit 15: LER 93-005-00 [April 27, 1993]: LER describes failures of three Okonite 4kV and two 12kV circuit underground cables. The cause of the 4kV cable faiure is still under investigation.

Exhibit 16: Memo from Rich McCurdy [TES] to Wells Fargo [March 18, 1993]: Identifies possible source of the chemical that attacked the cable jackets as an "accidental mixing of con. sulfuric acid and con. sodium hydroxide that resulted in an exothermic reaction causing some spillage."

Exhibit 17: NCR DC1-92-EM-N054 Rev. 00 Draft: March 12,

1993: Describes failure of 12kV cable during hi-pot test, possible causes including aging and submergence.

Exhibit 18: Results of Analytical Investigations to Determine the Root Causes of Medium Voltage Cable Failures at Diablo Canyon Power Plant, 2nd Draft [May 21, 1993]: Reports that root cause is unknown, makes recommendations for future.

Exhibit 19: PG&E Region V Morning Report [February 17, 1993]: Vendor describes the 12 kV cable degradation as "unprecedented and has not been seen by the industry previously."

Exhibit 20: PG&E's OSRG November 1992 Monthly Report: Found that the facts lead "to a strong preliminary conclusion that the cable has been degraded due to repeated submergence over the past 20 years."

Exhibit 21: Technical and Ecological Services Report #420DC-92.856 [September 10, 1992]: PG&E consultant reports on investigations of other cable failures.

ANCHOR-DARLING CHECK VALVE COVER DOWELS

Exhibit 22: LER 2-93-006-00 [7/28/93]

Exhibit 23: NCR DCO-93-MM-N016 [7/15/93]: Both Exhs. 9 and 10 discuss installation of improper bonnet

dowel pins, erroneous drawings supplied by vendor.

WRONG SIZE MOTOR INSTALLED ON SI-2-8974A

Exhibit 24: NCR DC2-93-EM-N031 [7/28/93]: Wrong motor was installed on MOV actuator. Root cause was determined as personnel error, cognitive.

HIGH RADIATION AREA ENTRY

Exhibit 25: NCR DC0-93-HP-N029 [7/27/93]: Four identified instances of personnel entering areas posted as high radiation areas [HRAs] occured without the required continuous monitoring or alarming dosimetry.

Exhibit 26: NRC Inspection Report 93-11 [5/13/93]

STORAGE AND HANDLING OF LUBRICANTS

Exhibit 27: NCR DC0-93-MF-N039 [7/27/92]: On 6/22/93 incorrect oil for the AWF motors was found at the intake storage area. Root cause has not been determined.

Exhibit 28: NCR DC0-91-MM-N061 [10/25/91]: During walk-downs of the Turbine Building 85' elevation on 7/12/91, QA identified several discrepancies in the handling and storage of lubricants

PASS DISSOLVED RCS HYDROGEN MONITOR

Exhibit 29: NCR DC0-93-TC-N020 [7/27/93];

Exhibit 30: LER 1-93-007-00 [5/28/93];

Exhibit 31: PG&E Reply to NOV in Enforcement Conference

Report 93-14 [6/22/93]: All three documents discuss sampling errors Two violations cited for [1] failure to implement and maintain a program that ensures capability to obtain and analyze reactor coolant samples and samples of radioiodines and particulates in plant gaseous effluents under accident conditions and [2] failure to perform a written safety evaluation to facilities and procedures for post-accident sampling and analysis of reactor coolant dissolved hydrogen.

AUXILIARY FEEDWATER PUMP DISCHARGE VALVE LCV-109

Exhibit 32: NCR DC2-93-EM-N037 [7/22/93] During testing, AFW pump failed to open electrically. The valve closed in accordance with step 12/5/4 of the procedure, but when it was to be reopened per step 12.5.5, it would not. No root cause had yet been determined when this NCR was issued.

INCOMPLETE TESTING OF CVI RESPONSE TIME

Exhibit 33: NCR DC1-93-TP-N021 [7/8/93];

Exhibit 34: LER 192-031-oo [5/20/93]: Technical specification for Unit 1 Containment Ventilation Isolation function was exceeded when the containment purge valves were opened without complete testing of the CVI response time.

PG&E SELF-EVALUATION CITES MAINTENANCE DEFICIENCIES

Exhibit 35: Self-Evaluation of Diablo Canyon Power Plant [July 1993]: evaluates management deficiencies.

FUEL HANDLING BUILDING

Exhibit 36: LER 2-93-004-01 [6/24/93];

Exhibit 37: LER 1-92-029-01 [6/24/93];

Exhibit 38: NCR DC1-91-TN-N007 [12/11/91];

Exhibit 39: LER-89-019-00-01 [[9/19/91];

Exhibit 40: OSRG April 1990 Monthly Summary;

Exhibit 41: OSRG November 1991 Monthly Summary: All of these documents discuss various events in fuel handling building, including an ammonia/hydrazine leak from a valve used in feedwater chemistry control; failure to place FHBVF in the iodine removal mode prior to moving the spent fuel assembly handling tool over the spent fuel pool; inoperability of FHB ventilation system due to malfunctioning water gauge;.

CONTAINMENT PERSONNEL AIRLOCK

Exhibit 42: NCR DC2-93-WP-N025 [6/23/93];

Exhibit 43: LER 2-90-011-00 [5/26/93];

Exhibit 44: LER 1-91-016-00 [10/28/91]: Documents describe repeated problems with leak-rate tests of the containment personnel airlock door seals.

INADVERTENT DILUTION OF BORON:

Exhibit 45: NRC Inspection Report Nos. 50-275/93-12 and 50-323/93-12 [June 18, 1993];

Exhibit 46: NRC Inspection Report 93-12 [June 18, 1993]: Documents discuss repeated errors in boron dilution.

COMPONENT COOLING WATER HEAT EXCHANGER

Exhibit 47: NCR DC2-93-TS-N017 [6/15/93]: On 3/18/93, during 2R5 eddy current examination the 30% of component cooling water [CCW] heat exchanger tubes that were tested indicated fretting on the outside diameter of the tubes at the baffle plates.

Exhibit 48: NCR DC2-92-TN-N011 [4/2/92]: Commitment in Work Order to scrape and clean CCW pump heat exchanger 2-1 during refueling outage was not met.

AUXILIARY BUILDING VENTILATION SYSTEM INOPERABLE

Exhibit 49: NCR DC2-93-MM-N012 [6/11/93];

Exhibit 50: LER-2-93-002 [4/5/93]: Unit 2 Auxiliary Building Ventilation System trains were made inoperable by the closure of a manual damper during an attempt to perform a recurring preventative maintenance activity.

FAILURE TO RE-INSTALL HOT SHUTDOWN PANEL COVERS

Exhibit 51: NCR DC0-93-EM-N030 [6/7/93]: Addresses failure

to re-install covers in the hot shutdown panel for both Unit 1 and Unit 2.

Exhibit 52: NCR DC1-93-EM-N019 [5/12/93]: On 4/1/93, the rear hinged panel of the Unit 1 RHF panel was found with no fasteners installed to secure the hinged panel to the main panel. This condition was considered a potential loss of seismic qualification that could have impacted the operability of vital 4kV bus F and its associated diesel generator during a seismic event.

CONTAINMENT EQUIPMENT HATCH NOT FULLY CLOSED DURING CORE OFF-LOAD

Exhibit 53: NCR DC2-93-MM-N013 [5/28/93];

Exhibit 54: LER 2-93-003-00 [4/5/93]: Core offload suspended when PG&E employees observed that Unit 2 containment equipment hatch had a visible, approximately 1/2 inch gap in the upper 25% of its sealing surface as observed from outside of the containment.

MANUAL REACTOR TRIP CAUSED BY FAILURE OF A FUSE FOR THE ROD CONTROL SYSTEM

Exhibit 55: LER 1-91-008-00 [May 23, 1993];

Exhibit 56: NCR DC1-91-EM-N046 [June 10, 1991]: On 4/24/91, a manual reactor trip was initiated in order to terminate an increase in reactor power. The cause of the power increase was an

urgent failure of the rod control system which rendered manual control rod movement inoperable. The cause of this event was the failure of a fuse in the bus duct disconnect to the rod control power supply cabinet. Investigation discovered 12 of 15 fuses in similar locations were of the wrong type.

LIMITORQUE 2-FCV-37 FAILED TO CLOSE

Exhibit 57: NCR DC2-93-EM-N014 [5/13/93]: Describes failure of Limitorque flow valve during testing; discovery of pooled lubricants; repair and return to service; and subsequent discovery of significant particulates, water and corrosion that had not been identified during earlier repair.

MISSING VALVE SEALS

Exhibit 58: NCR DC1-93-OP-N024 D2 [5/13/93]: Seals on component cooling water valves were not returned after maintenance. Other valves also found to be missing seals.

SAFETY INJECTION EMERGENCY CORE COOLING SYSTEM ACCUMULATOR TANKS

Exhibit 59: NRC Inspection Report 93-08 [4/27/93]

Exhibit 60: LER 2-87-023-01 [2/1/93]

Exhibit 61: PG&E DSRG March 1992 monthly summary: Documents describe identification of indications of intergranular stress corrosion cracking

[IGSCC] in Safety Injection [SI] accumulator tank stainless steel cladding, nozzles and skirt couplings.

CORROSION OF ASW ANNUBAR, DIESEL FUEL OIL AND CARBON DIOXIDE PIPING

Exhibit 62: NCR DCO-93-SS-N007 [April 27, 1993]: Describes water intrusion and corrosion of fire protection carbon dioxide [CO2] piping that supplies suppression capabilities to the Unit 2 diesel generators [DGs]. Notes that the potential for pipe degradation and leakage was previously identified.

Exhibit 63: NCR DC2-92-TN-N028 [October 21, 1992]: Discusses discovery of degraded annubar, diesel fuel oil, and carbon dioxide piping in Unit 2 west buttress area trench.

Exhibit 64: LER 1-92-006-01 [October 7, 1992], OSRG December 1992 Monthly Report: Discusses discovery of degraded piping.

CONTROL OF MEASURING AND TEST EQUIPMENT

Exhibit 65: NCR DCO-93-MM-N002 [April 12, 1993]: A Quality Assurance audit in the fall of 1992 "identified several instances where Mechanical Maintenance failed to document in the PIMS usage database that M&TE items were issued or used on certain Work Orders as required by

procedure. The same problem appeared to have occurred earlier.

Exhibit 66: PG&E Letter No. DCL-91-127 (May 10, 1991): Responds to Notice of Violation in Inspection Report Nos. 50-275/91-04 and 50-323/91-04 (March 4, 1991) regarding deficiencies in M&TE program, and outlines proposed corrective actions.

Exhibit 67: NCR DCO-90-MM-N089 (April 8, 1991): Describes corrective actions taken in response to NRC Inspection Report 90-29 (February 8, 1991), which found deficiencies in Mechanical Maintenance MT&E (measuring and test equipment) program.

Exhibit 68: NRC Inspection Report 85-23 (August 6, 1985);

Exhibit 69: NRC Inspection Report 90-29 (February 8, 1991);

Exhibit 70: Inspection Report 91-04 (March 4, 1991);

Exhibit 71: EA 91-028, Letter from R.P. Zimmerman, NRC, to J.D. Shiffer, PG&E, enclosing Inspection Report 91-06 (April 11, 1991): All of the NRC documents discuss deficiencies in M&TE program.

OVERTIME RESTRICTION VIOLATIONS

Exhibit 72: LER 1-92-021-01 (3/26/93): Documents failures to meet TS 6.2.2 regarding overtime restrictions. Previous occurrence noted.

CENTRIFUGAL CHARGING PUMP 2-1; DEGRADED COUPLING

Exhibit 73: NCR DC2-92-MM-N031 [3/12/93]: Documents increase in vibration on Centrifugal Charging Pump [CCP] 2-1. The coupling sleeve was found to be stiff due to hardened lubricant. This was the third occurrence involving CCP 2-1.

UNIT SHUTDOWN DUE TO INOPERABLE HIGH PRESSURE TURBINE STOP VALVE

Exhibit 74: LER 2-92-003-01 [3/10/93]: On 3/22/92, an unusual event was declared and a manual shutdown was commenced when PG&E determined that one high pressure turbine stop valve [FCV-144] was inoperable. FCV-144 was disassembled and it was determined that the nut that retains the valve disc to the valve swing arm had disengaged, allowing the valve disc to become separated from the valve swing arm.

DG 2-2 FAILED TO ACHIEVE RATED VOLTAGE DURING M-9A

Exhibit 75: NCR DC2-93-MM-N001 D5 [3/10/93];

Exhibit 76: PG&E Special Report 92-06 [1/27/93]: Mispositioning of the slip ring brushes caused low diesel generator output during testing.

MISSED ALERT FREQUENCY STP FOR AUXILIARY SALT WATER PUMP 1-2 and COMPONENT COOLING WATER VALVE CCW-2-RCV-16

Exhibit 77: NCR DC2-93-TS-9005 [3/3/93];

Exhibit 78: NCR DC1-92-TP-N052 [2/4/93];

Exhibit 79: LER 1-92-024-00 [11/17/92]: Documents describe missed alert frequency testing: twice for ASW pump 1-2 and once for component cooling water valves.

FUEL INJECTOR SNUBBER VALVES

Exhibit 80: NRC Inspection Report 92-35 [3/3/93]: Between 12/28 and 12/30/92, PG&E experienced three separate failures of snubber valves in the fuel injection of emergency diesel generator [EDG] 2-3. The snubber valves developed radial cracks which resulted in fuel leaks and degraded performance of affected cylinders.

IN-SERVICE PROMPT TEST DATA QUESTIONABLE

Exhibit 81: NCR DC0-92-TN-N055 [3/1/93];

Exhibit 82: PG&E reply to NOV in NRC IR 92-27 [11/25/92]: Documents describe erroneous revision to test procedures for the steam-driven auxiliary feedwater [AFW] pump. Error had been documented previously, but not corrected.

HOLD DOWN MOTOR BOLTS ON CENTRIFUGAL CHARGING PUMPS

Exhibit 83: NCR DC1-92-MM-N033 [2/24/93]: During preventative maintenance on centrifugal charging pump [CCT] 2-1, PG&E found several discrepancies on the motor hold down bolts, including unmarked bolts, bolts machined down to their root diameter, washers which had elongated holes

and washers that were stocked. Other bolts were overtorqued to 275 ft./lbs.

REACTOR COOLANT SYSTEM LEAKAGE

Exhibit 84: NCR DC2-91-MM-N069 [2/2/93];

Exhibit 85: LER 2-91-004-00 [9/16/91]: On 8/13/91, STP R-10C was performed and calculated an unidentified leakage rate from the Reactor Coolant System [RCS] of 1.4 gpm, which is in excess of the NRC license limit of 1.0 gpm. A review of the previous leak check surveillance identified a calculation error; the previous leak check underestimated the actual leak rate and this resulted in a violation of TS 3.4.6.2.

REACTOR CAVITY SUMP WIDE RANGE LEVEL CHANNEL 942A INOPERABLE

Exhibit 86: NCR DC2-91-TI-N096 DB [January 25, 1993]: Discusses inoperability of reactor cavity sump wide range level channels discovered in October of 1992. Notes previous similar problem in 1990, NCR DC2-90-TI-N076.

Exhibit 87: PG&E Letter No. DCL-91-190 [July 30, 1991], enclosing LER 2-91-010-01, Rev. 1: States that root cause for component failure is unknown. LER at 5.

Exhibit 88: Inspection Report 92-01 [February 28, 1991]: cites PG&E for inadequate corrective actions

to preclude recurrence of an undetected failure of a reactor cavity wide range instrument in Unit 2.

Exhibit 89: PG&E reply to NRC NOV in IR 92-01 [March 30, 1992]: Discusses causes of failure, corrective actions to be taken.

DCM SURVEILLANCE/MAINTENANCE REQUIREMENTS

Exhibit 90: NCR DC0-93-TN-N006 [2/12/93]: During an audit, a generic problem regarding implementation of Design Criteria Memorandum [DCM] Category I surveillance/maintenance requirements was identified.

SNUBBER AT PIPE SUPPORT

Exhibit 91: NCR DC1-92-MM-N021 [2/12/93];

Exhibit 92: LER 1-92-016-00 [11/30/92]: Documents damage to snubber at pipe support on a main feedwater flow control bypass line for SG 1-1.

CROSBY RELIEF VALVE BLOWDOWN RINGS

Exhibit 93: LER 1-93-002-00-2893 [2/8/93];

Exhibit 94: NCR DC0-90-MM-N013 [3/28/91]: Documents failure of pressure relief valves as result of improper blowdown ring adjustment.

GAS DECAY TANK SURVEILLANCE MISSED

Exhibit 95: NCR DC1-92-2C-N041 [2/2/93];

Exhibit 96: LER 1-92-017-00 [10/9/92]: Documents exceedance of time limit for survey of radiation

in Gas Decay Tank.

SHELF/SERVICE LIFE

Exhibit 97: NCR DCO-92-MF-N025 [2/17/93]: Discusses problems related to administrative controls on shelf/storage life.

SEISMIC CLIPS

Exhibit 98: NCR DC1-92-OP-N062, Rev. 0 [January 27, 1993]: Documents discovery that Unit One Reactor Trip and Bypass breakers did not have the required seismic clips installed as required by plant operating and surveillance test procedures and Design Change Memorandum S-38A, "Plan Protection System."

4KV BREAKER PROBLEMS

Exhibit 99: NCR DCO-92-EM-N014 [January 13, 1993]: Since 3/14/91, 4kV breakers have experienced a number of problems which include trip free problems, parts discrepancies, misalignment of parts, and mechanism adjustments being out of tolerance.

CONTAINMENT FAN COOLING UNIT [CFCU] BACKDRAFT DAMPERS

Exhibit 100: NCR DCO-92-MM-N022 [January 4, 1993]: Discusses recent "Frequent problems on various HVAC and related components. These problems would not be expected to occur if proper maintenance had been performed."

Exhibit 101: LER 1-92-023-00 [November 20, 1992]: Reports identification of cracked CFCU backdraft damper blades, condition places plant outsight design basis. Analyzes causes and effects.

Exhibit 102: PG&E Letter No. DCL-92-161 [July 20, 1992]: Responds to Notice of Violation in Inspection Report 92-17.

Exhibit 103: PG&E Letter No. DCL-92-134 enclosing LER 1-91-019-01, rev. 1 [June 5, 1992]: Revises previously issued LER, contains completed safety analysis.

Exhibit 104: NCR DCO-92-MM-N007 [February 12, 1992]: Discusses missing or defective counterweights found on CFCU backdraft dampers; causes; corrective actions; discusses examples of typical HVAC problems.

CONTROL OF FOREIGN MATERIAL/HOUSEKEEPING

Exhibit 105: NRC Inspection Report 92-31 [12/11/92];

Exhibit 106: NRC Diablo Canyon Shutdown Risk and Outage Management Inspection, NRC Inspection Report 50-275/92-201 [12/8/92]:

Exhibit 107: Inspection Reports 88-10 and 88-11 [6/17/88]

Exhibit 108: NRC NOV in Inspection Reports 88-07 [5/5/88], 88-10 and 88-11 [6/17/88]

Exhibit 109: NCR DC2-91-TN-N102 R2 [11/18/92],

Exhibit 110: NCR DCO-91-MM-N042 [5/19/92],

Exhibit 111: LER 2-91-012-00 [3/5/92]

Exhibit 112: PG&E reply to NRC EA 89-241,

Exhibit 113: PG&E letter #DCL-90-070 [3/12/90]: All of the above documents describe repeated discoveries of loose debris in containment.

SHUTDOWN RISK AND OUTAGE MANAGEMENT

Exhibit 114: NRC IR 50-275/92-201[unit 1]: Diablo Canyon Shutdown Risk and Outage Management Inspection [12/8/92]. Maintenance-related deficiencies in PG&E outage plan identified.

RADIATION MONITORS BYPASSED DURING A CONTAINMENT DISCHARGE

Exhibit 115: LER 1-92-027-00 [12/7/92]: During a Unit 1 containment venting operation, manual dampers were positioned in a manner that bypassed newly installed containment purge monitors. Since these monitors were bypassed, containment ventilation isolation upon a high radiation signal was inoperable, violating tech specs. Inadequate document control and procedures cited.

STEAM GENERATOR FEEDWATER NOZZLE CRACKING

Exhibit 116: NRC "summary of 10/20/92 public meeting to discuss steam generator feedwater nozzle cracking" [11/23/92]

Exhibit 117: Event 24304 [9/24/92]; LER 1-92-022-00 [10/30/92]: During 1R5 [9/24/92], ultrasonic

testing [UT] of the Unit 1 steam generator [SG] feedwater nozzles and piping identified erosion/corrosion and stress fatigue indications on piping in the main feedwater system near SG 1-1, SG 1-2, SG 1-3 and SG 1-4 nozzle-to-pipe welds.

PROCEDURAL CONTROLS DURING SHOT PEENING OPERATIONS

Exhibit 118: NRC NOV in NRC IR 92-26 [11/13/92]: Documents several instances occurred which involved the unanticipated spread of contamination and/or airborne radioactivity which resulted from inspection and maintenance operations for Steam Generator [SG] Shot Peening.

UNPLANNED ESF ACTUATIONS DUE TO PERSONNEL ERROR

Exhibit 119: NCR DC1-92-TI-N039 [10/2/92];

Exhibit 120: LER 1-92-013-00 [10/2/92]: On 9/6/92, the Fuel Handling Building Ventilation System [FHBVS] shifted to iodine removal mode. This event constitutes an Engineered Safety Features [ESF] actuation. This shift was caused by a high radiation alarm on radiation monitor RM-59. The root cause of the RM-59 alarm was determined to be personnel error during testing.

Exhibit 121: NCR DC1-91-OP-N038 [5/3/91]: Describes inadvertent actuation of SSPS Train A test

switch S-816 which caused the SSPS slave relay K603A to actuate, and in turn initiated an unplanned start of diesel generator 1-1 and a realignment of safety injection valves [an ESF]. The root cause was determined to be personnel error due to failure to follow procedures, inattention to detail and failure to perform the requirements of the verification process.

Exhibit 122: LER 1-91-011-00 [8/1/91]; NCR DC1-91-OP-N059 [7/23/91]: Describe another event [7/5/91] in which an unplanned start of ESF equipment occurred when an operator inadvertently actuated the wrong SSPS test switch.

Exhibit 123: LER 1-91-009-00 [6/17/91];

Exhibit 124: NCR DC1-91-TI-N047 D4 [1/24/92]: Both documents describe a Unit 1 reactor trip which occurred on 5/17/91 as a result of personnel error.

Exhibit 125: LER 2-91-006 [11/1/91]: While removing AC inverter IY-24 from service, the operators inadvertently opened the output breaker for inverter IY-23 instead of the intended breaker for inverter IY-24. This resulted in a momentary loss of power to the control room ventilation intake radiation monitor RM-26

which caused the control room ventilation system to shift from normal to pressurization mode. The root cause was determined to be personnel error [inattention to detail],

Exhibit 126: NCR DC2-91-TI-N088 D2 [10/30/91];

Exhibit 127: LER 2-91-007-00 [11/1/91]: Both documents describe incident in which technicians who were reconfiguring the SSPS incorrectly placed the outputs in operate prior to inhibiting the inputs, resulting in an inadvertent safety injection. This occurred because the technicians failed to utilize the applicable procedure during performance of an STP and did not practice self-verification or concurrent verification.

LIMITORQUE VALVE FAILURE

Exhibit 128: NCR DC2-92-EM-N026 D8 [September 17, 1992];

Exhibit 129: LER 1-92-010-00 [10/15/92]: Both exhibits document failure of limitorque valve operator due to improper assembly.

AUXILIARY FEEDER BREAKER 52HH13 FAILED TO OPEN

Exhibit 130: NCR DC2-91-EM-N095 D6 [9/24/92]: During plant restart, 4kV vital bus H auxiliary feeder breaker 52HH13 failed to open when the 4kV vital bus H startup feeder breaker 52HH14 was closed. Trip coil was later found to show

signs of severe overheating, and was also out of alignment.

INADEQUATE MAINTENANCE OF HOSGRI REPORT COMMITMENTS

Exhibit 131: LER 1-92-015-00 [9/11/92]: Documents PG&E failure to update seismic qualification after earthquake re-evaluation, or to keep updated, adequate records.

MOTOR PINION KEYS IN LIMITORQUE MOTOR OPERATORS

Exhibit 132: LER 1-91-021-00 [8/28/92]: Documents discovery of sheared and failed motor pinion keys in Limitorque motor operators.

CHEMICAL SPILL AND NOXIOUS GASES IN TURBINE BUILDING

Exhibit 133: NRC Inspection Report 92-20 [8/13/92]: Documents spill of hazardous material.

CONTROL OF LIFTING AND RIGGING DEVICES

Exhibit 134: PG&E reply to NOV [8/5/92];

Exhibit 135: LER 1-91-004-02, Special Report 91-02 R1, Diesel Generator 1-1 failure to load within TS limits [7/29/92];

Exhibit 136: NCR DC1-91-MM-N028 [10/23/91];

Exhibit 137: Inspection Report 92-16 [7/7/92]; All of these documents describe incorrect and unsafe use of cranes and lifting devices.

MAIN FEEDWATER PUMP OVERSPEED TRIP

Exhibit 138: NCR DC1-92-EM-N010 [July 29, 1992]: Discusses inverter failure which caused reactor trip,

plus nine previous failures.

Exhibit 139: Inspection Report 92-05 [4/17/92]: Reviews history of feedwater pump inverter failures.

Exhibit 140: Letter from Zimmerman to Rueger [April 16, 1992] enclosing Inspection Report 92-13 [April 15, 1992]: Discusses MFWP inverter failures.

LER 1-92-002-00 [April 3, 1992]: Discusses root and contributory causes of inverter failure.

Exhibit 141: Inspection report 92-13 [April 1, 1992]: Criticizes PG&E's narrow focus in addressing repeated feedwater pump problem, "causing PG&E to fix the existing equipment, rather than to question the adequacy of the design after repeated failures."

Exhibit 142: NCR DC1-91-TI-N045 [6/10/91]: Noted in NCR DC1-92-EM-N010 Rev. 0 as a previous similar event.

FAILURE TO CORRECT RELIANCE ON UNQUALIFIED SURGE SUPPRESSION DIODES

Exhibit 143: LER 2-92-005-01 [July 21, 1992]: Surge suppression diodes determined to be unqualifed due to personnel lack of attention to detail.

CONTAINMENT VENTILATION ISOLATION [CVI]

Exhibit 144: PG&E Documents: LER 1-92-005-01 [July 20, 1992];

Exhibit 145: NCR DC1-92-TI-N020 [6/24/92]: Both documents discuss spurious CVI activation on April 28, 1992, caused by a loose connector on the test box.

Exhibit 146: LER 1-91-013-00 [9/6/91], NCR DC1-91-TI-N068 [October 3, 1991]: Discuss spurious CVI activation on August 10, 1991; high frequency at DCPP.

Exhibit 147: LER 2-91-001-00 [8/13/91];

Exhibit 148: NCR DC2-91-TI-N062 [8/9/91]: Discuss spurious CVI activation on July 15, 1991.

Exhibit 149: LER 1-91-006-00 [April 25, 1991];

NCR DC1-91-EM-N041 [April 25, 1991]: Discuss CVI event on March 26, 1991.

Exhibit 150: LER 1-90-019-00 [January 28, 1991] NCR DC1-90-WP-N093 [January 18, 1991]: Discuss CVI on December 27, 1990.

Exhibit 151: LER 2-90-004-00 [May 17, 1990]; NCR DC2-90-TI-N025 [October 11, 1990]: Discusses CVI event on April 17, 1990.

ASSEMBLY OF THE EXPANSION BELLOWS

Exhibit 152: NRC NOV, Inspection Report 92-14 [6/5/92];

Exhibit 153: PG&E's Reply to NOV in NRC IR 92-14 [7/2/92]: NRC cited PG&E for failure to have appropriate written instructions for a certain assembly activity during installation of the

sixth diesel generator.

LOW VACUUM TURBINE TRIP AND SUBSEQUENT REACTOR TRIP

Exhibit 154: LER 1-92-004-00 [5/20/92]: Documents problems with vacuum pump which occurred during main feedwater pump turbine isolation. Circumventing of procedures, component failure, inadequate instructions cited as causes.

REACTOR TRIP ON STEAM GENERATOR LOW LEVEL WITH STEAM FLOW/FEEDWATER FLOW MISMATCH DUE TO PERSONNEL ERROR

Exhibit 155: LER 1-91-002-01 [May 17, 1991];

Exhibit 156: NCR DC1-91-WP-N012 [May 13, 1991]: On 2/1/91, a Unit 1 reactor trip occurred due to steam generator [S/G] low level with a steam flow/feedwater flow mismatch on 1-4 S/G. The trip was caused by personnel error.

RHR PUMP 1-2 MAINTENANCE PROBLEMS

Exhibit 157: NCR DC1-91-EM-N027 D7 [3/20/92]: Documents maintenance problems discovered during a routine overhaul of residual heat removal [RHR] pump 1-2 motor.

INCORRECT CALIBRATION DATA

Exhibit 158: LER 2-92-002-00 [3/13/92];

Exhibit 159: NCR DC2-92-TI-N009 [3/17/92]: A calibration of steam flow channel 532, completed 2/10/92, used an incorrect data sheet/scaling calculation which resulted in the channel being out

of acceptance specifications.

LOOSE CAMSHAFT DAMPENER FASTENER

Exhibit 160: NCR DC0-91-MM-N079 [2/21/92]: Describes maintenance defects found in camshaft on diesel generator [DG] 2-2.

MAIN STEAM SAFETY VALVES

Exhibit 161: LER 2-91-002-00 [12/20/91];

Exhibit 162: NCR DC2-91-MM-N072 [12/5/91]: Both documents describe problems with surveillance of main steam safety valves.

MISSED SURVEILLANCES OF ROD POSITION INDICATIONS

Exhibit 163: LER 1-91-017-00 [12/16/91]: Documents missed surveillance on rod position deviation monitor [RPDM].

FIRE DAMPER CARDOX ACTUATION FUSIBLE LINK ASSEMBLY INCORRECTLY INSTALLED AND FAILED DAMPERS

Exhibit 164: NCR DC2-91-SS-N013-D6 [9/20/91]: On 11/23/89, during performance of STP M-19B on the halon fire suppression system, two of the four fire/smoke dampers for the solid state suppression system room failed to close on manual actuation of the halon system, thus violating tech specs.

Exhibit 165: LER 1-90-018-00 [1/21/91]: On 12/12/90, the Unit 1 cable spreading room [CSR] ventilation system supply damper VAC-1-FD-220, failed to

close on carbon dioxide header pressurization during STP M-39B.

MISSED PMT FOR VALVE SI-2-8802B

Exhibit 166: NCR DC2-91-WP-N097 D3 [12/11/91];

Exhibit 167: LER 2-91-011-00 [11/20/91]: Tech spec violated when no preventive maintenance test was performed on valve SI-2-8802B.

AUXILIARY SALTWATER PUMP CROSSTIE VALVE

Exhibit 168: NCR DC0-91-EM-N009 [11/22/91]: During corrective maintenance on 6/29/90, the manual handwheel for Auxiliary Salt Water [ASW] pump crosstie valve SW-1-FCV-496 was identified as not manually operable due to extensive rust.

EDSFI STP AUDIT FINDING NOV A

Exhibit 169: NCR DC0-91-TN-N065 D6 [10/24/91] Discusses results of NRC electrical distribution system functional inspection, NOV issued for inadequate surveillance test procedures.

COMPONENT COOLING WATER HEAT EXCHANGER 1-1 FLOODING

Exhibit 170: NCR DC1-91-MM-N066 D5 [10/22/91]: On 8/2/91, a flooding event occurred as a result of multiple personnel errors in the preparation of the work order, inadequate clearance and noncompliance with the work instruction.

FAILURE OF AMSAC POWER SUPPLY

Exhibit 171: NCR DC0-90-EM-N081 [10/18/91]: Uninterrupted

Power Supply [UPS] which feeds the Chemistry laboratory/count room failed and battery backup was in degraded condition.

TESTCOCK VALVE ON DIESEL GENERATOR

Exhibit 172: NCR DC0-91-MM-N049 [10/2/91]: Documents improper maintenance on diesel generator testcock and testcock failure due to mechanical fatigue.

WELDING CONTROL PROGRAM

Exhibit 173: NCR DC0-91-MM-N037 [no date provided]: NCR DC0-91-MM-N037 was initiated when problems with the weld control system were discovered and identified as a recurring issue.

Exhibit 174: NCR DC1-91-MM-N018 [10/4/91]: Stud on containment liner found to be held by expoxy rather than welded.

Exhibit 175: NCR DC2-91-TN-N023 [6/19/91]: Addresses the problem involving weld work packages that do not always numerically specify the sizes of welds required.

INADEQUATE GUIDANCE ON DIESEL GENERATOR OPERABILITY

Exhibit 176: LER 1-91-014-00 [10/10/91]: On 2/13/91, all three diesel generators were inoperable while the spent fuel crane was operating with heavy loads over the fuel storage pool. The root cause of this event was lack of written guid-

once for control of diesel generator operability.

POWER REMOVED FROM RESIDUAL HEAT REMOVAL PUMP RECIRCULATION SUMP SUCTION VALVES AND CONTAINMENT SPRAY PUMPS

Exhibit 177: LER 2-91-003-00 [10/1/91]: During a routine control room walkdown, PG&E determined that both residual heat removal [RHR] pump containment sump suction valves 8982 A&B and both containment spray [CS] pumps were inoperable.

MAINTENANCE PERSONNEL QUALIFICATIONS

Exhibit 178: NCR DC0-91-TR-N044 [9/26/91]: Recent INPO Evaluation and QC surveillances revealed concerns with the implementation of the maintenance personnel qualifications program.

Exhibit 179: NRC Human Factors Study Report - Diablo Canyon 1 [8/23/91]: Study reports on technician performing work that he was unqualified to do.

LIMITORQUE MOVs NOT RAYCHEMED

Exhibit 180: NCR DC2-91-EM-N077 [9/16/91];

Exhibit 181: MOV CS-2-9001B was found during maintenance to have interconnecting motor leads that were not Raychemed, as required by a previous work order.

RIGGING OF UNAPPROVED STRUCTURES

Exhibit 182: NCR DCO-91-MM-N034 [9/4/91]: Numerous instances were found where plant personnel rigged from unauthorized rigging points.

EMERGENCY DIESEL FUEL OIL INVENTORY SURVEILLANCE MISSED

Exhibit 183: LER 1-91-012-00 [8/7/91]: Documents failure to perform surveillance as required by tech specs.

MAINTENANCE AND SURVEILLANCE SLOW TO SHOW IMPROVEMENT

Exhibit 184: NRC SALP report notes lack of management aggressiveness in resolution of problems.

UNAPPROVED QUALITY-RELATED WORK PERFORMED

Exhibit 185: NCR DC1-91-WP-N021 [6/11/91]: Maintenance work performed without an approved work order or design change notice.

REACTOR TRIP ON STEAM GENERATOR LOW LEVEL WITH STEAM FLOW/FEEDWATER FLOW MISMATCH DUE TO PERSONNEL ERROR

Exhibit 186: LER 1-91-002-01 [May 17, 1991];

Exhibit 187: NCR DC1-91-WP-N012 [May 13, 1991]: Personnel error caused a Unit 1 reactor trip due to steam generator [S/G] low level with a steam flow/feedwater flow mismatch on 1-4 S/G.

INOPERABLE ROOM TEMPERATURE MONITORS

Exhibit 188: LER 2-90-009-01 [4/3/91];

Exhibit 189: NCR DC2-90-TI-N068 [2/19/91]: Documents incorrect rewiring of high temperature alarm, failure to make timely discovery of problem.

MAIN FEEDWATER CHECK VALVES - LEAKING

Exhibit 190: NCR DC1-91-TN-N002 [2/18/91];

Exhibit 191: NCR DC1-90-OP-N083 [2/8/91];

Exhibit 192: LER 1-91-015-01 [1/25/91];

Exhibit 193: NRC Documents: NRC Review of LER 1-90-015-00 [1/18/91]: All of these documents describe leaking of check valves.

INADVERTENT DISCHARGE OF CARDOX SYSTEM

Exhibit 194: NCR DC0-90-SS-N063 [1/21/91]: On 9/20/90, while testing the carbon dioxide fire system to diesel generator [DG] 2-2 room, carbon dioxide was inadvertently discharged into DG 1-3 room. The root cause of this event was personnel error.

WRONG NIS CHANNEL ADJUSTED

Exhibit 195: NCR DC2-91-TI-N003 [1/16/91]: During removal from service of Nuclear Instrument System [NIS] Channel N-43 during surveillance testing, Channel N-42 switches were inadvertently manipulated causing Channel N-42 to be inoperable in violation of tech specs.

ASW PUMP VAULT DRAIN CHECK VALVES

Exhibit 196: NCR DC0-91-MM-N067 D6 [1/15/91]: On 8/8/91, mechanical maintenance removed the auxiliary salt water pump 1-1 and 1-2 vault drain check valves for routine periodic inspection and

refurbishment. No clearance was requested or approved for the work. The check valves were found to be degraded and both check valves were physically removed from the system.

FIRE PUMP 0-2 MAINTENANCE DEFICIENCIES

Exhibit 197: NCR DC0-90-MM-N057 [12/20/90]: Documents failure of Fairbanks-Morse fire pump 0-2, difficulty of repairing due to mechanical problems that were not addressed in the applicable maintenance procedure or vendor material. FCV-152 LEAKOFF LINE SUPPORTS

Exhibit 198: NCR DC2-90-MM-N078 [12/20/90]: Pipe supports on trip throttle valve declared inoperable due to missing parts, which were not available onsite.

BATTERY CHARGER 232

Exhibit 199: NCR DC2-90-EM-N028 [11/21/90]: Documents recurring problems with battery charger due to inadequate instructions for setting current control module or verifying current limit.

SIGHTGLASS INSTALLATION ON RESIDUAL HEAT REMOVAL PUMP 1-2

Exhibit 200: NCR DC0-90-EM-N070 [10/22/90]: Sightglass was modified, then restored without a governing work order or modification to the existing work order. Lens later cracked.

REPLACEMENT OF ROSEMOUNT TRANSMITTERS

Exhibit 201: LER 2-90-006-01 [10/5/90];

Exhibit 202: NCR DC2-90-TI-N039 [10/9/90]: These documents discuss incorrect rotation of Rosemount transmitters.

VALVES FW-2-LCV-106 AND 107

Exhibit 203: NCR DC2-90-MM-N064 [10/5/90];

Exhibit 204: NCR DC2-90-MM-N071 [11/14/90]: Packing gland sleeve for valve was inappropriately modified, and no replacement packing gland sleeve was available in the warehouse.

INADVERTENT MAIN STEAMLINE ISOLATION

Exhibit 205: NCR DC2-90-TI-N031 [9/19/90];

Exhibit 206: LER 2-90-005-01 [9/14/90]: These documents discuss improper calibration of transmitters.

MAINTENANCE ACTIVITIES ON LIMITORQUE MOTOR-OPERATED VALVES

Exhibit 207: PG&E reply to NOV in NRC IR 90-16 [7/23/90]: NRC issued a NOV citing two Severity Level IV violations involving maintenance activities on Limitorque motor-operated valves [MOVs].

SNUBBER FAILURES

Exhibit 208: NCR DC2-90-MM-N016 [7/16/90]: Investigation of steam generator water hammer did not reveal that a snubber had been damaged during the event.

Exhibit 209: NCR DC2-90-MM-N055 [No date provided]: On

8/15/90, snubber 2032-7SL was declared inoperable after the load stud connecting the snubber to the pipe clamp was found lying on a beam below the snubber.

SI-1-8805A FAILED TO CYCLE ON ACCUATION SIGNAL

Exhibit 210: NCR DC2-90-EM-N042 [6/27/90]: ' . '82, the motor operator for valve SI-1-8805A was overhauled as part of the preventative maintenance program for Limitorque Motor Operators. The valve failed on 5/25/90. The operator was overhauled and the declutch fork was found installed upside down. With the declutch mechanism installed upside down, it only partially engaged. The partial engagement caused excessive stress on the load bearing surfaces and eventually caused a failure. It took eight years for the operator to fail due to aging and stressing of components.

MISSED SURVEILLANCE OF SEALED SOURCES

Exhibit 211: LER 1-90-007-00 [June 1, 1990]: On 3/15/90, the surveillance test interval of TS 4.7.8.1.2 was exceeded when sealed radioactive sources #537 and #538 were not lube tested.

MAIN GENERATOR BACKUP RELAYS

Exhibit 212: DC2-90-EM-N044 [report has no date: event was on 5/5/90]: On 5/5/90, Unit 2 experienced a load rejection with the reactor at 42% power. The load rejection occurred due to a sensed generator undervoltage condition. The root cause for the problem was determined to be an installation error when replacing a fuse.

OVERSPEED OF TURBINE-DRIVEN AUXILIARY FEEDWATER PUMP

Exhibit 213: NRC NOV in Inspection Report 92-13 [4/13/90]: On 4/23/90, incomplete instructions were provided for the replacement of the Unit 2 turbine-driven auxiliary feedwater pump speed governor. Consequently, venting was not performed, and when the turbine was operated on 4/24/90, the turbine oversped.

MAINTENANCE ON RM-58

Exhibit 214: NCR DC2-90-TI-N010 [3/14/90]: Improper actions in removing radiation monitor from service led to fuel handling building system transfer. CHECK VALVE BUSHING FAILURE

Exhibit 215: NCR DC2-90-MM-N023 [No date provided, event occurred on 4/4/90]: Documents improper maintenance of check valve bushings.

FIRE IN ELECTRICAL PANEL

Exhibit 216: NCR DC0 90-SE-N080 [1/28/92]: Faulty compression termination during 1990 jumper installa-

tion and removal was probable cause of subsequent fire.

MISSED SURVEILLANCE ON THE BORIC ACID HEAT TRACE SYSTEM

Exhibit 217: NCR DC1-90-WP-N003 [1/22/90]: On 1/10/90, the surveillance test interval of TS 4.5.4.2.a was exceeded when each heat tracing channel for the boron injection tank and associated flow path had not been energized per surveillance test procedure [STP] R-16.

CONDENSER EXPANSION JOINT FAILURE SLEEVES NOT INSTALLED

Exhibit 218: NCR DC1-90-MM-N002 R1 [no date provided]: Leaking failure sleeves were removed for purposes of an inspection, but were not replaced. Numerous other similar events noted.

GENERAL MAINTENANCE FAILURES

Exhibit 219: Inspection Report 89-85 [July 5, 1989]: Identifies two primary concerns: failure to implement or maintain the design bases of the plant through engineering and procedures; failure to resolve identified problems in an effective and timely manner.

50-275/323-OCA-2 "NOT ADMITTED"

RELATED CORRESPONDENCE

DOCKETED
USNRC

Enclosure 1

'93 OCT 28 P6:53

OCTOBER 20, 1992

PUBLIC MEETING

STEAM GENERATOR FEEDWATER NOZZLE CRACKS

AT DIABLO CANYON UNIT 1

LIST OF ATTENDEES

NAME	ORGANIZATION
Warren Bamford	Westinghouse - NATD
Lee Banic	NRC/NRR/EMCB
Eric Benner	NRC/NRR/OEAB
Warren Fujimoto	PG&E - NTS
David Gonzalez	PG&E - ISI & DCPP
Robert Hermann	NRC/NRR/EMCB
Geoff Hornseth	NRC/NRR/EMCB
John Houtman	Westinghouse - NSD
Meena Khanna	NRC/NRR/PD5
William Koo	NRC/NRR/EMCB
Michael Mayfield	NRC/OEDO
James Medoff	NRC/NRR/EMCB
Kris Parczewski	NRC/NRR/EMCB
Pete Riccardella	Structural Integrity Associates (SIA)
Jack Roe	NRC/NRR/DRPW
Mike Roidt	Westinghouse - STC
Harry Rood	NRC/NRR/PD5
Jack Strosnider	NRC/NRR/EMCB
Henry Thailer	PG&E - Engineering
James Tomkins	PG&E - Licensing

AGENDA

Overview	Warren Fujimoto
NDE Results	Dave Gonzalez
Analysis	Henry Thailer
Long Term Plans	Henry Thailer

PG&E

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AGENDA

Overview	Warren Fujimoto
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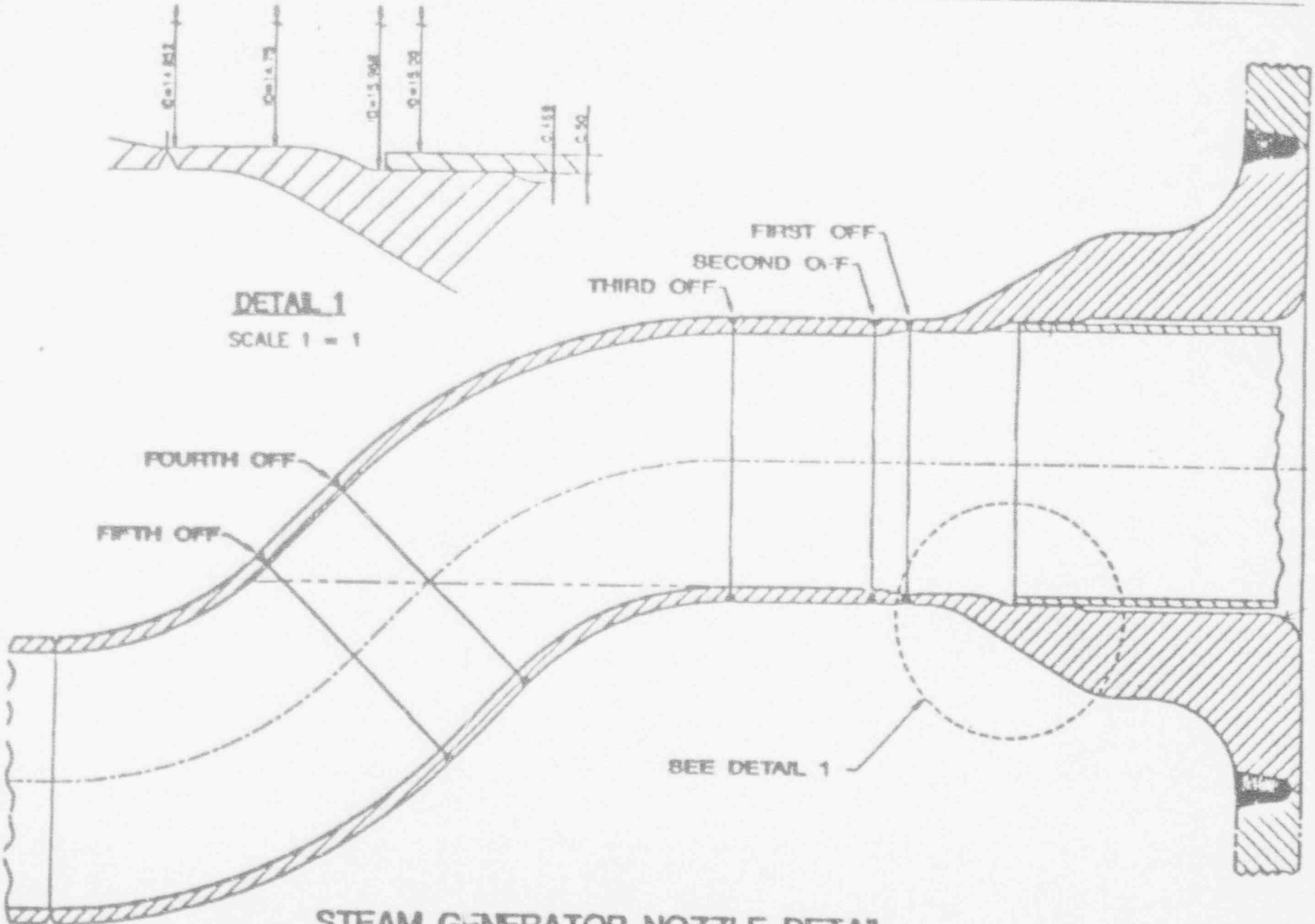
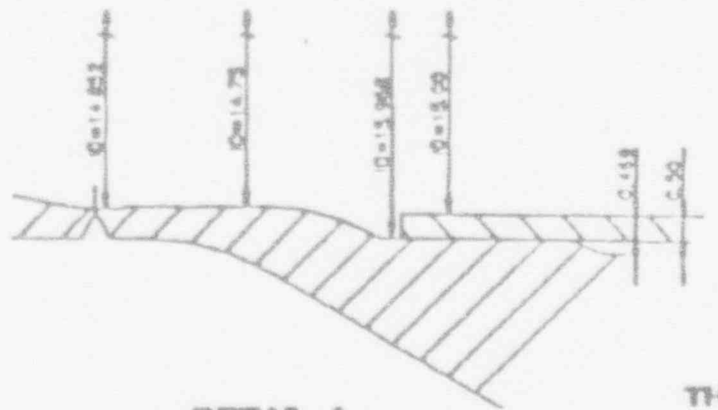
Long Term Plans	Henry Thailer



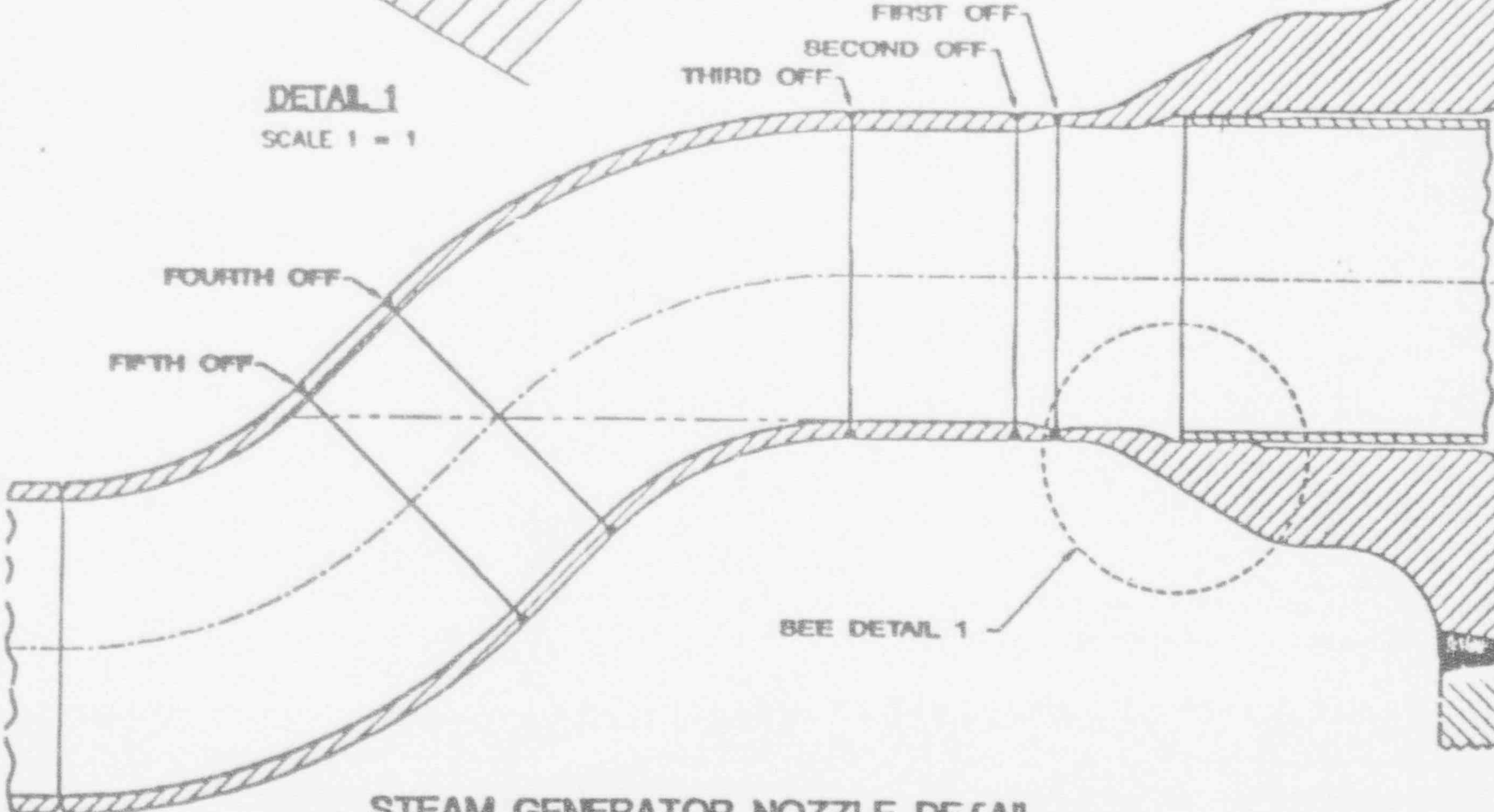
STEAM GENERATOR NOZZLE DETAIL

SCALE 6" = 1'-0"



DETAIL 1

SCALE 1 = 1



STEAM GENERATOR NOZZLE DETAIL

SCALE 6" = 1'-0"

FINDINGS

- Nozzle-to-Pipe Weld Cracks
- Analyzed Thermal Sleeve Erosion
  - Acceptable for Additional Cycle
- Elbow Cracks
- PG&E Operating Experience
- 1986 Unit 1 Radiographs

WHFR

FINDINGS

- Nozzle-to-Pipe Weld Cracks
- Analyzed Thermal Sleeve Erosion
  - Acceptable for Additional Cycle
- Elbow Cracks
- PG&E Operating Experience
- 1986 Unit 1 Radiographs

PG&E

WH FR

INDUSTRY EXPERIENCE

- IE Bulletin 79-13
- NUREG-0691
- NUREG/CR 5285
- U. S. Industry Experience
  - 25 of 54 Plants Reported Nozzle/ Pipe Cracking
  - One Plant Reported Nozzle Knuckle Cracks, Poor Chemistry
- Thermal Sleeves

WHFC

INDUSTRY EXPERIENCE

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- NUREG-0691
- NUREG/CR 5285
- U. S. Industry Experience
  - 25 of 54 Plants Reported Nozzle/ Pipe Cracking
  - One Plant Reported Nozzle Knuckle Cracks, Poor Chemistry
- Thermal Sleeves

PG&E

1992 NDE EXAMINATIONS OF FEEDWATER NOZZLES

- Planning for Feedwater Exams Commenced in May of 1992
- Inquiries for Industry Experience
  - Sequoyah
  - Turkey Point
    - Code Examinations Not Adequate for Small Thermal Fatigue Cracking
    - Became Aware of the Need for Enhanced UT
- Automated Scanning Selected for Accuracy and Repeatability

PG&E

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PG&E

ATTEMPT TO VERIFY INDICATIONS

- Radiography Performed on S/G 1-4
  - Gamma Plug Removed
  - Single Wall Shots With Max Source/Film Distance
  - No Cracks Detected
- Radiography of S/G 1-1 and 1-2
  - Panoramic Shots
  - No Cracks Detected
- Video Probe Inspection of ID
  - Results Inconclusive (Possible Indication)

PG&E

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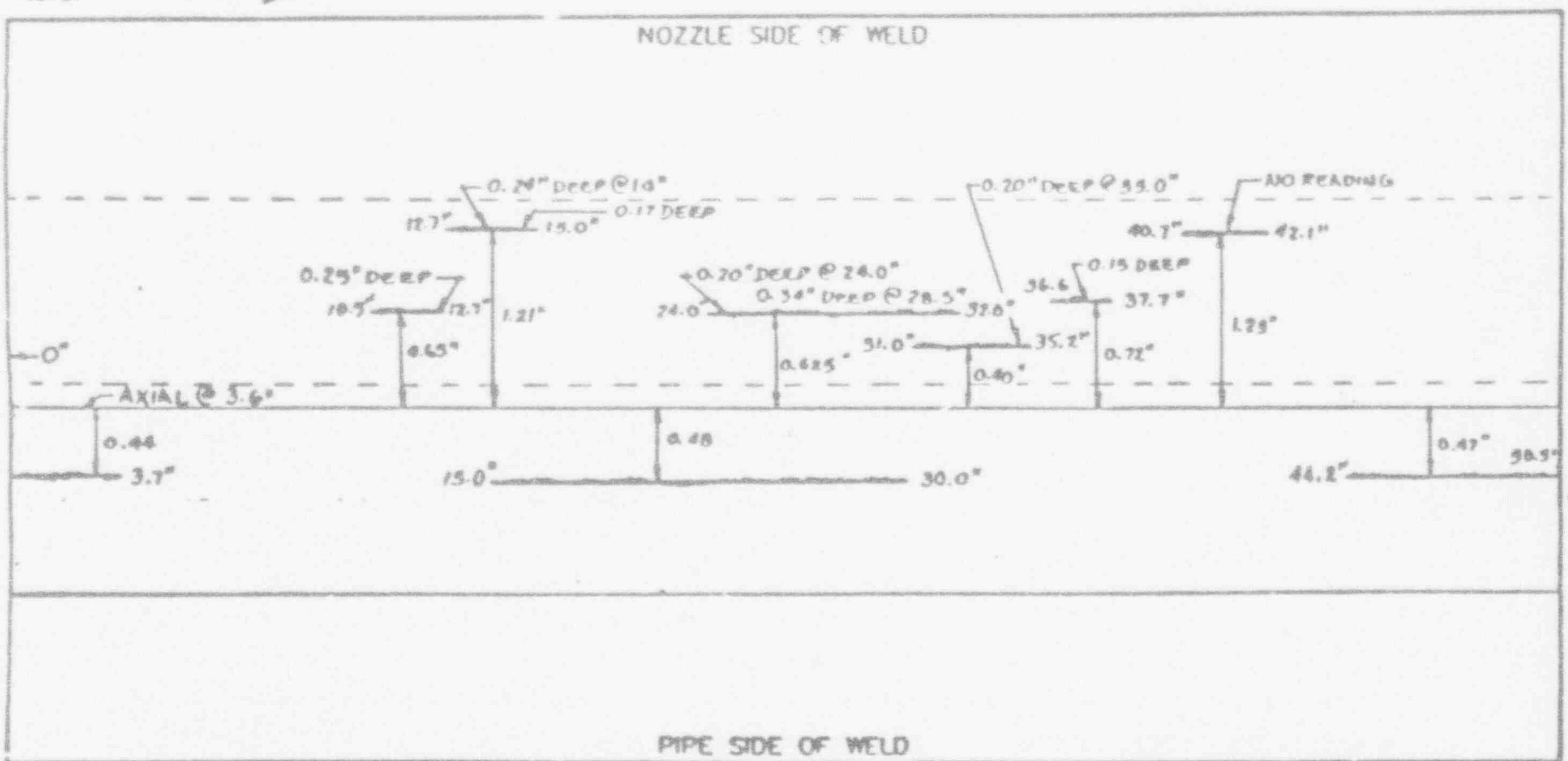
PG&E

FLOW

RESULTS OF ULTRASONIC INSPECTION
DCPP UNIT 1 - 1R5, FEEDWATER PIPE TO SG NOZZLE WELDS
DCPP ISI GROUP

0 DEGREES T.D.C. CLOCKWISE



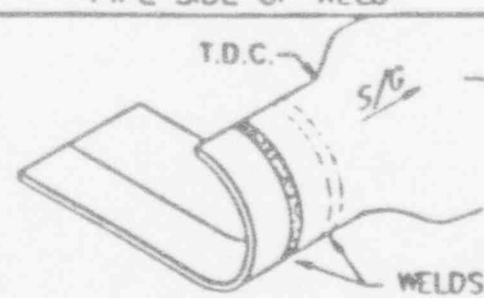
STEAM GENERATOR: 1-1

WELD NO. WICG 101A1-1

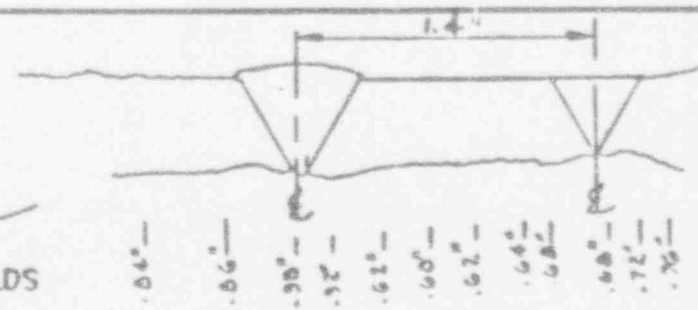
INSPECTOR NAME: HECHT/HOLLOW

DATE: 9/24/92

SCALE: NONE

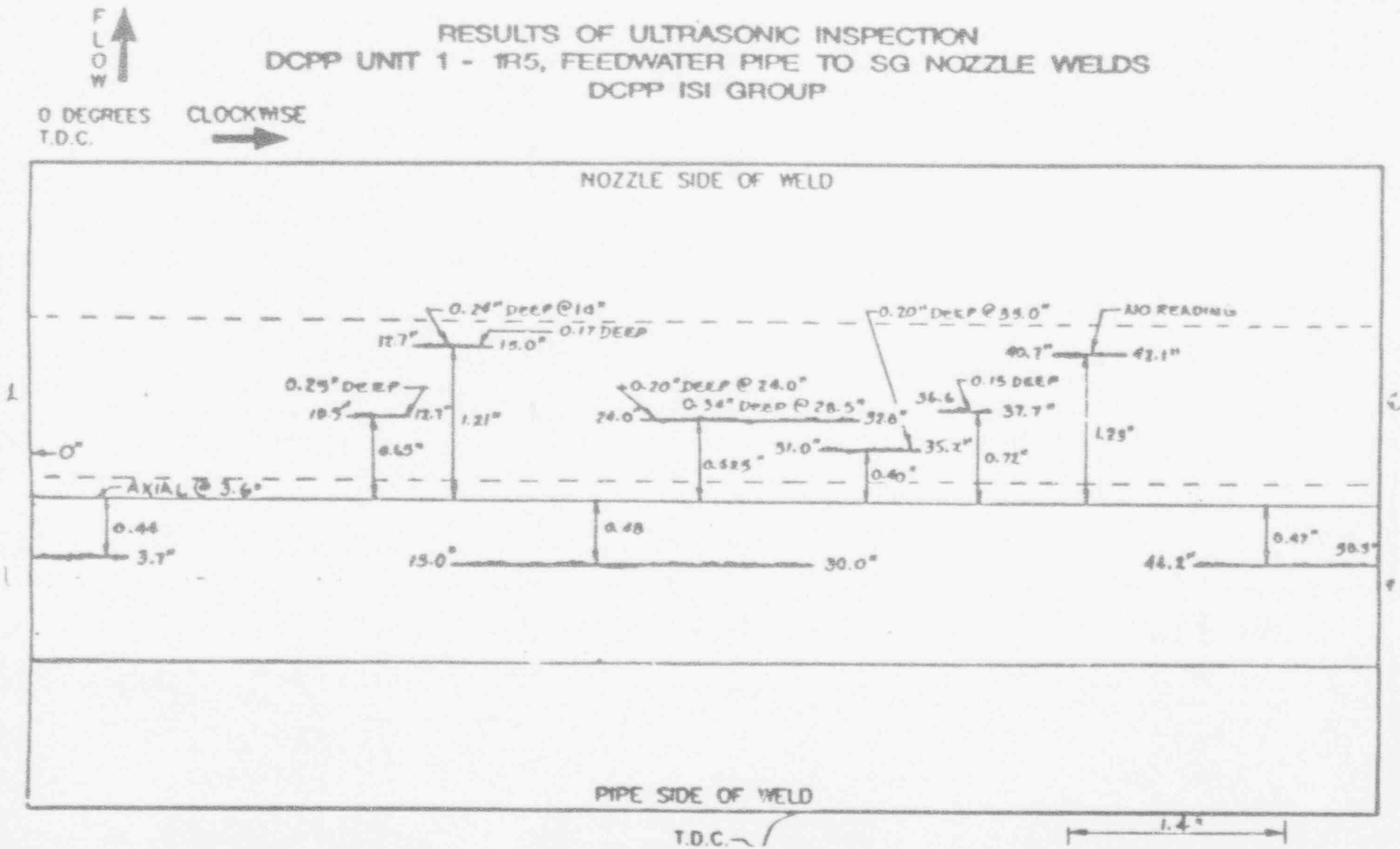


ROLLOUT

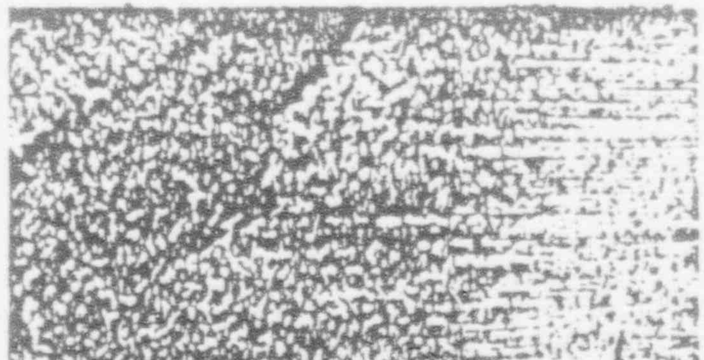


PROFILE

RESULTS OF ULTRASONIC INSPECTION
DCPP UNIT 1 - 1R5, FEEDWATER PIPE TO SG NOZZLE WELDS
DCPP ISI GROUP



FW Nozzle 1-3: 8 3/8" CCW from TDC. Cracks in A106 spool attached to nozzle. Deepest crack is 0.035".

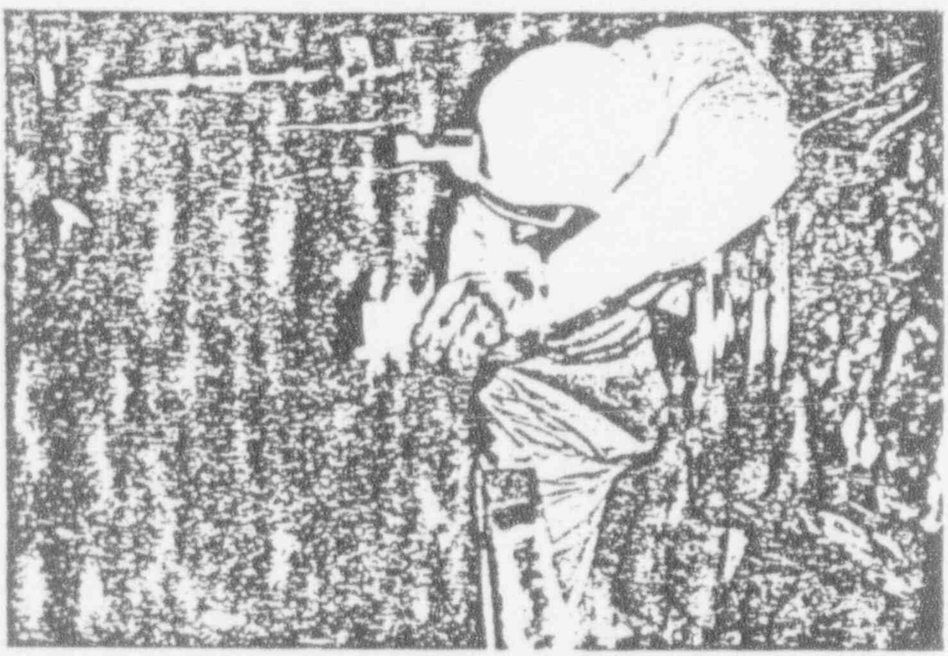


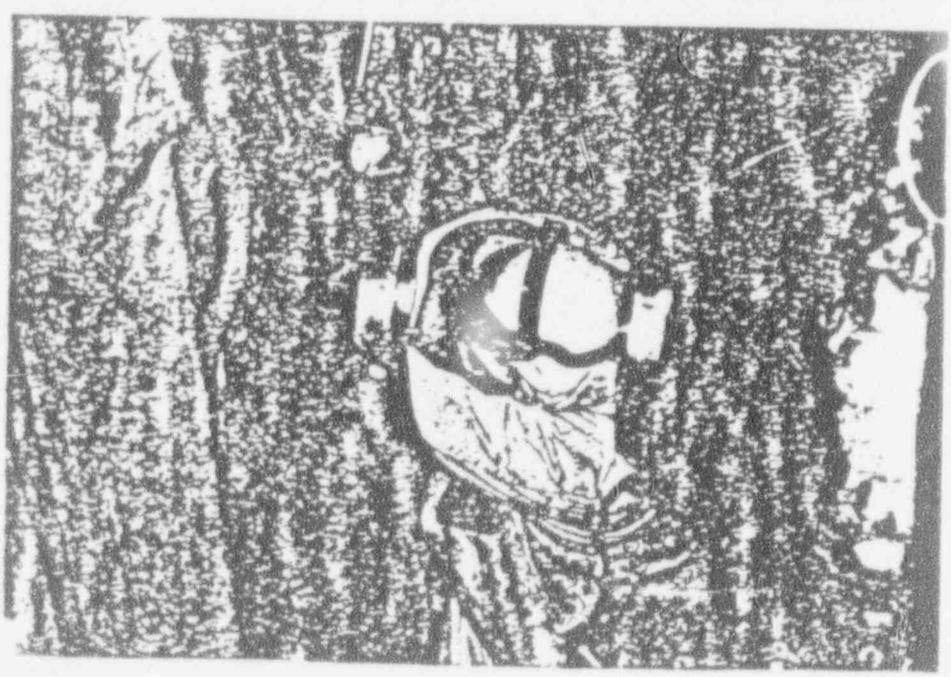
Magnification: 15X

50X

ELBOW EXAMINATION SUMMARY

- Access for Prep/Exam Difficult
- Surface Preparation Necessary for Adequate Examination
- MT Indications Detected After Prep
- Indications Removed with Flapper Wheel
- Indications Were Allowable Per Code
- Deepest Indication (S/G 1-3) Did Not Appear to be a Crack





ELBOW INDICATIONS

S/G	INDICATION DEPTH/LENGTH INCHES	CODE ALLOWABLE DEPTH/LENGTH INCHES
1-1	.030 / 7 3/4" Long Intermittent Ind's. Longest = 1/8"	.400 / 20
1-2	.010 / 2" Long Intermittent Ind's. Longest = 3/16"	.400 / 20
1-3	.107 / 360 Intermittent Ind's. Longest = 2.0"	.400 / 20
1-4	.047 / .125	.400 / 20

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NDE SUMMARY

ACTION PLANS

- Review NDE Assignment Methods to Ensure the Proper Welds are Clearly Designated for Exams.
- Analyze UT Data and Metallurgical Results and Determine Methods for Accurate Sizing of Thermal Fatigue Cracking.

DIABLO CANYON POWER PLANT

Analysis

Henry Thailer, Assistant Project Engineer
William Crockett, Manager - Technical Services
Peter Riccardella, Structural Integrity
Warren Bamford, Westinghouse
Michael Roidt, Westinghouse

PG&E

S:\...\GRAPHICS\HT-1

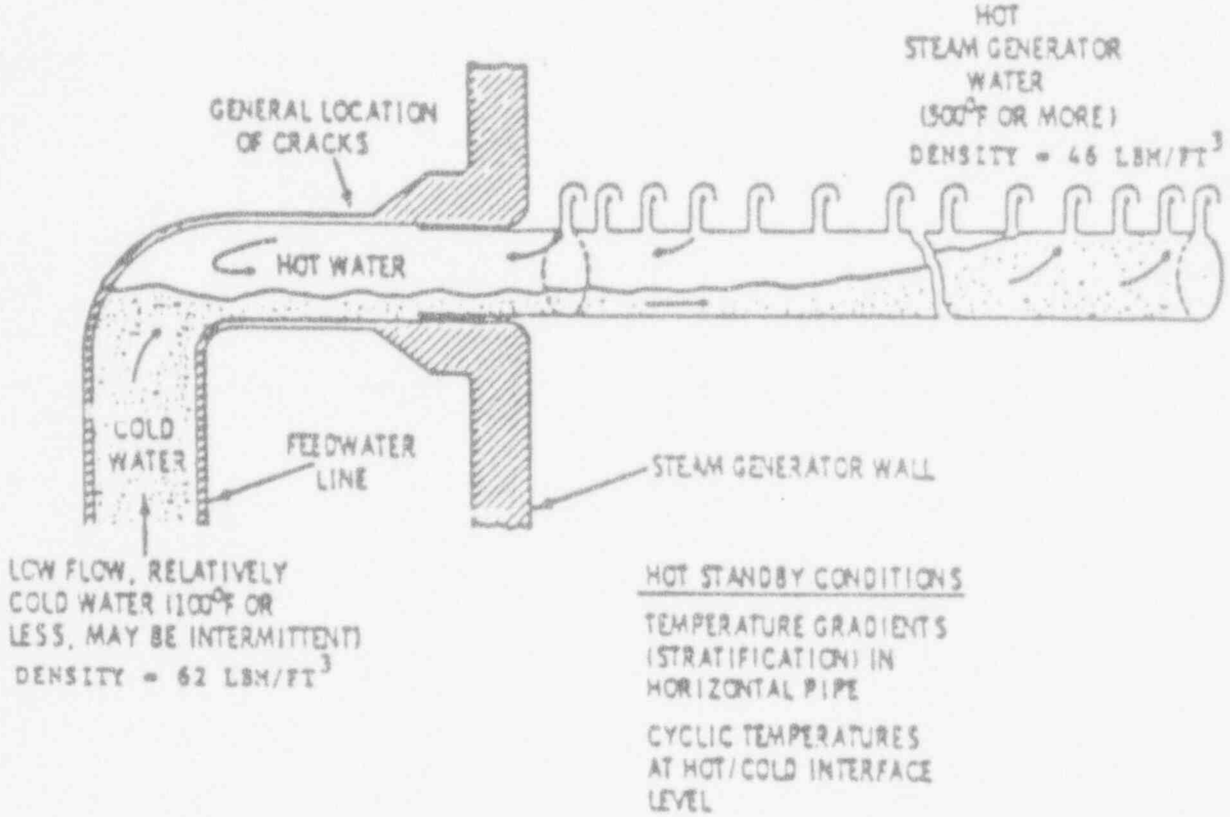
ANALYSES

- AFW Operational Characteristics
- Nozzle-to-Pipe Cracks
- Elbow-to-Pipe Cracks
- Thermal Sleeve Degradation
- S/G Nozzle and Feedring
  - Drainage
  - Knuckle Region
  - Water Hammer

NT88

POSSIBLE CAUSES

- Thermal Fatigue
  - Stratification
- Erosion/Corrosion
- Corrosion Fatigue
  - Contributory Mechanism
- Overstress
  - Waterhammer
  - Locked/Bound Supports
  - Global Stratification
- Fabrication



SCHEMATIC OF THERMAL STRATIFICATION AT LOW FLOW IN PWR FEEDWATER NOZZLES

PCR51739

DIABLO CANYON POWER PLANT
UNITS 1 AND 2

Auxiliary Feedwater

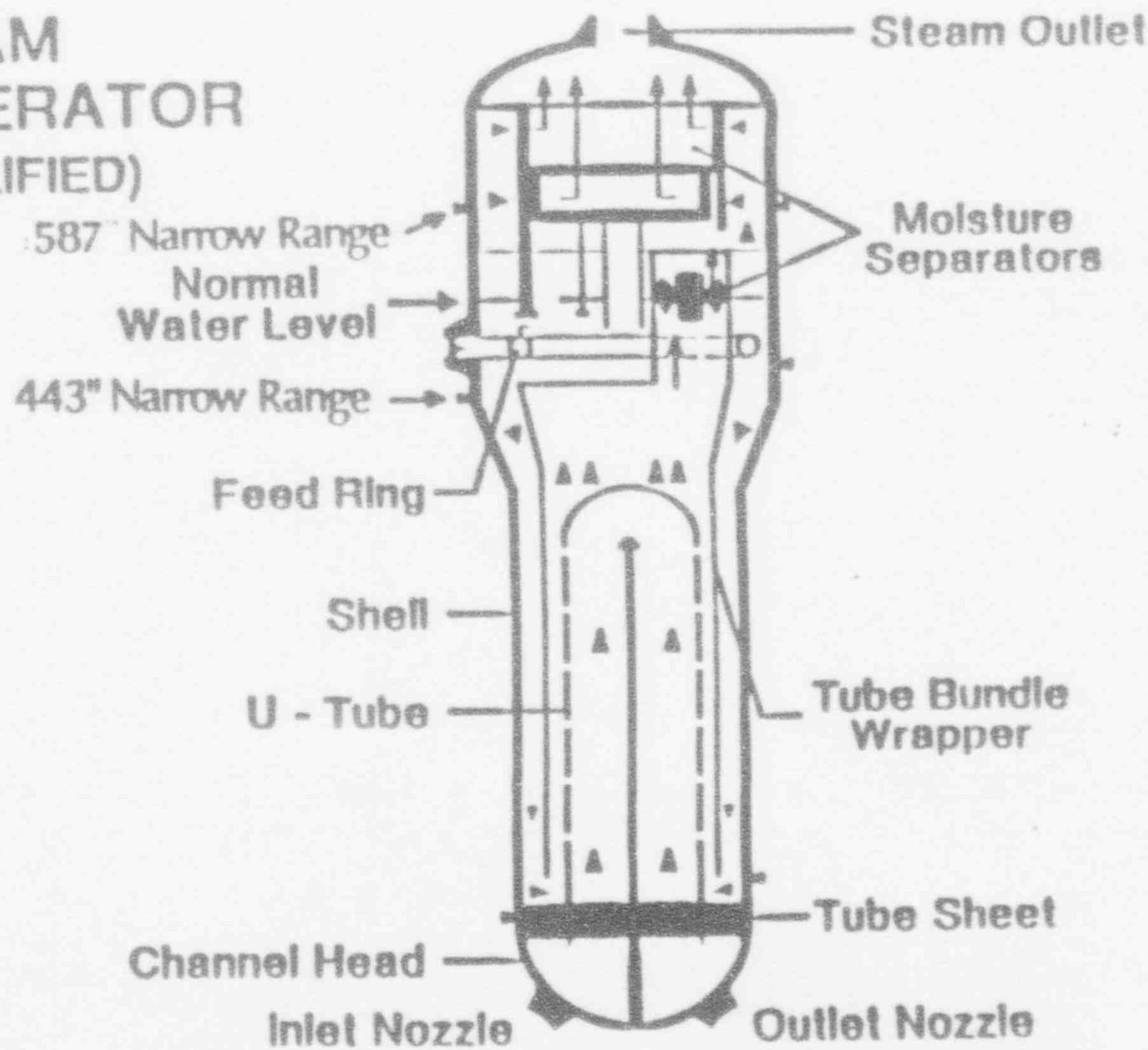
Operational Characteristics

Bill Crockett
Manager-Technical Services

PG&E

ec

STEAM GENERATOR (SIMPLIFIED)



TYPICAL AUXILIARY FEEDWATER EVOLUTIONS

EVOLUTION	DURATION		AUXILIARY FEEDWATER FLOW
REACTOR TRIP RECOVERY	20-30 MINUTES		APPROXIMATELY 400 GPM
HOLDING AT MODE 3 FROM A FORCED OUTAGE	TYPICALLY 2-4 DAYS		STEADY
SHUTDOWN (COOL-DOWN) TO RHR	BORATION	≈ 8 HRS	INITIALLY STEADY
	COOL-DOWN FROM 547F TO 300F	≈ 8 HRS	0-20 GPM AS YOU NEAR THE RHR TRANSFER POINT
	TRANSFER TO RHR	≈ 8 HRS	
		24 HRS	
STARTUP FROM A REFUELING OUTAGE	HEAT-UP TO MODE 3	≈ 20 HRS	0-40 GPM
	MODE 3	≈ 72 HRS	
	MODE 2 ON AUX FEEDWATER	≈ 48 HRS	
		140 HRS	
HOT FUNCTIONAL TESTING	91 DAYS FOR UNIT 1 40 DAYS FOR UNIT 2		SIMILAR TO STARTUP FROM REFUELING OUTAGE

TIME SPENT IN MODES 2/3 (DAYS)

(RCS > 350°F)

	UNIT 1	UNIT 2
HOT FUNCTIONAL TESTING	90.80	40.26
CYCLE 1		
PRE-COMMERCIAL	129.56	86.84
FORCED OUTAGE	16.77	24.65
IN/OUT REFUEL	21.25	12.00
TOTAL	167.58	123.49
CYCLE 2		
FORCED OUTAGE	19.89	15.66
IN/OUT REFUEL	16.17	9.83
TOTAL	36.06	25.49
CYCLE 3		
FORCED OUTAGE	3.18	25.12
IN/OUT REFUEL	9.96	8.04
TOTAL	13.14	33.16
CYCLE 4		
FORCED OUTAGE	13.90	0
IN/OUT REFUEL	6.75	11.67
TOTAL	20.65	11.67
CYCLE 5		
FORCED OUTAGE	10.45	5.51
IN/OUT REFUEL	0.79	N/A
TOTAL	11.24	5.51
PRE-COMMERCIAL	220.36	127.10
POST-COMMERCIAL	119.11	112.48
TOTAL TIME	339.47	239.58

IMPROVEMENTS

Outage Time
- Better Planning and Scheduling
- Hit
- OCC

Best Maintenance Practices
- Training
- Procedures

Reliability for Extended Runs
- Equipment Modifications
- Quality Maintenance
- Minimize Reactor Trips

PG&E

DIABLO CANYON POWER PLANT

Nozzle-to-Pipe Crack Evaluation

Peter Riccardella
Structural Integrity Associates

PG&E

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DCPP FEEDWATER NOZZLE/PIPE CRACKING EVALUATION

- ASME Section XI Flaw Evaluation
  - Allowable Flaw Size
  - Crack Growth Projections
- AFW Cycling Estimates (Flow Stratification)
- Critical Flaw Size Assessment (Leak Before Break)
- Unit 2 Operability Evaluation

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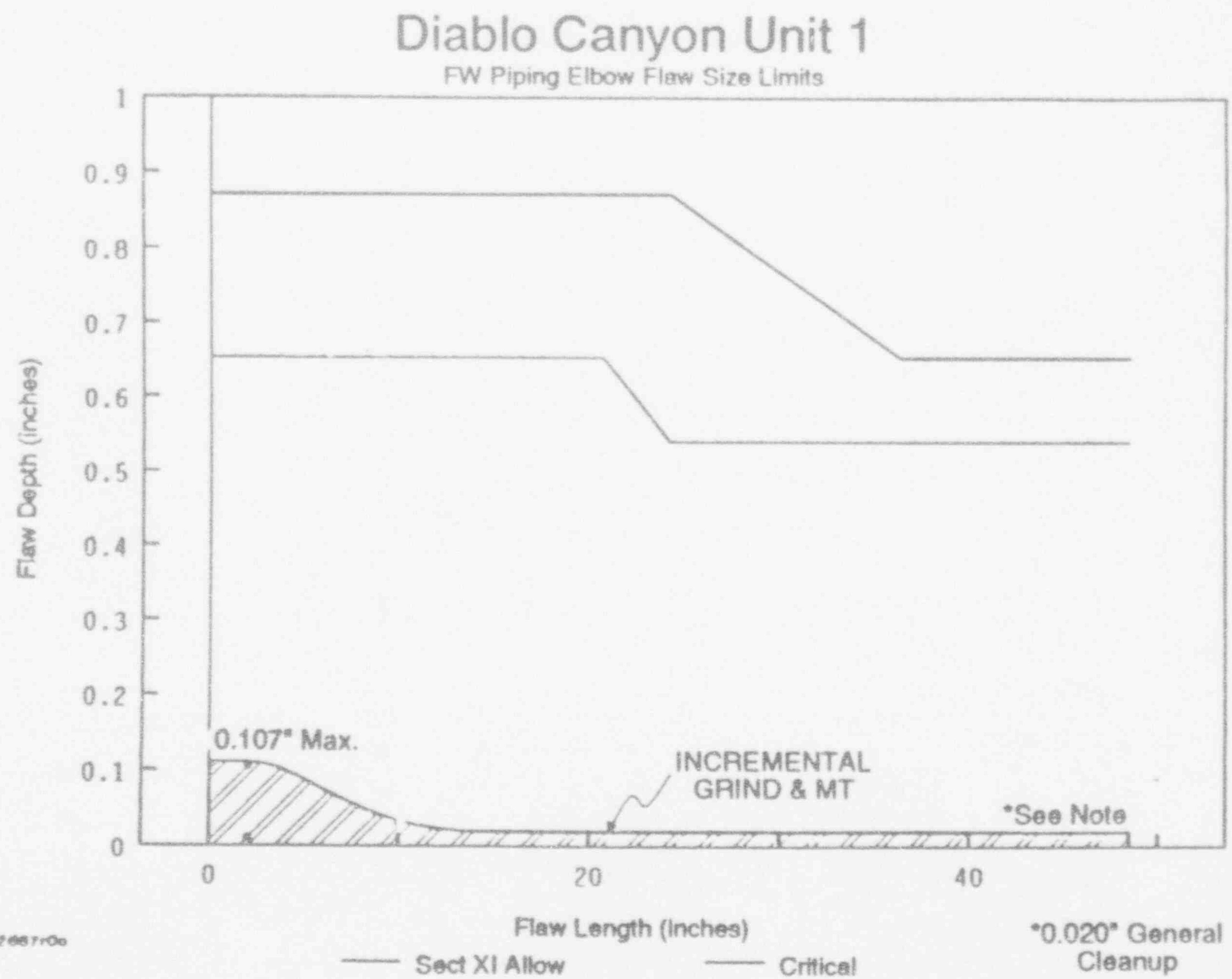
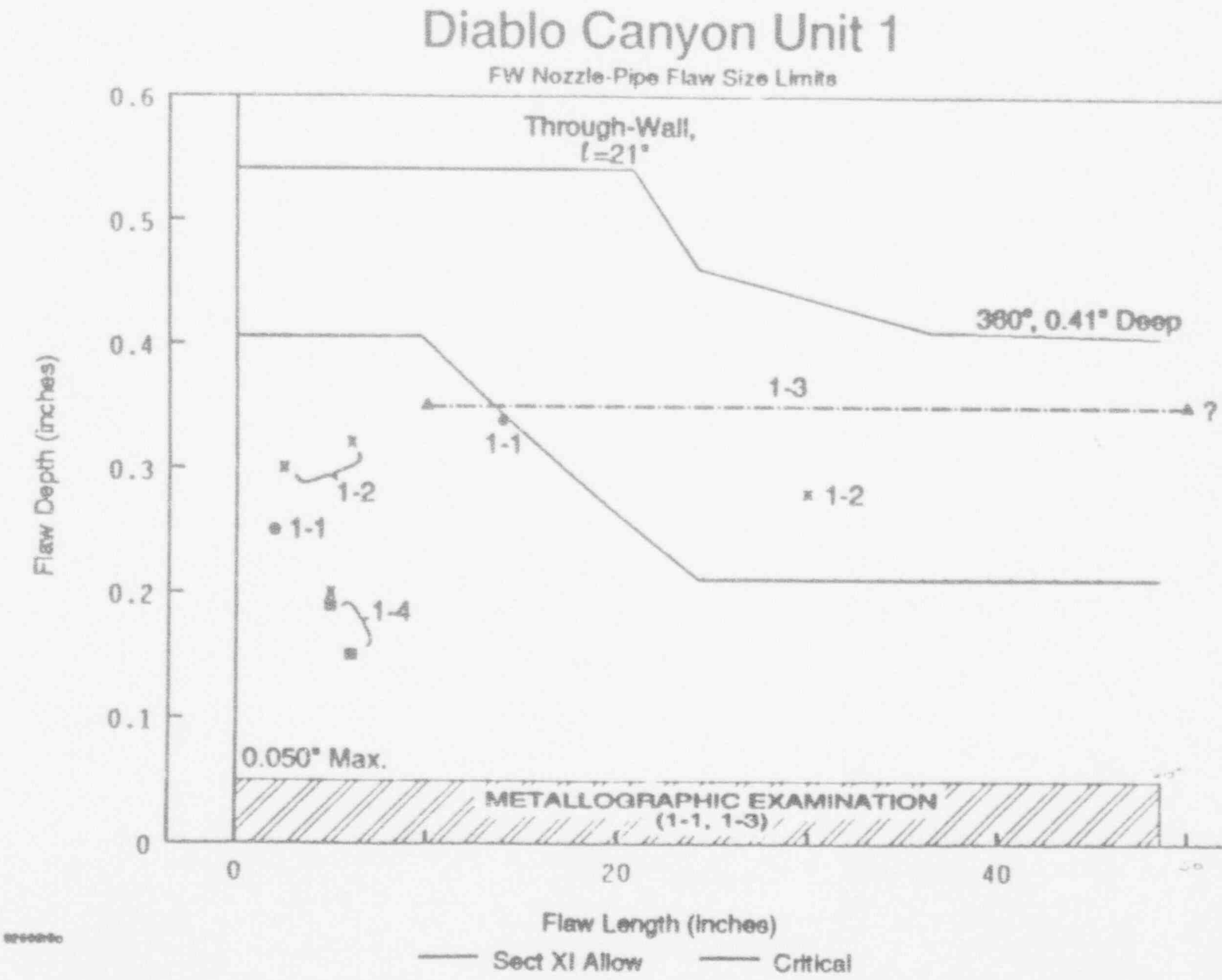
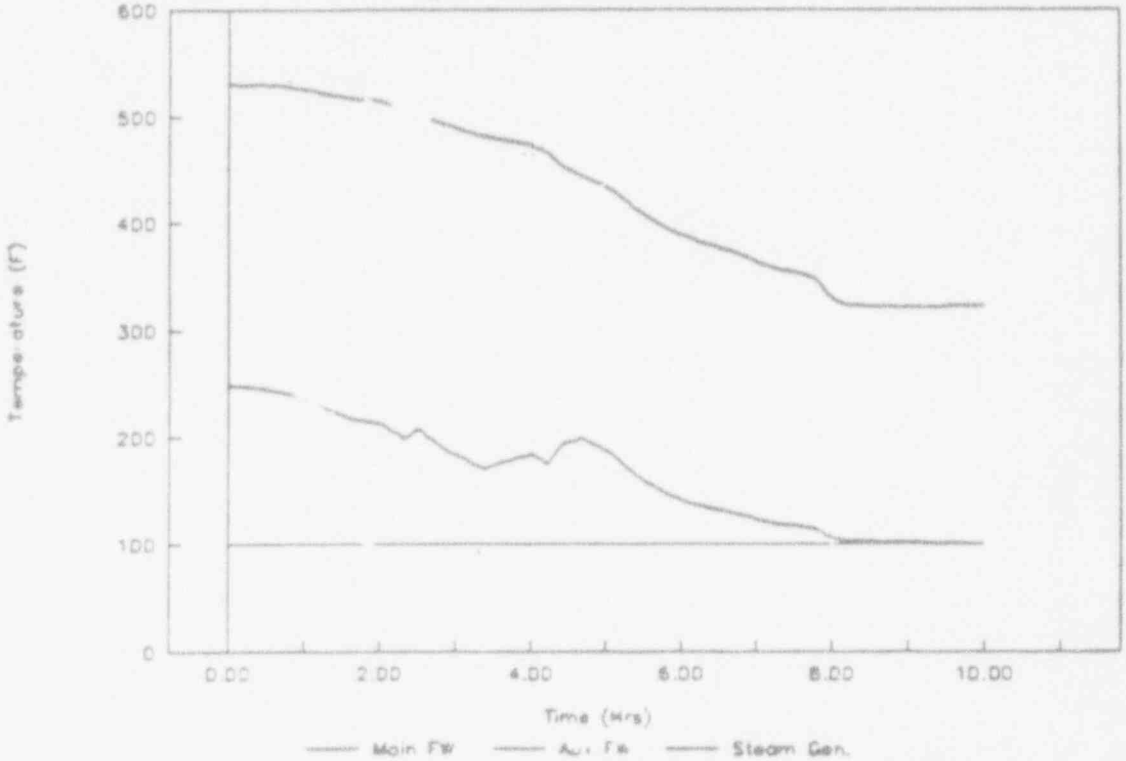
8:\...\GRAPHICS\HT-26


Diablo Canyon Unit 1
FW Piping Elbow Flaw Size Limits
Flaw Depth (inches)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0.107" Max.
INCREMENTAL
GRIND & MT
*See Note
0
20
40
Flaw Length (inches)
Sect XI Allow
Critical
*0.020" General
Cleanup


Diablo Canyon Unit 1
FW Nozzle-Pipe Flaw Size Limits
0.6
0.5
0.4
0.3
0.2
0.1
0
Through-Wall,
l=21"
360°, 0.41" Deep
1-3
?
1-1
1-2
1-1
1-2
1-4
0.050" Max.
METALLOGRAPHIC EXAMINATION
(1-1, 1-3)
0
20
40
Flaw Depth (inches)
Flaw Length (inches)
Sect XI Allow
Critical

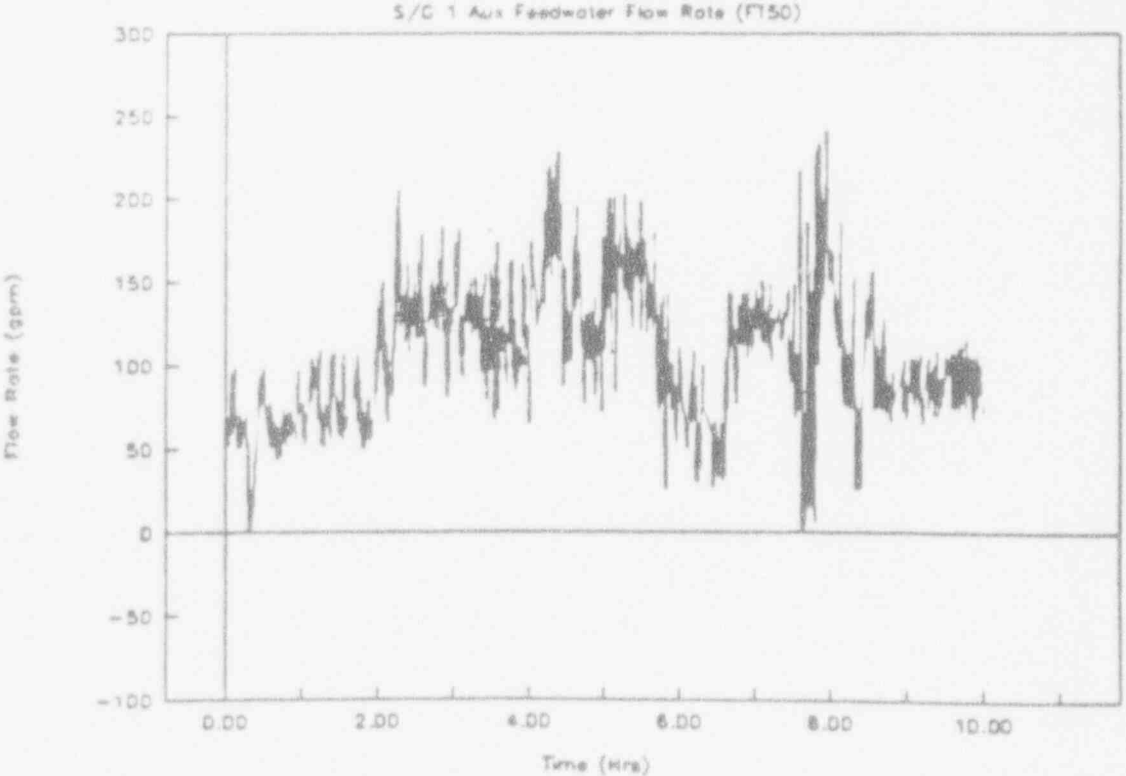
DIABLO CANYON UNIT 1 COOLDOWN 9/13/92

S/G 1 Steam & FW Temperatures

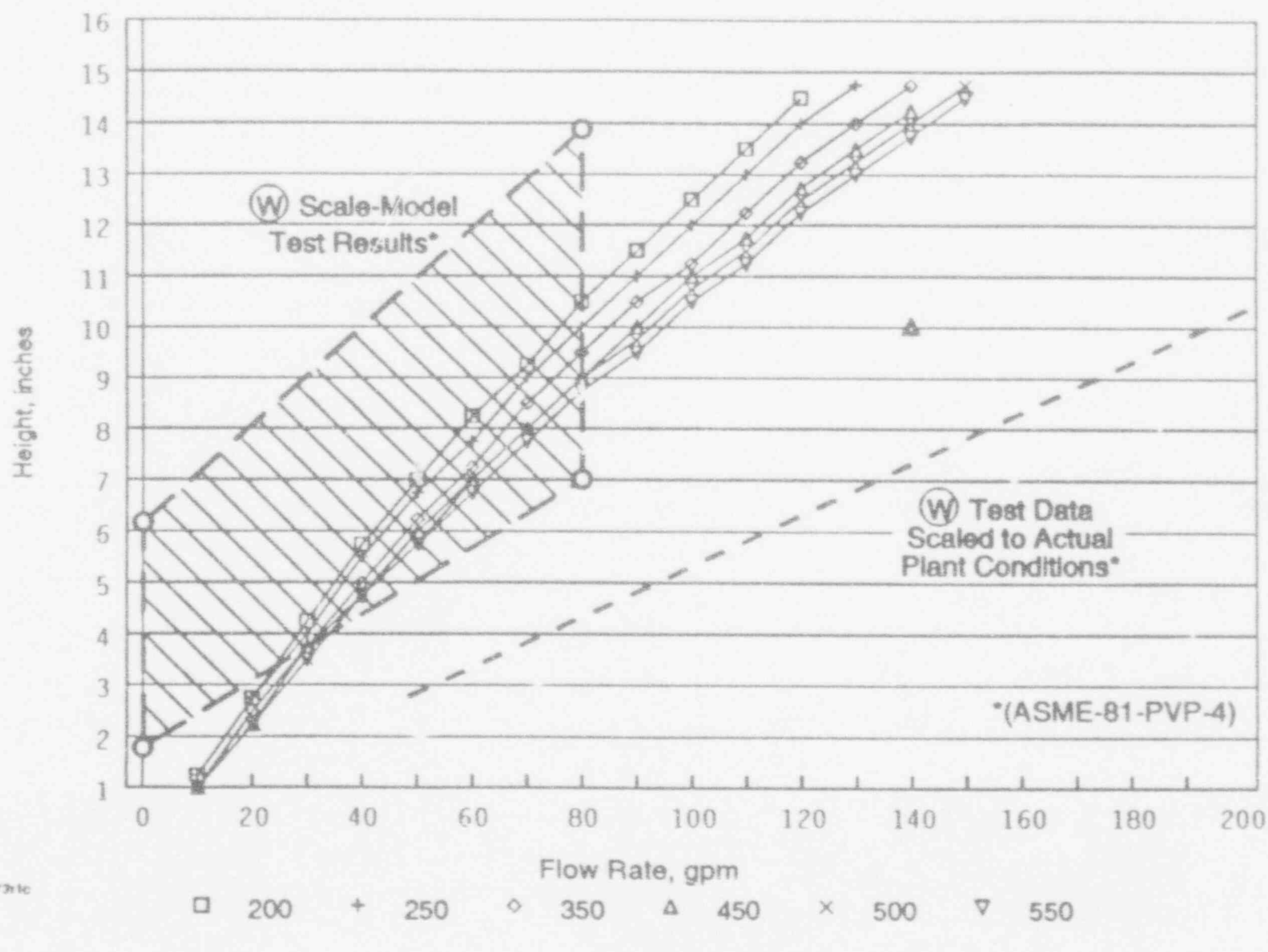


DIABLO CANYON UNIT 1 COOLDOWN (9/13/92)

S/G 1 Aux Feedwater Flow Rate (FT50)



Stratification Height at FW Nozzle



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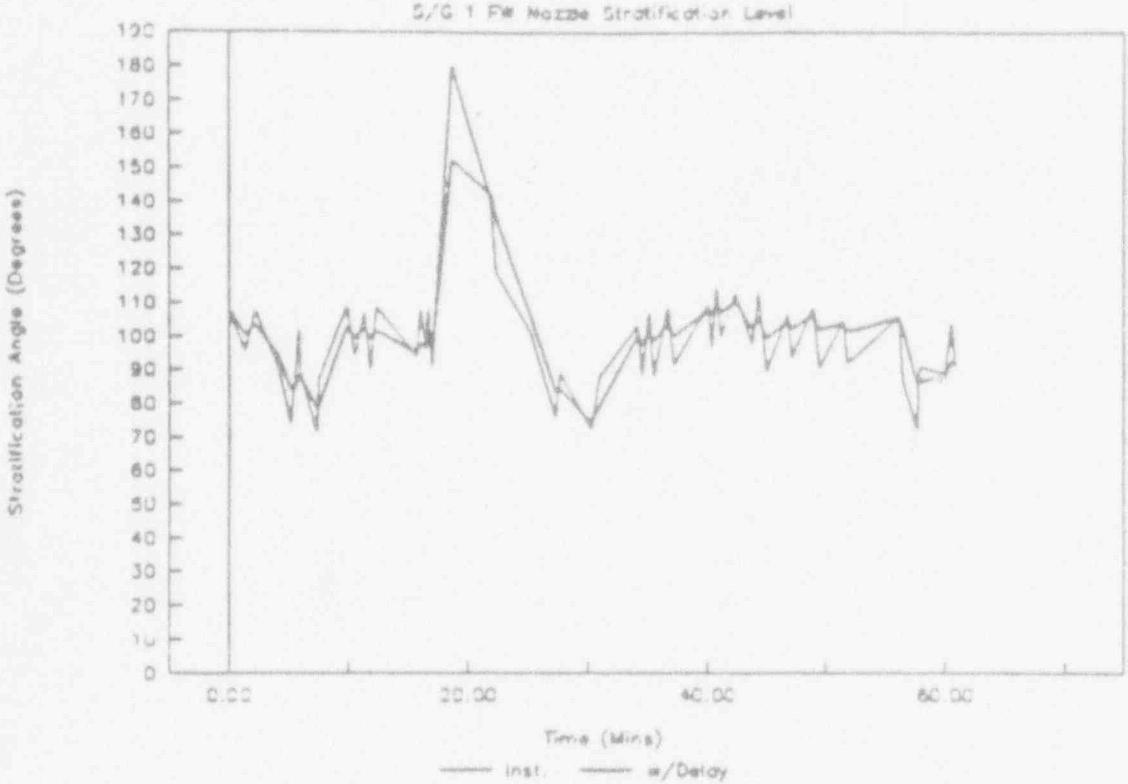
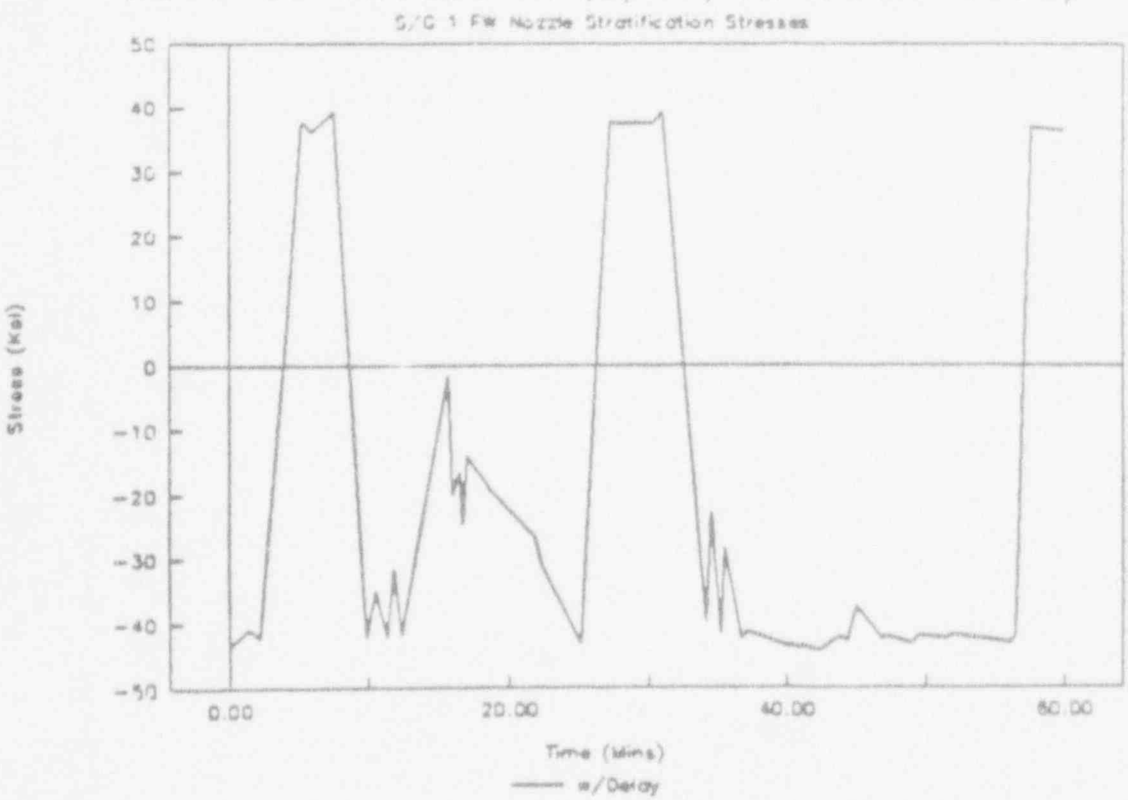
DIABLO CANYON U1 COOLDN (9/13/92-0100)

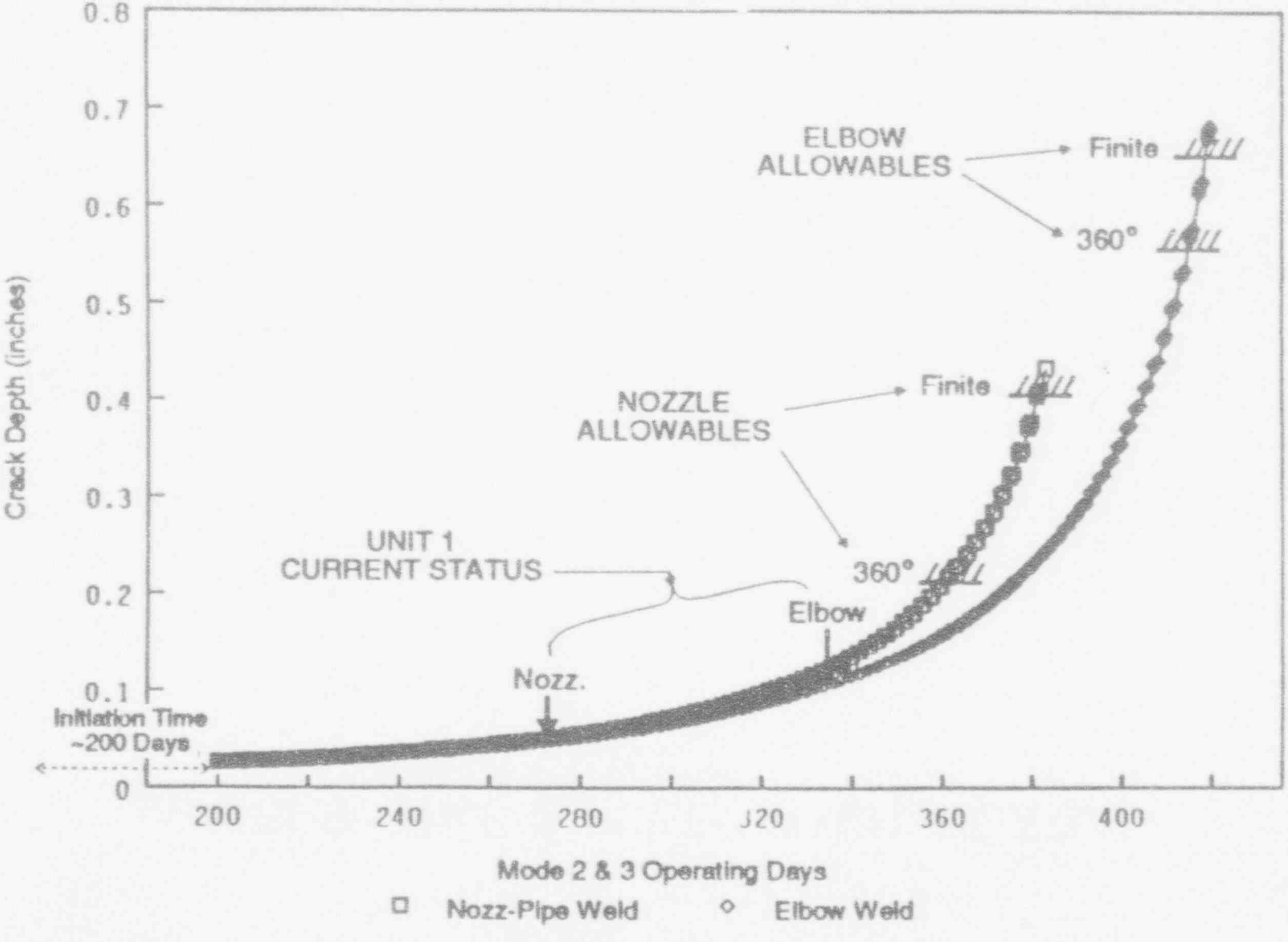


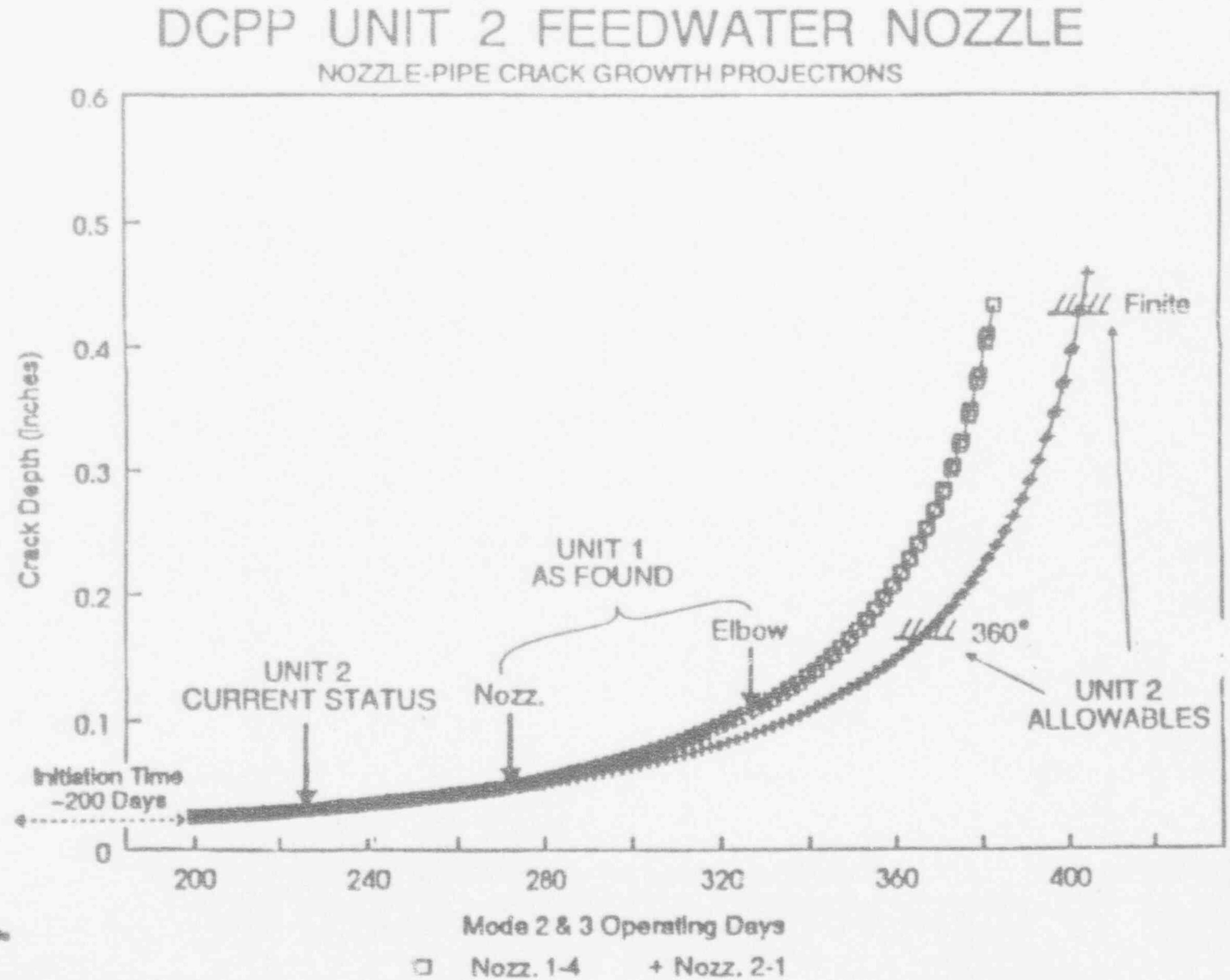
DCPP U1 COOLDOWN (9/13/92-0000-0100)



DCPP UNIT 1 FEEDWATER NOZZLE

NOZZLE-PIPE CRACK GROWTH PROJECTIONS




DCPP UNIT 2 FEEDWATER NOZZLE
NOZZLE-PIPE CRACK GROWTH PROJECTIONS
Crack Depth (Inches)
0.6
0.5
0.4
0.3
0.2
0.1
0
200
240
280
320
360
400
Mode 2 & 3 Operating Days
Nozz. 1-4
+ Nozz. 2-1
Initiation Time
~200 Days
UNIT 2
CURRENT STATUS
UNIT 1
AS FOUND
Nozz.
Elbow
Finite
360°
UNIT 2
ALLOWABLES

NOZZLE/PIPE CRACKING CONCLUSIONS

- Observed Cracking in Unit 1:
  - Significantly Below Code Allowables
  - Consistent with Industry Experience (IEB-79-13)
  - Consistent with DCPP AFW Flow/Stratification Cycles
  - Would Not Have Grown to Unacceptable Depth for Several Subsequent Fuel Cycles
- Potential for Unit 2 Cracking Evaluated and Not a Concern
  - 100 Days Less AFW Days (240 vs 340)
  - › 150 Days Additional AFW Days Before Postulated Cracking Would Reach Code Allowable
  - ˜ 5 Additional AFW Days Expected Until 2R5 (Spring, 1993)
- AFW Cyclii g Will Be Accurately Monitored During Future Operation
  - Local Thermocouples (Unit 1)
  - On-Line Fatigue Monitoring (Both Units)

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FILM COEFFICIENT

- No Gap, $h \approx 100$ B/hr. ft.^{2} °F
- Large Gap, $h \approx 900$ B/hr. ft.^{2} °F

PG&E

WH87

FATIGUE ANALYSIS

- All Design and Operating Transients were Considered
- Total Transient Cases About 30, Including a Complete Set of Feedwater Line Stratification Transients, at Various Interface Levels and Temperature Differences
- Two Cases: No Bypass, and Large Bypass
- Two Locations: Bore Region
Nozzle Knuckle Face Region
- All Other Locations Under the Thermal Sleeve were Less Limiting

PG&E

WH88

FATIGUE RESULTS

- Results: Nozzle Bore for 9700 hrs @ Mode 2/3

No Bypass:	U=0.17
Significant Bypass:	U=0.20

- Results: Nozzle Knuckle Face 9700 hrs @ Mode 2/3

No Bypass:	U=0.08
Significant Bypass:	U=0.22

- The Fact that Cracks Did Initiate in these Regions at One Plant Indicates a Significant Environmental Effect was Present
- Water Chemistry Control at Diablo Canyon Makes Environmental Influences Here Much Less Likely. Therefore the Fatigue Usage Results are Considered Directly Applicable

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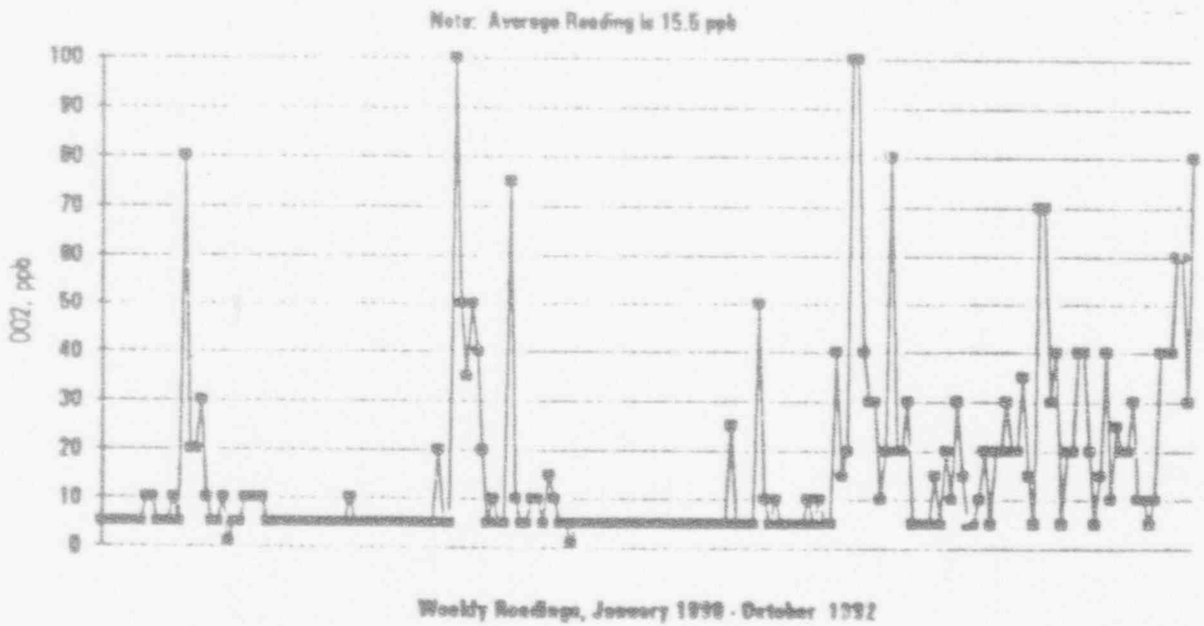
DISSOLVED OXYGEN: UNIT 1 CONDENSATE STORAGE TANK



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WHB10

STRATIFICATION PROFILES

Distribution by Profile Type

Plant	% Cycles in Profile #1	#3	#6	#5	#2
D.C. Cook	11.5	6.4	23.8	24.7	33.6
Salem	14.6	1.9	35.7	12.1	35.7
Ginna	22.4	20.9	14.9	28.4	13.1
Robinson	0.0	8.7	19.6	17.4	54.3

Interfa.e Level

Profile	Percent of Pipe Diameter
1	>85
3	76 to 85
6	56 to 75
5	46 to 55
2	< 45

Distribution by Temperature Difference

Plant	Duration (Hours)	% Cycles by ΔT, °F >350	>250	>150	<150
D.C. Cook	11143	74.1	13.2	9.2	3.0
Salem	5587	2.8	35.1	28.1	34.1
	5923	40.1	31.4	13.6	15.0
Ginna	3604	31.3	25.8	42.0	0.9
	3737	26.6	27.8	41.6	4.0
Robinson	4374	54.5	39.7	5.1	0.7
	2672	34.3	62.5	3.2	0.0

PLANT FATIGUE COMPARISONS

Hours at Hot Standby

Plant	S/G Model	Configuration	Hours	Cycle Mix
Ginna	44	Elbow	5038	Ginna
Salem	51	Elbow	8203	Salem
Indian Point 2	44	Straight Pipe	9764	Ginna
Diablo Canyon	51	Elbow	8160	Ginna/Salem

Fatigue Usage

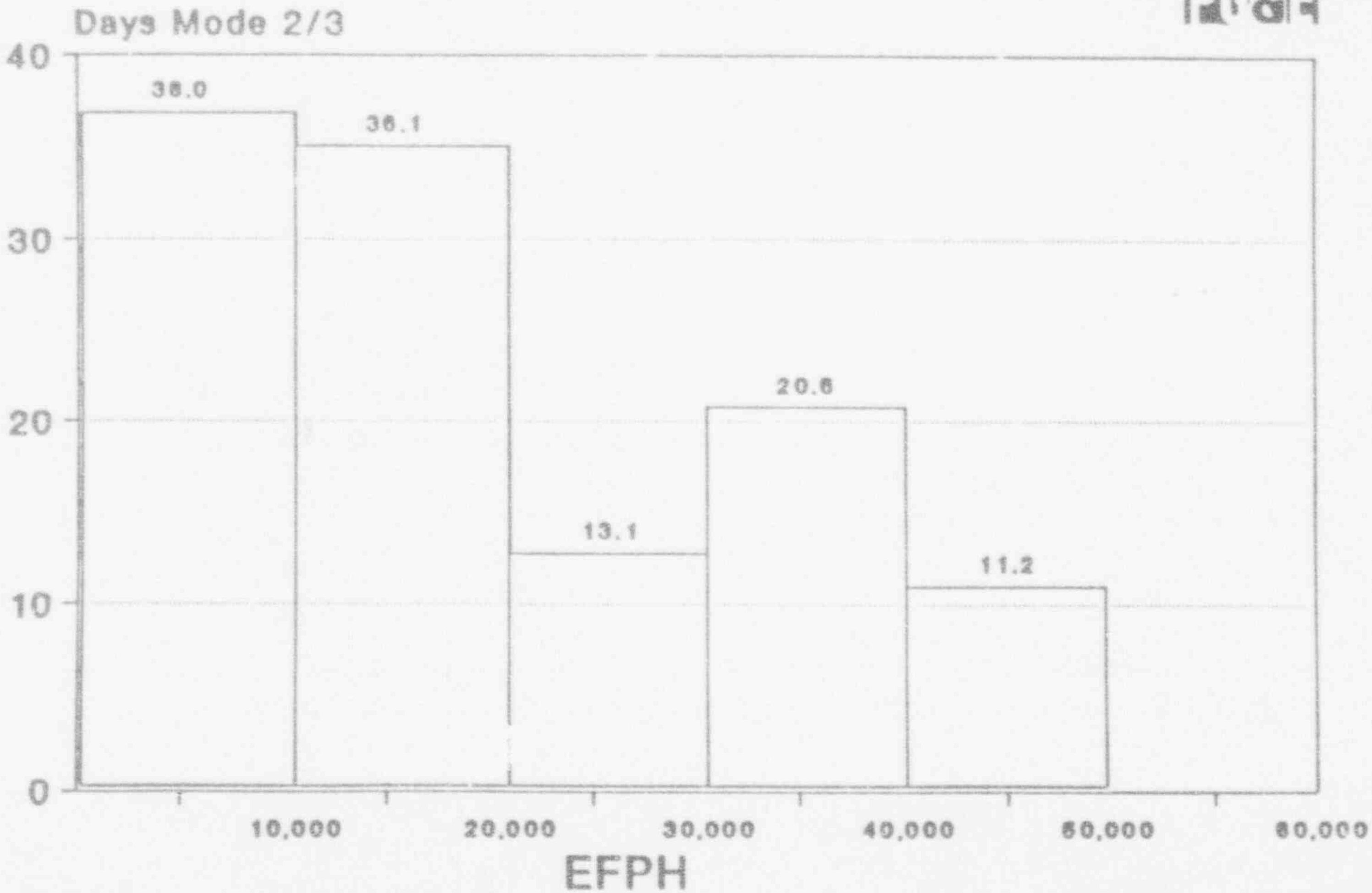
			Fatigue Usage[1]	
Plant	Location	Cycle Mix	Minimum	Maximum
Ginna	0° ER	Ginna	7.2	32.5
	67.5° ER		2.5	11.0
Salem	0° ER	Salem	2.1	9.3
	97.5 ER		0.9	4.7
Indian Point 2 Straight Pipe	0° PR	Ginna	0.04	0.17
	90° PR		0.01	0.03
	Knuckle		0.10	0.47
Diablo Canyon	0° ER	Salem	2.09	9.25
	97.5° ER		0.90	4.68
	Knuckle	Ginna	0.09	0.39
		Salem	0.02	0.07

(1) Excludes thermal striping effects

DESTRUCTIVE EXAMINATION MAXIMUM CRACK DEPTHS (INCH)

Plant	Crack Location		Pipe Config
	Counterbore	Knuckle	
Ginna	0.11	——	Elbow
Salem	0.12	——	Elbow
Indian Point 2	0.34	0.40	Straight
Diablo Canyon	0.05 0.34 (UT)	Not Expected	Elbow

HISTORY OF MODE 2/MODE 3 OPERATION
DCPP UNIT 1



FATIGUE CRACK GROWTH

- All Design and Operating Transients Considered
- Total Transient Cases About 30 - Same as Fatigue Analysis
- One Load Case: Large Bypass
- Two Locations: Bore Region
  Nozzle Knuckle Face Region
- Two Fracture Analysis Approaches:
  - Raju Newman K Expression
  - BWR Nozzle Corner K Expression (Most Realistic Geometry)

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WHB12

CRACK GROWTH RESULTS

- Results: Nozzle Bore

Initial Flaw Depth	Flaw Depth in 4 Calendar Years: Raju Newman	Flaw Depth in 4 Calendar Years: Nozzle Knuckle
0.10	0.24	0.16
0.20	0.48	0.32

- Results: Nozzle Knuckle Face

Initial Flaw Depth	Raju Newman	Nozzle Knuckle
0.10	0.23	0.16
0.20	0.46	0.32

Note: 4 Years Corresponds to Approximately 100 Days at Mode 2/Mode 3

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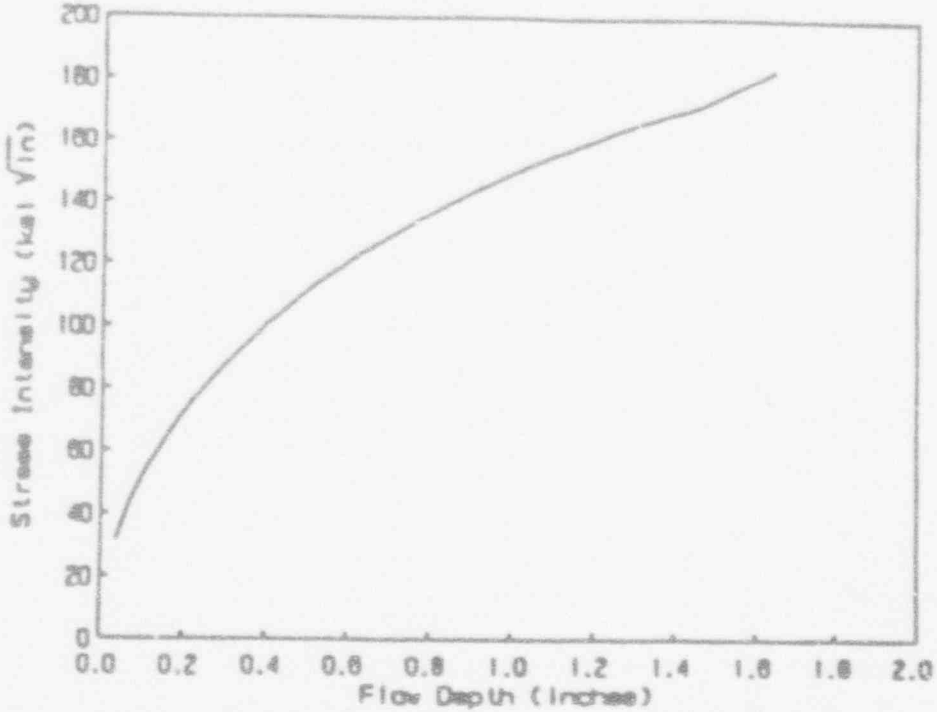
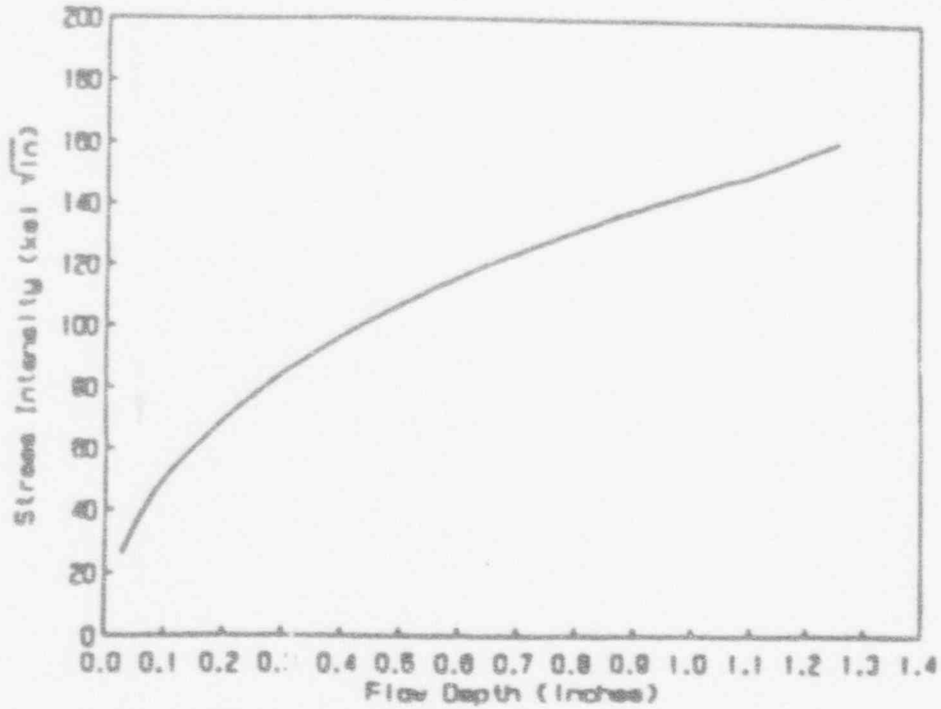
WHB19

ALLOWABLE FLAW SIZE: FEEDWATER NOZZLE BORE



ALLOWABLE FLAW SIZE: FEEDWATER NOZZLE FACE



WHB18

CONCLUSIONS

- Cracks in the Knuckle Region are not Predicted for Diablo Canyon
  - Fatigue Usage is Low
  - Severity of Thermal Stratification Loads is Much Less Than at the Plant Where Cracking Was Found
  - A Recent UT Inspection of One Nozzle Revealed no Cracking (2-15-91)
- Although Cracking is not Predicted, if Worst Case Cracks were to Exist in the Nozzle Region, the Predicted Size Would be Acceptable to Section XI
- Predicted Future Growth of Worst Case Cracks Was Found to be Relatively Small for a Future Service Period of 4 Years or 100 Days in Mode 2/Mode 3
- Therefore the Integrity of the Feedwater Nozzle Will be Maintained Through the Next Several Years of Service

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DIABLO CANYON POWER PLANT

Waterhammer

Mike Roidt
Westinghouse

WHAM1

WATERHAMMER

There are Two Ways of Developing Steam Void Collapse in the Horizontal Section of a Feedline

- Isolation of a Steam Volume While Filling the Feedline with "Cold" Water

- Isolation of a Steam Volume While Draining a Feedline Filled with Cold Water

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WHAM

(2)

Dwg. 7711A85

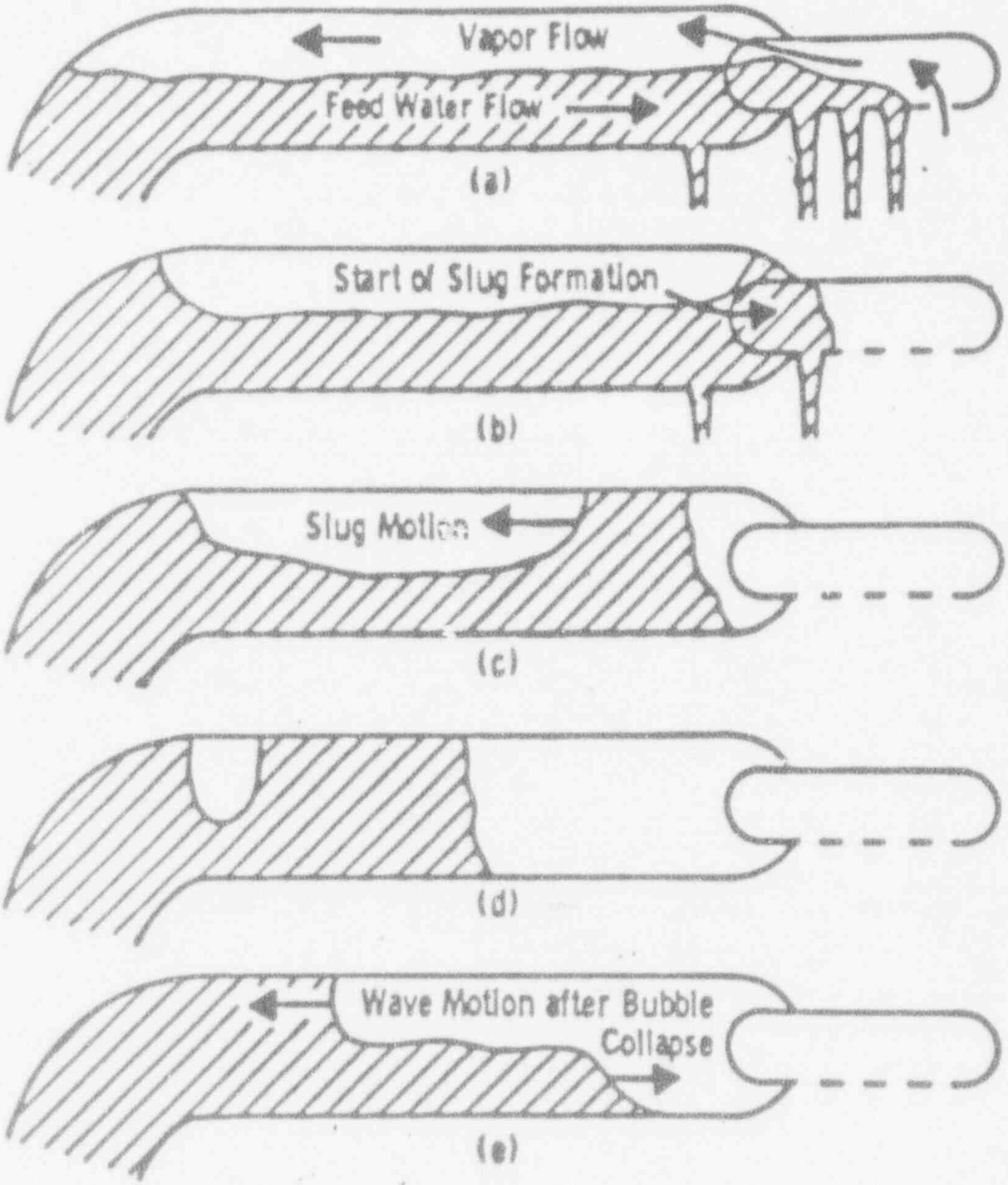
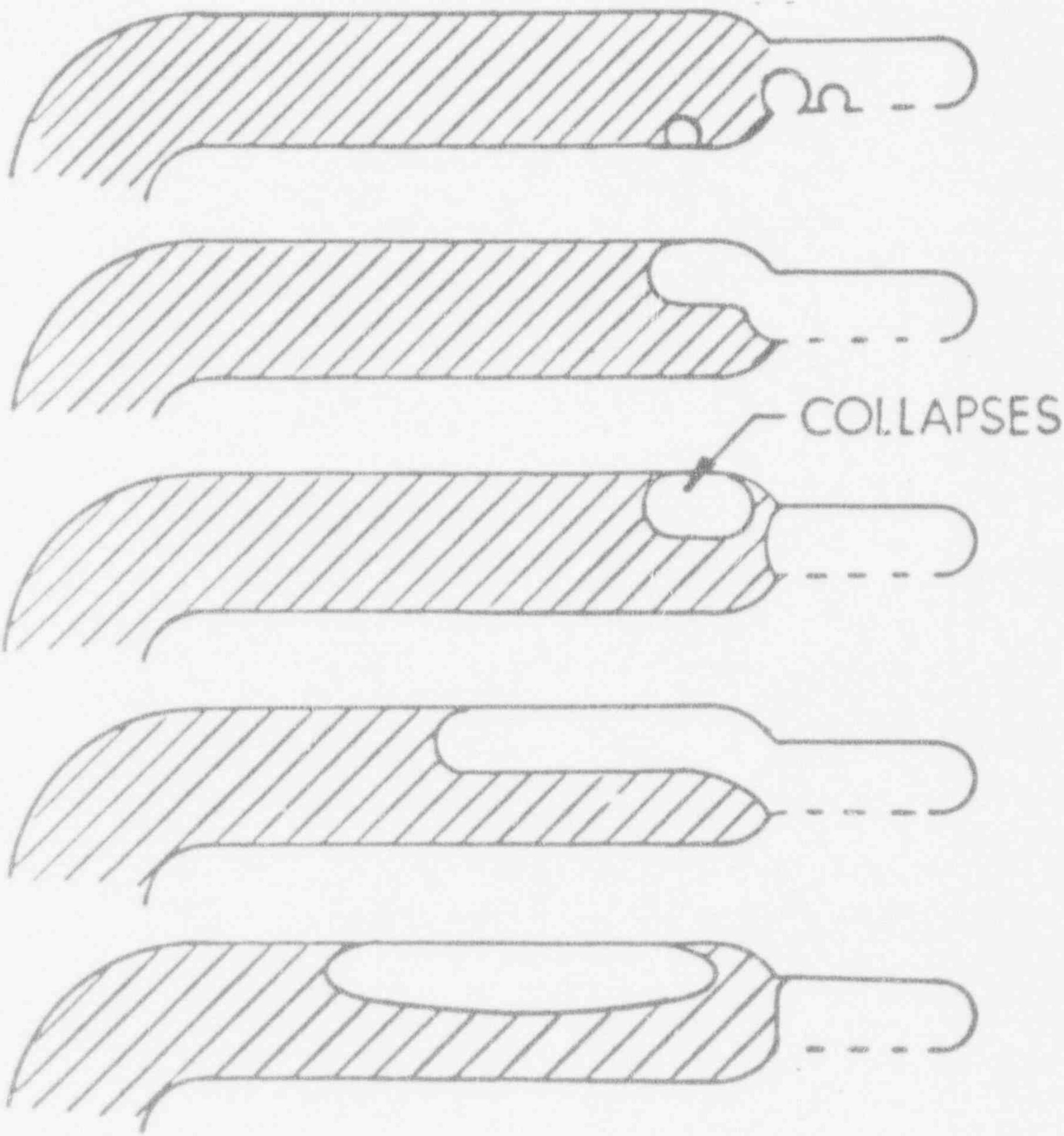
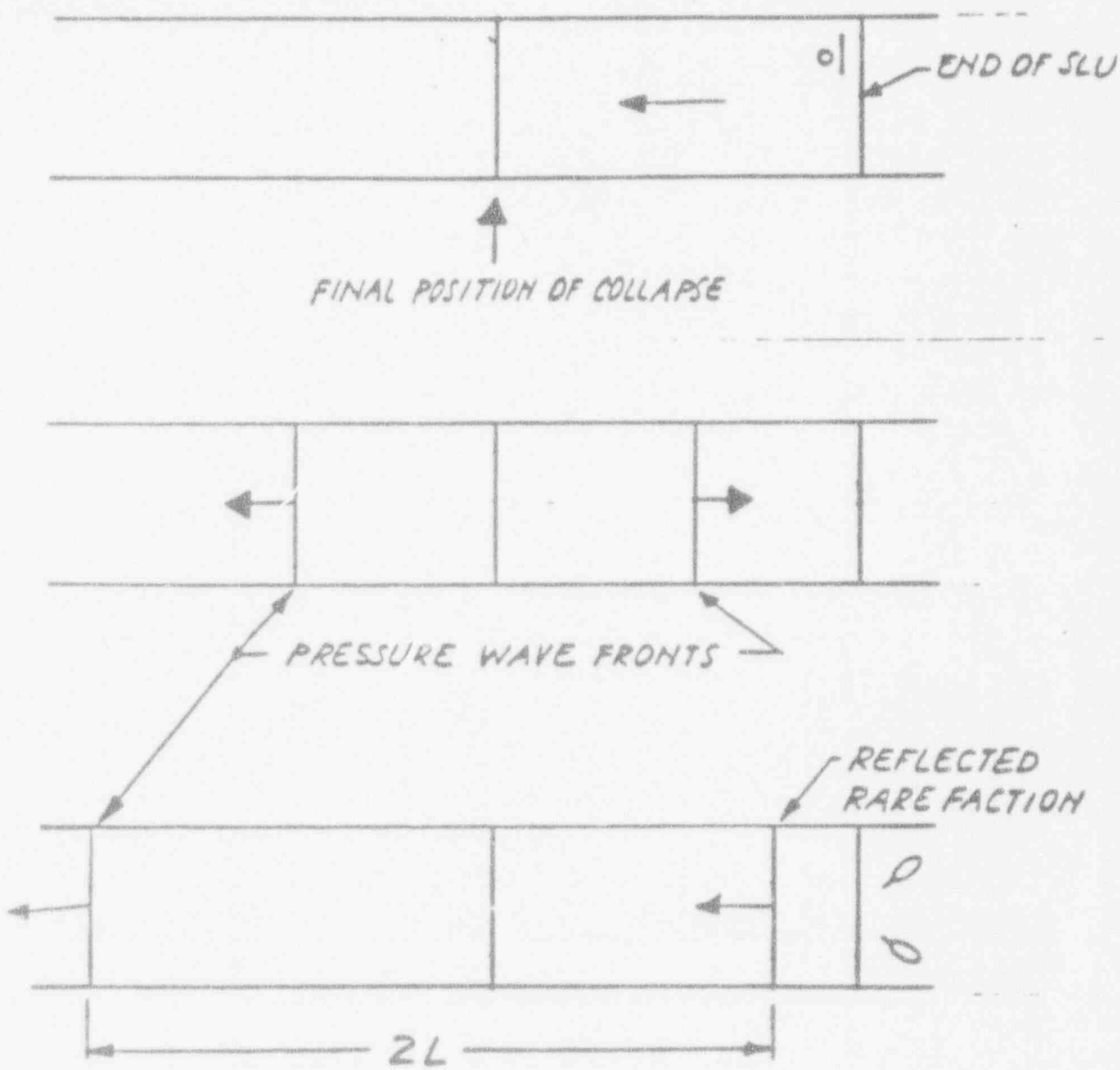


Fig. 9– Schematic representation of slugging mechanism



DRAINING A FEEDLINE FILLED WITH COLD WATER.

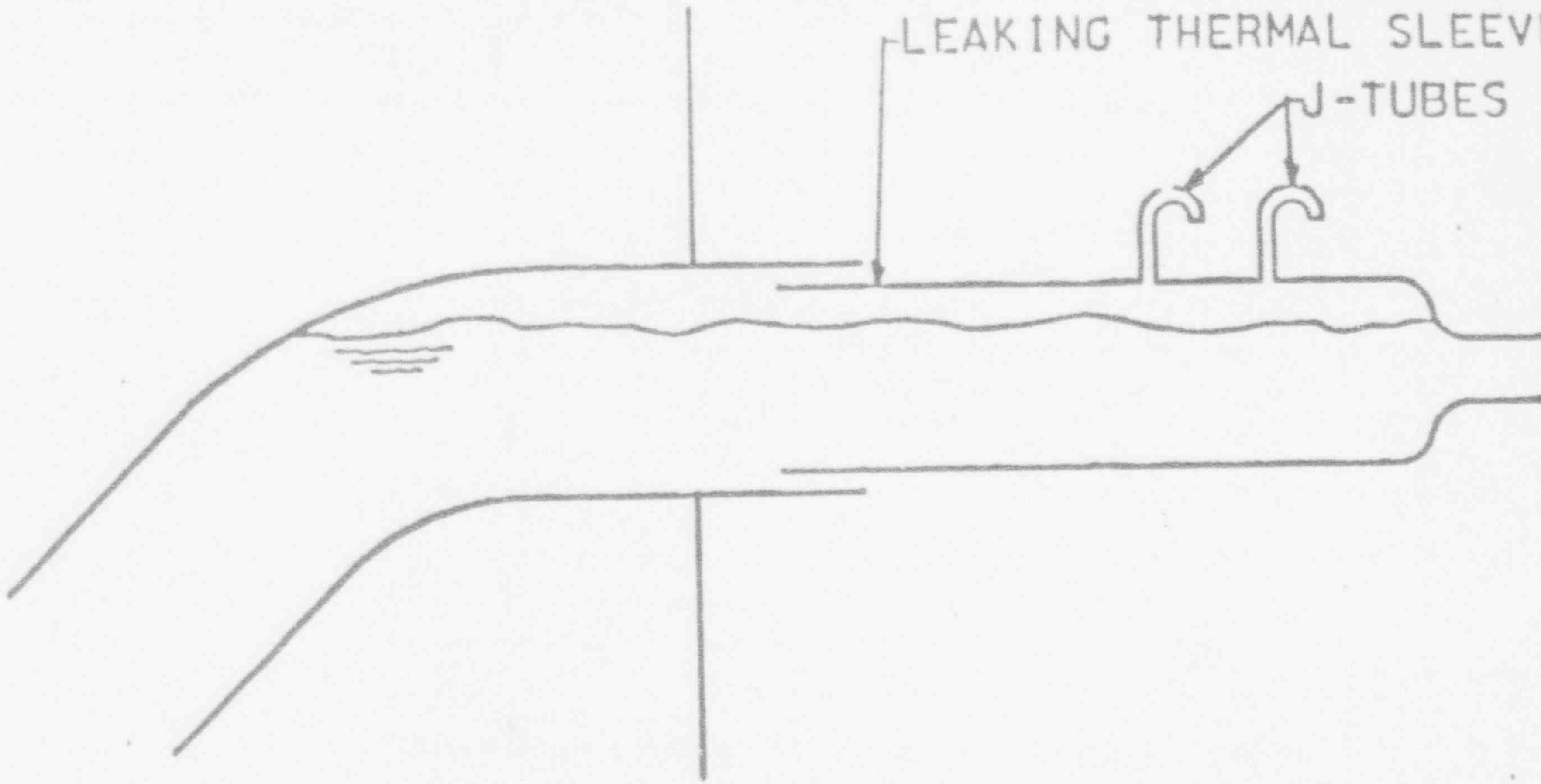
PHYSICS (APPROXIMATE) OF THE WATERHAMMER WAVE:



- Both Filling and Draining Configurations Require the Ability of the System to Isolate an Upper Section of Piping From the Steam Supply, the S/G

- The Configuration at Diablo Canyon Does Not Lend Itself to Such Isolation

WHAM2



DIABLO CANYON LAYOUT

WATERHAMMER EVENTS CONSIDERED AT DIABLO CANYON

- Waterhammer will Not Occur During Draining, Because, by Design the J Tubes and Thermal Sleeve Allow Steam to Replace the Water as the Feedline Drains
- Waterhammer is also Unlikely During Filling, Because of the J Tubes, but Cannot be Ruled Out, Because of the Possibility of Wave Action
- Therefore, the Cases of Waterhammer During Filling were Considered:
  - A Steam Volume Occupying 10% of the Pipe Cross-Section Extending from the Thermal Sleeve to the Elbows
  - A Steam Volume Occupying 10% of the Pipe Cross-Section Extending from the J Tube Nearest the Elbow to the Elbow

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WHAMS

L = Initial Length of the Isolated Steam Volume

C = Acoustic Speed in Water

ΔP = S/G Pressure - Feedwater Vapor Pressure

ρ = Water Density

G = Gravitational Constant

A = Pipe Cross-Section Area

f = Fraction of Pipe Cross-Section Occupied by Steam Volume

Length of Pressure Wave = 2L

Duration of Pressure Wave = $\frac{2L}{C}$

Increase in Pressure Across Wave = $C\sqrt{\frac{\rho \Delta P}{2g}}$

Kinetic Energy in Wave = K.E. = $fL\Delta PA$

whem9

Assume:

L - 4.5 ft, 2.25 ft

C - 4500 ft/sec

ΔP - 1000 - 345 = 655 psi

ρ - 52.3 lb/ft^3

g - 32.17 ft/sec^2

f - .1

A - 154in^2 $\qquad$ 2

Length of Pressure Wave 9 ft

Duration of Wave - .002 seconds

Pressure Rise Across Wave -8,650 psi

Kinetic Energy in Wave - 45,000 ft-lb (L=4.5ft)

22,500 ft-lb (L=2.25ft)

WHAM4

CONCLUSION

- A Steam Volume Collapse Waterhammer is Extremely Unlikely at Diablo Canyon, Because of the Geometry

- Plant Inspections indicate no Evidence of Waterhammer to Date

- In the Unlikely Event of an Occurrence, there Would be Insufficient Energy to Seriously Affect the Piping System

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WHAM7

DCPP EXPERIENCE

- No Reports or Evidence of MFW Waterhammer
- No Evidence of FW System Support Damage
  - Walkdowns
  - Snubber Stroking

CONCLUSIONS

- DCPP Design of the Feedring is to Preclude and Minimize Effects of Waterhammer
- Eroded Thermal Sleeve May Increase the Probability of a Waterhammer, but Also Acts to Decrease its Severity
- Improbable Event
- Waterhammer Effects are not Expected to Affect the Integrity of the DCPP Feedwater Line
  - Experience of a Hammer at Trojan, with an Eroded Sleeve, and Crack About 40% Through the Wall Did Not Affect the Pipe integrity.
  - Over Twenty Waterhammers at Other Plants Have Been Experienced in Feedwater Lines, with Only One Failure. Calculated Kinetic Energy For This Case Was More than an Order of Magnitude Higher than for DCPP.

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DIABLO CANYON POWER PLANT

Long Term Plans

Henry Thailer
Assistant Project Engineer

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PLANT MONITORING

- Install RTD Instrumentation
- Install Scratch Gages
- Software/Hardware
- On-Line Monitoring
- Data Evaluation
- Review Correlation Between Algorithm & Operating Data

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INSPECTION PLAN

- Factor in Lessons Learned from 1R5
- UT Every Outage Until Permanent Fix is Installed
- Baseline Permanent Fix After Installation

RELATED CORRESPONDENCE

MFP exhibit 1

50-275/323-OLA-2
I-MFP-1
"NOT ADMITTED"

191811

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WASHINGTON, D.C. 20555

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June 18, 1992

Mr. Greg M. Rueger
Senior Vice President & General Manager
Nuclear Power Generation Unit
Pacific Gas & Electric Co.
77 Beale St.
San Francisco, CA 94106

Dear Mr. Rueger:

The Nuclear Regulatory Commission's Performance Indicator Program provides eight performance indicators for use by NRC senior managers to monitor trends in the overall performance of individual nuclear power plants. These indicators provide an additional view of operational performance to supplement that obtained through other NRC programs. The purpose of this letter is to transmit to you the NRC performance indicators for the Diablo Canyon Nuclear Power Plant, Units 1 and 2 for the first quarter of 1992. I have also provided supplementary information extracted from the latest quarterly Performance Indicator Report, including the Executive Summary and the Overall Industry Summary table.

If I can be of any further assistance, you may contact me at (301) 492-4431.

Sincerely,

D E Hickman

Donald E. Hickman, Chief
Performance Indicator Section
Office for Analysis and Evaluation
of Operational Data
U.S. Nuclear Regulatory Commission

cc: w/enclosure
Senior Resident Inspector(s)

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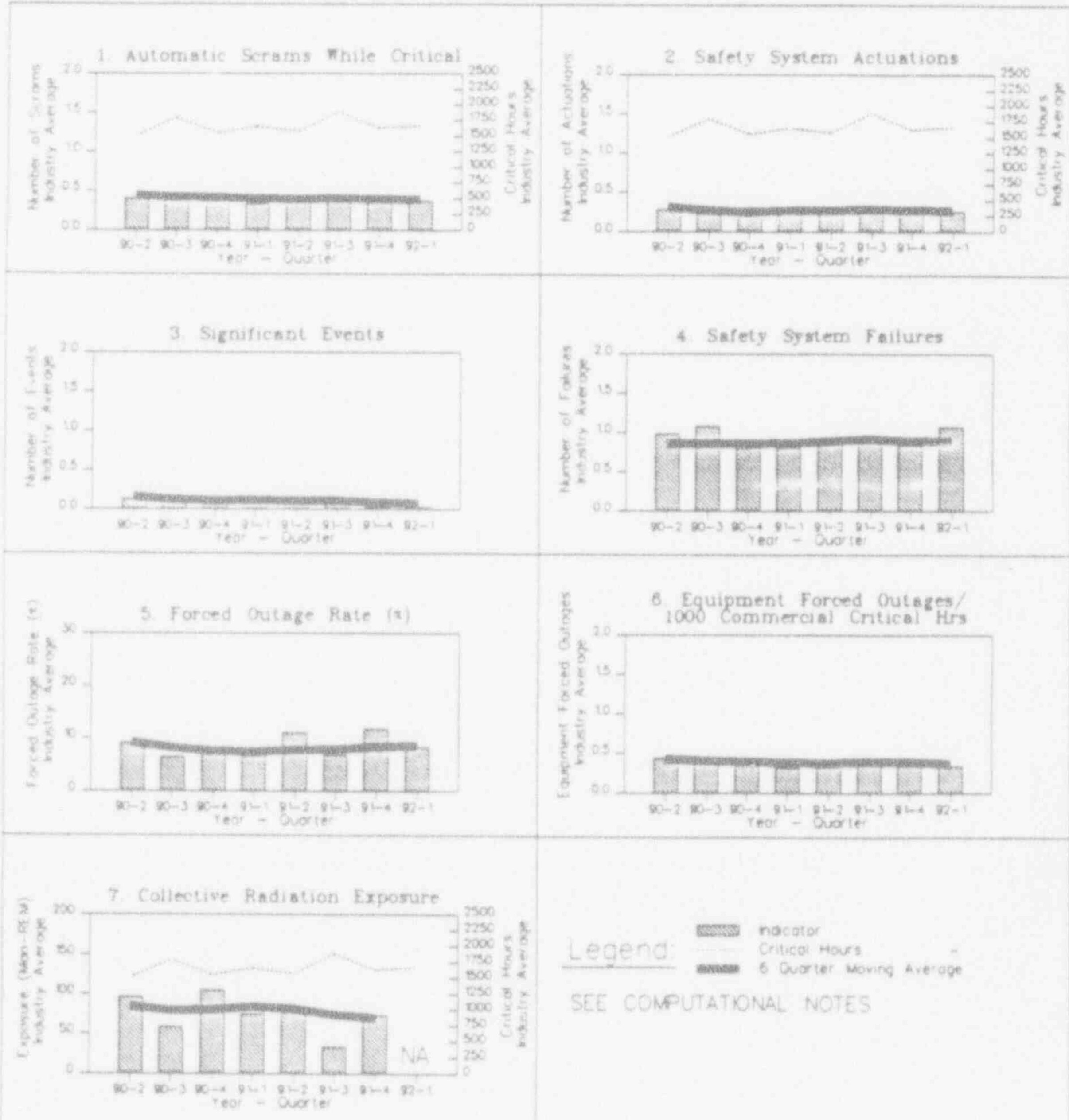
EXECUTIVE SUMMARY

This report presents the eight (8) NRC Performance Indicators (PIs) for the first calendar quarter of 1992. These eight indicators are: (1) automatic scrams while critical, (2) safety system actuations, (3) significant events, (4) safety system failures, (5) forced outage rate, (6) equipment forced outages per 1000 commercial critical hours, (7) collective radiation exposure, and (8) cause codes. Data are included for the calendar quarters 90-2 through 92-1 for 111 commercial U.S. nuclear power plants. Figure 1 shows the quarterly industry average trends over this period for all of the PIs except the cause codes, for which an average trend is not computed. Because of reporting techniques, the data for the collective radiation exposure lag the other PIs by one quarter.

FIGURE 1
QUARTERLY INDUSTRY PERFORMANCE INDICATOR AVERAGE TRENDS



UNITED STATES
NUCLEAR REGULATORY COMMISSION

ANNOUNCEMENT NO. 200

DATE: November 28, 1989

TO: All NRC EMPLOYEES

SUBJECT: REVISED GUIDANCE ON THE USE OF PERFORMANCE INDICATORS

This announcement revises the earlier guidance of NRC Announcement 30, dated February 5, 1988, regarding the use of the results of the NRC Performance Indicator Program. All NRC employees shall adhere to the following guidance.

The Performance Indicator Program provides an additional view of operational performance and enhances our ability to recognize areas of poor and/or declining safety performance of operating plants. However, it is only a tool and is to be used in conjunction with other tools, such as the results of routine and special inspections and the systematic assessment of licensee performance (SALP) program, for providing input to NRC management decisions regarding the need to adjust plant-specific regulatory programs.

It should be recognized that performance indicators have limitations and are subject to misinterpretation. Therefore, caution is warranted in the interpretation and use of the data. The application of performance indicators for purposes and in manners other than those stated above will be counter to the NRC objective of ensuring operational safety. To avoid such situations, the following specific directives are provided:

1. The Performance Indicator Program for operating reactors is a single, coordinated, overall NRC program under the direction of AEOD. NRC offices other than AEOD should not deviate from the NRC program without written permission of the EDO or the Director, AEOD.

191811

ANALYSIS OF THE PERFORMANCE INDICATOR DATA THROUGH MARCH 1992

1. INTRODUCTION

This U.S. Nuclear Regulatory Commission (NRC) report presents performance indicator data through March 1992, for 111 reactors. There are eight indicators in the NRC Performance Indicator Program for Operating Commercial Nuclear Power Plants: (1) automatic scrams while critical, (2) safety system actuations, (3) significant events, (4) safety system failures, (5) forced outage rate, (6) equipment forced outages per 1000 commercial critical hours, (7) collective radiation exposure, and (8) cause codes.

This first quarter 1992 report is based on performance indicator data that are extracted from Licensee Event Reports (LER) submitted in accordance with 10 CFR 50.73, immediate notifications to the NRC Operations Center in accordance with 10 CFR 50.72, monthly operating reports in accordance with plant technical specifications, and screening of operating experience by NRC staff. Radiation exposure data are obtained from the Institute of Nuclear Power Operations (INPO). Graphical presentations of each plant's data, including trends and deviations analyses, are provided in Part I of this report; Part II provides tabulated summaries of the data.

2. BACKGROUND

Since May 1986, an interoffice task group has been working to develop an overall NRC program for using quantitative indicators of nuclear power plant safety performance. In July and August of 1986, the group conducted a trial program for 50 plants with 17 prospective performance indicators. For the most part, this trial program used data through calendar year 1984. The group then selected eight performance indicators to be recommended as the best set for initial implementation. One of these, corrective maintenance backlog, was deleted by the staff following consideration of industry comments.

In October 1986, a prototype report was prepared by expanding the trial program data to 100 operating reactors and including the data through the first half of 1986. The staff's recommended program, the task group report, and the prototype report were documented in SECY-86-317, "Performance Indicators", dated October 28, 1986. The Commission was briefed on the staff's recommended program in November 1986, and approved the implementation of the program in December 1986, instructing the staff to delete the enforcement action index from the set of indicators. In February 1987, the first quarterly PI report was issued and provided to senior management. This report covered the calendar quarters 85-1 through 86-4. In May 1987, an annual collective radiation exposure indicator was incorporated into the first quarter 1987 report. This was later revised to a quarterly collective radiation exposure indicator and incorporated into the first quarter 1989 report. In 1989, as documented in SECY-89-046 and SECY-89-211, the staff proposed that a new performance indicator based on cause codes be added to the program. Through Staff Requirements Memoranda (SRM) dated March 15, 1989, and August 10, 1989, the Commission approved cause codes as a new singular performance indicator. The new cause code indicator was subsequently incorporated by the staff into the program beginning with the second quarter 1989 report.

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3. DEFINITIONS OF THE PERFORMANCE INDICATORS

The performance indicator data presented in this report are categorized according to specific definitions. The definitions of the eight indicators currently in the program are provided below.

3.1 Automatic Scrams While Critical (Scrams)

This indicator monitors the number of unplanned automatic scrams that occurred while the affected reactor was critical. Examples of the types of scrams included in this indicator are those that resulted from unplanned transients, equipment failures, spurious signals, or human error. Also included are those that occurred during the execution of procedures in which there was a high chance of a scram occurring, but the occurrence of a scram was not planned. Scram data are primarily derived from 10 CFR 50.73 Licensee Event Report (LER) information and supplemented as necessary from 10 CFR 50.72 Immediate Notification reports. The reactor was "critical" if the report so states. Otherwise, criticality is determined from a detailed review of the other operational information. This indicator is similar to the unplanned automatic scrams per 7000 critical hours indicator of INPO.

In addition to the data for this indicator, scrams above 15% power per 1000 critical hours and scrams from 15% power or below are provided in Part II, Tables 8.3 and 8.4 respectively, as supplemental inform on.

3.2 Safety System Actuations (SSA)

Safety system actuations are manual or automatic actuations of the logic or equipment of either certain Emergency Core Cooling Systems (ECCS) or, in response to an actual low voltage on a vital bus, the Emergency AC Power System. Input for this indicator are derived from LERs and supplemented by 50.72 reports. In determining which events should be counted by this indicator, the following conventions are used:

1. Only actuations of the High Pressure Injection System, Low Pressure Injection System, or Safety Injection Tanks are counted for pressurized water reactors (PWRs). For boiling water reactors (BWRs), only actuations of the High Pressure Coolant Injection System, Low Pressure Coolant Injection System, High Pressure Core Spray System, or Low Pressure Core Spray System are counted. Actuations of the Reactor Core Isolation Cooling System are not counted.

2. Actuations of Emergency AC Power Systems are counted only if they were in response to an actual low voltage condition on a vital bus.

3. Logic actuations of any of the equipment associated with the specific ECCS or Emergency AC Power System are considered necessary and sufficient to constitute a data count. For example, if only a valve in a system is commanded to move to its emergency operational position, this is counted as an actuation. A pump does not have to be commanded to go to its emergency mode of operation and fluid does not need to be injected for an occurrence to be counted.

4. Only one ECCS actuation is counted in any one occurrence, even if multiple ECCS systems actuate during the occurrence. For example, actuation of both the High Pressure Injection and the Low Pressure Injection Systems at a PWR during the same occurrence counts as only a single ECCS actuation.

5. Only one emergency diesel generator (EDG) actuation is counted in any occurrence, even if multiple EDGs actuate during the occurrence. For example, actuation of all four EDGs at a unit counts as only a single actuation for that occurrence.

6. Occurrences involving actuations of both an EDG on a dead bus and an ECCS are given a count of two, one for the EDG actuation and one for the ECCS actuation.

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7. At multi-unit sites that share equipment (e.g., a swing EDG or shared buses), actuations are counted and assigned to the unit at which the actuation signal or loss of power originated. If the signal source cannot be associated with one unit, the actuation is assigned to both units.

3.3 Significant Events (SE)

Significant events are those events identified by NRC staff through detailed screening and evaluation of operating experience. The screening process includes the daily review and discussion of all reported operating reactor events, as well as other operational data such as special tests or construction activities. An event identified from the screening process as a significant event candidate is further evaluated to determine if any actual or potential threat to the health and safety of the public was involved. Specific examples of the type of criteria are summarized as follows:

1. Degradation of important safety equipment. Events considered under this category include situations that had the potential to reduce or actually reduced the operational capability of equipment. One example is the identification of a common cause failure mechanism, which could cause redundant components or multiple independent components to fail in response to a test or actual demand signal. This category does not include such items as a missed surveillance test, if the equipment was subsequently tested and determined to be operable.

2. Unexpected plant response to a transient. Events considered under this category include situations in which changes in reactor parameters represent unanticipated reductions in margins of safety. For example, a rapid plant cooldown following a reactor trip exacerbated by a balance-of-plant malfunction or an undesirable system interaction. This category does not include minor differences in predicted and observed conditions that can be reasonably explained by instrument errors or modeling techniques and simplifying assumptions.

3. Degradation of fuel integrity, primary coolant pressure boundary,important associated structures. Events considered under this category include those of similar character to those identified in item 1 above, related to nuclear fuel, reactor coolant system containment, or important plant structures.

4. Scram with complication. Events considered under this category are scrams that occurred while the affected reactor was critical, followed by an equipment failure, malfunction, or personnel error. The failure, malfunction, or error generally does not include those that lead to or directly caused the scram. Failures that both cause the scram and reduce the capability of the mitigating system (e.g., electric power, instrument air, other auxiliary support functions, or deficient procedures) are counted.

   Examples of equipment failure/malfunctions include:

   - Mitigating system failures - Loss of redundancy due to single failures, reduced capacity, or margin. This includes components or trains out of service for maintenance.
   - Failure adding to complexity of event - Erroneous control system responses, electrical switching difficulties, mitigating system and key plant parameter instrumentation malfunctions/failures.
   - Additional event initiators - Stuck-open primary or secondary relief/safety valves, pipe breaks, and operating wrong equipment/trains.

   Examples of personnel errors include:

   - Improper control or termination of mitigating system.
   - Misdiagnosis of the event or failure to follow procedures.

In addition to the situations described in items 1 through 4 above, other broad categories considered for significant events include:

5. Unplanned release of radioactivity. Events considered under this category include unplanned releases of radioactivity that had the potential to exceed or actually exceeded the limits of the Technical Specifications or Regulations.

6. Operation outside the limits of the Technical Specifications. Events considered under this category include occurrences when plant operation was conducted inconsistent with the license requirements. This category applies to risk significant deviations and most likely does not include incidents involving missed surveillances, small errors in setpoints, or other administratively inoperable conditions.

7. Other. Events considered under this category include a series of events or recurring incidents that alone are not significant but when considered collectively represent ineffective corrective actions, or a deficiency in the plant hardware or administrative programs.

3.4 Safety System Failures (SSF)

Safety system failures are any events or conditions that could prevent the fulfillment of the safety function of structures or systems. If a system consists of multiple redundant subsystems or trains, failure of all trains constitutes a safety system failure. Failure of one of two or more trains is not counted as a safety system failure. The definition for the indicator parallels NRC reporting requirements in 10 CFR 50.72 and 10 CFR 50.73. The following is a list of the major safety systems, subsystems, and components monitored for this indicator:

Accident Monitoring Instrumentation
Auxiliary (and Emergency) Feedwater System
Combustible Gas Control
Component Cooling Water System
Containment and Containment Isolation
Containment Coolant Systems
Control Room Emergency Ventilation System
Emergency Core Cooling Systems
Engineered Safety Features Instrumentation
Essential Compressed Air Systems
Essential or Emergency Service Water
Fire Detection and Suppression Systems
Isolation Condenser
Low Temperature Overpressure Protection
Main Steam Line Isolation Valves
Onsite Emergency AC & DC Power w/Distribution
Radiation Monitoring Instrumentation
Reactor Coolant System
Reactor Core Isolation Cooling System
Reactor Trip System and Instrumentation
Recirculation Pump Trip Actuation Instrumentation
Residual Heat Removal Systems
Safety Valves
Spent Fuel Systems
Standby Liquid Control System
Ultimate Heat Sink

3.5 Forced Outage Rate (FOR)

Forced outages are those required to be initiated no later than the end of the weekend following the discovery of an off-normal condition. Based on the data provided in the monthly operating reports, the forced outage rate is the number of forced outage hours divided by the sum of unit service hours (i.e., generator on-line hours) and forced outage hours.

3.6 Equipment Forced Outages per 1000 Commercial Critical Hours (EFO)

This indicator is the number of forced outages caused by equipment failures per 1000 critical hours of commercial reactor operation. It is the inverse of the mean time between forced outages caused by equipment failures. The inverse number was adopted to facilitate calculation and display. The source of these data are the same as that for the forced outage rate.

2. Performance indicators are intended as a tool for senior NRC management to monitor trends in overall performance for a given plant. The performance indicators for a given plant should be viewed as a set. When viewed as a set, the performance indicators provide an additional measure of plant operational performance. However, they should not be used in communications with licensees as a measure of performance level.

3. Performance indicators are intended to be one of several tools for use by senior NRC management in decision-making regarding plant-specific regulatory programs. Senior management in each NRC office should have access to performance indicators for their assigned unit(s). Performance indicators are not to be overemphasized in relation to other measures of safety performance. For this reason, no regulatory action should be taken on the basis of Performance Indicator Program results alone.

4. Performance indicators do not provide a valid basis for ranking individual nuclear power plants and should not be presented in such a way as to imply "problem facility" status for individual plants.

5. The Performance Indicator Program is separate and distinct from the SALP program, although it is recognized that the indicators have relationships in varying degrees to SALP functional areas. Indicators, such as failures of a plant's safety systems or frequent forced outages due to equipment failures, may be symptomatic of safety problems. Thus, the staff may recognize events and failures captured by certain indicators in SALP discussions and reports, but these SALP references are to be based on the underlying causes of poor performance and not on the results of the Performance Indicator Program, either individually or as a set. Regional Administrators should ensure that our decision-making process adheres to this guidance, especially in SALP discussions and documentation.

6. NRC senior management should bear in mind when evaluating performance indicator results that the indicators are assessment tools that aid in identification of unanticipated performance, and that the underlying causes should be carefully assessed, evaluated, and understood (factoring in other available information).

7. Quarterly compilations of Performance Indicator Program results should be placed in the Public Document Room following dissemination to NRC management and the Commission.

It should be recognized that in conducting reviews, inspections, and evaluations of plants, it is often necessary to rely on plant data. Such information has been routinely used in our SALP, safety evaluation reports, and technical evaluation reports. The foregoing policy is not intended to change this process.

NRC staff must be sensitive to inappropriate pressure from any source which causes licensee personnel at individual nuclear power plants to "manage the indicators" or to take any actions that are contrary to plant safety because of performance indicators, individually or as a set (such as inhibiting reactor trips). Any such instances should be promptly communicated to appropriate licensee management and brought to NRC management attention.

James M. Taylor
Acting Executive Director
for Operations

3.7 Collective Radiation Exposure

This indicator is the total radiation dose accumulated by unit personnel. With the exception of the Indian Point and Millstone sites, unit values at multi-unit sites are obtained by dividing the station total by the number of units contributing to the exposure. The Indian Point and Millstone sites report individual unit values. The radiation exposure data are obtained from INPO and because of the reporting techniques employed in gathering the data, these data lag the other performance indicator data by one quarter.

3.8 Cause Codes

Cause codes are intended to identify possible deficiencies in six programmatic categories. The cause codes trend data are developed using the NRC's Sequence Coding and Search System (SCSS) database. Any event can have any or all of the cause codes assigned to it, but only one of each type can be assigned to any one event. This database is developed from all LERs, not just those associated with specific events monitored by the other PIs. The programmatic categories and their definitions are:

3.8.1 Administrative Control Problems

Management and supervisory deficiencies that affect plant programs or activities are included in this category. This category covers the implementation of the numerous functional disciplines necessary to operate a nuclear power facility such as operations, maintenance, licensing, design, health physics, etc. Examples of administrative control problems include poor planning, breakdown or lack of adequate management or supervisory control, inadequate interdepartmental coordination, poor communication between supervisors and staff or among departments, deficiencies resulting in weak or incorrect operating, surveillance or testing procedures, and departures from program requirements. The administrative control problems category is used if there is evidence that a particular problem is recurring and no effective corrective action has been taken. Specific examples are:

- No corrective action after a design problem is discovered.
- QA/QC problems.
- Radioactive shipments without labeling.
- Unauthorized work activity.
- Unqualified personnel performing plant tasks.
- 10 CFR 50.59 review not performed.
- Personnel contamination due to lack of warning signs.
- Technical Specification surveillance not scheduled.
- Inadequate procedure resulting in inadvertent safety injection.

3.8.2 Licensed Operator Errors

This programmatic cause category captures errors of omission or commission by licensed reactor operators during plant activities. These errors may initiate events or may be committed during the course of an event. Licensed operator errors typically occur due to carelessness, lack of experience or training, fatigue, stress, attitude, or poor work habits. Improper supervision is also included whenever the event is the result of improper instructions given by a licensed operator, such as an operations supervisor or control room shift supervisor. Not included in this category are administrative control problems, such as incorrect procedures or inadequate planning activities, which caused an operator to take inappropriate actions. Examples of licensed operator errors include:

- Operator withdrew control rods out of order.
- Operator failed to bypass scram discharge volume high level trip following a trip. A second trip resulted.

3.8.3 Other Personnel Errors

This programmatic cause category captures errors of omission or commission committed by non-licensed personnel involved in plant activities. Included in this category are plant staff (technicians, maintenance workers, equipment operators) and contract personnel. Not included in this category are administrative control problems, such as incorrect procedures or inadequate planning activities, which caused personnel to take inappropriate actions. This cause category is used in conjunction with the Maintenance Problems category when an event is the result of a personnel error involved with a maintenance activity. Examples of other personnel errors include:

- Test personnel inadvertently shorted two cables while performing test.
- Maintenance personnel omitted two fasteners while reassembling valve operator.
- Steps in surveillance procedure performed out of order.

3.8.4 Maintenance Problems

The intent of the maintenance problems cause category is to capture the full range of problems which can be attributed in any way to programmatic deficiencies in the maintenance functional organization. Activities included in this category are maintenance, testing, surveillance, calibration, and radiation protection. The deficiencies noted within this category generally lead to inadequate or improper upkeep and repair of plant equipment and systems or inadequate programs to monitor equipment and plant performance as necessary to prevent hardware failures.

This is the broadest of all categories and is intended to identify areas where improved plant performance is possible through a program which includes such things as increased attention to detail, more frequently performed surveillances, or the use of better trained personnel. The Maintenance Problems Cause category is used to track the performance of plant management's capability to properly repair failed equipment and to preclude equipment failures through improved preventative maintenance programs. Additionally, as an indication of potential maintenance problems, hardware failures which cannot be readily attributable to any preventable cause are also included in this category.

Maintenance related errors are often coupled with other cause categories such as Other Personnel Errors or Administrative Control Problems. The Maintenance Problems category is used in conjunction with other categories when an error occurs while a maintenance, surveillance, or test activity is in progress, whether the error was the result of a deficient procedure or a personnel error.

3.8.5 Design/Construction/Installation/Fabrication Problems

This category covers a full range of programmatic deficiencies in the areas of design, construction, installation, and fabrication. It is used in conjunction with other cause categories when necessary to capture all contributors to the event. One exception to the use of additional categories is that since the very nature of the design process implies a personnel error, it is <u>not</u> necessary to also included one of the personnel error categories for the design error itself.

Examples of the problems included in this category are:

- Check valve installed backwards resulted in RHR overpressurization when isolation valve was opened.
- Transmitter sensing lines reversed.
- Loss of control power due to underrated fuse.
- Use of wrong seal material resulted in solenoid malfunction.
- Equipment not qualified for the environment.
- Defect discovered in pump casing attributed to a manufacturing process.

The design modification process is an ongoing task at nuclear power plants. Examples of design modification problems included in this category are:

- Incorrect interpretation of plant drawings led to an incorrect design modification package.
- Incorrect modification package caused the installation of a component in an unfavorable configuration (e.g., incorrect wiring, incorrect location of instrumentation tubing, valve installed in wrong line, etc.).
- Post modification test procedure is incorrect due to incorrect information in the design modification package.

This cause category may be used in conjunction with other cause categories such as administrative control problems.

3.8.6 Equipment Failures (Electronic Piece-Part or Environmental-Related Failures)

This category is used for spurious or one-time failures of electronic piece-parts and failures due to meteorological conditions such as lightning, ice, high winds, etc. Electronic components which are included in this category are circuit cards, rectifiers, bistable, fuses, capacitors, diodes, resistors, transducers, amplifiers, and computation modules.

This category does not include failures that can be attributed to other problems, such as maintenance problems or design/construction/installation/fabrication problems. Additionally, failures of mechanical equipment for which a cause can not be specifically identified are included in the maintenance problems category.

Examples of electronic piece-part or environmental-related failures include:

- Flashovers occurred in switchyard due to high wind and rain from a thunderstorm.
- Capacitor failure in instrument power supply caused loss of signal from containment leakage detection radiation monitor.
- Surges from lightning strike close to plant propagated through the plant electrical system, causing the main generator to trip.

4. DISPLAY OF PERFORMANCE INDICATOR DATA

The performance indicator data are presented in this report on charts and tables as discussed in the following sections.

4.1 Quarterly Data

Figures 6.1a through 6.111a provide individual charts of the quarterly data trends for each of the PIs for each plant. Based on six-quarter moving averages, these charts display long term plant trends for each indicator. Except for the cause codes, these charts also display the industry six-quarter moving averages to provide a comparative performance level, with industry mean values for safety system failures and collective radiation exposure computed separately for boiling water reactors and pressurized water reactors. Additionally, distinctions in the industry average calculations are made based on plant age. For older plants, the industry averages are the older plant mean values; newer plants include both the newer plant and the older plant mean values. Also, except for the cause codes, individual bars displaying the actual quarterly indicator data values are included. To present a picture of the plant's recent operating history, the plant's critical hours are included for automatic scrams while critical, safety system actuations, and collective radiation exposure.

4.2 Trends and Deviations

Figures 6.1b through 6.111b contain two charts that provide plant profiles of the trends and deviations from corresponding performance indicator values. The "Short Term Trends" chart displays the number of standard deviations by which the plant's moving average for the most recent two-quarter period varies from the plant's moving average for the most recent six-quarter period. This information is provided for all of the PIs except collective radiation exposure. The "Deviation From Older Plant Means" chart displays the number of standard deviations by which the plant's moving average for the most recent six-quarter period varies from the industry's six-quarter moving average. Newer plant figures also contain a "Deviation From Newer Plant Means" chart that displays the number of standard deviations by which the plant's moving average for the most recent six-quarter period varies from the newer plant industry's six-quarter moving average. These deviation charts are provided for all of the PIs except collective radiation exposure and cause codes.

5. COMPUTATIONAL CONVENTIONS

The following conventions are used in the calculations and displays for this report.

1. Certain plants are excluded from the report and calculations as follows:

   With the exception of the collective radiation exposure calculations, plants in extended (i.e., long term) shutdown, where Commission approval is required for either restart or operation above low power, are excluded from the industry average calculations from the first full quarter after shutdown through the last full quarter before startup. Additionally, to avoid distorting the forced outage rate industry average, since a single plant can add almost a full percentage point to the average, the shutdown plants are also excluded from the forced outage rate industry average calculations for any quarters at the beginning or end of the shutdown period when the plants were not shutdown for those entire quarters. Radiation exposure can be significant during outages, hence the industry average for collective radiation exposure includes all periods, even those periods when a plant is in an extended shutdown. In addition to these selective exclusions, Rancho Seco ceased commercial operation on June 7, 1989, and is excluded from all PI calculations after the second quarter 1989. Likewise, Fort St. Vrain ceased all operations on August 29, 1989, and is excluded from all PI calculations after the third quarter 1989. Finally, no data are captured or included for Shoreham. The following listing tabulates the excluded plants and the calendar quarters for which the calculations were adjusted for this report.

PLANT	EXCLUDED PERIOD FOR FORCED OUTAGE RATE	EXCLUDED PERIOD FOR OTHER PIs
Browns Ferry 1	Entire Period	Entire Period
Browns Ferry 2	Through 91-2	Through 91-1
Browns Ferry 3	Entire Period	Entire Period
Fort St. Vrain	After 89-3	After 89-3
Peach Bottom 2	Through 89-2	Through 89-1
Peach Bottom 3	Through 89-4	Through 89-3
Pilgrim	Through 89-1	Through 88-4
Rancho Seco	After 89-2	After 89-2
Seabrook	Through 89-2	Through 89-1
Yankee-Rowe	After 91-3	After 91-3

2. Beginning with the second quarter 1989 report, the commercial operation date used for Clinton is November 24, 1987.

3. New plants are defined as those plants that have not completed one full calendar year of operation after receiving a full power license.

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4. "NA" is used under the following conditions for newer plants:

   - For safety system actuations, significant events, safety system failures, and cause codes, until an initial operating license is first received.
   - For automatic scrams, until critical hours are first reported.
   - For forced outages and equipment forced outages, until commercial operation is declared.
   - For collective radiation exposure, until the beginning of the first full calendar year of commercial operation.

   Thereafter, numerical values are used. For example, a plant shut down for an entire quarter after initial criticality has zero for scrams rather than "NA".

5. "NA" is used for collective radiation exposure for the most recent quarter for all plants, because these data lag the other indicator data by one quarter.

6. For those plants in extended shutdown, "NA" is used for all displays in the Trends and Deviations charts with the exception of the cause codes.

7. Indicator values of "NA" are not used in calculating averages and standard deviations. Zeros do count in such calculations.

8. The Quarterly Data charts (Figures 6.1a through 6.111a in Part I) are based on:

   - Older plant averages exclude plants in long term shutdown and outliers greater than or equal to 2.5 standard deviations above the quarterly mean. The averages for safety system failures and collective radiation exposure are computed separately for BWRs and PWRs.
   - Newer plant averages are single numbers representing the eight-quarter averages of all plants meeting the definition of a new plant during each quarter of the eight-quarter period.
   - The plant's average for the most recent six-quarter period (if there are not at least two quarters of data, no value is displayed on the chart).

9. The Trends & Deviations charts (Figures 6.1b through 6.111b in Part I) are based on:

   A. For the "Deviations from Older Plant Long Term Means" and "Deviations from Newer Plant Means" charts:

      - The plant's average for the most recent six-quarter period (if there are not at least two quarters of data, no value is displayed on the chart).
      - A recalculated mean of all older and newer plants' most recent six-quarter period averages (excluding those plant averages greater than or equal to 2.5 deviations above the original mean and the averages of plants in extended shutdown).
      - The standard deviation based on the most recent six-quarter period for older or newer plants (recalculated after excluding outliers and plants in extended shutdowns, as discussed above).

   B. For the "Short Term Trends" chart:

      - The plant's average for the most recent two-quarter period.
      - The plant's average for the most recent six-quarter period (if there are not at least two quarters of data for this average, no value is displayed on the chart).
      - A standard deviation based on the plant's most recent six-quarter period data.

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10. Report changes:

- Beginning with the first quarter 1989 report, the industry average forced outage rate is higher than the values reflected in earlier reports, primarily due to reclassification of an extended shutdown of Nine Mile Point 1 to a forced outage (from the licensee by letter dated March 14, 1989).
- Beginning with the first quarter 1989 report, the industry average for equipment forced outages per 1000 commercial critical hours is calculated using industry totals of equipment forced outages and commercial critical hours.
- Beginning with the third quarter 1989 report, the industry average forced outage rate is calculated using industry totals of forced outage hours and generator on-line hours.
- Beginning with the third quarter 1990 report, the "Power" field in the event description section of Part II has been renamed "Power History" and provides more accurate information about the status of the plant at the time of the event.
- Beginning with the first quarter 1991 report, the cause codes data are included for all quarters covered by the report.
- Beginning with the third quarter 1991 report, the collective radiation exposure data are reported beginning with the first full calendar year of commercial operation.
- Beginning with the first quarter 1992 report, the "Other Unit" field was added to more clearly identify those events assigned to more than one unit.

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FIGURE 6.27a

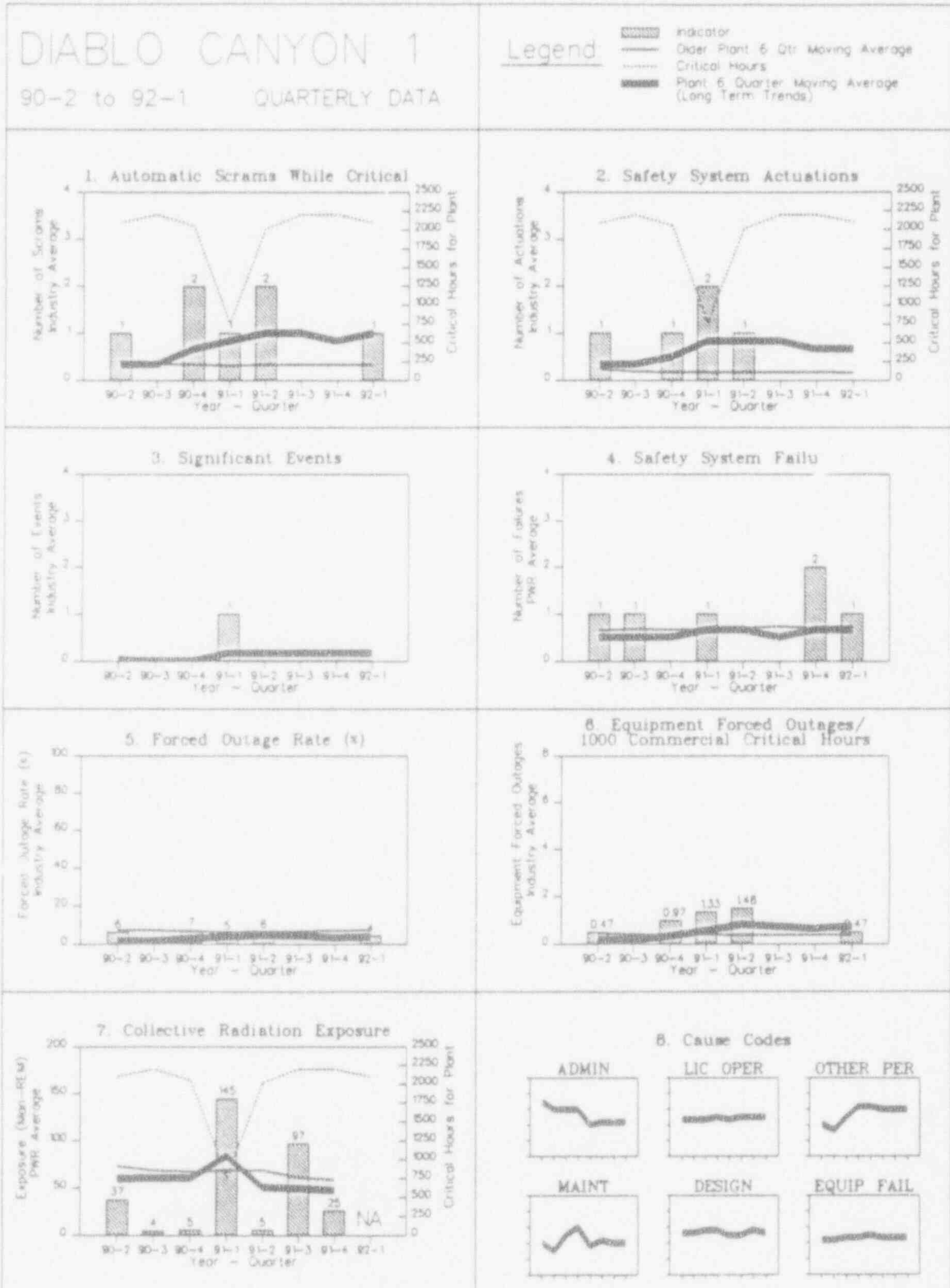

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FIGURE 6.27b

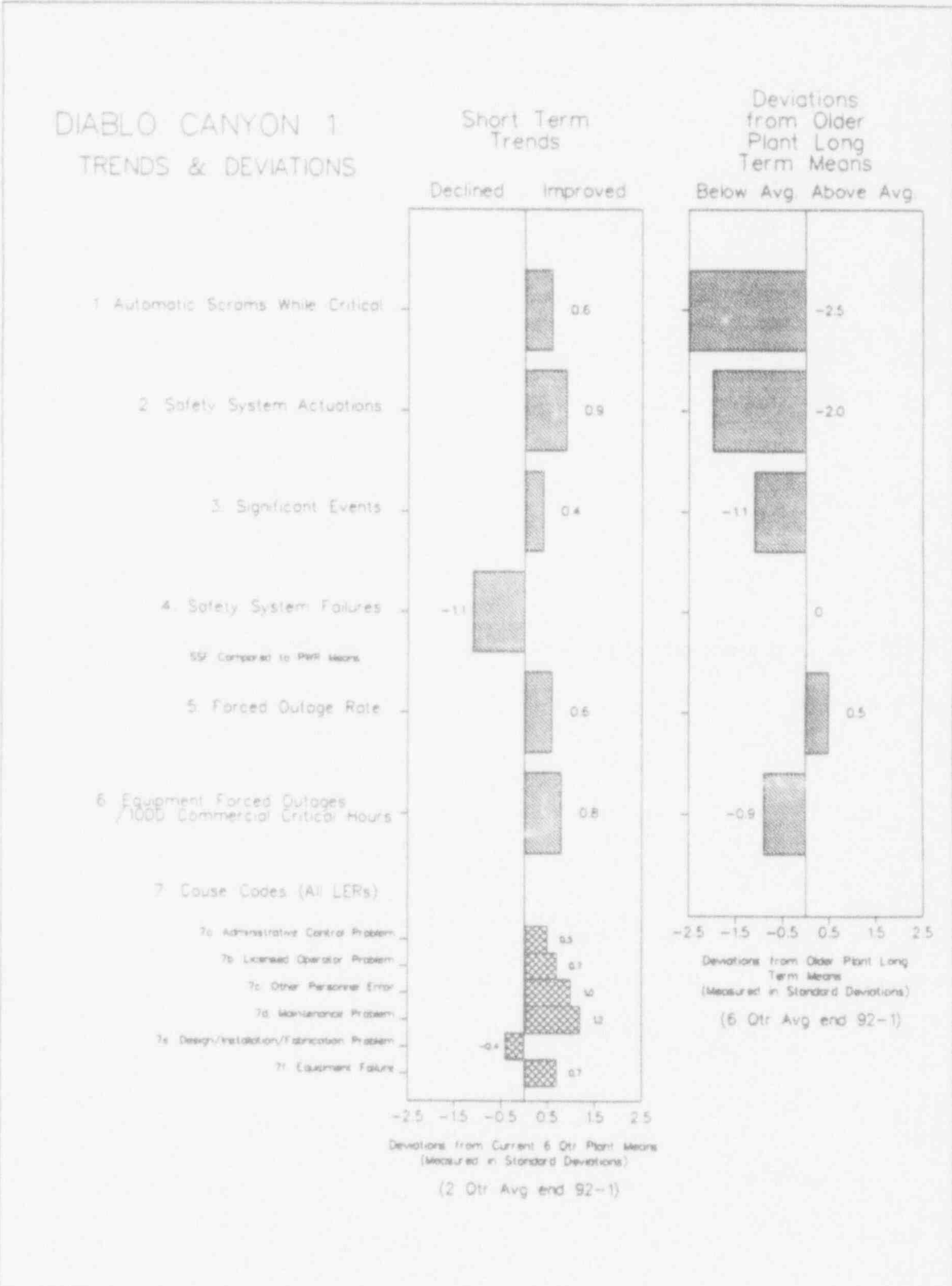

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FIGURE 6.28a

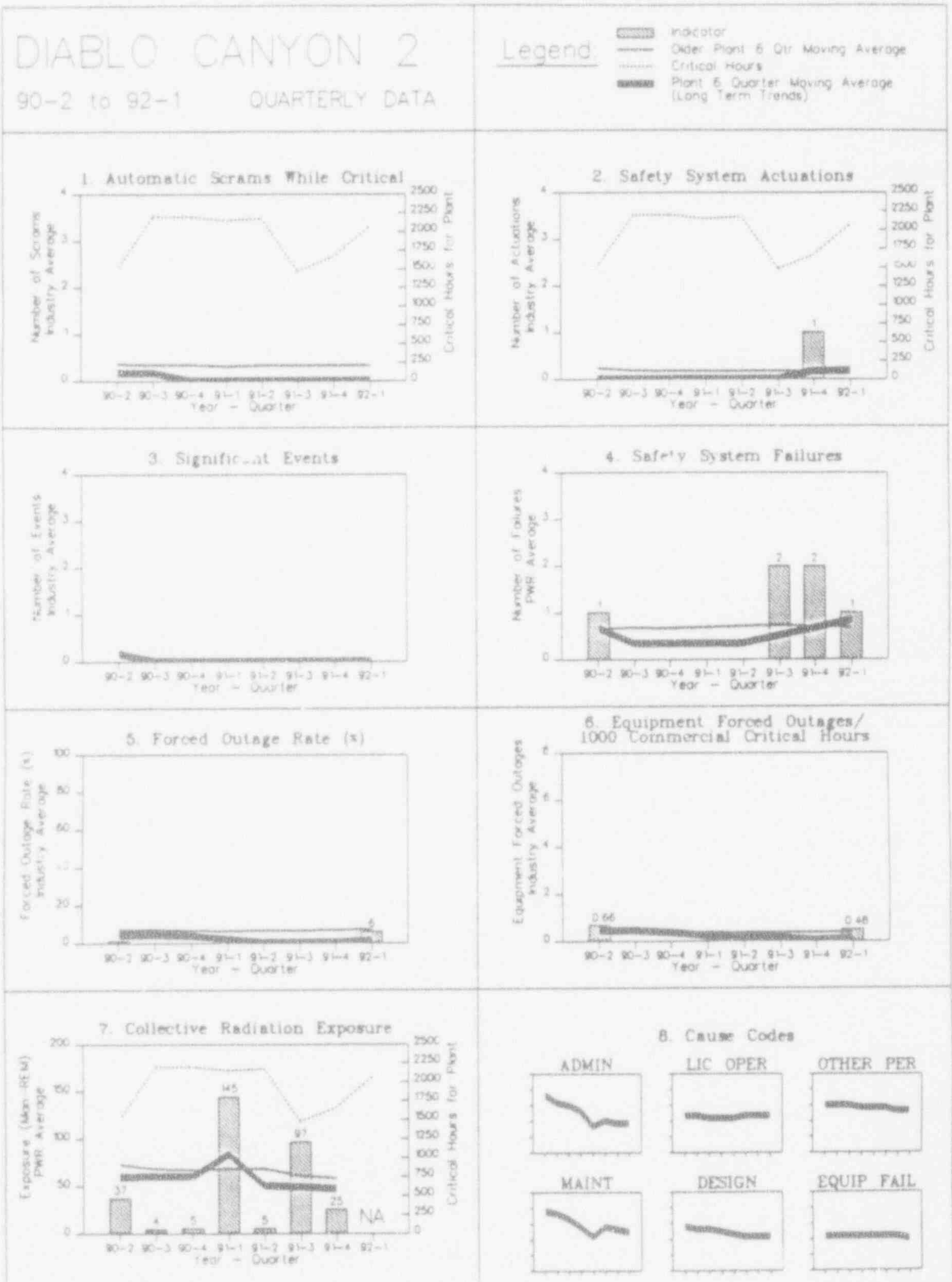

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FIGURE 6.28b

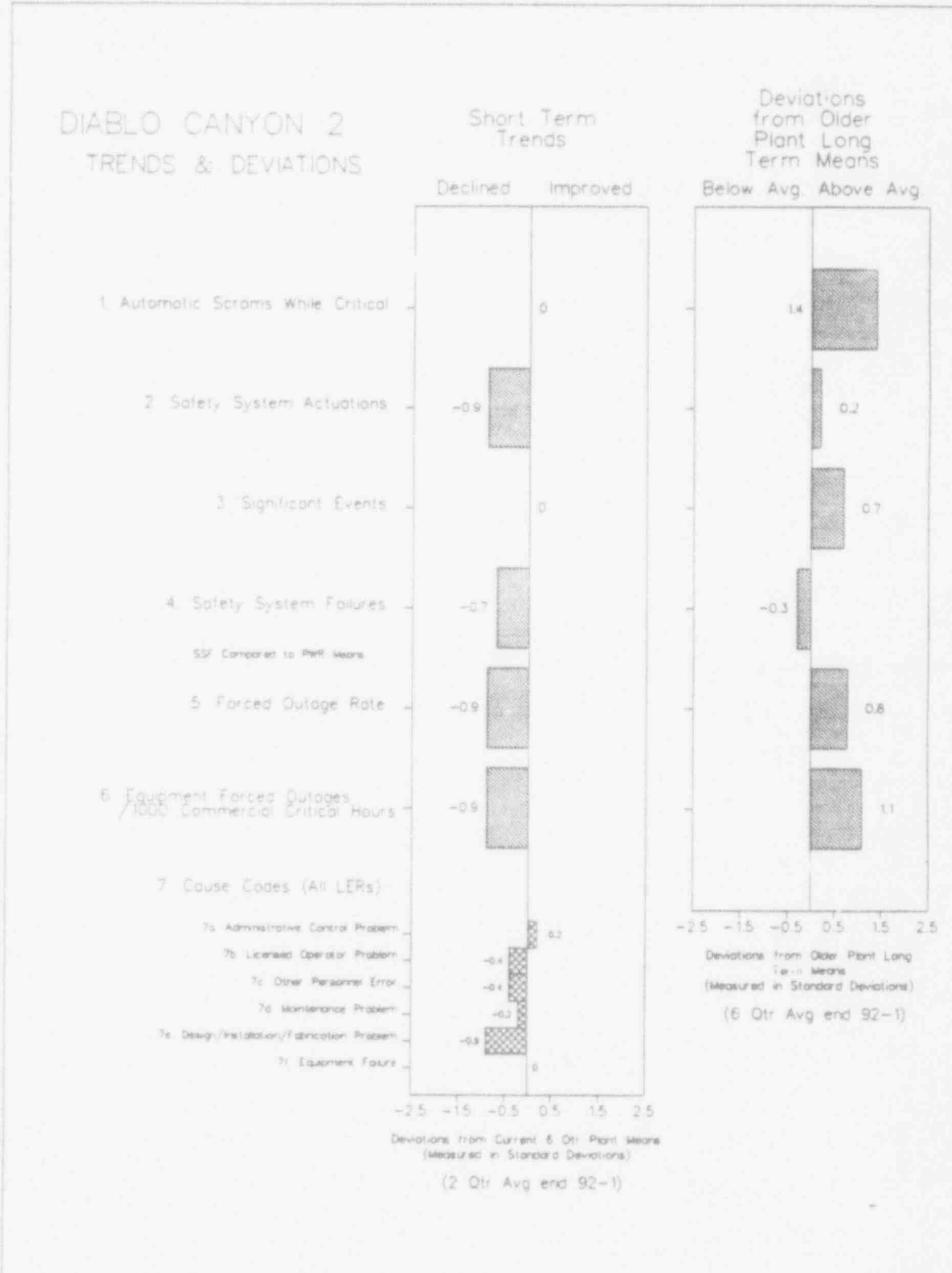

TABLE 7.27

DIABLO CANYON 1

PI EVENTS FOR 91-2

SCRAM 04/23/91 LER# 27591007 50.72#: 20877 PWR HIST: 50% FOLLOWING RUNBACK FROM 100%
DESC : A HIGH SG LEVEL RESULTED WHEN AN OPERATION AMPLIFIER FAILED ON A MFW PUMP TRACK AND HOLD CIRCUIT BOARD CAUSING THE MFW PUMP'S SPEED TO INCREASE. THE REACTOR TRIPPED AFTER THE TURBINE TRIPPED FROM HIGH SG LEVEL.

SCRAM 05/17/91 LER# 27591009 50.72#: 21028 PWR HIST: POWER OPERATIONS AT 100%
DESC : COGNITIVE PERSONNEL ERROR DURING APRM NI TESTING RESULTED IN A HIGH FLUX AT HIGH POWER REACTOR TRIP SIGNAL. THE CAUSE WAS A TECHNICIAN REMOVING THE FUSE FOR NI CHANNEL N42 WHILE CALIBRATING CHANNEL N41.

SSA 05/17/91 LER# 27591009 50.72#: 21028 PWR HIST: HOT STANDBY FOLLOWING SCRAM
DESC : FOLLOWING A SCRAM, EXCESSIVE COOLDOWN DUE TO A STUCK OPEN STEAM DUMP VALVE RESULTED IN A SAFETY INJECTION ACTUATION. APPROXIMATELY 6000 GALLONS WAS INJECTED.

PI EVENTS FOR 91-3

NONE

PI EVENTS FOR 91-4

SSF 11/21/91 LER# 27583039 50.72#: 22292
PWR HIST: CONDITION EXISTED IN ALL MODES UP TO 100% POWER SINCE INITIAL OPERATION.
GROUP : CONTROL ROOM EMERGENCY VENTILATION SYSTEM GROUP
SYSTEM : CONTROL BUILDING/CONTROL COMPLEX ENVIRONMENTAL CONTROL SYSTEM
DESC : DESIGN PROBLEMS IN THE CR VENTILATION SYSTEM COULD ALLOW UNFILTERED AIR TO BE DRAWN IN THROUGH THE RECIRCULATION FLOW PATH IF A BOOSTER FAN OR ITS DAMPER FAILED.

SSF 12/19/91 LER# 27591018 50.72#: 22493
PWR HIST: CONDITION EXISTED IN ALL MODES TO 100% POWER SINCE INITIAL OPERATION.
GROUP : COMPONENT COOLING WATER SYSTEM GROUP
SYSTEM : CLOSED/COMPONENT COOLING WATER SYSTEM
DESC : UNDER CERTAIN COMPONENT COOLING WATER SYSTEM ALIGNMENTS, THE HEAT LOAD DURING POST-LOCA COLD LEG RECIRCULATION MAY CAUSE CCW TEMPERATURE TO RISE ABOVE DESIGN LIMITS.

PI EVENTS FOR 92-1

SSF 02/19/92 LER# 27591019 50.72#:
PWR HIST: EVENT DISCOVERED DURING OPERATION AT 100% POWER.
GROUP : CONTAINMENT COOLING SYSTEMS GROUP
SYSTEM : CONTAINMENT FAN COOLING SYSTEM
DESC : THREE OF FIVE CONTAINMENT FAN COOLERS WERE DISCOVERED TO BE INOPERABLE DUE TO THEIR BACK DRAFT DAMPERS BEING STUCK OPEN.

SCRAM 03/06/92 LER# 27592002 50.72#: 22952 PWR HIST: POWER OPERATIONS AT 100%
DESC : THE FAILURE OF AN INVERTER POWER SUPPLY TO THE MFW PUMPS' SPEED CONTROLLER CAUSED AN OVERSPEED TRIP OF THE 1-1 MFW PUMP. A REACTOR SCRAM RESULTED DUE TO LOW SG LEVEL. THE CAUSE WAS POOR MANUFACTURING AND DESIGN OF THE INVERTER.

TABLE 7.27 (CONT.)

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DIABLO CANYON 1

TYPE	90-2	90-3	90-4	91-1	91-2	91-3	91-4	92-1
SCRAMS > 15% POWER/1000 CRITICAL HOURS	0.47	0.00	0.97	1.33	0.99	0.00	0.00	0.47
SCRAMS <= 15% POWER	0	0	0	0	0	0	0	0
TOTAL SCRAMS	1	0	2	1	2	0	0	1
SAFETY SYSTEM ACTUATIONS	1	0	1	2	1	0	0	0
SIGNIFICANT EVENTS	0	0	0	1	0	0	0	0
SAFETY SYSTEM FAILURES	1	1	0	1	0	0	2	1
FORCED OUTAGE RATE (%)	6	0	7	5	6	0	0	4
EQUIP. FORCED OUTAGES/1000 COMMERCIAL HRS	0.47	0.00	0.97	1.33	1.48	0.00	0.00	0.47
CRITICAL HOURS	2106	2208	2065	753	2027	2208	2209	2107
COLLECTIVE RADIATION EXPOSURE	37	4	5	145	5	97	25	NA
CAUSE CODES:								
ADMINISTRATIVE	1	0	0	2	0	4	1	0
LICENSED OPERATOR	0	0	0	1	0	2	0	0
OTHER PERSONNEL	0	0	5	4	2	1	0	0
MAINTENANCE	2	0	6	5	2	4	1	0
DESIGN/INSTALLATION/FABRICATION	0	1	1	1	0	0	2	0
EQUIPMENT FAILURE	0	0	1	0	1	0	0	0

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TABLE 7.28

DIABLO CANYON 2

PI EVENTS FOR 91-2

NONE

PI EVENTS FOR 91-3

SSF 09/01/91 LER# 32391003 50.72#: 21750
PWR HIST: EVENT DISCOVERED IN HOT SHUTDOWN.
GROUP : CONTAINMENT COOLING SYSTEMS GROUP
SYSTEM : CONTAINMENT SPRAY SYSTEM
DESC : DC CONTROL POWER FOR BOTH CONTAINMENT SPRAY PUMPS WAS DEENERGIZED THROUGH PERSONNEL ERROR, RENDERING BOTH PUMPS INOPERABLE. THIS OCCURRED DUE TO NOT PROPERLY FOLLOWING OPERATING PROCEDURES.

SSF 09/26/91 LER# 32391009 50.72#:
PWR HIST: EVENT DISCOVERED IN COLD SHUTDOWN.
GROUP : CONTAINMENT AND CONTAINMENT ISOLATION GROUP
SYSTEM : REACTOR CONTAINMENT BUILDING
DESC : EXCESSIVE VALVE LEAKAGE WAS DISCOVERED IN THE CHARGING SYSTEM THAT COULD HAVE EXCEEDED CONTROL ROOM AND EXCLUSION AREA BOUNDARY LIMITS.

PI EVENTS FOR 91-4

SSA 10/06/91 LER# 32391007 50.72#: 21961 PWR HIST: COLD SHUTDOWN
DESC : PERSONNEL ERROR CAUSED A SAFETY INJECTION SIGNAL TO OCCUR. NO ECCS PUMPS STARTED. ALL OTHER ACTUATIONS OCCURRED AS DESIGNED.

SSF 11/21/91 LER# 27583039 50.72#: 22292
PWR HIST: CONDITION EXISTED IN ALL MODES UP TO 100% POWER SINCE INITIAL OPERATION.
GROUP : CONTROL ROOM EMERGENCY VENTILATION SYSTEM GROUP
SYSTEM : CONTROL BUILDING/CONTROL COMPLEX ENVIRONMENTAL CONTROL SYSTEM
DESC : DESIGN PROBLEMS IN THE CR VENTILATION SYSTEM COULD ALLOW UNFILTERED AIR TO BE DRAWN IN THROUGH THE RECIRCULATION FLOW PATH IF A BOOSTER FAN OR ITS DAMPER FAILED.

SSF 12/19/91 LER# 27591018 50.72#: 22493
PWR HIST: CONDITION EXISTED IN ALL MODES TO 100% POWER SINCE INITIAL OPERATION.
GROUP : COMPONENT COOLING WATER SYSTEM GROUP
SYSTEM : CLOSED/COMPONENT COOLING WATER SYSTEM
DESC : UNDER CERTAIN COMPONENT COOLING WATER SYSTEM ALIGNMENTS, THE HEAT LOAD DURING POST-LOCA COLD LEG RECIRCULATION MAY CAUSE CCW TEMPERATURE TO RISE ABOVE DESIGN LIMITS.

PI EVENTS FOR 92-1

SSF 02/14/92 LER# 32392001 50.72#: 22816
PWR HIST: CONDITION EXISTED IN ALL MODES UP TO 100% POWER SINCE INITIAL OPERATION.
GROUP : EMERGENCY AC/DC POWER SYSTEMS GROUP
SYSTEM : EMERGENCY ONSITE POWER SUPPLY SYSTEM
DESC : BOTH EDGS WERE DETERMINED TO NOT MEET APPENDIX R REQUIREMENTS DUE TO LACK OF PROPER FIRE PROTECTION FOR THE FIELD CIRCUITS.

TABLE 7.28 (CONT.)

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DIABLO CANYON 2

TYPE	90-2	90-3	90-4	91-1	91-2	91-3	91-4	92-1
SCRAMS > 15% POWER/1000 CRITICAL HOURS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCRAMS <= 15% POWER	0	0	0	0	0	0	0	0
TOTAL SCRAMS	0	0	0	0	0	0	0	0
SAFETY SYSTEM ACTUATIONS	0	0	0	0	0	0	1	0
SIGNIFICANT EVENTS	0	0	0	0	0	0	0	0
SAFETY SYSTEM FAILURES	1	0	0	0	0	2	2	1
FORCED OUTAGE RATE (%)	1	0	0	0	0	0	0	6
EQUIP. FORCED OUTAGES/1000 COMMERCIAL HRS	0.66	0.00	0.00	0.00	0.00	0.00	0.00	0.48
CRITICAL HOURS	1526	2208	2209	2160	2183	1478	1665	2073
COLLECTIVE RADIATION EXPOSURE	37	6	5	145	5	97	25	NA
CAUSE CODES:								
ADMINISTRATIVE	2	0	0	0	0	4	1	0
LICENSED OPERATOR	1	0	0	0	0	1	1	0
OTHER PERSONNEL	3	0	0	0	0	2	2	0
MAINTENANCE	5	1	0	0	0	5	4	0
DESIGN/INSTALLATION/FABRICATION	1	0	0	0	0	0	1	0
EQUIPMENT FAILURE	0	1	0	0	0	0	0	0

Table 8.1 Overall Industry Summary

PLANT	AUTOMATIC SCRAMS WHILE CRITICAL 6 QTR AVG END 92-1	AUTOMATIC SCRAMS WHILE CRITICAL 2 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 6 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 2 QTR AVG END 92-1	SIGNIFICANT EVENTS 6 QTR AVG END 92-1	SIGNIFICANT EVENTS 2 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 6 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 2 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 6 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 2 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 6 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 2 QTR AVG END 92-1
ARKANSAS 1	0.33	0.00	0.17	0.00	0.00	0.00	1.17	1.00	2.50	0.00	0.34	0.00
ARKANSAS 2	0.17	0.00	0.00	0.00	0.00	0.00	1.50	1.00	5.67	15.50	0.49	0.79
BEAVER VALLEY 1	0.33	0.00	0.00	0.00	0.17	0.00	1.17	2.00	12.83	20.50	0.46	0.00
BEAVER VALLEY 2	0.17	0.50	0.17	0.00	0.00	0.00	0.67	0.00	0.33	1.00	0.08	0.23
BIG ROCK POINT	0.00	0.00	0.17	0.00	0.17	0.00	0.50	1.50	4.33	0.00	0.21	0.00
BRAIDWOOD 1	0.50	0.50	0.00	0.00	0.17	0.00	0.83	1.50	24.00	7.50	0.63	0.72
BRAIDWOOD 2	0.67	1.50	0.00	0.00	0.00	0.00	0.50	1.00	4.17	5.00	0.62	0.83
BROWNS FERRY 1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BROWNS FERRY 2	0.50	0.50	0.00	0.00	0.00	0.00	0.75	0.00	1.67	1.00	0.91	0.24
BROWNS FERRY 3	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BRUNSWICK 1	0.67	1.00	0.50	1.00	0.00	0.00	1.50	0.50	15.50	8.00	0.56	0.50
BRUNSWICK 2	0.67	1.00	1.17	2.00	0.00	0.00	1.33	0.50	12.50	7.00	0.25	0.27
BYRON 1	0.33	0.50	0.17	0.50	0.00	0.00	0.33	0.50	1.83	4.50	0.21	0.63
BYRON 2	0.17	0.50	0.00	0.00	0.00	0.00	0.17	0.00	2.67	6.00	0.26	0.26
CALLAWAY	0.67	1.00	0.17	0.00	0.00	0.00	0.33	0.00	3.90	7.00	0.52	0.23
CALVERT CLIFFS 1	0.17	0.50	0.00	0.00	0.00	0.00	1.00	1.50	7.17	6.00	0.26	0.51
CALVERT CLIFFS 2	0.17	0.00	0.17	0.00	0.00	0.00	0.83	1.00	8.17	8.00	0.55	0.27
CATAWBA 1	0.67	0.50	0.67	0.00	0.00	0.00	2.17	1.50	4.67	0.50	1.35	0.23
CATAWBA 2	0.50	0.50	0.00	0.00	0.00	0.00	1.83	1.50	4.83	3.50	0.99	1.24
CLINTON 1	0.33	1.00	0.00	0.00	0.00	0.00	0.50	0.00	10.17	16.50	0.64	1.15
COMANCHE PEAK 1	0.83	0.50	0.83	0.00	0.00	0.00	0.83	1.00	9.67	3.50	1.06	1.55
COOK 1	0.17	0.00	0.17	0.00	0.00	0.00	0.33	0.00	1.83	0.00	0.09	0.00
COOK 2	0.83	0.50	0.00	0.00	0.00	0.00	0.33	0.50	7.83	3.00	0.47	0.24
COOPER STATION	0.17	0.00	0.83	1.00	0.00	0.00	0.83	2.00	3.33	3.00	0.08	0.24
CRYSTAL RIVER 3	0.67	2.00	0.67	1.50	0.00	0.00	0.33	0.50	9.33	21.50	0.32	0.96
DAVIS-BESSE	0.33	0.50	0.00	0.00	0.00	0.00	0.17	0.50	2.67	6.50	0.35	0.81
DIABLO CANYON 1	1.00	0.50	0.67	0.00	0.17	0.00	0.67	1.50	3.67	2.00	0.71	0.24
DIABLO CANYON 2	0.00	0.00	0.17	0.50	0.00	0.00	0.83	1.50	1.00	3.00	0.08	0.24
DRESDEN 2	0.67	0.50	0.33	0.00	0.33	0.00	1.33	1.00	31.33	60.00	1.40	0.99
DRESDEN 3	0.17	0.00	0.00	0.00	0.17	0.00	1.00	1.00	1.67	0.00	0.18	0.00
DUANE ARNOLD	0.50	0.00	0.17	0.00	0.17	0.00	0.67	0.50	2.50	0.00	0.17	0.00
FARLEY 1	0.67	0.00	0.17	0.00	0.00	0.00	0.00	0.00	1.67	0.50	0.24	0.23
FARLEY 2	0.67	0.50	0.17	0.00	0.00	0.00	0.17	0.00	2.17	1.00	0.28	0.32
FERMI 2	0.33	0.00	0.33	0.50	0.00	0.00	1.17	1.00	2.50	1.00	0.44	0.00
FITZPATRICK	0.33	0.00	0.00	0.00	0.50	0.00	3.83	7.50	48.50	68.50	0.38	0.00

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Table 8.1 Overall Industry Summary (continued)

PLANT	AUTOMATIC SCRAMS WHILE CRITICAL 6 QTR AVG END 92-1	AUTOMATIC SCRAMS WHILE CRITICAL 2 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 6 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 2 QTR AVG END 92-1	SIGNIFICANT EVENTS 6 QTR AVG END 92-1	SIGNIFICANT EVENTS 2 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 6 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 2 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 6 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 2 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 6 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 2 QTR AVG END 92-1
FORT CALHOUN	0.00	0.00	0.17	0.00	0.17	0.00	1.50	0.50	10.50	4.00	0.45	0.48
GINNA	0.83	1.00	0.33	0.00	0.17	0.00	0.17	0.00	2.83	2.00	0.39	0.25
GRAND GULF	1.33	0.50	0.83	0.00	0.00	0.00	0.50	0.00	15.33	8.00	0.90	0.24
HADDAM NECK	0.17	0.50	0.00	0.00	0.00	0.00	2.50	2.50	8.67	8.50	0.77	2.32
HARRIS	0.17	0.00	0.00	0.00	0.33	0.00	0.83	0.50	3.83	3.00	0.11	0.00
HATCH 1	1.17	0.50	0.50	0.00	0.00	0.00	0.83	1.50	5.33	2.00	0.35	0.00
HATCH 2	0.33	0.00	0.17	0.00	0.00	0.00	0.33	0.50	3.00	0.50	0.10	0.00
HOPE CREEK	0.67	0.00	1.00	0.50	0.00	0.00	1.33	0.50	6.83	0.00	0.58	0.00
INDIAN POINT 2	0.50	0.50	0.83	0.50	0.00	0.00	0.33	0.00	4.33	7.00	0.65	1.41
INDIAN POINT 3	0.33	0.00	0.00	0.00	0.17	0.00	0.67	0.50	10.00	12.00	1.03	0.24
KEWAUNEE	0.17	0.50	0.00	0.00	0.00	0.00	0.67	0.50	0.17	0.50	0.00	0.00
LASALLE 1	0.33	0.50	0.00	0.00	0.00	0.00	1.00	2.00	2.17	4.00	0.29	0.47
LASALLE 2	0.33	0.50	0.50	1.50	0.00	0.00	0.50	0.50	4.00	2.50	0.40	0.46
LIMERICK 1	0.17	0.00	0.33	0.00	0.00	0.00	1.00	1.00	11.00	7.00	1.02	0.26
LIMERICK 2	0.00	0.00	0.17	0.00	0.00	0.00	1.50	3.50	1.00	0.00	0.41	0.00
MAINE YANKEE	0.67	1.00	0.17	0.50	0.00	0.00	0.67	1.00	16.17	7.00	0.86	0.48
MCGUIRE 1	0.67	0.00	0.33	0.00	0.17	0.00	2.17	1.00	18.50	25.50	1.23	1.26
MCGUIRE 2	0.33	1.00	0.17	0.00	0.00	0.00	1.83	1.00	10.83	7.50	2.31	2.20
MILLSTONE 1	0.00	0.00	0.00	0.00	0.17	0.00	2.17	3.00	39.17	89.50	0.34	1.03
MILLSTONE 2	0.17	0.00	0.00	0.00	0.00	0.00	1.50	1.00	33.67	40.00	1.17	1.30
MILLSTONE 3	0.17	0.00	0.00	0.00	0.33	0.00	1.33	2.00	41.00	70.00	0.45	0.00
MONTICELLO	0.83	0.00	0.50	0.00	0.17	0.00	0.83	0.00	4.17	2.00	0.16	0.24
NINE MILE PT. 1	1.17	1.00	1.00	1.00	0.17	0.00	1.00	1.50	15.83	32.50	0.57	0.72
NINE MILE PT. 2	0.50	1.00	1.00	2.00	0.33	0.50	0.33	0.00	13.50	8.00	0.43	0.59
NORTH ANNA 1	0.17	0.00	0.50	0.00	0.00	0.00	0.67	0.50	5.00	0.00	0.17	0.00
NORTH ANNA 2	0.50	0.50	0.50	0.00	0.00	0.00	0.50	0.50	2.17	2.00	0.36	0.60
OCONEE 1	0.33	0.50	1.17	0.00	0.17	0.00	1.17	0.50	3.50	2.50	0.66	0.47
OCONEE 2	0.00	0.00	0.00	0.00	0.00	0.00	1.67	1.50	2.33	0.00	0.12	0.00
OCONEE 3	0.83	1.50	0.67	1.00	0.17	0.00	1.17	0.50	9.17	25.50	1.04	2.21
OYSTER CREEK	0.17	0.00	0.33	0.00	0.17	0.00	0.33	0.00	3.[illegible]	2.50	0.17	0.00
PALISADES	0.50	0.50	0.67	1.00	0.00	0.00	1.50	4.00	4.00	3.50	0.77	0.81
PALO VERDE 1	0.33	0.50	0.33	0.50	0.00	0.00	0.17	0.00	6.00	15.00	0.28	0.60
PALO VERDE 2	0.50	1.00	0.17	0.50	0.00	0.00	0.33	0.00	3.50	5.00	0.34	0.52
PALO VERDE 3	0.67	1.50	1.00	2.00	0.00	0.00	0.33	0.00	9.33	10.00	0.49	0.23
PEACH BOTTOM 2	0.17	0.00	0.00	0.00	0.00	0.00	1.33	2.00	12.17	13.00	0.47	0.79

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Table 8.1 Overall Industry Summary (continued)

PLANT	AUTOMATIC SCRAMS WHILE CRITICAL 6 QTR AVG END 92-1	AUTOMATIC SCRAMS WHILE CRITICAL 2 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 6 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 2 QTR AVG END 92-1	SIGNIFICANT EVENTS 6 QTR AVG END 92-1	SIGNIFICANT EVENTS 2 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 6 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 2 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 6 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 2 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 6 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 2 QTR AVG END 92-1
PEACH BOTTOM 3	0.33	0.00	0.17	0.00	0.17	0.00	1.17	0.50	7.67	0.50	0.34	0.47
PERRY	0.00	0.00	0.00	0.00	0.17	0.00	1.33	2.50	6.50	10.00	0.34	0.52
PILGRIM	0.00	0.00	0.33	1.00	0.00	0.00	1.83	2.00	7.50	15.50	0.08	0.25
POINT BEACH 1	0.33	0.00	0.17	0.00	0.00	0.00	0.50	0.50	1.00	2.00	0.30	0.00
POINT BEACH 2	0.17	0.50	0.00	0.00	0.00	0.00	0.33	0.50	0.67	2.00	0.29	0.86
PRAIRIE ISLAND 1	0.33	0.00	0.00	0.00	0.00	0.00	0.50	1.50	1.00	0.00	0.16	0.00
PRAIRIE ISLAND 2	0.33	0.00	0.00	0.00	0.00	0.00	0.50	1.50	0.17	0.00	0.08	0.00
QUAD CITIES 1	0.33	1.00	0.00	0.00	0.00	0.00	2.17	2.00	13.00	11.00	0.17	0.51
QUAD CITIES 2	0.33	0.00	0.33	1.00	0.00	0.00	1.67	1.00	8.50	4.00	0.25	0.00
RIVER BEND	0.50	1.00	0.17	0.00	0.00	0.00	1.17	0.50	17.33	39.00	0.46	1.16
ROBINSON 2	0.17	0.00	0.00	0.00	0.17	0.00	0.33	0.00	0.67	0.00	0.08	0.00
SALEM 1	0.17	0.00	0.33	0.00	0.00	0.00	1.17	0.50	3.67	3.00	0.27	0.23
SALEM 2	0.17	0.50	0.17	0.50	0.17	0.50	0.67	0.50	26.50	79.50	0.35	1.06
SAN ONOFRE 1	0.17	0.50	0.00	0.00	0.00	0.00	0.17	0.00	5.83	3.00	0.21	0.25
SAN ONOFRE 2	0.33	0.00	0.17	0.00	0.17	0.00	0.83	1.50	11.17	10.00	0.36	0.00
SAN ONOFRE 3	0.17	0.00	0.17	0.50	0.17	0.00	0.33	0.00	5.00	0.00	0.18	0.00
SEABROOK	0.83	0.00	0.33	0.00	0.00	0.00	0.33	0.50	8.50	0.00	1.06	0.00
SEQUOYAH 1	0.00	0.00	0.00	0.00	0.17	0.00	0.83	0.50	6.00	7.00	0.17	0.00
SEQUOYAH 2	0.50	1.00	0.00	0.00	0.00	0.00	0.50	0.00	3.67	7.00	0.26	0.54
SOUTH TEXAS 1	0.83	1.50	1.17	0.00	0.00	0.00	0.67	1.00	29.17	8.00	0.31	0.00
SOUTH TEXAS 2	0.83	1.00	0.33	0.50	0.00	0.00	0.50	1.00	13.33	34.50	0.70	1.61
ST. LUCIE 1	0.33	0.00	0.00	0.00	0.00	0.00	0.17	0.50	0.83	0.00	0.31	0.00
ST. LUCIE 2	0.00	0.00	0.17	0.00	0.00	0.00	0.33	0.00	0.83	0.00	0.22	0.00
SUMMER	0.00	0.00	0.33	0.50	0.00	0.00	0.17	0.50	0.83	2.50	0.30	0.90
SURRY 1	0.00	0.00	0.50	0.00	0.17	0.00	[illegible]	0.50	2.00	6.00	0.00	0.00
SURRY 2	0.33	[illegible]	0.17	0.00	0.17	0.00	1.67	1.50	24.83	7.50	2.98	0.52
SUSQUEHANNA 1	0.17	0.00	0.33	0.00	0.00	0.00	1.00	1.50	0.83	0.00	0.24	0.00
SUSQUEHANNA 2	0.17	0.00	0.17	0.50	0.00	0.00	0.50	1.50	2.83	3.50	0.16	0.24
THREE MILE ISL 1	0.33	0.00	0.00	0.00	0.00	0.00	0.17	0.50	0.33	0.00	0.00	0.00
TROJAN	0.17	0.00	0.33	0.50	0.33	0.00	1.17	0.50	6.17	0.00	0.12	0.00
TURKEY POINT 3	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.50	0.33	1.00	0.15	0.46
TURKEY POINT 4	0.17	0.50	0.33	0.50	0.00	0.00	0.33	0.50	1.67	5.00	0.36	1.09
VERMONT YANKEE	0.83	0.50	0.33	0.00	0.17	0.00	1.17	1.50	3.50	0.50	0.25	0.00
VOGTLE 1	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.50	0.00	0.08	0.00
VOGTLE 2	0.67	0.50	0.17	0.00	0.17	0.00	0.67	0.50	1.83	[illegible]	0.25	0.00

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Table 8.1 Overall Industry Summary (continued)

PLANT	AUTOMATIC SCRAMS WHILE CRITICAL 6 QTR AVG END 92-1	2 QTR AVG END 92-1	SAFETY SYSTEM ACTUATIONS 6 QTR AVG END 92-1	2 QTR AVG END 92-1	SIGNIFICANT EVENTS 6 QTR AVG END 92-1	2 QTR AVG END 92-1	SAFETY SYSTEM FAILURES 6 QTR AVG END 92-1	2 QTR AVG END 92-1	FORCED OUTAGE RATE (%) 6 QTR AVG END 92-1	2 QTR AVG END 92-1	EQUIPMENT OUTAGES PER 1000 COMM CRITICAL HOURS 6 QTR AVG END 92-1	2 QTR AVG END 92-1
WASH. NUCLEAR 2	0.33	0.50	0.50	1.00	0.17	0.50	3.33	6.50	36.00	21.00	0.54	1.11
WATERFORD 3	0.67	0.50	0.33	0.50	0.00	0.00	0.50	0.50	2.33	2.50	0.63	0.49
WOLF CREEK	0.17	0.50	0.33	0.00	0.17	0.00	0.67	0.50	26.00	78.00	0.16	0.48
YANKEE-ROWE	0.75	NA	0.50	NA	0.50	NA	0.25	NA	4.50	NA	0.45	NA
ZION 1	0.17	0.50	0.50	1.00	0.00	0.00	0.50	0.50	38.17	21.50	0.63	0.76
ZION 2	0.50	0.00	0.17	0.00	0.17	0.00	0.33	0.00	23.50	0.00	0.87	0.00
* INDUSTRY AVERAGE	0.39	0.37	0.27	0.24	0.07	0.01	NA	NA	8.74	10.13	0.46	0.44
* BWR AVERAGE	NA	NA	NA	NA	NA	NA	1.19	1.46	NA	NA	NA	NA
* PWR AVERAGE	NA	NA	NA	NA	NA	NA	0.74	0.72	NA	NA	NA	NA

* Does not include suppressed plants.

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Nuclear Plant Aging Research (NPAR) Program Plan

Components, Systems and Structures

U.S. Nuclear Regulatory Commission

Office of Nuclear Regulatory Research

NUREG-1144
Rev. 1
RD, RG, RM, RV

Nuclear Plant Aging Research (NPAR) Program Plan

Components, Systems and Structures

Manuscript Completed: September 1987
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Division of Engineering
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555

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ABSTRACT

The Nuclear Plant Aging Research (NPAR) Program described in this plan is intended to resolve technical safety issues related to the aging degradation of electrical and mechanical components, safety systems, support systems, and civil structures used in commercial nuclear power plants. The aging period of interest includes the period of normal licensed plant operation, as well as the period of extended plant life, that may be requested in utility applications for license renewals.

Emphasis has been placed on identifying and characterizing the mechanisms of material and component degradation during service and utilizing research results in the regulatory process. The research includes evaluating methods of inspection, surveillance, condition monitoring, and maintenance as a means of managing aging effects that may impact safe plant operation. Specifically, the goals of the program are:

- Identify and characterize aging effects that, if unchecked, could cause degradation of components, systems, and civil structures and thereby impair plant safety.
- Identify methods of inspection, surveillance, and monitoring, and evaluate residual life of components, systems, and civil structures that will ensure timely detection of significant aging effects before loss of safety function.
- Evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the rate and extent of degradation caused by aging.

The NPAR Program is based on a phased approach to research. The objectives of the Phase I studies are: to identify and characterize aging and wear effects; to identify failure modes and causes attributable to aging; and to identify measurable performance parameters, including functional indicators. The functional indicators have a potential use in assessing operational readiness of a component, structure, or system in establishing degradation trends, and in detecting incipient failures.

The objectives of the Phase II studies are: perform indepth engineering studies and aging assessments based on in situ measurements; perform postservice examinations and tests of naturally aged/degraded components; and identify improved methods for inspection, surveillance, and monitoring, or for evaluating residual life, and make recommendations for utilizing research results in the regulatory process.

The objective of the projected Phase III or the extended portion of research is to provide for the resolution of issues that may be raised during the "results utilization efforts."

FOREWORD

The U.S. Nuclear Regulatory Commission's (NRC's) hardware-oriented engineering research program for plant aging and degradation monitoring of components and systems was first discussed in the initial version of the program plan, NUREG-1144, issued in July 1985. It was stated in the plan that NUREG-1144 would be a living document and would be revised periodically. The revisions would reflect the experience gained in implementing the plan and incorporate comments received from within the NRC, industrial codes and standards committees, and domestic and foreign organizations and institutions.

The Office of Nuclear Regulatory Research (RES) staff has received numerous comments from various offices within the NRC as well as from individuals, organizations, and institutions outside NRC, both domestic and foreign, since issuing the original program plan. The NRC provided planning guidance for needed safety research on plant aging and license renewal in its 1986 Policy and Planning Guidance document (NUREG-0885, Issue 5). The Executive Director for Operations provided specific program guidance to the staff for FY 1986 to 1988 planning and program development. The NRC staff provided their comments on the current research program and needs for additional research and prioritization by "user-need" letters to RES and through the Technical Integration Review Group for Aging and Life Extension review of the Nuclear Plant Aging Research (NPAR) Program.

As a part of the overall phased approach to aging research, significant progress has been made in completing the Phase I engineering research for selected components and systems during the past 24 months. These components and systems include: motor-operated valves, check valves, electric motors, emergency diesel generators, chargers and inverters, circuit breakers and relays, batteries, auxiliary feedwater pumps, and reactor protection systems. Progress has also been made in developing models and approaches to evaluate relative impacts of aging on risk. The Phase I segment of research for evaluating systems-level aging effects, from operating experience and risk evaluation of aging phenomenon, has been completed. In consideration of plant life extension/license renewal, progress has been made in identifying major technical safety issues and defining major light water reactor components and structures according to their risk significance. A preliminary study also has been completed identifying degradation sites and life-limiting processes for each major component. Finally, more has been learned from operating experience and from expert opinions.

Reflecting all the aforementioned inputs, this document presents a revised research plan, which addresses identifying and resolving technical safety issues relevant to plant aging and license renewal. This plan focuses on plant safety systems, electrical and mechanical components, civil structures, and the utilization of technical data in the regulatory process.

This program plan for components, systems, and civil structures, in conjunction with its sister plan for primary system pressure boundary components, form the overall framework for NPAR within the Division of Engineering, Office of Nuclear Regulatory Research of the NRC.

Comments on this document are welcome and will be considered in developing subsequent editions of this plan. Comments need not be restricted to the research activities described herein; comments identifying omissions and/or recommending additional research are also welcome.

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ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
AECB	Atomic Energy Control Board
AEOD	Office of Analysis and Evaluation of Operational Data (NRC)
AFWP	Auxiliary Feedwater Pump
AIF	Atomic Industrial Forum
ALEXCC	Aging and Life Extension Coordinating Committee
ASME	American Society for Mechanical Engineers
ASPS	Accident Sequence Precursor Study
BNL	Brookhaven National Laboratory
BV	Block valve
BWR	Boiling Water Reactor
CB	Circuit Breaker
CCW	Component Cooling Water
DE	Division of Engineering
DOE	Department of Energy
DRAA	Division of Reactor Accident Analysis (NRC)
DRPS	Division of Reactor and Plant Systems (NRC)
ECCAD	Electrical Circuit Characterizations and Diagnostics
ECCS	Emergency Core Cooling System
EDO	Executive Director for Operations
EMEB/DE	Electrical and Mechanical Engineering Branch of the Division of Engineering
EPRI	Electric Power Research Institute
FRG	Federal Republic of Germany
HPCI	High Pressure Coolant Injection System (PWRs)

IAEA	International Atomic Energy Agency
I&C	Instrumentation and Control
IEEE	Institute of Electrical and Electronic Engineers
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
IPRDS	In-Plant Reliability Data System
IS&MM	Inspection, Surveillance and (condition) Monitoring Methods
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LWR	Light Water Reactor
MCC	Motor Control Center
MEB/DE	Materials Engineering Branch of the Division of Engineering
MIC	Microbiologically Influenced Corrosion
NBS	National Bureau of Standards
NDE	Nondestructive Examination
NOAC	Nuclear Operations Analysis Center (ORNL)
NPAR	Nuclear Plant Aging Research
NPRDS	Nuclear Plant Reliability Data System
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation (NRC)
NSAC	Nuclear Safety Analysis Center operated by the nuclear industry-supported Electric Power Research Institute (EPRI)
NUMARC	Nuclear Utility Management and Resources Committee
NUPLEX	Nuclear Utility Plant Life Extension
OL	Operating License
ORNL	Oak Ridge National Laboratory
OSRR	Operational Safety Reliability Research

PNL	Battelle Pacific Northwest Laboratories
PORV	Power-Operated Relief Valve
PRA	Probabilistic Risk Assessment
PWR	Pressurized Water Reactor
QOA	Quantification of Aging
RCIC	Reactor core isolation cooling
RES	Office of Nuclear Regulatory Research
RHR	Residual Heat Removal
RPS	Reactor Protection System
SCSS	Sequence Coding and Search System
SEA	Systems Engineering Associates
SNL	Sandia National Laboratories
SRP	Standard Review Plan
SSEB/DE	Structural and Seismic Engineering Branch of the Division of Engineering
SWS	Service Water System
TIRGALEX	Technical Integration Review Group for Aging and Life Extension

1. INTRODUCTION

Since the early 1980s, it has become clear that the current generation of commercial nuclear power plants has gone beyond the development stage and is reaching a stage of relative maturity. The prototype reactors of the late 1950s and early 1960s in the United States have led to the development of two types of commercial light water reactors (LWRs): the pressurized water reactor (PWR) and the boiling water reactor (BWR). The United States now has approximately 100 reactors in commercial operation and a few of these reactors have been operating for over 20 years. As the population of LWRs has matured and advanced in age, the need for a research program that would provide a systematic assessment of the effects of plant aging on safety was recognized. The Director of the Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission (NRC), in his comments on the Long-Range Research Plan, identified a need for a research program to investigate the safety aspects of aging processes in commercial nuclear power plants. Initiating an aging research program was also recommended by the Advisory Committee on Reactor Safeguards (ACRS) in their 1983 report to Congress.

The NRC provided guidance for needed safety research on plant aging and license renewal in its Policy and Planning Guidance document (NUREG-0885). Also, the Executive Director for Operations (EDO) has provided specific program guidance to the staff for FY 1986 to 1988 planning and program development.

The NRC Office of Nuclear Regulatory Research (RES) has developed and implemented a hardware-oriented engineering research program for plant aging and degradation monitoring of components and systems. This program is called the Nuclear Plant Aging Research (NPAR) Program, first described in the July 1985 issue of NUREG-1144 (Ref. 1), and discussed at length at the July 1985 International Conference on Nuclear Plant Aging, Availability Factor, and Reliability Analysis (Ref. 2). This report describes the NPAR Program for components, systems, and civil structures, which is being conducted by the Electrical and Mechanical Engineering Branch of the Division of Engineering (EMEB/DE). A similar program on aging that focuses on vessels, piping, steam generators, and nondestructive examination techniques is being conducted by the Materials Engineering Branch of the Division of Engineering (MEB/DE). The program plan developed by MEB/DE is a sister plan to the NPAR plan. The two plans form the overall framework for aging research within the Division of Engineering, Office of Nuclear Regulatory Research of the NRC.

Significant progress has been made since issuing the original program plan. The Phase I engineering research has been completed for selected components and systems. These components and systems include: motor-operated valves, check valves, auxiliary feedwater pumps, emergency diesel generators, electric motors, batteries, chargers and inverters, and circuit breakers and relays in safety-related systems and reactor protection systems. Also, onsite assessments of electrical circuits have been performed and aged components and materials are being retrieved from the Shippingport Atomic Power Station. Progress also has been made in

developing models and approaches to evaluate relative impacts of aging on risk. The main objective of this document is to revise the original research plan by incorporating what has been learned from the NPAR Program activities and the comments received from the various industry and government institutions and organizations, domestic and foreign.

This revised NPAR Program Plan describes the research effort currently being implemented to resolve the technical safety issues relevant to plant aging and operating license renewal and describes the utilization of the technical data in the regulatory process.

1.1 Background and Need

Aging affects all reactor structures, systems, and components to various degrees. For the NPAR Program, aging refers to the cumulative degradation of a system, component, or structure that occurs with time, and, if unchecked, can lead to an impairment of continuing safe operation of a nuclear power plant as it advances in age. Necessary measures must be taken to ensure that age-related degradation does not reduce the operational readiness of a plant's safety systems, components, and structures and does not result in common-mode failures of redundant, safety-related equipment, thus reducing defense in depth. It is also necessary to ensure that aging does not lead to failure of equipment in a manner that causes an accident or severe transient.

To establish a perspective for describing the NPAR Program, it is of interest to examine the current status of commercial operating nuclear power plants. As of June 1987, there were 102 licensed commercial power plants in operation in the U.S. The age distribution of these plants is listed below.

Operating Lifetime [Years Since Operating License (OL)]	Number of Plants
More than 20	3
Between 15 and 20	17
Between 10 and 15	40
Between 5 and 10	13
less than 5	29

The two oldest operating plants, Yankee Rowe (OL Date--July 9, 1960) and Big Rock Point (OL Date--August 30, 1962), have been in operation for 26 and 24 years, respectively. However, they are demonstration plants with design power of <200 MWe. The next oldest plant is San Onofre 1 (OL Date--March 27, 1967), which has a net capacity of 430 MWe. In

addition to the plants currently in operation, there are approximately 18 more plants under construction. Most of these plants are expected to be in operation within the next decade.

As the population of U.S. LWRs has matured, problems have already occurred that are the result of time-dependent degradation mechanisms such as stress corrosion, thermal aging, radiation embrittlement, fatigue, and erosion. These problems include failures in pumps, valves, and relays, embrittlement of cable insulation, and cracking of the heat-treated anchor heads for posttensioning systems in containment. Although progress is being made to mitigate the age-related degradation that has already been identified, significant questions still remain because of the variety of components in a commercial power reactor, the complexity of the aging process, and the limited experience with prolonged operation of these power plants.

The NPAR Program has been developed to provide a systematic research effort into how aging affects the safety of the plants currently in operation. This program provides a comprehensive effort to: learn from operating experience and expert opinion; identify failures due to age degradation; foresee or predict safety problems resulting from age-related degradation; and develop recommendations for surveillance and maintenance procedures that will alleviate aging concerns.

The aging program also provides key information to enable the NRC to resolve technical safety issues and define its policy and regulatory position on plant life extension and license renewal. License renewal in this document refers to renewing an OL. Reactors are licensed for up to 40 years of operation under the current regulations. Current regulations also permit license renewal. The Technical Integration Review Group for Aging and Life Extension (TIRGALEX) developed a working definition for life extension. Life extension is defined to include license renewal beyond the original license term of 40 years and a program for systematic hardware renewal of plant systems, equipment, components, and structures.

Utilities currently are planning to apply for license renewals and have defined a tentative schedule for several key steps in the process. Two representative LWRs have been the subject of an EPRI/DOE utility-sponsored pilot study on plant life extension (Ref. 3). The two plants that are the subject of this project are Monticello, a 545-MWe BWR (OL Date--September 8, 1970) and Surry 1, a 788-MWe PWR (OL Date--May 25, 1972). At a technical level, this project is to provide an initial evaluation of the effects of aging on commercial nuclear plants and establish the scope of the effort needed to extend the operating lifetime of these plants beyond their initial 40 years of licensed operation. The first submittal to the NRC is expected in 1993. A large number of additional submittals for license renewal can be expected shortly thereafter. To keep pace with these industry plans and prepare for the large number of submittals, the NRC will need to devote substantial efforts over the next several years to define the requirements for license renewal. The first license for a large plant (>400 MWe) will not expire until about the year 2007 (assuming the license term is defined from

OL issue date). However, the utilities need to decide between requesting a plant license renewal or planning new generating capacity approximately 10 to 15 years before the end of the licensed period, to allow for the long lead times required for planning and construction. A firm NRC policy will be required for license renewal by early 1990. Based on this policy, appropriate regulations, guides, and review procedures can then be written and issued by 1992, to allow preparation and submittal of the first license renewal application by 1993. Reviewing these applications at this early stage will show the viability of the life extension option in sufficient time (by 1995) for a utility to elect an alternative option, if necessary.

Thus, the NRC needs to clearly define its policy and regulatory positions in the near future to ensure the safe operation of aged plants during the current license period and for extended life. Clearly defined policies and criteria are needed to ensure that requests for license renewal address the primary regulatory concerns and issues.

1.2 Framework for Identifying and Resolving Technical Safety Issues

The TIRGALEX was established in 1986 by the EDO to facilitate the planning and integration of NRC plant aging and license renewal/life extension activities. The initial objectives of TIRGALEX have been to clearly define the technical safety and regulatory policy issues associated with plant aging and life extension and develop a plan for resolving the issues in a timely, well-integrated and effective manner.

Figure 1.1 shows the framework recommended by TIRGALEX, and adopted in the NPAR Program, for planning and integrating agency activities related to plant aging and license renewal/life extension. As can be seen on the left side of the figure, technical information on aging and license renewal is already being developed by a variety of sources. This information is compiled and will be updated periodically by RES to ensure that all NRC offices involved in aging and license renewal have current information on ongoing related efforts.

Using the TIRGALEX Integration Plan, the technical data currently being developed in related projects and the regulatory user needs, identified by the Office of Nuclear Reactor Regulation (NRR), are the key inputs used to establish the priority of the research program elements. The RES then has the responsibility for carrying out the necessary research programs.

Hardware-oriented engineering research needed to resolve the issues related to aging is being conducted in DE where two programs are being conducted. The NPAR Program for components, systems, and structures is being performed by the EMEB/DE. The aging research program on the vessels, piping, steam generator, and nondestructive examination techniques is being performed by the MEB/DE.

As the principal technical elements in these research programs are completed, the data and information is made available for use in the

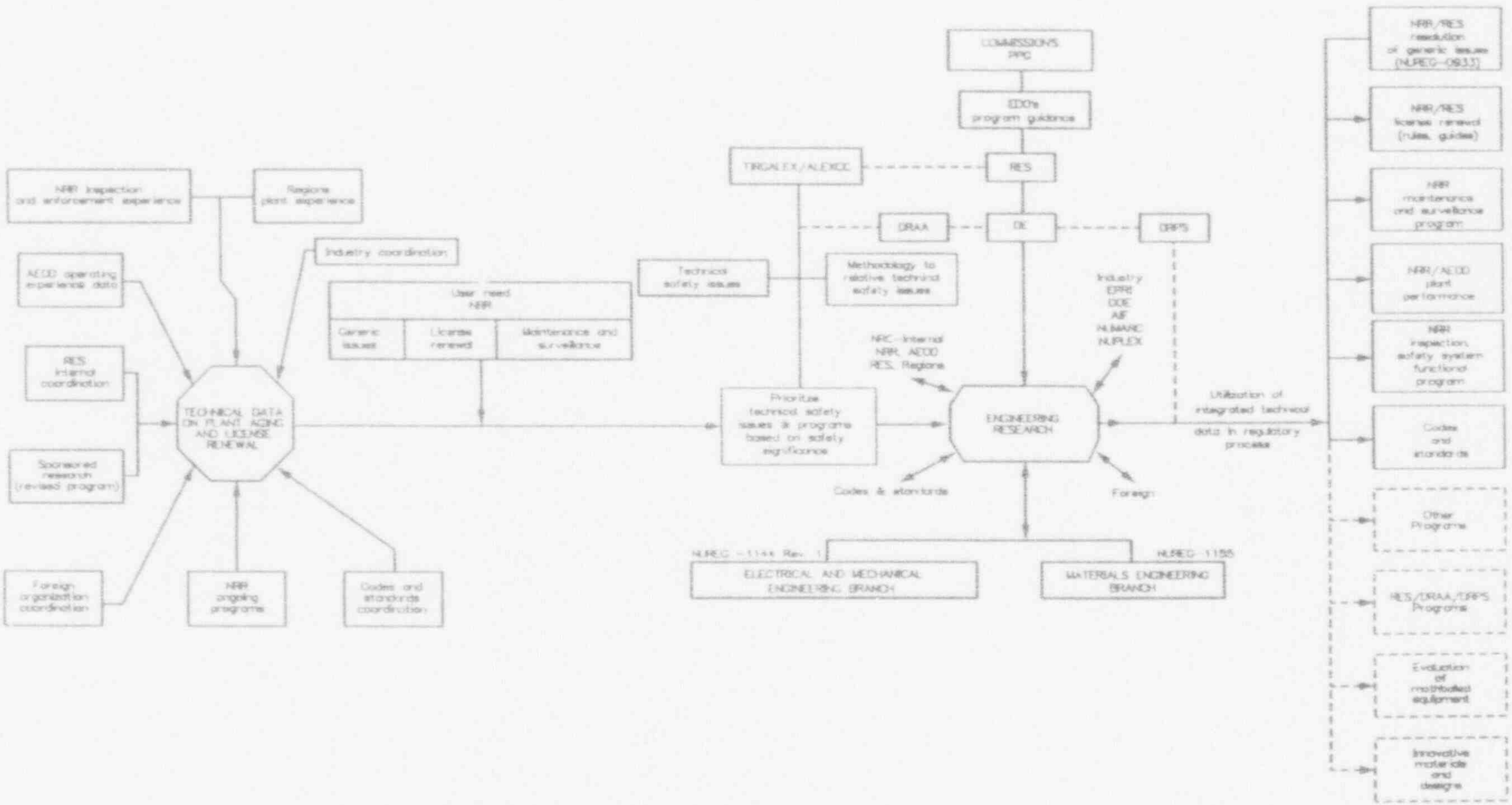

Figure 1.1. NPAR coordination and technical integration.

regulatory process. RES will also make use of research findings as they impact the RES responsibility for developing regulatory criteria, guides and standards, and review procedures.

1.3 Organization of NPAR Plan

Section 2 contains a discussion of the technical safety issues related to aging and safe operation of plants of all ages. The nature of aging processes are discussed first, followed by a discussion of the potential impact of aging on safety and the technical objectives of the research considered in the NPAR Program.

Section 3 contains an overview of the utilization of the NPAR Program results in the regulatory process. The discussion of utilization is divided into seven categories: License Renewal, Generic Issues, Maintenance and Surveillance, Plant Performance, Inspection of Safety Systems and Components, Codes and Standards, and Other Programs. Also, a brief synopsis of the utilization of research results in support of the regulatory process is included.

Section 4 contains an outline of the systematic approach used in the NPAR Program for assessing the effects of aging on plant safety systems, components, and structures. The criteria used to identify systems, components, and structures important to safety are discussed, as is the phased approach developed to study the effects of age-related degradation.

Section 5 contains the description of major program elements and the scope of work for the subjects related to the systems, components, and structures included in the NPAR Program.

Section 6 contains a description of the program coordination and technical integration performed within the NRC, with other government agencies, and with external institutions and organizations, domestic and foreign.

Section 7 contains a discussion of the schedules developed for the various NPAR activities. The schedules include research activities in consideration of license-extension efforts to be completed by the early 1990s, and the continuation of age-related confirmatory research.

Appendix A contains a description of the NPAR strategy and a phased approach used in conducting research. Included also are the methods used for the initial selection of systems and components for aging studies and the development of application guidelines and recommendations.

Appendix B contains a description of the major program elements being addressed by the NPAR Program.

Appendix C contains a description of the research activities being performed as part of the NPAR Program. The scope and current status of each of the major projects are discussed.

Appendix D contains an overview of other ongoing programs related to aging and life extension. The coordination required between the NPAR effort and other ongoing activities is discussed, with emphasis on the need to optimize the use of available resources.

2. TECHNICAL SAFETY ISSUES

A broad set of technical safety issues has been developed to provide focus and direction for the NPAR Program. These issues are based on operating experience, expert judgment, and risk significance. These technical issues include the questions that need to be answered, problems that need to be solved, and measures that must be taken to ensure that safety levels are maintained as the present generation of reactors age. The technical safety issues will be developed further and prioritized by first examining the nature of the aging process, and then examining the potential role aging plays in plant safety and the agency's mission to address plant aging and life extension/license renewal.

The specific technical objectives of the research program have been developed to address this broad set of technical safety issues. The program technical objectives and the technical issues then provide the framework required for developing and guiding the individual research projects in the program.

2.1 Nature of Aging Processes

Commercial nuclear power plants are large engineered complexes comprised of many different systems, components, and structures that cover a broad spectrum of materials and designs. The plants operate in a variety of different environments and must meet different functional requirements. The various components, systems, and structures are inspected and maintained by a variety of methods and general approaches. Consequently, a number of factors can cause degradation of the functional capability of a component, system, or structure. For example:

- Material degradation mechanisms are active during storage and operation. Typical causes of degradation include: neutron embrittlement, fatigue, erosion, corrosion, oxidation, thermal embrittlement, and chemical reactions.

- Stressors can be introduced by improper storage, operating environment, or external environment. Irradiation, primary and secondary coolant chemistry, and vibratory loads are the typical examples of stressors introduced by the operating environment. Freezing and thawing, brackish water, and humidity are typical examples of stressors introduced by external environment. Synergistic influence of electrical and mechanical stressors in combination with other internal and external environment also contribute to degradation processes.

- Service wear: accumulation of fatigue damage due to plant operational cycling, service wear of rotating equipment, and wear of the drive rod assembly in a control rod drive mechanism are typical examples.

- Excessive testing: frequent testing of emergency diesel generators is a typical example.

- Improper installation, application, or maintenance: investigation by NRC (Ref. 4) has indicated that 30% of the nuclear plant abnormal occurrences can be attributed to faulty and improper maintenance.

These factors and others, with time, can act either singly or synergistically to degrade a component, system, or structure.

"Aging" is defined in this report as the cumulative degradation that occurs with the passage of time in a component, system, or structure. Thi degradation takes place because of one or more of the factors listed above. This degradation can, if unchecked, lead to a loss of function and an impairment of safety. Aging is a complex process that begins as soon a a component or structure is produced and continues throughout its service life. Aging plays a significant role in the operation of a nuclear plant and must be factored into the determination of safe operating lifetime limits. It also is important in the evaluation for license renewal. No nuclear plant, including those still under construction or being mothballed, should be considered immune from its effects.

2.2 Potential Impact of Aging on Safety

The main concern addressed by this research program is that plant safety could be compromised if degradation of key components, systems, or structures is not detected before a loss of functional capability, and timely corrective action is not taken. In this way, aging can result in a undetected reduction in the defense-in-depth concept. The defense-in-dept concept requires the public be protected from the accidental release of fission products by a series of multiple barriers and engineered safety systems.

Age degradation of the reactor components, equipment, and structures can reduce the overall level of safety. Experience at operating power plants provides examples where age degradation of vital components could lead to a loss of the margins provided by the defense-in-depth concept. These examples include items such as failure of emergency diesel generators, degradation of valves, and stress corrosion cracking of heat-treated anchor heads in prestressed concrete containments.

Age degradation of the major components must be evaluated when considering plant life extension and license renewal. The major components are the large, expensive, permanent parts of the reactor system, not routinely replaced or refurbished. Age degradation must be assessed, and an evaluation of the residual life of the major components is required if plant safety is to be ensured during extended life operation.

Age degradation can also cause a loss of operational readiness in engineered safety systems, which are required to mitigate the consequences of a failure of a vital component, such as an assumed break in the primary system boundary. Examples of safety systems are the emergency core cooling system, reactor protection system, and containment spray system.

A survey (Ref. 5) of licensee event reports (LERs) conducted by Oak Ridge National Laboratory (ORNL), as part of the planning for this aging research plan, shows that numerous instances of aging-induced failures of equipment have been reported. The reported events indicate that essentially all types of safety-related systems have been affected by a variety of degradation processes. Also, ORNL described the background of selected age-related LERs in more detail to provide a better perspective regarding the safety significance of age degradation (Ref. 6). Based on these studies, aging effects can contribute to both: (a) the probability of initiation of transients and accidents, and (b) the probability of failure of the mitigating equipment during operation.

Aging can also lead to a higher probability of common mode failures in nuclear power plants. This is an area of potentially the greatest concern. Aging can lead to wide-scale degradation of a physical barrier or to simultaneous degradation of redundant components. If such degradation occurs in part of the reactor coolant pressure boundary, as in the steam generator tubes, then an excess stress, resulting from an event such as a pressure transient or a seismic event, could result in multiple, simultaneous tube failures. This has the potential of releasing radioactivity outside the containment.

A second type of common mode failure is simultaneous failure of redundant components. Age-related degradation can occur in redundant components of safety systems, causing the components to simultaneously fail during a transient or accident. This could lead to loss of functional performance of the safety system. Thus, aging can lead to common mode failures that can result in accident initiation or in loss of safety function and the capability for accident mitigation.

Qualification of electrical equipment is required to demonstrate that it will function in accident environments. The prototype equipment used in some of the qualification tests are artificially aged to simulate service degradation. However, there is some doubt that such techniques realistically represent the effects of inservice degradation. For example, it is known that accelerated radiation aging at the high dose rates typically employed by commercial testing laboratories does not produce the degree of embrittlement of cables as may be caused by radiation at the actual dose rate encountered inside containment during operation. Also, with natural aging rather than artificial aging, the polymeric materials used in certain types of solenoid valves have been observed to become more vulnerable to failure under LOCA conditions. Because of the evidence that artificial or accelerated aging techniques may be inadequate, it is difficult to assess the increased degree of vulnerability of safety equipment at this time. This equipment, degraded by age-related service and wear, may be vulnerable to common mode failure during accidents and transients that involve abnormal stresses and demands on the equipment.

2.3 Technical Objectives of the Research

The NRC has the responsibility for ensuring that licensed reactors can continue to be operated safely during their initial licensed lifetime and

during any period of extended life operation. Because of the complexity age-related degradation and the diversity of the degradation processes, coordinated research program is necessary to: (a) identify the measures that are available to manage age-related degradation, and (b) identify anticipated problems that may result from plant aging. Using these two general criteria as guidance, a set of nuclear plant aging and life extension technical safety issues has been developed for the NPAR Progra and these are listed below:

- What structures, systems, and components are susceptible to ag effects that could adversely affect public health and safety? Which of these structures, systems, and components are maintai and are replaceable?

- What are the degradation processes of materials, components, a structures that could, if unchecked (improperly maintained and, not replaced), affect safety during normal design life and dur extended life?

- How can operational readiness of aged structures, systems, and components be ensured during 40-year design life and during extended life?

- Are currently available examinations and test methods adequate identify all relevant aging mechanisms before safety is affected? If not, what efforts are under way to improve them?

- What criteria are required to evaluate residual life of components and structures? What supporting evidence (data, analyses, inspections, etc.) will be needed?

- How should structures, systems, and components be selected for comprehensive aging assessments and residual life evaluations? Which structures, systems, and components should be selected?

- How effective are current programs for mitigating aging (e.g., maintenance, replacement, and repair)?

- What kinds of reliability assurance and maintenance programs wi be needed to ensure operational readiness of aged safety system and components?

- What additional changes will be needed in codes and standards t address aging? What schedule should be followed?

These safety issues form the basis for establishing the technical objectives of the NPAR Program.

The technical objectives of the NPAR Program are:

- Identify and characterize aging effects that, if unchecked, could cause degradation of structures, components, and systems and thereby impair plant safety.

- Identify methods of inspection, surveillance, and monitoring; and evaluate residual life of components, systems, and civil structures, which will ensure timely detection of significant aging effects before loss of safety function.

- Evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the rate and extent of degradation caused by aging.

The aging research program has been developed to meet these objectives. The program involves: (a) risk-oriented identification and selection of components, systems, or structures for which assessments of the impact of aging on safety performance are to be conducted; (b) review of design base safety margins, qualification testing, operating experience, and methods for surveillance, inspection, monitoring, and maintenance, leading to the development of recommendations for indepth engineering studies; (c) engineering studies, including verification of inspection, surveillance, monitoring, and maintenance methods, evaluation of residual life models, in situ examinations, collection of data from operating equipment, and cost/benefit analyses.

The program developed to meet the above objectives includes a variety of projects. Because of the multidisciplinary scope of the research and the need to make the best use of the available resources, the research effort is focused on key components and structures in the systems of risk significance. The priority of the research effort has been established by taking into account: (a) information gained from the 3-day workshop that was attended by over 300 people from the U.S. and other countries representing a wide spectrum of interests and expertise (Refs. 7 and 8); (b) information gained from the EPRI/DOE workshop on plant life extension held in 1986 in Alexandria, Virginia, in which results were presented from the pilot projects at Surry 1 and Monticello (Ref. 3); (c) insights gained from the risk assessments completed to date (Refs. 9 and 10), (d) advice from a cross section of knowledgeable people; and (e) plant operating experience, including LERs and Institute of Nuclear Power Operation's (INPO's) Nuclear Plant Reliability Data System (Refs. 5 and 11). Other ongoing NRC programs, industry-sponsored research, and programs being conducted in foreign countries are also considered in developing the program plan. In those cases where relevant information is available or is being developed, the NPAR Program has been planned to avoid duplication of effort.

3. UTILIZATION OF RESEARCH RESULTS

The NPAR Program's goals are to obtain a better understanding of the aging and degradation processes in components and structures and provide improved confidence in available methods for detecting and managing aging degradation. This program will provide a basis for timely and sound regulatory decisions regarding continued safe operation of nuclear plants of all ages as well as for the anticipated requests for license renewals. Understanding aging and degradation processes and detecting and managing degradation damage at an early stage, before functional capability is impaired and continued safe operation becomes questionable, will avoid unplanned and costly plant shutdowns. Also, use of the research results will make operating plant maintenance more effective. Wear from excessive testing can be minimized through using more effective surveillance techniques and result in the improved reliability of equipment.

In addition to the general benefits mentioned above, the NPAR Program is structured to respond to the following specific user-oriented needs:

- Develop data for identifying and resolving technical safety issues related to plant aging and license renewal.

- Support NRR/RES in resolving generic safety issues involving aged plant safety systems, support systems, and electrical and mechanical components.

- Evaluate and recommend surveillance and maintenance methods needed to monitor age-related degradation and to support license renewal.

- Develop technical data and provide recommendations useful for developing plant performance indicators (useful to AEOD and NRR for plant inspections and for review of applications for extended license requests).

- Provide information for developing inservice inspection procedures suitable for aged components, systems, and structures.

- Develop recommendations for revising appropriate industry codes and standards.

- Develop technical data useful to RES for the Operational Safety Reliability Research (OSRR) Program and for NRR to evaluate the status of "mothballed" equipment.

The following sections contain a brief description of the NRC staff-defined needs and of how the results of the NPAR Program can be utilized in the regulatory process.

3.1 License Renewal

The NRC needs to clearly define its policy and regulatory positions in the near future so that utility planning for plant life extension can proceed in an orderly manner.

The extension of the period for a nuclear power plant license is provided for in Section 50.51 of Part 50 of the Code of Federal Regulations, which states that a license is issued for a fixed period of time, not to exceed 40 years from the date of issuance. It also states that "Licenses may be renewed by the Commission upon the expiration of the period." Although specific requirements for a license renewal are not defined, it is clear that the "aged" condition of the plant will have to be considered in any utility request for a license renewal. A pressing need for the NRC at the present time is to develop guidance for industry on regulatory policy, rules, and procedures for life extension. By 1992, at the latest, utilities will need to have NRC policy, rules, guidance, and procedures in hand in order to prepare license renewal applications by 1993.

The NPAR activities include: the review of Sections 3 through 10 of the Standard Review Plan (SRP) and associated guidance to identify technical safety issues to be addressed for license renewal; residual lifetime evaluations of major components and structures likely to be considered for life extension; and the review of appropriate technical specifications of methods for early detection and control of aging degradation. The NPAR Program will ensure that this aging/license renewal perspective is factored into its ongoing programs and activities.

The NPAR Program is developing and integrating the vast amount of aging-related data so that the technical safety issues related to license renewal are identified and resolved in an effective and timely manner. Program coordination and technical integration are important elements of the NPAR program. This integration will be accomplished by maintaining, evaluating, and updating the state-of-the-art information obtained from ongoing programs related to aging and license renewal. These programs are sponsored by NRC, industry, and foreign organizations. With this process, the program has prioritized major components and structures that are considered important to evaluate requests for license renewal

Any additional research projects that may be needed to resolve the technical safety issues in consideration of license renewal will be added to the NPAR Program as they are defined.

3.2 Generic Safety Issues

One of the objectives of the NPAR Program is to support NRR/RES in resolving aging-related generic safety issues identified in NUREG-0933, "A Prioritization of Generic Safety Issues." NUREG-0933 contains a recommended priority list to assist in the timely and efficient resolution of safety issues that have a high potential for reducing risk. The NPAR Program results, which can be used in resolving several of these generic safety issues, are listed in Table 3.1. For example, the NPAR Program can

TABLE 3.1 Generic safety issues, with elements of aging, benefiting from NPAR program results.

Issue Number	Title
23	Reactor Coolant Pump Seal Failures
29	Bolting Degradation or Failures in Nuclear Power Plant
51	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems
55	Failure of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand
70	PORV and Block Valve Reliability
84	CE PORVs
93	Steam Binding of Auxiliary Feedwater Pumps
107	Generic Implications of Main Transformer Failures
113	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers
115	Enhancement of the Reliability of Westinghouse Solid State Protection System
118	Tendon Anchorage Failure
120	On-Line Testability of Protection Systems
124	Auxiliary Feedwater System Reliability
125.I.6	Valve Torque Limit and Bypass Switch Settings
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems
127	Testing and Maintenance of Manual Valves in Safety-Related Systems
128	Electrical Power Reliability
130	Essential Service Water Pump Failures
132	RHR Pumps Inside Containment
A-17	Systems Interaction

TABLE 3.1 (continued)

Issue Number	Title
A-44	Station Blackout
A-45	Shutdown Decay Heat Removal Requirements
A-47	Safety Implications of Control Systems
B-56	Diesel Reliability
C-9	RHR Heat Exchanger Tube Failures
HF8	Maintenance and Surveillance Program
II.C.4	Reliability Engineering
II.E.6.1	Test Adequacy Study

support the resolution of the Generic Safety Issue B-56, "Diesel Reliability," by evaluating aging and service wear of emergency diesel generators.

The NRR has provided "users-need requests" to RES for resolving some specific issues that are listed in Table 3.1. The NPAR Program is supporting NRR in resolving the Generic Issue II.E.6.1, "Test Adequacy Study," and by assessing methods for monitoring motor-operated valves. The third issue in this category is GI-70, "PORV and Block Valve Reliability."

A residual life assessment task is being performed as part of NPAR to evaluate the age degradation and residual life of major LWR components. The results of this task will indirectly be supportive to NRR in resolving several generic safety issues related to the primary reactor coolant system components. The results of this task will be used in resolving safety issues related to plant life extension and in developing regulatory guidelines and review procedures for use by NRR in reviewing applications for license renewal.

3.3 Maintenance and Surveillance

Maintenance and surveillance programs at nuclear plants are significant contributors to system and plant reliability. The NPAR Program supports the NRR Maintenance and Surveillance Program by evaluating the role of maintenance in managing aging effects. This evaluation consists of:

- Reviewing current practices and procedures, carried out by nuclear utilities, to maintain equipment.
- Reviewing nuclear equipment vendor's recommendations for maintenance of components or subcomponents selected for aging assessments.
- Performing an evaluation, including a comparative analysis, of the relative merits of performing maintenance when a component has been discovered to be malfunctioning (corrective maintenance), and when an observation has been made through surveillance, inspection, or monitoring, that a component may not function when required during a design basis or "trigger" event (preventive maintenance). Emphasis is placed on the relationship between failures (causes or modes) expected to be experienced during operation and those that would potentially occur under the stresses associated with design basis or trigger events.
- Identifying, where possible, those component failure mechanisms likely to be induced through preventive or corrective maintenance. Specifically, look for those failures that might be detectable through short-term, postmaintenance surveillance, inspection, or monitoring.
- Developing recommendations, for acceptable or preferred maintenance practices, based on the preceding activities.

- Evaluating the relative merits of predictive inspection and monitoring methods that can be used to identify imminent failures (predictive maintenance). Predictive maintenance will enable corrective maintenance or replacement to be scheduled based on actual equipment performance. This approach lends itself to use of reliability methods and condition monitoring to mitigate equipment degradation due to aging.

The major emphasis of all the above activities is on the technical aspects of maintenance rather than on institutional, organizational, programmatic, or human factor considerations.

The NPAR Program has been structured to define maintenance and surveillance needs to ensure the operational readiness of aged power plant safety systems and components and provide support to the NRR staff in their review of the requests for license renewal. The NPAR Program also provides the aging-related information for developing maintenance program criteria and standards and maintenance indicators that NRR staff can monitor for specific components and systems.

3.4 Plant Performance Indicators (Involving Aging Considerations)

The operating performance of nuclear power plants, especially in the 10 to 20 years before the end of a plant's operating license, is a significant factor in evaluating requests for plant license renewals. The term "performance indicators" refers to a set of data that may be correlated with individual plant safety performance. Periodic review of the aging trends indicated by the plant performance indicators can aid in evaluating plant performance as they advance in age.

In accordance with the early NRC (IE and now AEOD) study, these indicators may be divided into two categories: direct indicators of current plant performance, i.e., safety system failures; and indirect or programmatic indicators, i.e., an enforcement action index. The NRC staff has selected an optimum set of six indicators on the basis of the deliberations of a task group on performance indicators and discussions with industry representatives. The selected indicators are:

1. Automatic Scrams While Critical,

2. Safety System Actuations,

3. Significant Events,

4. Safety System Failures,

5. Forced Outage Rate, and

6. Equipment Forced Outage per 1000 Critical Hours.

The third indicator, Significant Events, includes degradation of important safety equipment, primary coolant pressure boundary components, and important associated structures. The research results emanating from

the NPAR Program could be used to evaluate the effectiveness of the first four of the above-mentioned plant performance indicators involving elements of aging.

3.5 Inspection

The NPAR Program can potentially support several ongoing NRR programs that guide the regional activities relevant to aging, aging detection, and mitigation of aging degradation. These programs include the Safety System Functional Inspection Program and the Generic Communication Program.

In general, the Safety System Functional Inspection Program assesses whether plant modifications of selected safety systems have degraded the design margin to the point where the system's ability to mitigate design basis events is impaired. This program consists of an indepth review of a small number of safety systems and is usually conducted at older plants.

The objectives of the Generic Communication Program are to:

- Inform licensees of problems, including those due to aging, that have developed in individual plants, and
- Require action when these problems are shown to be significant and generic.

These programs apply to the pressure boundary hardware, drivers, actuators, electrical power, and the instrumentation and controls of engineering safety features.

The NPAR Program will support NRR in establishing inspection procedures that are relevant to aging; NRR includes these procedures in the Inspection Enforcement Manual issued to guide the activities of the regions. For example, some inspection procedures establish guidance for ascertaining that inservice inspection and testing activities are programmed, planned, conducted, recorded, and reported in accordance with Section XI of the ASME Boiler and Pressure Vessel Code.

The NPAR Program has the potential to support the ongoing inspection effort conducted by the regional offices in accordance with the NRR inspection program. The objective of this effort is to ensure that systems and components have not been measurably degraded as a result of any cause, including aging. To provide the inspection staff with an up-to-date knowledge of NPAR research results, the results from the program will be summarized at the conclusion of each phase and a briefing will be given for the regional and NRR inspection staff.

3.6 Codes and Standards

Codes and standards help define the inservice inspection requirements to ensure operational integrity of selected power plant electrical and mechanical components. The NPAR Program will develop recommendations to revise relevant ASME and IEEE Codes and Standards to ensure safe operation

with aged components and systems. These recommendations will be developed through active participation in the relevant technical committees.

The Special Working Group on Life Extension--ASME Section XI--is coordinating activities related to codes and standards of interest to the NPAR Program. A special IEEE working group was established to investigate the codes and standards aspects of plant life extension as it may be affected by instrumentation and electrical control equipment. The components and systems currently of interest and being considered in ASME standards are listed in Table 3.2. Some of the relevant IEEE standards are listed in Table 3.3. Periodic briefings and information exchanges with appropriate codes and standards committees are scheduled as part of NPAR.

3.7 NPAR Interfaces with Other Programs

A number of additional NRR/RES programs and activities that have potential to utilize the NPAR Program results are:

- Equipment Qualification
- Reliability Technology
  - Frantic III
  - PETS
  - PRISM
  - NUREG-1150.
- Evaluation of Mothballed Plants
- Innovative Materials and LWR Designs

3.7.1 Equipment Qualification

The NPAR Program results support implementing of Section 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants," of 10 CFR Part 50, which includes the requirement:

> "Equipment qualified by test must be preconditioned by natural or artificial (accelerated) aging to its end-of-installed life condition. Consideration must be given to all significant types of degradation which can have an effect on the functional capability of the equipment. If preconditioning to an end-of-installed life condition is not practicable, the equipment must be replaced or refurbished at the end of this designated life unless ongoing qualification demonstrates that the item has additional life."

TABLE 3.2. Develop recommendations to revise ASME standards for operation and maintenance of mechanical equipment.

Standard Number	Title
ASME OM-1	Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices.
ASME OM-2	Requirements for Performance Testing of Nuclear Power Plant Closed Cooling Water Systems.
ASME OM-4	Examination and Performance of Nuclear Power Plant Dynamic Restraints (Snubbers).
ASME OM-5	Inservice Monitoring of Core Support Barrel Axial Preloads in PWRs.
ASME OM-6	Requirements for Performance Testing of Pumps in Light Water Cooled Nuclear Power Plants.
ASME OM-8	Requirements for Preoperational and Periodic Performance Testing of Motor-Operated Valve Assemblies.
ASME OM-10	Requirements for Inservice Testing of Valves in Light Water Cooled Nuclear Power Plants.
ASME OM-13	Requirements for Periodic Testing and Monitoring of Power-Operated Relief Valve Assemblies.
ASME OM-14	Requirements for Vibration Monitoring of Rotating Equipment.
ASME OM-15	Requirements for Performance Testing of Nuclear Power Plant Emergency Core Cooling Systems.
ASME OM-16	Inservice Performance Testing of Nuclear Power Plant Diesel Drives.
ASME OM-19	Startup and Periodic Testing of Electro-Pneumatic-Operated Valve Assemblies Used in Nuclear Power Plants.

TABLE 3.3. Develop recommendations to revise IEEE standards for electrical equipment for nuclear power plants.

Standard Number	Title
IEEE 308	Criteria for Class 1E Power Systems for Nuclear Power Generating Stations.
IEEE 317	Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations.
IEEE 323	Qualifying Class 1E Equipment for Nuclear Power Generating Stations.
IEEE 334	Standard for Type Test of Continuous Duty Class 1E Motors for Nuclear Power Generating Stations.
IEEE 336	Installation, Inspection, and Testing Requirements for Class 1E Instrumentation and Equipment at Nuclear Power Generating Stations.
IEEE 344	Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.
IEEE 382	Standard for Qualification of Safety-Related Valve Actuations.
IEEE 383	Standard Types Tests of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Station.
IEEE 387	Criteria for Diesel Generator Units Applied as Standby Power Supply for Nuclear Power Generating Stations.
IEEE 501	Seismic Testing of Relays for Nuclear Power Generating Stations.
IEEE 535	Qualification of Class 1E Lead Storage Batteries for Nuclear Power Generating Stations.
IEEE 572	Qualification of Class 1E Connection Assemblies for Nuclear Power Generating Stations.
IEEE 549	Qualify Class 1E Motor Control Centers for Nuclear Power Generating Stations.
IEEE 650	Qualification of Class 1E Static Battery Chargers and Inverters for Nuclear Power Generating Stations.

TABLE 3.3. (continued)

Standard Number	Title
IEEE 944	Application and Testing of Uninterruptible Power Supplies for Nuclear Power Generating Stations.
IEEE/ANSI C37.13-1981	Low Voltage ac Power Circuit Breakers Used in Enclosures.

The evaluation of actual aging processes through the research program provides a basis for assessing the adequacy of industry methods for preconditioning before qualification testing or may lead to recommendations for surveillance or monitoring. This may involve recommendations for revisions of the IEEE standards related to environmental qualification through participation of researchers in the aging research program and in the relevant IEEE standards committees and through the development of industry consensus based on the results of the research. Some of the relevant IEEE standards are listed in Table 3.3.

3.7.2 Reliability Technology

The reliability program has developed a framework and process that can be applied to maintain LWR safety.

The hardware-oriented NPAR Program has the potential to support the major elements of the NRC's Reliability Research and Technology Program. The NPAR Program is evaluating causes of component and structural aging at nuclear power plants, the safety and risk implication of this aging, and methods for detecting and controlling significant aging effects. As part of its efforts, the NPAR Program is collecting failure-rate data on aging and developing quantitative techniques that can be used to quantify the risk and reliability effects of aging, using probabilistic risk assessment (PRA) event tree and system models. These results from the NPAR Program can assist the Reliability Research and Technology Program to: monitor plant/equipment performance; compare plant and equipment performance to acceptable or desired levels to help early detection of degradation; help identify causes of important problems; and help evaluate corrective action and verify effectiveness through performance monitoring.

3.7.2.1 FRANTIC III. The computer code FRANTIC III, used for time-dependent reliability and risk evaluations, was developed by NRC and is particularly useful in technical specification evaluations. Technical data generated in the NPAR Program will be used in developing and evaluating time-dependent models and in determining risk significance of aging effects.

3.7.2.2 PETS - Probabilistic Evaluation of Technical Specification Program. The PETS Program is developing methods for using reliability and risk analyses to improve technical specifications. The development is focused on approaches for modifying allowed outage periods and surveillance test intervals, on a plant-specific or generic base. The aim is for PETS to be available on software for personal computers for NRC and industry use.

For specific components and systems to be studied in the NPAR Program, surveillance and monitoring methods will be recommended to alleviate aging concerns. The recommendations will include identifying component performance parameters and functional indicators and optimize surveillance intervals. Therefore, for these specific components and systems, the PETS Program could use NPAR results.

3.7.2.3 PRISM - Plant Risk Status Information Management System. The PRISM system is a computer software package written for an IBM-XT personal

computer, to provide plant-specific tools for plant inspectors and others whose jobs require little or no PRA background. It is a decision-oriented, user-friendly, menu-driven program that contains data base management and interactive routines to aid NRC inspectors in allocating their efforts toward those areas that have greatest impact on plant safety. Again, for specific components and systems addressed in the NPAR Program, the PRISM project could benefit from NPAR results.

3.7.2.4 NUREG-1150 - Reactor Risk Reference Document. The NPAR Program has potential to support the data base input for the development of NUREG-1150 to account for aging and time-dependent failures. NUREG-1150 provides the results of major risk analyses for six different U.S. LWRs, using the state-of-the-art methods. It is intended that this document provide a data base and insights to be used in a number of regulatory applications including: (a) licensing--evaluating the risk relevance of proposed plant licensing changes, risk effectiveness of existing regulations, and risk priorities of generic technical issues; (b) inspection--developing the methodology and data to set priorities for inspection activities; and (c) research--establishing programs that directly address the analytical and experimental uncertainties identified in NUREG-1150. The draft report for comment of NUREG-1150 was issued in February 1987.

The technical data integration with the aforementioned research projects will be recommended to the ALEXCC for implementation.

3.7.3 Evaluation of Long-Term Outages and Mothballing of Plants

The NPAR Program results could support NRR in developing criteria for evaluating plans involving: long-term outages of operating plants, prolonged delays in plants under construction reaching operational status, mothballing plants during construction, and reactivating laid up or mothballed equipment. The NPAR Program is integrating information related to the degradation processes active in the nuclear power plant structures having safety and risk implications. Some of this information will be useful in evaluating the integrity of mothballed equipment or equipment inactivated during a long-term outage. For example, the NPAR Program is integrating information on microbiologically influenced corrosion (MIC) that is active in mothballed or inactivated equipment filled with liquid. Such degradation was discovered in the stainless steel service water system of H. B. Robinson 2. It occurred after an extended outage to replace the lower assemblies of the steam generators. Use of suitable lay-up procedures could have mitigated the degradation from MIC.

3.7.4 Innovative Materials and LWR Designs

The NPAR Program is identifying and evaluating materials that are susceptible to aging and the critical degradation sites and mechanisms active in the components and structures that are critical to plant safety. These results from the NPAR Program should be considered in the design of the advanced LWRs to ensure higher safety margins. Specifically, components- and systems-specific inspections, surveillance, and condition monitoring methods identified in the NPAR Program could be incorporated as

a built-in diagnostic system in the advanced LWR designs. This design feature would assist in establishing early baseline data and trending of performance parameters and functional indicators.

3.8 Brief Synopsis of NPAR Results in Support of the Regulatory Process

The support to be given to NRC staff defined needs by the various NPAR activities is shown in Table 3.4. This table summarizes in matrix form how each of the ongoing and planned NPAR activities support (and has potential to support) the various user-oriented needs. These activities are discussed in detail in Appendix C and the milestones and schedules for the various activities are given in Section 7. Results in support of the regulatory process have already been obtained in several NPAR-sponsored research activities. A brief description of these results is provided as follows.

- Issued NUREG/CR-4302. Operating experience review and analysis were completed to determine failure modes and causes due to aging of check valves in plant safety systems. This research supports NRR in the resolution of Generic Safety Issue II.E.6, "In Situ Testing of Valves." The ASME Operation and Maintenance (O&M) Committee has been made aware of the results of the study. This NPAR effort related to check valves has been referred to the NSSS Owners Groups' representatives regarding industry actions in response to the check valve and water hammer event at San Onofre, Unit 1.

- Issued NUREG/CR-4597. A study was completed to characterize aging of Auxiliary Feedwater Pumps (AFWP) and evaluate inspection and degradation monitoring methods. Potential failures of the AFWP have been attributed to the presence of large hydraulic forces, particularly at low flow rates, which are substantially different from the best efficiency flow. Methods for detecting failure modes and differentiating between failure causes were defined. The research will support the upgrading of Regulatory Guide 1.147 and Inservice Inspection Code Case Acceptability--ASME Section XI, Division 1.

- Issued Draft NUREG/CR-4590. The evaluation of operational experience and expert opinion indicated that the aging of nuclear service emergency diesel generators is observable; follows recognizable patterns; shows changes in the modes of aging degradation with time; is confined to few, relatively major components; increases as percentage of all failures with time; and is caused by normal operational stressors. The primary causes of diesel generator aging are vibration, adverse environment, and human errors. The results of this research have been conveyed to NRR and they can be used in resolving Generic Safety Issue B-56, "Diesel Reliability," and to upgrade ASME Sections III and XI pertaining to diesel generators.

TABLE 3.4. Potential use of NPAR results, involving aging consideration, for components, systems, and structures.

NPAR Research Activities	License Renewal	Generic Safety Issues	Maintenance and Surveillance	Plant Performance Indicators	Inspection	Codes and Standards
Motor-operated valves	*	✓	✓	✓	✓	✓
Check valves	*	✓	✓	✓	✓	✓
Solenoid-operated valves	*		✓		✓	
Auxiliary feedwater pumps	*	✓	✓	✓	✓	✓
Electric motors	*		✓		✓	✓
Chargers/inverters	*		✓		✓	✓
Batteries	*		✓		✓	✓
Power-operated relief valves	*	✓	✓		✓	
Snubbers	*	✓	✓		✓	✓
Circuit breakers	*	✓	✓		✓	✓
Penetrations/connectors/cables	✓		✓		✓	✓
Diesel generators	✓	✓	✓	✓	✓	✓
Transformers	✓	✓	✓		✓	✓
Heat Exchangers	*	✓	✓	✓	✓	
Compressors	*		✓		✓	
Bistables/switches	*		✓		✓	
High pressure ECCS	*		✓	✓	✓	✓
RHR/low pressure ECCS	*		✓	✓	✓	✓
Service water system	*	✓	✓	✓	✓	✓
Component cooling water system	*		✓	✓	✓	✓
Reactor protection system	*	✓	✓	✓	✓	✓
Class 1-E distribution system	*	✓	✓	✓	✓	✓
Auxiliary feedwater system	*	✓	✓	✓	✓	✓
Control rod drive system	✓		✓		✓	✓

TABLE 3.4. (continued)

NPAR Research Activities	License Renewal	Generic Safety Issues	Maintenance and Surveillance	Plant Performance Indicators	Inspection	Codes and Standards
Civil structures	✓					
Risk evaluation of significant aging effects	✓	✓	✓	✓	✓	
Residual life assessment	✓		✓		✓	
Shippingport aging evaluation	✓		✓		✓	

* under review.

- Issued NUREG/CR-4564. Operating experience review and analyses were completed to determine failure modes and causes, due to the aging of battery-chargers and inverters that are used in plant safety systems. The identified major contributors to failures are fuses and capacitors, and involve overheating and aging/wearout. The results of this research in combination with the output of Phase II studies will be used to provide recommendations to upgrade IEEE Standard 650, Qualification of Class 1E Static Battery Chargers and Inverters for Nuclear Plant Generating Stations. The approval of this standard has been temporarily placed on hold to incorporate aging-related conclusions from NUREG-4564 into the standard.

- Issued NUREG/CR-4380. A field test program was carried out to evaluate a technique of valve signature analysis to detect and differentiate abnormalities, including time-dependent degradation (aging), and incorrect adjustments in motor-operated valves. Measurements were made at four operating plants to verify monitoring techniques and to obtain characteristic "signatures" indicative of degradation and misadjustments of motor-operated valves. This research supports NRR in the resolution of Generic Issue II.E.6, "In Situ Testing of Valves." The research results emanating from the NPAR effort were used in Bulletin No. 85-03: Motor-Operated Valve Common-Mode Failures During Plant Transients Due To Improper Switch Settings.

- Issued NUREG/CR-4279. A study was completed to identify aging of hydraulic and mechanical snubbers used on safety-related piping and components of nuclear power plants. The ASME Section XI Code Committee and ANSI/ASME/OM4 Committee have been made aware of the results of the study, and a value-impact analysis reflecting the reduction in the number of snubbers in existing plants is being incorporated in draft Regulatory Guide SC 708-4, Rev. 1, "Qualification and Acceptance Tests for Snubbers Used in Systems Important to Safety."

- Issued Draft NUREG/CR-4692. A study was completed for NRR using NPAR data in the resolution of Generic Issue No. 70, "PORV and Block Valve Reliability." The report contains a review of nuclear power plant operating events involving failures of power-operated relief valves (PORVs) and associated block valves (BVs). Aging-related data include failure mode, failure mechanism, and severity. The report also addresses questions such as: (a) how do operator/maintenance actions contribute to valve failures?; (b) are certain designs more prone to failures than others?; and (c) to what extent would upgrading (valves, operators, and control systems of safety-related systems) have prevented the failure?

- Issued NUREG/CR-4234. Review and analysis of operating experience data were accomplished to determine the failure modes and causes (due to aging) for motor-operated valves. This research supports the NRR efforts to resolve Generic

Issue II.E.6, "In Situ Testing of Valves." The ASME Operation and Maintenance (O&M) Committee has been made aware of the results of this study. Also, this NPAR effort has been referred to the NSSS Owners Groups' representatives involved in responding to Bulletin No. 85-03: Motor-Operated Valve Common-Mode Failures During Plant Transients Due to Improper Switch Settings.

50-275/323-OLA-2 RELATED CORRESPONDENCE MFP exhibit 21
I-MFP-21 "NOT ADMITTED"

Report Issued: September 10, 1992 Report: 420DC-92.856

Pacific Gas and Electric Company
Laboratory Test Report
Technical and Ecological Services
3400 Crow Canyon Road
San Ramon, CA 94583

SUBJECT: DIABLO CANYON POWER PLANT 4KV LOAD CENTER FEEDER CABLE FAILURE (REF. ACTION REQUEST NO. AO266115).

As requested, we have conducted investigations to determine the cause of the insulation failure on the section of cable that was removed from the 4kV circuit supplying power to load center No.14D located at the cooling water intake structure compound.

Cable Description

The faulted section of cable received at TES, San Ramon, measured approximately 35 feet in length. The cable was manufactured by The Okonite Company in 1972 at their Plant #5 located in Santa Maria, CA. It is described as "Okaguard Shielded Okoprene", 1/C, 4/0 - 19x CC, 5kV rated insulation, with 0.030" semi-conducting strand screen, 0.110" Okaguard black insulation, 0.030" semi-conducting insulation screen, 2-1/2" x 0.010" semi-conducting tape, 1.0" x 0.005" coated copper shield tape, FN-1 cable tape, #159 cable tape.

Fault Locating Process

Careful examination of the neoprene outside jacket material revealed no obvious fault location along the cable length.

There was an area approximately 7 feet from one end of the cable (referenced as 'A' end) that had a bend in it and the cable was more elliptical in shape than round. Also in this same area, there were positive signs that the cable had been under some mechanical stress because of slight abrasions showing on the jacket's surface and a reddish material on the jacket. These factors indicated this portion of the cable probably passed through a conduit bend that had some rust on its surface. In this portion of the cable there were also grayish stains on the jacket surface that may be the result of the cable having been exposed to a wet environment.

pc: DLBauer
CADooher
RTHanson
MLRockfield
CFShortt

Date: August 31, 1992
Tested by: [signature]
Approved by: [signature]

92891/60005530/beu10w

Because of the above observations, it was suspicioned the fault would be found in the bend area. However, when the outer jacket material was removed, no fault was found in this portion of the cable.

Having passed the bend area, the jacket material was further removed until the fault was located approximately 20 feet from the `A' end of the cable. The jacket material at the fault location showed no signs of being under mechanical stress nor were there any stains present. Overall, the jacket was relatively clean in the faulted area of the cable.

Cable Dissection and Analysis

Upon locating the fault, a 22 inch section of cable was cut from the cable that placed it directly in the ce ..er. This short section of cable was dissected beginning with removing several outer layers of materials. This included the mechanical stress relief tapes, tinned copper foil, and semi-conductive tape. The fault was carefully inspected and photographed after the removal of each layer of material.

The one-inch tinned copper foil was properly overlapped and showed no signs of wrinkling either side of the fault point.

Following the removal of the various cable layers, there remained only the Ethylene Propelene Rubber 110 mil thick insulation material and 19 strand copper conductors. A four inch section was cut from the 22 inch section with the fault remaining in the center.

The copper strands were then removed and inspected. It was found that the strand directly under the punctured insulation was blackened and contained a pit. The depth of the pit was 0.87mm or 32 percent of the diameter of the copper strand. The pit was conical shaped and had a surface diameter of 1.24 m This pit was the result of an arc that developed when the insulation punctured.

The insulation on both sides of the fault was thinly sliced and examined under magnification for any physical abnormalities. There were no significant findings from this procedure. As is common with these types of cable failures, the insulation at the faulted point is severely damaged and any possible imperfections are obliterated, nonetheless; there were no signs of cracking or treeing of the insulation material adjacent to the fault.

Unfortunately in the process to locate the fault point, the entire jacket of the 35 foot section of cable was removed. Therefore, no complete cable sample remained for performing electrical AC/DC withstand or breakdown voltage testing.

Plant Test Records

The plant electrical maintenance records show that periodic DC "hi-pot" tests, up to 7kV, were performed on these cable circuits. This potential is well below the test voltage applied at the factory when the cable is manufactured. Power cable, having an insulation rating of 5kV, is normally tested at the factory to withstand a potential of 40kV DC for fifteen minutes.

Summary of Analysis

At the fault point:

*** The cable showed no signs of having been under any severe mechanical stresses, i.e., compression, shear, tension, or excessive bending.

*** The outside jacket material showed no signs of being chafed.

*** The jacket material was relatively clean and showed no signs of being submerged in water.

*** There was no indication of "treeing" of the EPR insulation.

*** The pitting of one conductor strand indicates a somewhat severe arc occurred before the circuit protection alarmed or cleared the fault.

Periodic "hi-pot" test voltage levels were well below specified rated withstand voltage levels for this type cable.

Conclusions and Discussion

The factors above show that the overall condition of the cable was good in the location where the fault occurred.

The analysis did not provide any clear positive indicators as to what may have caused the failure.

Aging insulation may be responsible for the cable failing but there is no positive evidence to support this effect. Aging must be considered because this cable was manufactured in 1972, installed in 1974, and has been subjected to a fairly harsh environment for many years.

There is indeed a possibility the failure is an isolated incident and not related to aging. Cable failure can result during switching operations that cause an electrical surge on the circuit. Also, manufacturing insulation defects must be considered, but are less likely in this case, because this cable has been in service for many years.

In order to get a second failure analysis opinion and let the cable manufacturer comment, we sent the faulted section of cable to Dr. Jack Lasky of Okonite Company in Ramsey, New Jersey. Dr. Lasky conducted a comparable analysis at his laboratory and reported back to TES via phone on Friday, August 28, 1992. In his expert opinion, there were indeed no clear indicators as to what caused the failure. He said the insulation material looked in excellent condition and can only conclude the failure is the result of an unknown isolated incident.

Recommendations

During the last three years, we have investigated three separate cable failure cases; two from Diablo and one from the Livermore National Laboratory.

Although each of these cables was different, they did have the following similarities: Okonite Manufacturer, EPR insulation, water in the conduit, and manufactured about 20 years ago. Based on these observations, there is a slight suggestion that some factor, like cable aging, may be taking place causing isolated random failures.

We suggest the following course of action for your consideration:

1. Schedule a meeting at Diablo or elsewhere to discuss these cable failures in a forum that brings several PG&E departments together. The primary objective of the meeting would be to determine if more cable testing is required with a particular emphasis on aging effects, if any. For example, the University of Connecticut has a material science laboratory that can provide extensive cable diagnostic services.

2. There is no compelling evidence to suggest that the cable failures we have investigated are anything but random isolated events. However, it may be prudent for planning and budget purposes to consider a cable replacement program for at least high priority circuits.

Please feel free to call Verne Wyman or Ron Bush (251-5304) at any time to discuss this report.

50-275/323-OCA-2 MFP Exhibit T-1
I-MFP-T-1

"NOT ADMITTED" RELATED CORRESPONDENCE

'93 OCT 28 P6:53

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

March 15, 1989

NRC INFORMATION NOTICE NO. 89-30: HIGH TEMPERATURE ENVIRONMENTS AT NUCLEAR POWER PLANTS

Addressees:

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose:

This information notice is being provided to alert addressees to potential problems resulting from high temperature environments in areas that contain safety-related equipment or electrical cables. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances:

In November 1988, while Duane Arnold Energy Center (DAEC) was shut down for refueling, the licensee for DAEC discovered 1 pinhole leak, 2 through-wall cracks, and 30 flaw indications on the control rod drive (CRD) insert lines inside the drywell. The defects were caused by externally induced chloride stress corrosion cracking. The area near the defects contained Rockbestos Firewall III radiation, cross-linked, polyethylene-insulated, electrical cable with a Hypalon (Neoprene Chloroprene) jacket. The cable had previously been degraded by exposure to local drywell temperatures in excess of 270°F. When the damaged electrical cable was replaced, loose degraded insulation lodged in the conduit and the field junction box. Moisture from steam leaks condensed in and dripped through the conduit onto the CRD piping. The condensate contained chlorides that were leached from the insulation lodged in the conduit and the junction box. There are several areas at a reactor facility where degradation of cables and leaching of chloride may occur because of high temperature and humidity. In addition to the drywell, the licensee for DAEC also found indications of chlorides leaching on the steam tunnel.

During a refueling outage in November 1988, the licensee for Dresden Unit 2 discovered evidence that paint inside the upper region of the drywell had been exposed to elevated temperatures. Further investigation revealed that the Limitorque operators on the steam supply valves to the high-pressure

coolant injection system and the isolation condenser (located in the same area) had indications of exceeding their environmental qualification (EQ) design temperature. Grease samples taken from these valves showed significant degradation, and the lower main bearing of one valve operator was damaged. Other equipment affected by the high temperature included two vessel head vent valves and a standby liquid control valve. Also, the electrical insulation on about 50 cables was cracked. The root cause for the elevated temperature at Dresden was attributed to a deficiency in procedures that resulted in the ventilation ducts in the upper region of the drywell being left closed for about 18 months while the plant was in operation.

In August 1987, the NRC became aware that Arkansas Nuclear One, Unit 1 (ANO-1), had probably operated since it was licensed in 1974 with containment temperatures ranging from 90°F to 180°F. The bulk average temperature was roughly 140°F. Safety-related electrical equipment is environmentally qualified to operate at temperatures up to 120°F. Also, design basis accident scenarios had been analyzed assuming an initial containment temperature of 110°F. Over the years, the licensee for ANO-1 attempted to reduce the high containment temperature by installing improved insulation on the reactor coolant system and by acid cleaning of the chillers used for the containment cooling units. These efforts resulted in a very limited temperature reduction.

Discussion:

In the boiling-water reactor events described above, elevated drywell temperature was responsible for degradation of safety-related equipment. Electrical cables are vulnerable to degradation when exposed to high temperatures that exceed their design EQ temperature even for a short period. Regarding the DAEC event, the elevated temperature along with high humidity led to the degradation of safety-related components.

In the ANO-1 event, the higher local temperatures exceeded some of the EQ temperatures for some of the safety and non-safety equipment and components. Also, the higher bulk temperature exceeded the ambient temperature assumed in some of the accident analyses. Three of the analyses that were affected were:

1. The reactor building peak pressure analysis.
2. The inadvertent initiation of the containment spray system analysis.
3. The internal containment subcompartment differential pressure analysis.

There has been a history of reports since 1982 of boiling-water reactors (BWRs) and pressurized-water reactors (PWRs) experiencing excessive heat load problems within the drywell and localized high temperature areas within containment. On June 30, 1988, the NRC issued Temporary Instruction (TI) 2515/98, "Information of High Temperature Inside Containment/Drywell in PWR and BWR Plants." The objective of this TI was to determine whether or not high containment or drywell

temperatures were a plant-specific problem or generic to all PWRs and BWRs. Preliminary findings from the TI showed that:

1. BWRs, especially Mark I and II containments, routinely operate very close to their EQ temperature limit.

2. In the drywells of BWRs there may be substantial temperature gradients (i.e., 100°F or more) that may or may not be detected depending on the location of instrumentation and circulation of the drywell air.

3. The BWR drywell head region seems most susceptible to high temperature.

4. Some PWRs experienced high containment temperatures but the licensees failed to recognize the safety significance and take corrective actions.

It is important for licensees to be aware that there are areas within the plant where the local temperature may exceed equipment qualification specifications even when the bulk temperature, as measured by a limited number of sensors, is indicating that it is lower than the qualification temperature.

No specific action or written response is required by this information notice. If you have any questions about this matter, please contact one of the technical contacts listed below or the Regional Administrator of the appropriate regional office.

Charles E. Rossi

Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

Technical Contacts: R. Anand, NRR
(301) 492-0805

T. Greene, NRR
(301) 492-1176

Attachment: List of Recently Issued NRC Information Notices

LIST OF RECENTLY ISSUED
NRC INFORMATION NOTICES

Information Notice No.	Subject	Date of Issuance	Issued to
89-29	Potential Failure of ASEA Brown Boveri Circuit Breakers During Seismic Event	3/15/89	All holders of OLs or CPs for nuclear power reactors.
89-28	Weight and Center of Gravity Discrepancies for Copes-Vulcan Air-Operated Valves	3/14/89	All holders of OLs or CPs for nuclear power reactors.
89-27	Limitations on the Use of Waste Forms and High Integrity Containers for the Disposal of Low-Level Radioactive Waste	3/8/89	All holders of OLs or CPs for nuclear power reactors, fuel cycle licenses and certain by-product materials licenses.
89-26	Instrument Air Supply to Safety-Related Equipment	3/7/89	All holders of OLs or CPs for nuclear power reactors.
89-25	Unauthorized Transfer of Ownership or Control of Licensed Activities	3/7/89	All U.S. NRC source, byproduct, and special nuclear material licensees.
89-24	Nuclear Criticality Safety	3/6/89	All fuel cycle licensees and other licensees possessing more than critical mass quantities of special nuclear material.
89-23	Environmental Qualification of Litton-Veam CIR Series Electrical Connectors	3/3/89	All holders of OLs or CPs for nuclear power reactors.
89-22	Questionable Certification of Fasteners	3/3/89	All holders of OLs or CPs for nuclear power reactors.

OL = Operating License
CP = Construction Permit

50-275/323-OLA-2
I-MFP-T-5
"NOT ADMITTED"

MFP exhibit T-5

RELATED CORRESPONDENCE

'93 DEC 28 P6:53

Aging Qualification

The SE9090 silicone rubber* (used as the primary insulation in the control cables installed at Diablo Canyon) was tested for elongation properties following heat aging. The following test data was extracted from product data SE9090A (Appdx A) attached to this analysis:

Duration	Temp	% Elongation
(Unexposed	Original)	280% (REF 14, Pg
4 days	480°F (522°K)	120% (REF 15 Appdx A,
60 days	410°F (483°K)	120% (REF 15 Appdx A,

120% elongation represents 57% loss of elongation and, therefore, approximates industry standards for equivalent life time (50% loss of elongation is an industry standard for maximum useful life).

The 120% elongation (end of life)

*(The silicone rubber was used for aging analysis since the silicone/hypalon was not preaged. The hypalon

data may be analyzed to obtain an energy of activation for SE9090:

$$Ea_{SE9090} = \frac{k_b \times \ln\left(\frac{t_1}{t_2}\right)}{\left(\frac{1}{T_1 °k} - \frac{1}{T_2}\right)} \quad \text{Arrhenius Eqn.}$$

Boltzmann's Constant $k_b = 0.00008617$ eV/°K
Duration at Temp. 1 $t_1 = 4$ days
Duration at Temp. 2 $t_2 = 60$ days
Temperature 1 $T_1 = 480°F\ (522°k)$
Temperature 2 $T_2 = 410°F\ (483°k)$

$$Ea_{SE9090} = \frac{(0.00008617)\left(\ln \frac{4}{60}\right)}{\left(\frac{1}{522} - \frac{1}{483}\right)} = \underline{\underline{1.5086\,eV}}$$

As may be expected, the energy of activation for this silicone rubber is relatively high. Generically, most silicon rubbers are relatively immune to thermal degradation; hence, silicon rubbers are often used for high temperature applications.

Ref 11, Page 1 indicates that SE9090 silicone rubber was aged for 7 days at 150°C (423°K) prior to LOCA testing. Using the E_a calculated on page: the qualified life may be calculated using Arrhenius methods:

$$E_a = 1.5086\ eV$$

$$t_{TEST} = 7\ days \qquad T_{TEST} = 423°K$$

$$T_{servic.} = \underset{(Ambient)}{49°C} + \underset{(I^2R\ Rise)}{40°C}^{①} = 89°C\ (362°K)$$

$$k_b = 0.00008617\ eV/°K\ \text{(Boltzmann's Constant)}$$

Arrhenius EQn.

$$t_{LIFE} = \frac{t_{test}}{e^{\left[\frac{E_a}{k_b}\left(\frac{1}{T_{TEST}} - \frac{1}{T_{SERV}}\right)\right]}} = \frac{7\ days}{e^{\left[\frac{1.5086\,eV}{.00008617}\left(\frac{1}{423K} - \frac{1}{362K}\right)\right]}}$$

$$t_{LIFE} = 7481.5\ days = \underline{\underline{20.5\ years}}.$$

However, it is highly unlikely (and would violate PG&E ____ e) that the cables are loaded to 100% of rating. Assuming a very conservative 90% loading; the I^2R rise may be calculated:

$$T_{90\%} = \frac{T_{100\%} \times (0.9I)^2}{I^2} = T_{100\%} \times \frac{0.81\,\cancel{I^2}}{\cancel{I^2}} = 0.81\,T_{100\%}$$

① Cable is designed for 90°C operation. With 49°C ambient, permissible I^2R rise is 41°C — rounded off to 40°C.

This means that 90% loading produces 81% of rated temperature rise. For a 40°C rated I^2R rise, a 90% loading produces an I^2R rise of 0.81 x 40°C = 32.4°C. Using this in the Arrhenius equation:

$t_{TEST} = 7$ days $\quad T_{TEST} = 423°K$

$T_{service} = \underset{(ambient)}{49°C} + \underset{(I^2R\ rise)}{32.4°C} = 81.4°C$ (354.4°K

$k_b = 0.00008617$ eV/°K (Boltzmann's Constant)

Arrhenius Eqn.

$$t_{LIFE} = \frac{t_{TEST}}{e^{\left[\frac{E_a}{k_b}\left(\frac{1}{T_{TEST}} - \frac{1}{T_{service}}\right)\right]}} = \frac{7 \text{ days}}{e^{\left[\frac{1.5086}{.00008617}\left(\frac{1}{423} - \frac{1}{354.4}\right)\right]}}$$

$t_{LIFE} = 21{,}105.8$ days $= 57.8$ years

While testing clearly shows that the cable is qualified for 20.5 years under worst case loading, after further analysis we conclude that the cable is qualified for 57.8 years under designed operating conditions.

Ref 11, Pg. 1 shows that the SE9090 silicone rubber underwent 50 days of simulated LOCA testing.

△3 The postulated curves (REF 2) indicate containment temperature returns to approx. 110°F* after 24 hrs. The post LOCA test conditions are 250°F for 3 days and 200°F for 46 days for an equivalent average temperature of 203°F $\left(\frac{250°F \times 3 + 200°F \times 46}{49}\right)$

This represents an overtesting that may be extended by Arrhenius analysis:

t_{TEST} = 49 days Ref 11, Pg. 1

T_{TEST} = 203.06°F (95.03°C, 368.2°K) (See above)

$T_{SERVICE}$ = 43.33°C (110°F) (Ambient - REF 2) + 32.4°C (I²R Rise - Ref 15, Pg 4) = 75.7°C (348.8

△3

E_a = 1.5086 eV (see page 2).

k_b = 0.00008617 eV/°K (Boltzmann's Constant)

$$F_{LOCA} = \frac{t_{TEST}}{e^{\left[\frac{E_a}{k_b}\left(\frac{1}{T_{TEST}} - \frac{1}{T_{SERV}}\right)\right]}} = \frac{49}{e^{\left[\frac{1.5086}{.00008617}\left(\frac{1}{368.2} - \frac{1}{348.85}\right)\right]}}$$

t_{LOCA} = 383 days

From this analysis it is concluded that

△3 the LOCA test in REF 11 provides 1 year operability with margin for 1 year.

* 110°F is conservative, since the containment temperature would approach outside ambient [illegible]

50-275/323-OLA-2 I-MFP-F-1 179004 026.142

"NOT ADMITTED"

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684
TWX 910-372-6587

James D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

RELATED CORRESPONDENCE '93 OCT 28 P6:53

MFP
exhibit F-1

October 16, 1991

PG&E Letter No. DCL-91-249

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-91-015-00
Violation of Technical Specification 3.7.10 When an Hourly Fire Watch Patrol Was Not Performed Due to Inadequate Instructions

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(i)(B), PG&E is submitting the enclosed Licensee Event Report (LER) regarding a violation of Technical Specification 3.7.10 when an hourly fire watch patrol in safety-related equipment rooms was not performed.

Sincerely,

James D. Shiffer

cc: Ann P. Hodgdon
John B. Martin
Phillip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution
INPO

DC1-91-SS-N081

Enclosure

5512S/85K/JHA/2246

RECEIVED
OCT 17 1991

TEXT (17)

I. Plant Conditions

Unit 1 was in Mode 1 (Power Operation) at 100 percent power and Unit 2 was defueled.

II. Description of Event

A. Event:

On September 17, 1991, at 0300 PDT, the action statement for Technical Specification (TS) 3.7.10 was not met for Units 1 and 2 when the required 0200 PDT fire watch patrol was not performed in the following safety-related equipment rooms: (1) component cooling water (CCW) pump 2-2 (CC)(P) room, (2) inverter 1-3 (ED)(INVT) room, (3) the Unit 1 charging pump (BQ)(P) rooms, (4) the Unit 1 CCW heat exchanger (CC)(HEX) room, and (5) the Unit 1 containment (NH) penetration area. These rooms had inoperable fire barriers.

TS 3.7.10 requires that all fire barriers that protect safety-related equipment be operable. If the fire barrier is inoperable or impaired, the TS action statement requires, in part, that the fire detection equipment be verified operable and that an hourly fire watch patrol be established. The hourly fire watch patrol is performed by the individual designated as the hourly roving fire watch.

When a fire barrier for safety-related equipment is identified as impaired, the fire barrier is placed on a fire barrier impairment list. The fire barrier impairment list is included in the list of inspection areas during the performance of the hourly fire watch patrol.

On September 17, 1991, the fire barrier impairment list included several fire barriers required by TS 3.7.10. In accordance with the action statement of TS 3.7.10, an hourly fire watch patrol had been established.

The hourly fire watch patrol begins in the turbine building (NM), ends in the auxiliary building (NF), and takes approximately 40 minutes to complete. The additional 20 minutes each hour are used for fire watch personnel to exchange duties. The exchanges are such that the hourly roving fire watch relieves a continuous fire watch, who in turn relieves another continuous fire watch, until each fire watch station has been relieved. The last continuous fire watch in the chain assumes the responsibilities of the hourly roving fire watch. Each exchange takes place in the turbine building at a continuous fire watch post. Duty exchanges could occur only at a continuous fire watch post because the continuous fire watch must be maintained at all times. A delay in exchanging duties at one continuous fire watch post can delay all subsequent exchanges.

TEXT (17)

On September 17, 1991, the 0200 PDT hourly fire watch patrol was not performed because the hourly roving fire watch was unable to quickly exit from the radiologically controlled area (RCA) of the plant. The hourly roving fire watch attempted to contact his supervisor as he had been directed, but was unable to do so until it was too late to correct the situation.

After the hourly roving fire watch exited from the RCA and duty exchanges were completed, the hourly fire watch patrol was reestablished at 0303 PDT, September 17, 1991, and the patrol was performed. The last hourly roving fire watch had been completed at 0139 PDT. The total elapsed time between hourly fire watch patrols did not exceed two hours and three minutes.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times for Major Occurrences:

1. September 17, 1991, at 0300 PDT: Event/Discovery date - The 0200 hourly fire watch patrol was not performed in violation of TS 3.7.10.

2. September 17, 1991, at 0303 PDT: The hourly fire watch patrol was reestablished.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

Contracted fire watch personnel identified the missed patrol to the night outage fire watch supervisor.

F. Operators Actions:

None.

G. Safety System Responses:

None.

III. Cause of the Event

A. Immediate Cause:

The immediate cause of the problem was that the 0200 PDT hourly fire watch patrol was not performed until 0303 PDT because the hourly roving fire watch was unable to exit from the RCA and exchange duties with another fire watch.

B. Root Cause:

The root cause of the event was determined to be that no written instructions existed to assure that TS-related fire impairments would be inspected each hour during unexpected conditions which could delay fire watch personnel.

IV. Analysis of the Event

Plant fire barriers are designed to prevent fire in one component or equipment compartment from affecting other safety-related equipment necessary to maintain the plant in a safe condition. TS 3.7.10 requires that all fire barriers that protect safety-related equipment be operable. If a fire barrier required by TS 3.7.10 is inoperable or impaired, the TS requires, in part, that fire detection equipment be verified operable and that an hourly fire watch patrol be established.

The hourly fire watch patrol was not performed for two hours and 3 minutes. Had a fire started during the time when no hourly fire watch patrol was performed, the fire would have been identified by plant fire detection equipment (IC) or by individuals in the auxiliary and turbine buildings who were involved in the Unit 2 fourth refueling outage.

Since a fire during the time when no fire watch patrol was performed would have been detected, the operability of equipment was not jeopardized, and the health and safety of the public were not affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

The next hourly fire watch patrol was performed and did not identify any problems.

B. Corrective Actions to Prevent Recurrence:

1. Written instructions have been added to the fire watch round status logsheets stating (1) the hourly roving fire watch should first contact the senior fire watch on site when a problem arises that may delay the hourly fire watch patrol; (2) the senior fire

TEXT (17)

watch on site will arrange to have a relief individual perform a partial or complete TS impairment inspection; (3) if a relief individual is not available, the senior fire watch on site shall contact the Shift Foreman and request an inspection of the TS-related fire barrier impairments by Operations shift personnel or by the shift industrial fire officer; and (4) if the senior fire watch cannot be contacted in a timely manner, the fire watch may call the Shift Foreman directly.

2. An incident summary will be prepared concerning this event and will be reviewed with all fire watch personnel. The hourly roving fire watch patrol instructions resulting from this event will be included in initial roving fire watch training.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Events:

None.

50-275/323-OLA-2
I-MFP F-4
"NOT ADMITTED"

RELATED CORRESPONDENCE 193293

026.1429

Pacific Gas and Electric Company

'93 OCT 28 P6:53

July 20, 1992

PG&E Letter No. DCL-92-160

MFP
exhibit F-4
8/20/93 Dollie Feigel Reptr.

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-92-007-00
Missed Fire Watch and Manual Engineered Safety Feature Actuation from Chemical Spill Due to Personnel Error

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(i)(B) and 10 CFR 50.73(a)(2)(iv), PG&E is submitting the enclosed Licensee Event Report describing an event that led to (1) a violation of Technical Specification 3.7.10 when an hourly fire watch patrol in safety-related equipment rooms was not performed, and (2) a control room ventilation system shift from its normal ventilation mode to the pressurization mode (an Engineered Safety Feature actuation). This event was caused by personnel error.

This event has in no way affected the health and safety of the public.

Sincerely,

Greg Rueger

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
CPUC
Diablo Distribution
INPO

DC2-92-OP-N029

Enclosure

5825S/85K/SDL/2246

LICENSEE EVENT REPORT (LER)

193199

FACILITY NAME (1): DIABLO CANYON UNIT 1

DOCKET NUMBER (2): 0 5 0 0 0 2 7 5 | PAGE (3): 1 OF 8

TITLE (4): MISSED FIRE WATCH AND MANUAL ENGINEERED SAFETY FEATURE ACTUATION FROM CHEMICAL SPILL DUE TO PERSONNEL ERROR

EVENT DATE (5) MON	DAY	YR	LER NUMBER (6) YR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MON	DAY	YR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
06	20	92	92	- 0 0 7 -	0 0	07	20	92	DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73(a)(2)(i)(B) and 50.73(a)(2)(iv)

OTHER - (Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
RAYMOND L. THIERRY, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4004

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A				N						

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (16)

On June 20, 1992, at 1800 PDT, with Units 1 and 2 in Mode 1 (Power Operation) at 100 percent power, the action statement for Technical Specification 3.7.10 was not met for Units 1 and 2. At 1821 PDT, the control room ventilation system was manually shifted from the normal operation mode to the pressurization mode. This mode shift is an Engineered Safety Feature actuation.

On June 20, 1992, at 1718 PDT, during a condensate demineralizer resin regeneration, an acid/caustic spill caused a chemical mist to enter portions of the turbine building. As a prudent personnel safety measure, the turbine building was evacuated and the roving 1-hour fire watch was discontinued. The 1-hour fire watches were resumed at 0210 PDT on June 21, 1992.

The root cause of the event was personnel error. In order to save time, the non-licensed operator consciously decided to fill the acid and caustic day tanks simultaneously, although the Operating Procedure cautions that only one day tank be filled at a time.

The corrective actions for the event include counseling of the operator, preparation of an incident summary of the event and reviewing it with control operators, and design changes to the condensate polisher system.

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I. Plant Conditions

Units 1 and 2 were in Mode 1 (Power Operation) at 100 percent power.

II. Description of Event

A. Summary:

On June 20, 1992, at 1718 PDT, during a condensate demineralizer (KD) resin regeneration, approximately 700 gallons of chemicals were spilled when the caustic and acid day tanks (KD)(VLR) were overfilled during chemical transfer operations. Since the tanks overflow into a common bermed area, the subsequent chemical reaction yielded a cloud of steam and entrained chemicals.

The chemical spill resulted in activation of the plant fire brigade and an assistance call to the California Department of Forestry. Most areas of the Units 1 and 2 turbine building were evacuated as a precautionary measure, and Unit 2 was placed in an Unusual Event status.

On June 20, 1992, at 1800 PDT, the action statement for Technical Specification (TS) 3.7.10 was not met for Units 1 and 2 when the required hourly fire watch was not performed. At 1821 PDT, the control room ventilation system (CRV) was manually shifted from normal operation to the pressurization mode. This mode shift is an Engineered Safety Feature (ESF) actuation.

B. Background:

The condensate polishing system is part of the secondary plant chemistry control (SD). It is designed to maintain the chemical requirements for condensate water in order to ensure a chemically favorable environment in the steam generators (TB)(SG). A 93% solution of sulfuric acid and a 50% solution of sodium hydroxide are used in the resin regeneration process. The caustic regeneration system consists of a caustic storage tank, caustic day tank, caustic regeneration pumps (KD)(P), caustic heat exchanger (KD)(HX), and associated valves (KD)(V) and piping (KD)(PSX). The acid regeneration system consists of an acid storage tank, acid day tank, acid regeneration pumps, and associated valves and piping.

The control system (KD)(LIC) for the condensate polishers is equipped with a computer system (KD)(CPU), which records valve positions as well as high level alarms from the day tanks. The alarms are displayed via printed messages on both computer monitor (KD)(MON) and printer (KD)(PRNT). There are no audible alarms in the polisher office and no local alarms at the day tanks.

TS 3.7.10 requires that an hourly fire watch and operable fire detection (IC) be provided for fire barrier impairments. The following areas were required to have an hourly fire watch in accordance with this TS: The Unit 1 component cooling water (CCW) heat exchanger (H/X)(BI)(HX) room, Units 1 and 2 diesel generator (EA)(GEN) fire areas, Unit 1 4 KV switchgear (EA)(SWGR) and cable spreading (FA) areas, Unit 1 12 KV switchgear and cable spreading areas, and Unit 2 85-ft CCW H/X Room.

The CRV has four modes of operation. Mode 1 is normal operation and Mode 4 is high radiation/phase "A" pressurization. In mode 4, the ventilation system is designed to isolate and pressurize the control room by filtering air through the HEPA/charcoal filter (VI)(FLT). This action also pressurizes the Technical Support Center (TSC) (NM)(VLR) ventilation.

C. Event Description:

On June 20, 1992, a Unit 2 condensate demineralizer resin regeneration was in progress. At approximately 1635 PDT, a non-licensed auxiliary control operator (ACO) began a series of resin regeneration steps. The ACO was concerned with saving time and turning over his watchstation to the next shift with the regeneration sequence incomplete. Knowing the next series of resin regeneration steps would take about 10 minutes, the ACO decided to complete the unrelated task of filling the acid and caustic day tanks simultaneously, disregarding the precaution in Operating Procedure OP C-7C:IV, "Operating Procedure Condensate Polishing System Resin Bed Regeneration." Filling of the acid and caustic day tanks normally takes about 10 to 15 minutes for the acid tank and 15 to 20 minutes for the caustic tank. Following initiation of the day tank filling process, the ACO continued with the next step in the resin regeneration proce . During that evolution, he forgot about the day tank filling process.

On June 20, 1992, between 1650 PDT and 1705 PDT, following completion of resin cleaning procedure OP C-7C:IV, the high level alarms for the acid and caustic day tank were displayed on the condensate polisher system computer. These alarms were not noted by the ACO since they were mixed with other messages that were expected due to the operating evolutions in progress. At 1700 PDT, the action statement for TS 3.7.10, requiring an hourly fire watch for fire barrier impairments, was performed.

Shortly after the day tank high level alarms were initiated, the tanks began to overflow into a common overflow line and berm area. The mixing of the two chemicals produced an exothermic reaction yielding water, heat (steam), salt byproduct, unreacted caustic, and unreacted acid. The mixture discharged from the common overflow line in all directions of the bermed area. The steam and chemical mixture formed

a dense mist that began to enter the 85-ft elevation of the polisher area, and the 104-ft elevation of the buttress area, including the hallway outside of the TSC. The mist also entered the north end of the Unit 2 turbine building through the screen roll-up door directly east of the acid and caustic bermed area.

On June 20, 1992, at 1718 PDT, a chemistry technician noticed the chemical cloud and notified the control room. The control room sounded the site fire alarm (IC)(FRA) and notified the condensate polisher ACO. The condensate polisher ACO recognized the problem and immediately isolated the tank transfer.

On June 20, 1992, between 1725 PDT and 1730 PDT, the fire brigade assembled on the turbine building 140-ft elevation, and the Shift Supervisor directed that a public address (PA) announcement be made to evacuate the turbine building as a precautionary measure and requested assistance from the California Department of Forestry (CDF). An Unusual Event was declared.

On June 20, 1992, at 1800 PDT, the fire watch surveillance required by TS 3.7.10 was missed when the required hourly fire watch was not performed. At 1815 PDT, fire brigade members installed ventilation fans to exhaust the fumes from the condensate polisher area, preventing further transit of the fumes to the turbine building. It was noted that turbine building conditions rapidly improved at this time. At 1821 PDT, the control room ordered the ventilation shifted from Mode 1 (normal operation) to Mode 4 (pressurization mode). At 1830 PDT, a CDF team arrived at the site and assessed the situation. They recommended that the general spill area be classified as a type A hazardous waste area, and that access be blocked to the area until appropriate protective clothing could be delivered from offsite. At 2046 PDT, the portable ventilation fans, which are gasoline powered, ran out of fuel, and could not be re-fueled and re-started since they were in the hazardous spill area. With the ventilation fans not running, the fumes from the spill area again began to affect the Unit 2 turbine building. A second evacuation notice was made on the PA system.

On June 20 and 21, 1992, between 2315 PDT and 0100 PDT, a Hazardous Materials Team assembled, gross cleanup was started, air samples were taken of all turbine building areas, and the samples indicated that access restrictions were not necessary. Free access was restored to all areas of the plant except the immediate spill area.

On June 21, 1992, at 0210 PDT, the hourly fire watch surveillance required by TS 3.7.10 was performed satisfactorily and the Unusual Event was terminated.

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

E. Dates and Approximate Times for Major Occurrences:

1. June 20, at 1700 PDT: TS 3.7.10 requiring hourly fire watch was last performed.

2. June 20, at 1718 PDT: Chemistry technician discovered spill and reported it to the control room.

3. June 20, at 1722 PDT: ACO terminated spill.

4. June 20, at 1735 PDT: Unusual Event (UE) was declared. Initial notifications were made.

5. June 20, at 1800 PDT: TS 3.7.10 action statement was not met when fire watch was not performed.

6. June 20, at 1821 PDT: CRV was manually shifted to Mode 4.

7. June 21, at 0210 PDT: UE was terminated. Hourly fire watch in accordance with TS 3.7.10 action statement was resumed.

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

A chemistry technician discovered the spill and reported the situation to the control room. At approximately the same time, a mechanic noticed a smokelike cloud in the U-2 85-ft elevation of the turbine building. He reported it to his foreman and the Shift Supervisor.

H. Operators Actions:

1. The onsite fire brigade was assembled.

2. The acid and caustic day tank transfer was secured.

3. The control room and TSC ventilation systems were placed in Mode 4 (pressurization mode).

I. Safety System Responses:

Upon manual actuation, the CRV system ventilation shifted to the pressurization mode.

III. Cause of the Event

A. Immediate Cause:

The immediate cause of the event was that the acid and caustic day tanks were simultaneously filled and both tanks overflowed. The overflow lines from the day tanks join into a common overflow line near the caustic tank and empty just above the floor into the northwest side of the day tank berm area.

Since these lines overflow into the same area and the caustic tank had been overflowing for some time, the end of the common overflow line became submerged. When the acid tank began to overflow, the mixture of the highly concentrated acid and caustic produced a steam and acid mist.

B. Root Cause:

The root cause of the event was personnel error. In order to save time, the non-licensed operator consciously decided to fill the acid and caustic day tanks simultaneously although the Operating Procedure cautions that only one day tank be filled at a time.

C. Contributory Cause:

1. The overflow lines for the acid and caustic tanks are piped together. There is also a common berm area that surrounds the caustic and acid day tanks and associated pumps.

2. Although both tanks have high level alarms that initiated, they did not prompt the ACO to take corrective actions. The alarms are inadequately designed because they do not emit audible signals and they are displayed only on a CRT along with other messages.

IV. Analysis of the Event

Plant fire barriers are designed to prevent fire in one fire area from spreading to adjacent areas containing safety-related equipment necessary to maintain the plant in a safe condition. TS 3.7.10 required that all fire barriers that protect safety-related equipment be operable. If a fire barrier required by TS 3.7.10 is inoperable or impaired, the TS requires, in

part, that detection equipment be verified operable and that an hourly fire watch patrol be established.

The hourly fire watch was not performed for approximately 8 hours. Had a fire occurred during the time when no hourly fire watch patrol was performed, the fire would have been identified to control room personnel by plant fire detection equipment (IC).

Fire brigade fire suppression equipment (KP) was readily available in areas adjacent to the chemical spill. The fire suppression equipment available included: a fire engine (KP)(ENG), self-contained breathing apparatuses, exhaust fans, hazardous materials response kits, portable breathing compressor, local fire extinguishers (KQ), and offsite fire fighting personnel.

The CRV system was conservatively manually shifted from the normal ventilation mode to the pressurization mode per the control room directive. The chemical mist did not pose a threat to the public because most of the entire mass of spilled acid reacted with the excess of caustic in the berm and the mist remained inside the facility. A multi-disciplined team has determined that no safety-related equipment in the spill area or adjacent areas was affected.

Since a fire would have been detected and extinguished during the 8 hours the 1-hour fire patrol was not present, the operability of equipment was not jeopardized, and the health and safety of the public were not affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

1. The ACO closed the storage tank fill lines to the caustic and acid day tanks. As a precautionary measure, the ACO de-energized the acid and caustic pumps by opening their supply breakers (EC)(BKR) and then secured the resin regeneration in progress.

2. As an additional precautionary measure, the turbine building was evacuated and the air was sampled. Access was then reinstated and the hourly fire watches were resumed.

B. Corrective Actions to Prevent Recurrence:

1. The ACO was counseled concerning his failure to perform his duties with adequate attention to detail.

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2. An Operations Incident Summary will be prepared for this event and reviewed with Operations personnel.

3. Design changes will be implemented on the condensate demineralizer regeneration system to provide a separate audible annunciator system (KD)(ANN).

4. A design change will be initiated to separate the overflow piping on the acid and caustic day tanks.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Problems:

None.

50-275/323-OLA-2
I-MFP-F-7
"NOT ADMITTED"

RELATED CORRESPONDENCE

MFP exhibit
F-7

'93 OCT 28 P6:53

MANAGEMENT SUMMARY

On November 21, 1991, during the performance of STP M-39B in the Unit 2 Cable Spreading Room (CSR), the north half of fire damper VAC-2-FD-220 failed to close. The chain holding the damper was corroded and stuck to the left rod support bracket. The rod bracket was rust colored and appeared somewhat corroded. The contact area between the rod bracket and the chain was of a greenish color. (Attachment 1).

A technician easily separated the chain from the bracket with a screwdriver and the damper dropped. This was the only damper failure during this test.

The root cause of the chain link corroding and sticking to the bracket was that no design drawings or criteria for the CO2 actuation portion of the fire damper specified either the material type or bracket clearance tolerance. Therefore, the wrong material was used and a small gap exists between the chain and the bracket of the two north damper bracket halves.

In order to prevent recurrence of this problem the following corrective actions will be implemented:

1. Issue two Recurring Task Orders (per unit) to inspect, clean and lubricate the damper bracket every 3 months until the design has been modified.

2. Develop an adequate damper actuator design which considers the material selection, bracket gaps and actuator bar retaining device.

NCR DC2-91-SS-N101

128' CABLE SPREADING ROOM CLASS II SUPPRESSION FIRE DAMPER FAILED TO CLOSE DURING STP M-39B.

I. Plant Conditions

Unit 2 was in mode 1 at 100% power.

II. Description of Event

A. Event:

Summary.

On November 21, 1991 Damper VAC-2-FS-220 was being tested when the north half of the Unit 2 cable spreading room (CSR) ventilation system supply fire damper, VAC-2-FD-220, failed to close during the performance of STP M-39B, "Routine Surveillance Test of Cable Spreading Room Carbon Dioxide Fire System Operation". (Reference 1).

Background.

The damper is constructed in two sections. A chain holds the damper in the open position. When the chain is released, the damper will close. The chain is held in place by a fusible link and by a CO2 system actuation rod. If the fusible link melts, the chain releases and the damper closes. Additionally, if the CO2 system is actuated, a separate actuation rod will move horizontally, release the chain and allow the damper to close (Attachment 1).

Chronology.

On September 17, 1988 during STP M-39B, an almost identical incident occurred. The north half of the Unit 2 CSR ventilation system supply fire damper VAC-2-FD-220 failed to close due to chain corrosion. The problem was corrected by freeing the chain (reference 6, QE # 5325).

On November 21, 1991, the same north half of the Unit 2 CSR ventilation system supply fire damper, VAC-2-FD-220, failed to close during the performance of STP M-39B, "Routine Surveillance

Test of Cable Spreading Room Carbon Dioxide Fire System Operation" (reference 1).

After this most recent failure, the damper actuation mechanism was inspected. The inspection identified that the bracket on the actuation device was rust colored and appeared to be corroded. The chain link was of a shiny chrome color. The areas where the chain and the bracket touched were corroded and of a greenish color (reference 1).

The technician easily separated the chain from the bracket with a screwdriver and the damper dropped. This was the only damper failure during this test (reference 1, 14 and 15).

B. Inoperable Structures, Components or Systems that Contributed to the Event:

Damper VAC2-PD-220 failed to close during a routine surveillance test.

C. Dates and Approximate Times for Major Occurrences.

1. September 17, 1988: The north half of damper VAC-2-FD-220, failed to close during STP M-39B due to excessive rust on the damper retaining chain. (Ref. 6, QE 5325).

2. November 2, 1990: Damper VAC-2-FD-220 was successfully tested during performance of STP M-39B

3. December 12, 1990: The Unit 1 CSR ventilation supply damper VAC-1-FD-220 fails to close on header pressurization during STP M-39B (caused by the chain not properly coupled to the actuating rod). VAC-2-FD-220 was inspected at the time for proper configuration , but not for possible chain corrosion. (reference 7: NCR DC-1-86-TN-N137).

4. November 21, 1991: Event/discovery date. Damper VAC-2-FD-220, north half failed to close during STP M-39B. The chain was found to be corroded at one point to the left rod bracket.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

The event was identified by the engineer and technician during the performance of STP M-39B on November 21, 1991.

F. Operators Actions: None.

G. Safety System Responses: None.

III. <u>Cause of the Event</u>

A. Immediate Cause:

The north half of damper VAC-2-FD-220 failed to close because the chain holding up the damper was corroded and stuck to the left rod bracket.

B. Determination of Cause:

1. Human Factors:

a. Communications: N/A.

b. Procedures:

Do the procedures adequately address damper's lubrication and maintenance?

STP M-39B and M-70 did not specifically require that the CO2 actuation mechanism be lubricated on a regular basis. The only specific lubrication requirements are for the damper track.

c. Training:

Are inspectors trained on proper lubrication techniques?

The maintenance personnel are trained on the appropriate methods for lubricating the dampers. However, the appropriate lubrication techniques and locations for the actuation device were not specified.

d. Human Factors:

The dampers are located in an area of high air flow, poor visibility and limited access. These conditions impede inspection of the chain and the actuation bracket.

e. Management System:

The corrective action for QE 5325 was ineffective in preventing the problem from recurring. This QE is discussed in section II A (Event) and Section (VI) B 3 (Previous Similar Events).

2. Equipment/Material:

a. Material Degradation:

Corrosion was identified between the first link of the chain and the retaining bracket. The corrosion prevented release of the CO2 actuation chain that allows the damper to close. (Attachment 1).

b. Design:

Is the design adequate?

The configuration of the actuating device lends itself to multiple failure mechanisms. A review of past records indicates previous problems with the damper.

Was the environment considered when the actuation mechanism was designed?

There is no design document for the installation of the actuator device, only the damper itself.

c. Installation:

Did the installation of the actuation mechanism inhibit the function of the damper?

The CO2 actuation mechanism was fabricated and installed on site during plant construction. The installation may have contributed to the corrosion problem as the two affected bracket halves appear to have less clearance than the other 3 similar brackets.

d. Manufacturing: N/A.

e. Preventive Maintenance: N/A

f. Testing:

Does the test frequency meet PG&E and NFPA standards?

NFPA standards specify testing of the damper every 2 years. PG&E testing requirements specify more frequent testing.

g. End-of-life failure: N/A.

C. Root Cause:

The root cause of the chain link corroding and sticking to the bracket was that no design drawings or criteria for the CO2 actuation portion of the fire damper specified either the material type or bracket clearance tolerance. Therefore, the wrong material was used and a small gap exists between the chain and the bracket of the two north damper bracket halves.

D. Contributory Cause:

None.

IV. Analysis of the Event

A. Safety Analysis:

The CSR ventilation supply damper VAC-2-FD-220 north half failed to close during STP M-39B due to the chain being stuck to the corroded rod bracket. This event appears to be similar to the event of September 17, 1988 on the same unit (reference 7). The damper was returned to operable status within one hour of discovery per Tech Specs 3.7.10 and 3.7.9.3.

A continuous fire watch was established in the CSR during the period in which the fire damper was non-functional. In addition, a roving fire patrol and operable fire detection instrumentation was provided to the CSR from November 2, 1990 to November 21, 1991. A continuous fire watch was also provided in the CSR for all but six days between November 2, 1990, and November 21, 1991.

If a fire would have occurred in the CSR during this period, it would have been rapidly detected and/or reported by the fire watch. The fire brigade would have responded to the fire and extinguished it using the available fire suppression equipment.

An assessment of the impact of the open damper on CO2 concentration was performed and determined that there is no

assurance that the design basis of the CO2 concentration would have been met with half of the damper open.

In the event that a fire did destroy the CSR, an orderly and safe reactor shutdown could have been performed from the remote shutdown panel.

Therefore, the health and safety of the public were not adversely affected by this condition.

B. Reportability:

1. Reviewed under QAP-15.B and determined to be non-conforming in accordance with Section 2.1.7, as a problem that was previously identified and which corrective actions were ineffective.

2. Reviewed under 10 CFR 50.72 and 10 CFR 50.73 per NUREG 1022 and determined not to be reportable in accordance with 10 CFR 50.73(a)(2)(i)(B) since the Limiting Condition for Operation (LCO) was met. NUREG 1022 states "In general, for the purpose of evaluating the reportability of situations found during surveillance tests, it should be assumed that the situation occurred at the time of discovery, unless there is firm evidence to believe otherwise."

   In this case the limited condition for operation was met because it is assumed that the condition occurred at the time of discovery since the mechanic stated (see reference no. 15) that it took very little pressure to free the rusted bar guide.
   Therefore, there is no firm evidence to believe that the condition occurred during the six day period when there was no continuous fire watch in this area prior to the time of discovery.

3. This problem does not require a 10 CFR 21 report.

4. This problem does not require reporting via an INPO Nuclear Network entry since the Cardox actuation rod is of a unique design.

5. Reviewed under 10 CFR 50.9 and determined to be not reportable since this event does not have a significant implication for public health and safety or common defense and security.

V. Corrective Actions

A. Immediate Corrective Actions:

1. The damper was returned to an operable status within one hour of discovery per tech specs 3.7.10 and 3.7.9.3.

2. Issue two Recurring Task Orders for inspection, cleaning and lubrication of the damper bracket on a 3 month frequency until the design change to modify the actuator assembly is implemented.

   RESPONSIBILITY: L.M. Neal ECD: 3/24/92
   DEPARTMENT: Mechanical Maintenance.
   AR # A0252789 AE # 5.

B. Investigative Actions:

Contact NECS and request assistance (obtain design info) in determining the types of material and corrosion mechanisms present in the affected dampers. Also investigate and evaluate any design and/or installation differences between the four dampers. This AE supersedes AE # 1.
NECS assistance is requested on AE # 2 to provide any design information available. Assistance of Will Barkhuff requested on AE # 4. to determine metals used in components and to evaluate the corrosion effects on these components. Design differences documented in AE # 1.

RESPONSIBILITY: DAVID POWELL.
DEPARTMENT: Emergency/Safety Services.
AR #: A0252789 AE # 3.
STATUS: COMPLETE.

C. Corrective Actions to Prevent Recurrence:

1. Because of the lack of an adequate design detail describing the material and component clearances and due to the history of previous problems with these specific dampers, the TRG recommends that a design be developed and a design change be implemented for these dampers. Consideration should be given to:

   - Material selection.
   - Bracket gaps.
   - Actuator bar, retaining device (to prevent the bar from disengaging from the bracket).

   RESPONSIBILITY: L.M. Neal ECD: 9/25/92
   DEPARTMENT: Mechanical Maintenance.
   AR # A0252789 AE # 6.

D. Prudent Actions (not required for NCR closure):

None.

VI. Additional Information

A. Failed Components:

Ventilation system damper VAC-2-FD-220.

B. Previous Similar Events:

1. DC1-86-TN-N137 - During the "Puff test" of the CO2 fire system in the Unit 1 Cable Spreading Room the class II ventilation supply fire damper did not fully close.

   The root cause of this event was incorrect installation of the damper during the plant construction.

   Corrective action: The TRG determined that the condition identified in this NCR was a result of the original installation and DCN DC1-SH-37482 was issued to add a positive closure spring to the fire damper. Rework of the fire damper was performed under WO C0027567 and documented on AR A0073829. However, this corrective action did not prevent this NCR because the failure mechanism was different. Additionally, the spring installed on one half of damper VAC-1-FD-220 was never installed on the other identical dampers. The design change was specific only to the one section of the damper.

2. NCR DC1-90-SS-N085 - On November 29, 1990 both sections of Unit 1 CSR ventilation system supply fire damper, VAC-1-FD-220, failed to close on CO2 header pressurization during STP M-39B.

   The root cause was indeterminate, but most likely to be a personnel error when reassembling the actuator assembly following routine testing.

   Corrective actions: STP M-39B was enhanced to include a drawing of the fusible link attachment between the cardox system and the ventilation dampers. A qualified and experienced fire protection engineer was hired as the test director for fire protection system surveillances. STP M-70 was revised to include a caution statement and to provide verification of the fire damper as-left condition.

This event was found reportable and LER 1-90-018 was submitted.

The corrective actions from this NCR did not prevent this event from reoccurring because the failure mechanism was different.

3. QE Q0005325.

On September 19, 1988 during the performance of STP M-39B fire damper VAC-2-FD-220 failed to close. The damper was subsequently released by lightly tapping it.

The root cause of this event that allowed fire damper VAC-2-FD-220 to stick open during the cardox testing was determined to be due to a corroded chain. The probable cause may have been due to improper protection from corrosion when it was installed.

The corrective action to prevent recurrence was to provide adequate PM requirements. Those requirements included lubrication of the dampers in accordance with STP M-39B and STP M-70 on an 18 month frequency.

However, a review of the QE as part of this NCR determined that the lubrication requirements in STP M-39B and STP M-70 did not specifically address the actuation device.

C. Operating Experience Review:

1. NPRDS:

Not applicable. The actuation rod and fusible link assemblies are unique PG&E designs.

2. NRC Information Notices, Bulletins, Generic Letters:

NRC Information Notice 89-52: "Potential Fire Damper Operational Problems" (ref. 3).
This information notice discusses potential problems with fire dampers not closing under operating air flow conditions. The recent problem associated with damper actuation is not within the scope of IN 89-52. Therefore, this notice could not have prevented the current event.

3. INPO SOERs and SERs:

None (ref. 4).

D. Trend Code:

SS department, C1 cause code

E. Corrective Action Tracking:

The tracking action request is A0252789.

F. Footnotes and Special Comments:

During this event, the engineer and technician performing STP M-39B noticed that one end of the actuator bar had bounced out of its support guides and was laying at the bottom of the damper. Although this occurrence did not contribute to the damper failure, the TRG recognizes that this condition could in the future possibly interfere with proper damper closure upon Cardox actuation. Therefore, the design change to replace the carbon steel brackets with stainless steel brackets will include a modification to ensure that the actuation bar will remain in its guides and preclude the possibility of interfering with the damper closure. (Ref. Corrective Action C-2).

G. References:

1. Initiating Action Request A0252260.

2. Tracking Action Request A0252789.

3. Technical Specifications 3.7.9.3. and 3.7.10.

4. P&ID 102023. Location of damper 2-FD-220.

5 Clearance # 00030318 and 00032656 showing the 6 days where there was no fire watch.

6. AR A0252255.
   AR A0252288.
   AR A0124033.
   QE Q0005325.

7. NCR DC1-86-TN-N137.
   NCR DC1-90-SS-N085.

8. LER 1-90-018, "Fire Damper Cardox Actuation Fusible Link Assembly Incorrectly Installed For Indeterminate Reason."

9. LER 1-89-019. "Fuel Handling Building Ventilation System inoperable during fuel movement due

10. WO R0044133 with STP M-39B conducted on 07/12/88.

11. WO R0047400 with STP M-39B conducted on 01/13/90.

12. STP V-11 conducted on 04/02/90 per WO R0050255.

13. STP M-39B completed on 01/09/91.

14. Statement from Greg Smith, mechanic that freed the damper linkage.

15. Statement by David Powell, Fire Protection engineer who witnessed the release of the damper linkage by the mechanic Greg Smith.

H. TRG Meeting Minutes:

On December 3, 1991 the TRG convened and considered the following:

a. The management summary was revised to remove the battery ground indication and the cardox master seal leakage.

b. The description of the event was also revised to remove the previous events, and add some information on how the technician separated the chain from the bracket.

c. The dates and approximate times of the events were also revised to add the November 2, 1990 event and delete the December 21, 1990 event.

d. The determination of cause was also reviewed to add some questions and statements which may lead to the root cause.

2. It was decided that the contributory cause will be determined later.

3. The analysis of the event was revised to incorporate the continuous fire watch and the actions that would have been taken in the case of a fire in the CSR and would not affect the health and safety of the public.

4. It was agreed that the reportability will be further evaluated by Regulatory Compliance to assure that this event was not reportable at this time.

5. It was decided that one Action Evaluation will be written to encompass the following investigative actions:

a. Materials/Coatings.

b. Adequacy of Corrective action QE.

c. Adequacy of Preventive Maintenance.

1. Lubricant.

2. Frequency.

3. Instrument/training.

4. Configuration of damper for this application.

6. TRG to reconvene on 1/17/92 to review the investigative actions and determine the Root Cause and Corrective Actions and potential reportability for inadequate corrective action.

On January 17, 1992, the TRG reconvened and considered the following:

1. The TRG reviewed the NCR write-up and recommended editorial changes to clarify the problem.

2. The TRG discussed the results of the investigative actions. The TRG determined that additional information was required from NECS regarding the design of the actuation system, and the reason for limiting the installation of an assist spring to one section of one damper.

3. The TRG will reconvene on 1/24/92 to discuss the results of the NECS actions.

MEETING MINUTES OF THE 1/24/92 TRG

On 1/24/92 the TRG reconvened and considered the following:

1. Discussion with NECS on the design consideration of the actuator.

2. The previous NCR DC1-86-TN-N-137 was discussed It was agreed that the assist spring was installed on only one of the 4 dampers, to assist the damper since it had been installed backward (Ref. 8).

3. The determination of cause was reviewed and the statements under management system, design and installation were revised.

4. The material issue was discussed. It was pointed out that W. Barkhuff verified that the rods were made of Austenitic Steel, the rod brackets and chain links of Carbon Steel. The last link of the chain , which is the link contacting the actuator rod and bracket, is made of austenitic stainless steel.

5. It was recommended to increase the brackets gap.

6. The design of the actuating mechanism was discussed.

This NCR should be sent to the PSRC by 2/24/92.

This NCR should be closed by 03/31/93.

I. Remarks:

The estimated completion date was changed from 10/15/92 to 03/31/93, due to funding requirements for AE # 6 of the tracking AR # A0252789.

J. Attachments:

Damper 2-FD-220 drawing.

50-275/323-OLA-2
I-MFP-F-8
"NOT ADMITTED"

MFP exhibit F-8

RELATED CORRESPONDENCE

DCO-92-TN-N004
October 8, 1992

'93 OCT 28 P6:54

MANAGEMENT SUMMARY

Two events are described in this NCR:

1. Work Order (W/O) R0077008, a partial STP M-80A, "Outdoor Fire Hose Annual Operability And Hydrostatic Test," was closed on September 15, 1991 without completing a hydro of all of the long term cooling water (LTCW) hoses stored on racks 1, 1A, 2, 3, 6 and 7. The initial TRG convened on January 31, 1992.

2. Diesel driven fire pumps 0-2 (February 1992) and 0-3 (October 1991) failing to develop acceptable discharge pressures during the performance of STP P-24 was incorporated in this NCR during a TRG reconvene on May 1, 1992.

The root causes and corrective actions for these events were determined to be:

1. STP M-80A included requirements for testing Technical Specification related equipment and non-Technical Specification equipment and did not clearly distinguish the differences in acceptance criteria for each category of equipment.

   Corrective actions consisted of: (1) the separation of non-Technical Specification equipment from the existing STP M-80A, (2) Surveillance Coordination determination of the appropriate actions for STP reviewers and (3) the addition of a requirement for rejecting ARs in AP C-12 to be reviewed with the rejecting Maintenance foreman to resolve STP closure concerns.

2. The portable fire pump discharge pressure gauge snubbers mounting to the piping becomes clogged with debris.

   Corrective actions consisted of: (1) the revision of STP P-24 to provide additional guidance on seismic restraint installation, (2) WPC coordination of the biannual PMs between Operations and Maintenance to identify discrepancies and (3) resolution of material problems for the portable diesel driven fire pumps with NECS.

NCR DCO-92-TN-N004

I. Plant Conditions

Unit 1 was in Mode 1 (Power Operation) at 100% power. Unit 2 was in Mode 1 at 100% power.

II. Description of Event

A. Event:

Event 1:

On August 11, 1991, STP M-80A, "Outdoor Fire Hose Annual Operability And Hydrostatic Test," became due, with a Technical Specification date of November 11, 1991.

Work Order (W/O) R0077008, a partial STP M-80A, "Outdoor Fire Hose Annual Operability And Hydrostatic Test," was closed on September 15, 1991 without completing a hydrostatic test of all of the long term cooling water (LTCW) hoses stored on racks 1, 1A, 2, 3, 6 and 7. Some of the five inch soft hoses were tested and their coupling separated; these hoses were not replaced as of January 16, 1992.

Event 2:

Action Request (AR) A0249955 documents testing of diesel driven portable fire pump 0-3 in October 1991 that resulted in pump discharge pressure indicating lower than acceptable. It was believed that the discharge pressure gauge was inaccurate, however, in November I&C checked the gauge and found it to be accurate. This AR was taken to history.

In February of 1992, AR A0259976 documented that diesel driven portable fire pump 0-2 could not meet the required discharge pressure during testing. This problem has been incorporated into the resolution of this NCR. AR A0265120 documents additional seismic concerns regarding portable fire pump 0-3.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times for Major Occurrences:

Event 1:

1. August 11, 1991: STP M-80A comes due.

2. September 15, 1991: W/O R0077008 taken to complete without all testing completed.

3. February 21, 1992: Hoses were inspected, tested and repaired. All work complete on W/O C0096011.

Event 2:

1. October 27, 1991: STP P-24, "Testing of the Portable Long Term Cooling Pumps," performed on portable Fire Pump 0-3. Discharge pressure not acceptable. I&C to check gauge.

2. November 22, 1991: AR A0249955 closed, no adjustments made.

3. February 29, 1992: STP P-24 performed on portable Fire Pump 0-2. Discharge pressure not acceptable. I&C to check gauge.

4. March 5, 1992: W/O R0094630 issued to inspect/adjust discharge pressure gauges.

5. April 23, 1992: STP P-24 performed on portable Fire Pump 0-3. Discharge pressure not acceptable. AR A0259976

written to document the problem.

6. May 6, 1992: STP P-24 performed on portable Fire Pumps 0-1, 0-2 and 0-3. Pumps 0-2 and 0-3 discharge pressures not acceptable. ARs A0266423 and A0266425 written to document this condition.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

Event 1:

While reviewing completed work orders Work Planning determined that not all testing specified in work order R0077008 had been completed.

Event 2:

While reviewing completed STP P-24 on portable Fire Pumps 0-2 and 0-3 System Engineering determined the test results were unsatisfactory.

F. Operators Actions:

None required.

G. Safety System Responses:

None required.

III. Cause of the Event

A. Immediate Cause:

Event 1:

A complete STP M-80A was not performed on the hoses.

Event 2:

Portable Fire Pumps 0-2 and 0-3 indicated unacceptable discharge pressure on installed gauges during surveillance testing.

B. Determination of Cause:

Refer to the Root Cause Analysis (Attachments One and Two) attached to this NCR.

C. Root Cause:

Event 1:

STP M-80A included requirements for testing Technical Specification related equipment and non-Technical Specification equipment and did not clearly distinguish the differences in acceptance criteria for each category of equipment.

Event 2:

The portable fire pump discharge pressure gauge snubbers mounting to the piping becomes clogged with debris.

D. Contributory Cause:

Event 1:

1. The STP tracking AR was erroneously rejected.

2. There has been a lack of support for the LTCW hoses.

3. There has been a failure to maintain the LTCW system hoses properly.

Event 2:

1. The STP did not provide complete guidance on portable fire pump priming and operation.

2. Operations personnel were not familiar with portable fire pump operation.

3. Material problems with the portable fire pumps not consistently recognized and resolved.

IV. Analysis of the Event

A. Safety Analysis:

The LTCWS has eight different lineups to supply water to the auxiliary feedwater (AFW) system. In order of desirability of use they are:

1. Unit 1 and 2 condensate storage tanks (CST),
2. Condenser hotwell via the condensate pumps and CST,
3. Makeup water transfer (MWT) tank via the MWT pumps
4. Fire water storage tank (FWST) via FCV-436/437,
5. Condensate hotwell via hose connections and portable fire pump,
6. Raw water reservoir via hose connections and portable fire pump,
7. Diablo Creek via hose connections and portable fire pump and
8. Auxiliary saltwater via the fire water tank.

This order of desirability is based on convenience and water purity. Non use of any one of these options does not affect the other choices. Therefore, although option number 6 above is currently inoperable, an alternate supply of long term cooling water from the FWST is and has been available to support design basis accidents.

Of the 8 alternative sources listed in the FSAR as sources of long term cooling water, 4 can be achieved using installed piping and plant equipment. These are the preferred sources for long term cooling.

* The Unit 1 and 2 CST
* Main condenser hotwells
* Makeup water transfer tank
* Fire water storage tank.

The four sources described above are proceduralized in OP D-1:V.

Following reactor shutdown, the backup means of removing core decay heat is through the use of the auxiliary feedwater system. When temperatures are sufficiently reduced to permit transfer to the residual heat removal system, cooling to cold shutdown is then initiated. In the event this is not feasible and the originally designed supply of cooling water from the condensate storage tank (CST) becomes exhausted, the LTCWS provides additional cooling water to bring the plant to cold shutdown. The LTCWS provides a means of delivering water to the auxiliary feedwater pump inlet for steam generator cooling of the reactor coolant system. The system is to function when normal feedwater supplies are depleted in order to:

- Maintain the plant in hot standby for an extended period of time beyond the capacity of the design volume from the CST if cold shutdown is not achievable, and/or

- Provide a backup to the RHR system for cooling during the cold shutdown evolution.

The LTCWS uses existing permanent systems and pumps to transfer water from the various sources to the auxiliary feedwater pumps. The LTCWS provides portable pump driver units with hoses and systems connections to cross-connect permanent systems and to backup non-seismically qualified systems.

As discussed above, the LTCWS is a supplementary system to the CST (178,00 gallons) and FWST (270,000 gallons). A total of 448,000 gallons of water are available in seismically qualified systems while only 222,600 gallons are required to cooldown from hot standby to 350°F for the worst case condition of cooldown by natural circulation. The LTCWS consists of eight backup sources of cooling water. Hoses are provided because it was assumed that the seismically non-qualified piping would fail in an earthquake.

The shortage of required hoses reduces the amount of backup water available for cooling. However,

as indicated in the HOSGRI Seismic Evaluation, Appendix J, page J-17, the ultimate backup source for long term cooling for an indefinitely extended period of hot shutdown is seawater which is unaffected by the above condition. Therefore, although a shortage of hoses prevents the full utilization of one of the backup water sources, adequate water sources would be available to accomplish the intended function of long term cooling.

As discussed above, multiple redundant sources of water are available to provide alternate sources of water for long term cooling water. These multiple redundant sources of water can also be used to supplement fire fighting capability following a seismic event to augment the capability of the portable fire pumps on a temporary basis pending permanent resolution of the current portable fire pump problems. The portable fire pumps were a commitment identified in Supplement 8 to the SER, page 9-17. In addition, the Site Fire Truck could be used to feed the AFW if other alternatives prove less effective.

Based on the above analysis, operation of Units 1 and 2 with the LTCWS degraded does not adversely affect the health and safety of the public.

B. Reportability:

1. Reviewed under QAP-15.B and determined to be non-conforming in accordance with Section 2.1.8.

2. Reviewed under 10 CFR 50.72 and 10 CFR 50.73 per NUREG 1022 and determined to be not reportable.

3. This problem does not require a 10 CFR 21 report.

4. This problem does not require reporting via an INPO Nuclear Network entry.

5. Reviewed under 10 CFR 50.9 and determined to

be not reportable since this event does not have a significant implication for public health and safety or common defense and security.

6. Reviewed in accordance with AP C-29, "Operability Evaluation," and determined that an OE is not required.

V. Corrective Actions

A. Immediate Corrective Actions:

Event 1:

Work Planning drafted and issued a work order to restore the LTCW system. Work order C0096011 assigned on February 4, 1992 to inspect/test/replace hoses; work completed on February 25, 1992.

RESPONSIBILITY: J. Mellinger (PGMW) COMPLETE
AR A0257289, AE # 09

Event 2:

Mechanical Maintenance (with Operations support) disassembled, cleaned and inspected the instrument snubbers for the portable fire pump discharge pressure gauges.

RESPONSIBILITY: L. Price (PGMC) COMPLETE
AR A0257289, AE # 19

B. Investigative Actions:

Event 1:

1. NECS - Engineering will determine what standards are applicable to the LTCW hoses and the appropriate hydrostatic test pressure.

   RESPONSIBILITY: G. Maroofi (NCEM) COMPLETE
   AR A0257289, AE # 01

2. Regulatory Compliance will determine whether this incomplete surveillance is reportable.

RESPONSIBILITY : J. Nolan (PTRC) COMPLETE
AR A0257289, AE # 02

3. NECS - Engineering will investigate the need for maintaining the LTCW hoses/pump considering current plant design.

RESPONSIBILITY: G. Maroofi (NCEM) COMPLETE
AR A0257289, AE # 03

4. Emergency/Safety Services will determine if there is a need for training in sign-offs for STPs.

RESPONSIBILITY: D. Cosgrove (PASE) COMPLETE
AR A0257289, AE # 04

5. Regulatory Compliance to determine if LTCW system is considered operable from review of Operations logs.

RESPONSIBILITY: J. Nolan (PTRC) COMPLETE
AR A0257289, AE # 05

6. Surveillance Coordination will determine if there is an adequate procedure for closing STPs with outstanding problems.

RESP: L. Cossette (PTEX) COMPLETE
AR A0257289, AE # 06

7. Determine if adequate guidance exists regarding closing-out (or signing-off) an STP when some of the equipment has not yet passed the test. Is it good enough just to initiate an AR as was done in this case?

RESP: L. Cossette (PTEX) COMPLETE
AR A0257289, AE # 07

8. Quality Control to perform a root cause analysis for this event.

RESP: T. McKnight (PQCE) COMPLETE
AR A0257289, AE # 15

Event 2:

9. System Engineering to consult with Operations Engineering in the establishment of a complete performance history of the LTCW system pumps with emphasis on inadequate performance during testing.

   RESP: L. Cossette/S. Baker (PTEX) COMPLETE
   AR A0257289, AE # 18

10. Review design documents to determine if the instrument snubber for the portable fire pump discharge pressure gauge is depicted in any design document and a requirement for those pumps.

   RESPONSIBILITY: G. Maroofi (NCEM) COMPLETE
   AR A0257289, AE # 20

C. Corrective Actions to Prevent Recurrence:

Event 1:

1. Emergency/Safety Services will revise STP M-80A into separate tests for fire protection considerations (M-80A) and for LTCW considerations (M-80C), including the development of recurring task work orders. The Fire Protection Specialist will be responsible for the review of test results and the resolution of problems identified during these STPs.

   RESP: D. Cosgrove (PASE) COMPLETE
   AR A0257289, AE # 10
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

2. NSARA to document their position on the elimination of the LTCW function of the hoses without changing any existing commitments in the tracking AR.

   RESPONSIBILITY: D. Ogden (NRAS) COMPLETE
   AR A0257289, AE # 12
   No OE required.

Not outage related.
Not an NRC commitment.
Not a CMD commitment.

3. Surveillance Coordination will determine what actions are appropriate to have STP reviewers establish that additional documents that have been generated relative to an STP (e.g., ARs, exemption requests, QEs, etc.) must be closed or otherwise tracked to ensure open items are completed.

   RESP: L. Cossette (PTEX) COMPLETE
   AR A0257289, AE # 16
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

4. Review the AP C-12 requirements for rejecting ARs with the Maintenance foreman who rejected the ARs written to resolve the STP concerns.

   RESPONSIBILITY: S. Allen (PGMX) COMPLETE
   AR A0257289, AE # 17
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

Event 2:

6. Plant Engineering to revise STP P-24 to provide additional guidance for the installation of seismic restraints on portable long term cooling pumps as well as general pump operation.

   RESP: E. Chaloupka (PTEX) COMPLETE
   AR A0257289, AE # 21
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

7. Work Planning to coordinate between the Maintenance and Operations Departments to

enable six month preventative maintenance and surveillance testing be performed together such that discrepancies identified can be expeditiously corrected.

RESPONSIBILITY: J. Bard (PGWM) COMPLETE
AR A0257289, AE # 23
No OE required.
Not outage related.
Not an NRC commitment.
Not a CMD commitment.

8. Issue an AT EWR AR to coordinate material problems with NECS for the portable diesel driven fire pumps that require a design change notice to resolve (reference ARs A0266423 and A0266425, ref. 9 and 10 respectively).

RESPONSIBILITY: L. Price (PGMC) COMPLETE
AR A0257289, AE # 26
No OE required.
Not outage related.
Not an NRC commitment.
Not a CMD commitment.

9. Implement a design change to resolve material problems described in references 9 and 10 and in AE # 23.

RESPONSIBILITY: C. Rhodes (NCEM) ECD: 5/3/93
AR A0257289, AE # 25
No OE required.
Not outage related.
Not an NRC commitment.
Not a CMD commitment.

D. Prudent Actions:

Event 1:

~~1. Issue an AT EWR AE to NECS - Engineering (NCEM) requesting a design change to eliminate any commitments made regarding the LTCW and fire protection functions of the pumps and hoses stored east of the plant on the hillside.~~

~~RESP: J. Anastasio (PTES) COMPLETE~~
~~AR A0259381 (from AR A0257289, AE # 13)~~
~~No OE required.~~
~~Not outage related.~~
~~Not an NRC commitment.~~
~~Not a CMD commitment.~~

This action was deleted by the TRG.

2. Draft and transmit an EWR to NECS for specification of hose covers for the LTCW hoses when in storage.

   RESP: J. Anastasio (PTES) ECD: 6/10/93
   AR A0268252
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

Event 2:

3. Revise procedures for the operation of the LTCW system to include the specifics of portable fire pump operation to facilitate the periodic testing and securing of the pumps and their support equipment.

   RESPONSIBILITY: J. Skaggs (PGOE) ECD: 8/3/92
   AR A0267173
   No OE required.
   Not outage related.
   Not an NRC commitment.
   Not a CMD commitment.

VI. Additional Information

A. Failed Components:

Event 1:

None.

Event 2:

Portable diesel driven fire pumps 0-2 and 0-3.

B. Previous Similar Events:

NCR DC0-89-TN-N089, "Long Term Cooling Water Supply System Not Maintained Operable," discusses the commitments expressed and implied in the FSAR regarding the LTCW system. Corrective actions for this non-conformance included the issue of a design change to correct deficiencies and revisions of STPs M-80A and P-24 to include adequate system testing. These corrective actions apparently were not in sufficient depth to permanently resolve LTCW system problems.

C. Operating Experience Review:

1. NPRDS:

   Not applicable.

2. NRC Information Notices, Bulletins, Generic Letters:

   None.

3. INPO SOERs and SERs:

   SOER 86-1, "Reliability of PWR Auxiliary Feedwater Systems."

D. Trend Code:

Event 1:

SS (Emergency/Safety Services) - B5 (procedure deficiency.

Event 2:

ME (NECS - Engineering) - C1 (material/equipment deficiency, engineering/design).

E. Corrective Action Tracking:

1. The tracking action request is A0257289.

2. The corrective actions are not outage related.

F. Footnotes and Special Comments:

Mr. J. D. Shiffer has commented that even though PG&E didn't commit to having the reservoir hoses, they seem to be a good insurance policy. These hoses should not be eliminated, we (DCPP) should be able to remember to test them.

G. References:

1. Initiating action request A0256102.
2. Earlier action request A0023493.
3. Earlier action request A0087744.
4. Earlier action request A0091371.
5. Earlier action request A0152418.
6. Earlier QE Q0008569.
7. Earlier QE Q0008932.
8. Letter dated March 4, 1992 from JB Hoch to BW Giffin, "Long Term Cooling Water System," CHRON 186097.

H. TRG Meeting Minutes:

1. On January 31, 1992, in room 527 of the administration building at 10:00 PST, the initial meeting of the TRG convened. A discussion regarding testing of the hoses for the LTCW system concluded that fire protection functions of the system should be separated from LTCW considerations for the system.

   Investigative actions and corrective actions as noted above were assigned.

   The TRG will reconvene on February 14, 1992.

2. On February 14, 1992, in room 527 of the administration building at 1:00 pm PST, the TRG reconvened to discuss the preliminary position NSARA has taken that the long-term

cooling function of the hoses to the reservoirs and Diablo creek can be eliminated without an FSAR revision. An entry on the annual design change describing the change is all that is necessary.

The TRG agreed with the NSARA position and identified the additional investigative and corrective action marked in the text of this NCR with revision bars in the right-hand margin.

The TRG will reconvene if significant changes to PG&E positions occur or if additional corrective actions are considered necessary.

The estimated closure date of this NCR is July 1, 1992.

3. On March 10, 1992, at 1:00 pm PST in room 527 of the Administration Building, the TRG reconvened to discuss the status of investigative and corrective actions assigned in this NCR and determine who has "ownership " of the LTCW system.

   STP M-80A will be revised to separate "Q" from non-"Q" by moving the non-"Q" to STP M-80C. Former corrective action #6 has become a prudent action.

   The TRG determined that this NCR will address STP performance only, any seismic concerns regarding the LTCW system equipment or other equipment will not be addressed in this NCR.

   As shown in paragraph III.B, there has been no determination of cause prepared for this NCR. There is no reconvene planned for this TRG.

4. On April 17, 1992, at 10:00 am PDT in room 425 of the administration building, the TRG reconvened to discuss the status of corrective actions. Revisions to the correctives actions previously identified are as noted above.

   A new corrective action was assigned to QC to

review the criteria for rejecting ARs with the cognizant department to preclude misunderstandings. An evaluation was made to determine if this is a generic problem by QC reviewing a number of ARs. No generic problem is apparent. The TRG concurred that no further actions for this concern are justified.

The Chairman of this TRG is now C. Groff.

The ECD for this NCR is scheduled for August 3, 1992.

5. On May 1, 1992, at 1:00 pm PDT in room 527 of the administration building, the TRG reconvened to discuss adding concerns regarding the portable diesel driven fire pumps being unable to achieve the specified discharge pressure during testing of 65 psig.

   This writeup will be edited by C. Groff prior to the next TRG reconvene (scheduled for May 12, 1992). The next TRG meeting will be to discuss and summarize investigative actions.

6. On May 20, 1992, at 1:00 pm PDT in room 533 of the administration building, the TRG reconvened to discuss the progress of corrective actions identified in earlier TRGs.

   It was established that Fire Protection will assume responsibility for the LTCWS soft hoses.

   Additional investigative and prudent actions as noted above were identified by the TRG.

   The TRG will reconvene on June 4, 1992.

7. On June 4, 1992, at 10:00 am PDT in room 527 of the administration building, the TRG reconvened to discuss the status of identified actions. Revised status is shown above adjacent to the revision bars in the right-hand margin. Additional actions as noted above were also identified.

A root cause analysis for event #2 will be provided by Systems Engineering (S. Baker).

The estimated completion date for this NCR is June 1, 1993 based on completion of design changes for the portable fire pumps.

This TRG will reconvene on or about June 21, 1992 to verify the root cause proposed above and to evaluate gathered test information.

8. On June 25, 1992, at 10:00 am PDT in room 533 of the administration building, the TRG reconvened to discuss completion of this NCR.

   The root causes and corrective actions as amended and noted above were agreed on.

   No reconvene of this TRG is planned.

   The results from the recent monthly surveillances were discussed by S. Baker (PTET) and L. Price (PGMM). Tests were observed with the instrument snubbers removed and cleaned. Flow readings were recorded as acceptable. The corrective action to coordinate the biannual PMs of Maintenance with Operation's running of the surveillance was agreed upon to enable instrument snubber cleaning activities prior to Operations performing the surveillance. This routine cleaning of the instrument snubbers was determined to be an effective corrective action.

I. Remarks:

1. Two specific items have been discussed within the forum of this TRG dealing with the ongoing support and maintenance of the LTCWS.

   a. Early on, the issue of ownership was raised, discussed and initially considered a contributing cause for the current problems with the LTCWS. Conversations with Plant Management clearly directed that the LTCWS did not warrant a system

engineer. The maintenance and problem resolution activities were to be handled within the current work processes at the Plant.

b. The development of an Equipment Control Guideline (ECG) for the LTCWS hoses and portable diesel driven fire pumps was an initial corrective action. The reason for development of an ECG on non-technical specification, non-safety related equipment of this nature was to emphasize the priority of the corrective maintenance activities in support of maintaining the system in operating condition. This action was not supported by Plant Management.

J. Attachment(s):

1. Event # 1 Root Cause Analysis.

2. Event # 2 Root Cause Analysis.

50-275/323-OLA-2
I-MFP-F9
"NOT ADMITTED"

MFP exhibit F-9

RELATED CORRESPONDENCE

DOCKETED
USNRC

DCO-93-SS-N032
July 22, 1993

'93 OCT 28 P6:54

DCO-93-SS-N032
INADVERTENT CO2 DISCHARGE IN DG 2-3

MANAGEMENT SUMMARY

On May 27, 1993, at approximately 1415 PST, a post maintenance test of FCV-104 was performed using a partial STP M-39A2. DG 1-2 was chosen as the source of the CO2 system initiation. All precautions specified by the STP were followed. There were no visible system abnormalities and all the timers were verified to be timed out in accordance with the STP. However, initiation of the test resulted in an inadvertent discharge of CO2 in the DG 2-3 room at 1448.

Investigations immediately following the discharge revealed that the local selector valve for DG 2-3 was in the open position and the electrical CO2 circuits had not actuated. It was therefore concluded that the CO2 system had actuated manually.

Although the inadvertent discharge was a personnel safety concern, this event did not affect the operability of the DGs.

A second puff test was attempted on June 4, to investigate if the DG 2-3 actuator valve handle becomes mispositioned as a result of testing. However, the test was not completed, and another inadvertent discharge took place. This second discharge occurred with the abort valve closed. Because the cause of the failure was unknown, the CO2 system was isolated by closing FP-95 to ensure personnel safety.

The May 27 discharge was caused by human error, in that the operator did not recognize that the position of the valve handle was different from other DG Units. The June 4 discharge appears to have been caused by an abnormality with FCV-100, causing it to stick open. The upstream header isolation valve, FCV-104, had previously been improperly reassembled and pieces of the valve were found in FCV-100. (Ref. QE Q0010752.) A blank flange was subsequently installed in FCV-100 to facilitate reopening FP-95 to restore CO2 capability to the unaffected portions of the system.

The TRG reconvened on July 22, 1993, and determined the corrective actions and discussed the use of the Winter Green odorizer during Cardox testing. The TRG plans to reconvene on September 14, 1993.

DC0-93-SS-N032
INADVERTENT CO2 DISCHARGE IN DG 2-3

I. Plant Conditions

Unit 1 and Unit 2 were in Mode 1 (Power Operation) at 100 percent power.

II. Description of Event

A. Summary:

On May 27, 1993, at approximately 1415 PST, a post maintenance test of FCV-104 was performed using a partial STP M-39A2. Diesel Generator (DG) room 1-2 was chosen as the source of the CO^2 system initiation. All precautions specified by the STP were followed. There were no visible system abnormalities and all the timers were verified to be timed out in accordance with the STP. However, initiation of the test resulted in an inadvertent discharge of CO2 in DG room 2-3 AT 1448.

A second puff test was attempted on June 4, to determine if the DG 2-3 actuator valve handle becomes mispositioned as a result of testing. However, the test was not completed, and another inadvertent discharge took place. This second discharge occurred with the abort valve closed. Because the cause the failure was unknown, the CO2 system was isolated by closing FP-95 to ensure personnel safety.

B. Background:

The low pressure Cardox system consists of five separate headers with normally closed (N/C) pilot-operated valves, which open to charge the respective header with Carbon Dioxide. These five headers consist of:

1. Unit 1 and Unit 2 DG rooms and cable spreading rooms (CSRs).
2. Unit 1 lube oil (LO) room.
3. Unit 2 LO room.
4. Cardox Hose reels stations.
5. Unit 1 and Unit 2 # 10 turbine bearings.

Upon actuation of the Cardox system in a given fire area, a timer is actuated. The timer sequences the alarms and opens the solenoid valves over a 4 minute period. The solenoid valves supply motive pressure to open the master and local selector valves for the affected areas. Once the master valve and local selector valve are open, Cardox is discharged to the affected fire area.

Equipment Control Guideline (ECG) 18.5, "CO2 System," requires that the low pressure Cardox system be operable. In areas where redundant systems or components could be damaged by the same fire, a continuous fire watch must be established when the automatic low pressure Cardox system is inoperable in the area. The continuous fire watch and backup fire suppression equipment must be in place for those areas in which redundant systems or components could be damaged. For other areas supplied by the low pressure Cardox system, an hourly fire watch must be established. When a Cardox hose reel station is inoperable, backup fire suppression equipment must be provided for the affected area within 1 hour.

C. Event Description:

On May 23, 1993, FCV-104, the isolation valve for the DG room and Cable Spreading Room CO2 system header, was replaced due to leakage.

On May 27, 1993, at approximately 1415 PST, a post maintenance test of FCV-104 was performed using a partial STP M-39A2. DG 1-2 was chosen as the source of the CO2 system initiation. All precautions specified by the STP were followed. There were no visible system abnormalities and all the timers were verified to be timed out in accordance with the STP. However, initiation of the test resulted in an inadvertent discharge of CO2 in DG room 2-3 at 1448.

A pre-TRG meeting held May 28, 1993, at 1000 PST, determined that the CO2 system had actuated manually because the DG 2-3 local selector valve was in the open position and the electrical CO2 circuits did not actuate. It was also determined that this event did not affect the operability of the DGs.

On June 1, 1993, inspection of the manual actuation valve for DG room 2-3 determined that the operation of

the manual actuation handle is significantly different from the operation of those in the other five DG rooms.

A second partial STP M-39A3 was attempted on June 4, 1993, to determine if the DG 2-3 actuator valve handle becomes mispositioned as a result of testing. However, the test was not completed, and another inadvertent discharge took place. This second discharge occurred with the abort valve closed. Because the failure was unknown, the CO2 system was isolated by closing FP-95 to ensure personnel safety.

On June 7, 1993, investigations determined that the subject local selector valve handle operated properly, and did not become mispositioned as a result of the test.

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

FP-2-FCV-100 was either stuck open or leaking.

E. Dates and Approximate Times for Major Occurrences:

1. May 27, 1993 at 1448:

   Event/Discovery Date - Inadvertent CO2 discharge into DG Room 2-3.

2. June 4, 1993 at about 11:20:

   Event/Discovery Date - Inadvertent CO2 discharge into DG Room 2-3. (Please refer to Q₋ Q0010752.)

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

Control room alarm indicated a CO2 discharge in DG room 2-3 on May 27 and personnel observations on June 4.

H. Operator Actions:

DG1-2 CO2 system testing was immediately halted.

I. Safety System Responses:

None required.

III. Cause of the Event

A. Immediate Cause:

The May 27, 1993 discharge occurred because the local selector valve handle was in the open position. (The subsequent discharge that occurred during investigations on June 4, 1993, was caused by a problem with FP-2-FCV-100, causing it to stick open or leak by. The CO2 discharge header was therefore allowed to discharge to DG 2-3 as soon as the header was charged during the partial STP M-39A3.)

B. Determination of Cause:

(A root cause analysis will be provided later.)

C. Root Cause:

The two inadvertent CO2 discharges, on May 27 and June 4, 1993, were caused by different problems. The May 27 discharge was caused by human error, in that the operator did not recognize that the position of the valve handle was different from other DG units. The June 4 discharge appears to have been caused by an abnormality with 2-FCV-100 (ref. QE Q0010752).

D. Contributory Causes:

1. The labeling of the handle did not correspond to the correct operating position.

2. Human factor design. The manufacturer changed the design, such that the handle travels opposite to the original design used on the other DCPP DG CO2 systems.

3. The step in the PMT Procedure for returnign the valve to the closed operator error and/or differences in valve handle operation.

IV. Analysis of the Event

A. Safety Analysis:

1. Personnel Safety

Because the electrical CO2 circuits were not actuated during these events, the roll down doors did not close and the discharged CO2 dissipated

rapidly. The evaporation of liquid cardox will freeze water vapor out of the air, which will take the appearance of a white fog or cloud. This indication was noted immediately after this event. Any personnel in the DG 2-3 room would have noted the discharge and immediately left the room.

2. Cardox System Operability

The CO2 tank is sized for two complete generator purges, two complete discharges to the largest hazard area (CSR), plus a reserve for hose reels. The discharge of CO2 to D/G 2-3 did not create a situation where there was insufficient CO2 reserve to prevent any other hazard area from performing its design fire fighting function (ref. FSAR 9.5-9).

Section 9.5 of the FSAR takes credit for the availability of the CO2 system in specific plant fire areas to mitigate the damage caused by fire. However, the ability to achieve and maintain a safe shutdown of the plant is not dependent upon the proper operation of the CO2 suppression system. 3-hour rated barriers separate redundant diesel generators. This ultimately provides the required separation mandated by the NRC via 10CFR50 Appendix R. There are three diesels available to support a safe shutdown.

The hourly roving fire watches remain in place in DG 2-3 as well as the other five DGs to provide a compensating measure for the inoperable CO2 system for DG 2-3.

3. Diesel Generator Operability

The operability of D/G 2-3 would not be affected by an inadvertent discharge to the D/G 2-3 room because engine combustion air is drawn from outside the building (ref. DCM S-21). In addition, the configuration of the D/G rooms is such that even with the roll-up doors open, it would be difficult for discharged CO2 to travel up to the D/G air intake, due to being heavier than air and to the number of obstacles along the path.

Thus the health and safety of the public or plant personnel were not affected by these events.

B. Reportability:

1. Reviewed under QAP-15.B and determined to be non-conforming in accordance with Section 2.1.2 as a significant non-routine event that may adversely affect the safe operation of the plant.

2. Reviewed under NUREG 1022 and determined to be not reportable in accordance with 10 CFR 50.73 because it does not meet reportability criteria. The CO2 gas released did not interfere with the ability of personnel to perform duties necessary to shut the plant down and maintain it in a safe shutdown condition.

3. This problem does not require a 10 CFR 21 report because it does not involve a defective component or a failure to comply with regulations.

4. This problem will not require reporting via an INPO Nuclear Network entry. It is unique to this plant due to the design change to add the lockout relays.

5. Reviewed under 10 CFR 50.9 and determined to be not reportable since this event does not have a significant implication for public health and safety or common defense and security.

V. Corrective Actions

A. Immediate Corrective Actions:

1. Review the partial STP M-39A2 for DG 1-2 to validate the acceptability as a PMT for the replacement FCV-104.

RESPONSIBILITY: D. Powell
DEPARTMENT: Safety
TRACKING AR: A0308314, AE #07
ECD: 6/04/93
STATUS: Complete

The STP was reviewed on June 2, 1993, and accepted as a PMT.

2. Install a blank flange in the upstream side of the 3" inlet line to 2-FCV-100, ideally with a test connection.

RESPONSIBILITY: R. Waltos

DEPARTMENT: Mechanical Maintenance
TRACKING AR: A0308314, AE #08
ECD: 6/05/93
STATUS: Complete

3. Develop a plan to restore the CO2 system for the diesel generator rooms. Resolve the appropriate ARs, clearances, jumpers, and identify the required PMT and ISLT. Include a temporary lamacoid for the local selector valve for the DG 2-3 room to clearly identify the closed and open handle positions.

   RESPONSIBILITY: D. Powell
   DEPARTMENT: PASE
   TRACKING AR: A0308314, AE #13
   ECD: 7/15/93
   STATUS: Assigned

B. Investigative Actions:

1. Please document that the electrical timer circuit for DG 2-3 did not actuate during the CO2 discharge on May 27, 1993, and that the electrical timer for DG 1-2 went through a normal sequence.

   RESPONSIBILITY: R. Hanson
   DEPARTMENT: Electrical Maintenance
   TRACKING AR: A0308314, AE #09
   ECD: 6/09/93
   STATUS: Complete

2. Please document that the CO_2 discharge on May 27, 1993, was terminated when the partial STP M-39A2 for DG 1-2 was secured.

   RESPONSIBILITY: P. Lucas
   DEPARTMENT: Safety
   TRACKING AR: A0308314, AE #10
   ECD: 6/09/93
   STATUS: Complete

3. Please document that the local selector valve for 2-FCV-100 was found with the manual actuator handle straight down (in the open position), after the May 27, 1993, inadvertent CO_2 discharge.

   RESPONSIBILITY: R. Hanson
   DEPARTMENT: Electrical Maintenance
   TRACKING AR: A0308314, AE #11

ECD: 6/09/93
STATUS: Complete

4. Collect previous test history for the Diesel Generator 2-3 CO2 system.

   RESPONSIBILITY: D. Powell
   DEPARTMENT: Safety
   TRACKING AR: A0308314, AE #02
   ECD: 6/04/93
   STATUS: Complete

5. Initiate a work order to observe 2-FCV-100 pilot operation.

   RESPONSIBILITY: J. Nystrom
   DEPARTMENT: Work Planning
   TRACKING AR: A0308314, AE #03
   ECD: 6/4/93
   STATUS: Complete

6. Investigate the sticky pushbutton documented on AR A0307054.

   RESPONSIBILITY: Hanson
   DEPARTMENT: Electrical Maintenance
   TRACKING AR: A0308314, AE #04
   ECD: 6/04/93
   STATUS: Complete

7. (Design Document Research) Investigate how the local selector valve for DG 2-3 room works differently from those in the other five rooms.

   RESPONSIBILITY: J. Gregerson
   DEPARTMENT: NES
   TRACKING AR: A0308314, AE #05
   ECD: 6/09/93
   STATUS: Complete

8. Perform operability/reportability review for this event.

   RESPONSIBILITY: Farradj/Sisk
   DEPARTMENT: NES/Regulatory Compliance
   TRACKING AR: A0308314, AE #06
   ECD: 6/04/93
   STATUS: Complete (See AR A0308220, AE #01.)

9. Evaluate the feasibility/acceptability of modifying

the local selector valve for the DG 2-3 room to make its operation consistent with the other five DG room local selector valves. Document response on AR A0308791.

RESPONSIBILITY: J. Gregerson
DEPARTMENT: NES
TRACKING AR: A0308314, AE #14
ECD: 6/15/93
STATUS: Complete

10. Disassemble and inspect FCV-100 for DG 2-3 room and determine its failure mechanism and repair method.

RESPONSIBILITY: Machado
DEPARTMENT: PGMA
TRACKING AR: A0308314, AE #15
ECD: 6/15/93
STATUS: Complete

11. Develop a plan to inspect the cardox piping downstream of 2-FCV-100 for debris.

RESPONSIBILITY: D. Pierce
DEPARTMENT: PGMA
TRACKING AR: A0308314, AE #16
ECD: 6/30/93
STATUS: Complete

12. Review PIMS to determine if other similar valves have been repaired, but not replaced.

RESPONSIBILITY: D. Powell
DEPARTMENT: Safety
TRACKING AR: A0308314, AE #17
ECD: 6/22/93
STATUS: Complete

13. Include an inspection plan to locate missing debris in DCP-P-47734 (CO_2 pipe replacement).

RESPONSIBILITY: D. Pierce
DEPARTMENT: PGMA
TRACKING AR: A0308314, AE #18
ECD: 6/30/93
STATUS: Overdue

14. Determine the root cause for the May 27, 1993, inadvertent CO_2 discharge.

RESPONSIBILITY: D. Cosgrove
DEPARTMENT: Safety
TRACKING AR: A0308314, AE #19
ECD: 6/30/93
STATUS: Complete

15. Determine the root cause for the June 4, 1993, inadvertent CO_2 discharge.

    RESPONSIBILITY: D. Pierce
    DEPARTMENT: PGMA
    TRACKING AR: A0308314, AE #20
    ECD: 6/30/93
    STATUS: Overdue

16. Conduct a discharge test in DG room 2-3 and puff tests (STP M-39s) after the implementation of DCP 47734 with odorizer "cut in" to determine if there is a problem with wintergreen odorizer saturation.

    RESPONSIBILITY: Powell, D. L.
    DEPARTMENT: Safety
    TRACKING AR: A0308314, AE# 25
    ECD: 9/14/93
    STATUS: Assigned

17. Identify any NFPA Code requirements relating to the use of wintergreen odorizer in CO2 fire protection systems.

    RESPONSIBILITY: Gregerson, J. A.
    DEPARTMENT: NES, Mechanical
    TRACKING AR: A0308314, AE# 26
    ECD: 9/1/93
    STATUS: Assigned

C. Corrective Actions to Prevent Recurrence:

1. Modify the handle position lamacoid to indicate the proper position and direction of operation for all local selector valves.

    RESPONSIBILITY: D. POWELL
    DEPARTMENT: SAFETY
    TRACKING AR: A0308314, AE #21
    Outage Related? No
    OE Related? No
    NRC Commitment? No
    CMD Commitment? No

ECD: 8/6/93
STATUS: Assigned

2. Amend and revise the design drawing for the Chematron local selector valve to reflect the new design provided by the manufacturer.

RESPONSIBILITY: J. GREGERSON
DEPARTMENT: NES
TRACKING AR: A0308314, AE #22
Outage Related? No
OE Related? No
NRC Commitment? No
CMD Commitment? No
ECD: 8/6/93
STATUS: Assigned

3. Add a step to the STP M-39 series procedures to verify the local selector valve handle position of the other installations on the CO_2 system header being tested before performing the test.

RESPONSIBILITY: D. POWELL
DEPARTMENT: SAFETY
TRACKING AR: A0308314, AE #23
Outage Related? No
OE Related? No
NRC Commitment? No
CMD Commitment? Yes
ECD: 8/6/93
STATUS: Assigned

4. Write and re-perform PMT 18.07 (CO2 concentration test) in Diesel Generator room 2-3, upon completion of DCP 47734.

RESPONSIBILITY: HJALMARSON
DEPARTMENT: Nuclear Engineering
TRACKING AR: A0308314, AE #24
Outage Related? No
OE Related? No
NRC Commitment? No
CMD Commitment? No
ECD: 8/6/93
STATUS: Assigned

D. Prudent Actions (not required for NCR closure):

1. Inspect old FCV-104 internals to determine cause of

leak-by.

RESPONSIBILITY: B. Waltos ECD: 6/15/93
Mechanical Maintenance
AR A0307647

2. Issue an INPO Nuclear Network entry requesting information regarding industry's use of wintergreen odorizer when testing CO2 fire protection systems. Collect all responses for presentation to the TRG.

RESPONSIBILITY: Sisk, D. P./Chan, J.
DEPARTMENT: Regulatory Compliance
TRACKING AR: TBD
ECD: 9/14/93
STATUS: Assigned

VI. Additional Information

A. Failed Components:

None.

B. Previous Similar Events:

NCR DC0-90-SS-N063

While testing the carbon dioxide system to diesel generator (D/G) 2-2 room, CO2 was inadvertently discharged into D/G 1-3 room as noted by the D/G 1-3 discharge alarm in the control room.

Root cause:

The root cause of this event was personnel error in that the room timer had not been allowed to time out after the last test (STP M-39A) of the diesel generator 1-3 cardox system as required by the procedure.

Corrective actions to prevent recurrence:

1. Enhance timer indicators to more clearly show when the room timer has timed out.

2. Revise STP M-39A, M-39B, and M-39C to enhance precautions before resetting lockout relays and warn operators about checking time positions before testing.

3. Revise STP M-39A, M-39B, and M-39C to add an

instruction as to how to verify the timer has timed out. Add also an independent verification that the timer has timed out.

C. Operating Experience Review:

1. NPRDS.

   Not applicable.

2. NRC IE Information Notices, Bulletins, Generic Letters:

   IE Information Notice 85-87: HAZARDS OF INERTING ATMOSPHERES
   IE Information Notice 85-87 (ref. 11) contains information about the general hazards of inerting atmospheres and enclosed spaces. The notice does not address the prevention of inadvertent discharges of inert gases.

3. INPO SOERs and SERs:

   SER 55-85: PERSONNEL INJURY DUE TO INADVERTENT CARBON DIOXIDE DISCHARGE (ref. 12)
   The root cause of this event was that the cardox system was charged with CO2 prior to the completion of pre-operational testing. The recent event had a different set of root causes, and knowledge gained from the prior event would not have prevented the recent event.

D. Trend Code:

   TBD.

E. Corrective Action Tracking:

1. The tracking action request is A0308314.

2. Corrective actions are not outage related.

F. Footnotes and Special Comments:

   None.

G. References:

1. AR A0308220

2. AR A0308232
3. NECS E3.2
4. DCM S-21
5. "Sequence of Events," prepared by D. Cosgrove
6. AR A0307054, regarding the sticking push-button
7. Quality Evaluation (QE) Q0010752
8. AR A0308791
9. AR A0307647

H. TRG Meeting Minutes:

NOTE: A PRE-TRG MEETING WAS HELD BEFORE THIS EVENT WAS DETERMINED TO BE A NONCONFORMANCE.

1. The initial TRG convened on June 4, 1993 to continue investigations.

   The TRG chairman presented and discussed the event chronology (see reference 5), described the diesel generator room CO_2 system and reviewed investigations to date.

   The TRG identified that immediate efforts are needed to re-open FP-95 to restore CO_2 to the diesel generator rooms. Before this can happen, further investigation is needed to determine the exact location cause of the problem.

   On May 27, it appeared as though the manual selector valve had been cycled manually. There was no indication that the electrical timer circuit had actuated. The configuration of this valve, in particular, the handle position, is different from that of the other manual selector valves (in the other diesel generator rooms).

   It is possible that FCV-100 is stuck open.

   There were some questions regarding the position of the abort valve during testing.

   A history search should be performed to determine

if other CO_2 tests had been performed after May 14, noting the position of the actuator valve.

A second puff test was attempted on June 4, to check the final resting position the actuator valve handle. However, the test was not completed, and another inadvertent discharge took place. The pushbutton was observed to stick, as it was during the May 27 test.

Removing FCV-100 for testing was discussed as a possible investigative action. However, there were concerns that removal could alter conditions and hamper investigation. The TRG assigned an immediate corrective action (number 2 above) to install a blank flange upstream of FCV-100.

The TRG will reconvene on June 9, 1993 to continue investigation into this event.

2. The TRG reconvened on June 9, 1993, to discuss the results of investigative actions, and to continue investigations.

   Testing revealed that FCV-100 was leaking, but that the abort valve and local selector valve operated properly. The focus would now be on investigating the cause of the FCV-100 leaking. Since the plant started using these types of valves there was a modification from a leather seat to a teflon seat. All of the diesel generator room valves of this model have the teflon seats, but there are others in the plant that probably still have leather seats.

   The leak must have developed after or during the first puff test on June 4, but before the discharge resulting from the second puff test that day. It was suggested that FCV-100 may have intermittent leaking.

   The TRG reviewed some of the details of both inadvertent CO_2 discharges. The event chronology, prepared by Safety, will be updated.

   The TRG determined that the two CO_2 discharges, on May 27 and June 4, 1993, were caused by different problems. The May 27 discharge appears to have been caused by misposition of the selector valve.

The June 4 discharge appears to have been caused by an abnormality with FCV-100. This later discharge appears to be the first that has occurred with the abort valve closed.

A potential reportability issue is the gap under the diesel generator room doors, which allows CO_2 to escape from the room. An AR was initiated to address this issue.

The TRG assigned new actions, AEs 13 - 15 on tracking AR A0308314.

The TRG will reconvene on June 15, 1993.

3. The TRG reconvened on June 15, 1993, developed additional investigative and corrective actions, and determined the cardox system upstream of 2-FCV-100 to be functional but inoperable. The TRG is scheduled to reconvene July 1, 1993, to review the root cause, and results of investigative actions.

4. The TRG reconvened on July 1, 1993, to discuss and develop additional investigative and corrective actions.

   Since June 15, 1993 inspections have been made in the cardox piping for screws found missing on FCV-104.

   Initial inspections were made in the cardox piping downstream of FCV-100 in the ceiling of the diesel 2-3 room. Pieces of teflon seals thought to have come from FCV-104 were found.

   July 1, 1993 the blank flanges upstream of FCV-100 was removed and the valve internals were examined, but nothing was found. 1 screw, 2 screw heads and part of the seal and seal backing ring are still missing.

   FCV-100 has been put back together, but a post maintenance test may not be done until the rest of the investigation is finished, which may not be until August of 1993, when the inspection for unaccounted debris will be performed in abandoned trench piping.

   The DG 2-3 abort valve will closed until the local selector valve is modified to account for the new model and 2-FCV-101 is tested.

   TRG Chairman concurs that the root cause for the pilot valve mispositioned on May 27, was human

error, in that the operator did not return the valve tot eh closed position upon completion of the previous PMT 18.01 puff test.

Contributory causes of the May 27, 1993 event is:

1) Labeling of the handle that did not match the correct operating positions.

2) Human factor design. The manufacturer changed the design, such that the handle travel opposite of the original design used on the other DCPP DG Cardox systems.

The root cause of the June 4 accidental discharge was equipment failure due to a screw coming loose in an upstream valve due to human error (knowledge exceeded). The proper maintenance manual was not available to the mechanic that reassembled the valve during previous corrective mainterance.

One contributory cause for the June 4, 1993 event was that the work order had faulty or incomplete information. The right revision for the vendor manual didn't get into the work order. The reason may either be human error, knowledge exceeded, or that the information that was logged into RMS was hard to find.

In an attempt to avoid inadvertent discharge of the Cardox system in the future corrective action V.C.1 was assigned so that CO2 test procedures are revised to verify that the local selector valves are closed, prior to performing the STP.

A warning in the OPs procedure, next to the diesel 2-3 test section, describing the position settings for the handle and direction of operation is discussed in the second corrective action V.C.2. This corrective action is needed because of the infrequency of the process and the chances of error due to recall for the operator in using the handle may be high.

Corrective action V.C.3 states that, NES engineering is to modify the design drawings to include the new design as well as the old design valve operator.

Because of the mispositioning of the handle, the

diesel 2-3 Cardox test results are suspect. Therefore the last corrective action was issued V.C.4, to reperform the CO2 test ub 2-3.

5. The TRG reconvened July 22, 1993, to discuss (1) the NCR write up (2) NSOC comments, and (3) the use of the Winter Green odorizer during Cardox testing.

The meeting minutes for the July 1, 1993, TRG were discussed and the TRG concurs that any topic that deals with the failure of FCV 104 should be reffered to QE #10752 and not be discussed in the NCR to avoid conflicts between the two.

The TRG agreed that there is no objective evidence to conclude that the step in PMT 18.01 was not performed, rewording was needed to describe item #3 of the contributory cause section in the write up of the meeting minutes. The statement should have been written:

3) The step in the PMT Procedure for returning the valve to the closed position was not successful due to operator error and/or differences in valve handle operation.

The Nuclear Safety Oversight Committee (NSOC) met July 2, 1993, to review NCRs. This NCR (DCO-93-SS-N032) was reviewed on the standpoint of personal safety.

NSOC discussed valving out the Winter Green odorizer during testing. NSOC does believe the Winter Green odorizer should be used during the testing. They believed the only reason not to use the Winter Green scent is the cost of the capsules.

The TRG discussed whether to leave the winter green odorizer in or to cut it out during testing. The following is a list of reasons from the discussion:

A. ODORIZER CUT IN	B. ODORIZER CUT OUT
Inadvertant discharge might occur. System currently indeterminant (ref. QE #10752)	Expensive ($325 per test, 9 times a year)
Delayed access into the area after	De-Sensitization effect. Workers will get use to smelling winter green

discharge	odor.
Identifies leaks in non-tested areas	Precaution signs are added at specific hazardous areas.
History shows inadvertant discharges for various reason.	Doesn't provide any warning (only helps people coming in after discharge)
	Already have testing precaution- discharge alarms
	Pre-evacuation (in specific hazard areas)

After voting, the majority of the TRG favored cutting in the winter green odorizer during testing, by a vote of eight to two.

A decision was made to delay implementation of the odorizer until after the next series of Cardox discharge tests. Then an evaluation can be made as to whether the implementation should be made permanent.

The TRG will reconvene September 14, 1993.

I. Remarks:

None.

J. Attachment(s):

None.

RELATED CORRESPONDENCE

192801

Pacific Gas and Electric Company

50-275/323-OLA-2
I-MFP-F10

DOL. 1479

July 8, 1992 "NOT ADMITTED" '93 OCT 28 P6:54

PG&E Letter No. DCL-92-156

MFP exhibit
F-10

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 2-92-001-01
Conditions Outside and Deviations From the 10 CFR 50 Appendix R Plant Design Basis Due to Personnel Error

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(ii)(B) and Item 19 of Supplement 1 to NUREG-1022, PG&E is submitting the enclosed revision to Licensee Event Report (LER) 2-92-001-00 regarding the Unit 2 Diesel Generators (DGs) 2-1 and 2-2 field circuits being outside the design basis of the plant with respect to Appendix R criteria. The primary purpose of this revision is to report three additional Units 1 and 2 conditions that also were determined to be outside the design basis of the plant with respect to Appendix R criteria. The additional conditions are: (1) inadequate separation of steam generator and reactor coolant system circuits in containment; (2) inadequate isolation of alternate shutdown capability from the effects of a fire in the control and cable spreading rooms; and (3) inadequate isolation of emergency diesel generator control circuits from the effects of a fire in the control and cable spreading rooms. These conditions were identified as a part of PG&E's ongoing Appendix R Design Basis Documentation Enhancement Project or were referred to the Appendix R Project from other reviews now in progress.

In addition to the four reportable conditions, the Appendix R Project identified four other plant conditions that also are not in conformance with Appendix R criteria. Although PG&E does not believe that these additional four conditions are reportable, for completeness the scope of this LER has been expanded to include a discussion of these conditions as well.

These conditions did not affect the health and safety of the public.

Sincerely,

Greg Rueger

Gregory M. Rueger

58115/85K

RECEIVED
JUL 13 1992
CMM
Corresp. Control Center

PG&E Letter No. DCL-92-156 July 8, 1992

192801

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
William J. Wagner
CPUC
Diablo Distribution
INPO

DCO-91-EN-N002
DCO-91-EN-N027
DCO-92-EN-N001
DCO-92-EN-N012

Enclosure

5811S/85K/ALN/2246

LICENSEE EVENT REPORT (LER)

192801

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3	1 OF 33

TITLE (4) CONDITIONS OUTSIDE AND DEVIATIONS FROM THE 10 CFR 50 APPENDIX R PLANT DESIGN BASIS DUE TO PERSONNEL ERROR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MON	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MON	DAY	YR	FACILITY NAMES	DOCKET NUMBER (S)
									DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5
04	28	92	92	- 0 0 1 -	0 1	07	08	92		0 5 0 0 0

RATING (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)
1	X 10 CFR 50.73(a)(2)(ii)(B)
1 0 0	OTHER - (Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
RAYMOND L. THIERRY, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4004

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (if yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (16)

PG&E began an Appendix R Design Basis Documentation Enhancement Project in June 1991. Four plant conditions were determined to represent conditions outside the design bases of the plant with respect to Appendix R criteria during this Project. These conditions involved: (1) inadequate diesel generator (DG) field circuit separation; (2) inadequate separation of steam generator and reactor coolant system circuits in containment: (3) inadequate isolation of alternate shutdown capability circuits in the control and cable spreading rooms; and (4) inadequate isolation of DG control circuits in the control and cable spreading rooms. One-hour, non-emergency reports were made for these conditions in accordance with 10 CFR 50.72(b)(1)(ii)(B) on February 14, June 8, June 19, and June 25, 1992, respectively.

Four other conditions that represented deviations from Appendix R criteria also were identified during this Project: (1) auxiliary saltwater pump/exhaust fan circuitry; (2) DG switch Thermo-Lag enclosures; (3) power-operated relief/auxiliary spray valve circuitry; and (4) emergency lighting. Although PG&E does not believe that these conditions are reportable, they have been included in this LER for completeness.

The root cause of the reportable events was determined to be personnel error due to a lack of attention to detail. Corrective actions include establishing fire watches, notification to operators, initiation of design changes, revision of procedures, issuance of memoranda to design personnel, and training.

I. Plant Conditions

Units 1 and 2 have been in various Modes and at various power levels with the conditions described below.

II. Description of Event

A. Summary:

PG&E identified Conditions 1 through 4 below as a result of PG&E's currently ongoing Appendix R Design Basis Documentation Enhancement Project, or as a result of referral to the Project from other reviews now in progress, and determined that they were reportable in accordance with 10 CFR 50.72. Further, reviews that led to initiation of the Appendix R Project and investigations during the Project identified four additional conditions that were determined not to be reportable.

The conditions that were determined to be reportable are:

1. *DG 2-1 and 2-2 Field Circuitry*

On February 14, 1992, at approximately 1330 PST, PG&E determined that lack of 2-hour rated fire barriers for Diesel Generator (DG) 2-1 and 2-2 (EK)(DG) field circuits (ED), in conjunction with the Appendix R design basis fire for Fire Area 22-C, could potentially result in the inability of the DGs to develop and sustain rated voltage. These circuits are in separate conduits (ED)(CND) and are separated by approximately ten feet, with a minimal in situ and transient combustible loading in the fire area. However, FSAR Update, Section 9.5, states that two DGs are necessary for safe shutdown in the event of a design basis fire, and therefore the potential for disabling two of three DGs in a design basis fire represented a condition outside the design basis of the plant with respect to Appendix R criteria. A one-hour, non-emergency report was made for Unit 2 on February 14, 1992, at 1350 PST, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

2. *SG and RCS Indication Circuitry*

On June 8, 1992, at approximately 1610 PDT, PG&E determined that lack of adequate redundant circuit separation in Units 1 and 2 containments (NH) for steam generator (SG) level indication (AB)(LI) and reactor coolant system (RCS) temperature indication (AB)(TI), in conjunction with the Appendix R design basis fire for containment, could potentially result in degraded ability to monitor natural recirculation cooldown. These circuits are in

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separate conduits and are separated by approximately 12 feet for Unit 1 and 14 feet for Unit 2. In situ and transient combustible loading is less than 10 minutes, and entry of combustible materials and ignition sources into containment is strictly controlled. However, the potential for disabling these circuits represented a condition outside the design basis of the plant with respect to Appendix R criteria. A one-hour, non-emergency report was made for Units 1 and 2 on June 8, 1992, at 1638 PDT, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*

On June 19, 1992, at approximately 1200 PDT, PG&E determined that lack of adequate fuse (EJ)(FU) design to provide circuit separation for several 4 kV safe shutdown components required to achieve Mode 3 (Hot Standby) in Units 1 and 2, in conjunction with the Appendix R design basis fire for the control room (NA) or cable spreading rooms, could potentially result in an inability to immediately have control of these components when plant shutdown functions are transferred from the control room to the Hot Shutdown Panel (HSP) (JE)(PL).

The current 4 kV dc control circuit (EJ) design for alternate shutdown equipment provides redundant Appendix R fusing on the positive side of control room and HSP circuits and a common fuse on the negative side of the circuits. If operator actions to transfer control to the HSP are not completed prior to fire damage to the circuits, the fire could potentially blow the fuses necessary for the control room, control room/cable spreading room transfer isolation, 4 kV switchgear (EB)(SWGR), and HSP circuits and disable breaker (EB)(BKR) operation. To restore component operability, operators must either replace the fuses or manually close the individual breakers at the 4 kV switchgear.

However, NRC Letter, "Position Statement on Allowable Repairs for Alternative Shutdown and on the Appendix R Requirement for Time Required to Achieve Cold Shutdown," dated July 2, 1982, considers replacement of fuses to be a repair action, and such actions generally are not accepted by the NRC in order to achieve Mode 3. Further, while the capability exists to manually close the individual breakers (and mechanical breaker operation instructions are posted in the breaker cubical), the potential need for this action is not explicitly proceduralized and no analysis existed to show that the time required for operators to re-establish control of the components is acceptable in order to meet plant design bases. Therefore, the potential for disabling these circuits represented a condition outside the design basis of the plant with respect to Appendix R

criteria. A one-hour, non-emergency report was made for Units 1 and 2 on June 19, 1992, at 1230 PDT, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

4. *DG Control Circuitry*

On June 25, 1992, at approximately 1730 PDT, PG&E determined that lack of adequate fuse design for DG control circuits in Units 1 and 2, in conjunction with the Appendix R design basis fire for the control room or cable spreading rooms, could potentially damage the DG normal and backup control circuitry. This potential damage could result in the loss of 125 V dc control power, which would result in an inability to operate the DGs from the local control panels. This Condition was identified during followup investigation for Condition 3 above.

In the event of a control room or cable spreading room Appendix R design basis fire coupled with a loss of offsite power and subsequent evacuation of the control room, the operators must have alternate capability for safe shutdown of the plant. FSAR Update, Section 9.5, states that two DGs are necessary for safe shutdown in the event of a design basis fire. Since a postulated control room or cable spreading room fire could potentially prevent start of the DGs from the local control panels, the potential for disabling these circuits represented a condition outside the design basis of the plant with respect to Appendix R criteria. A one-hour, non-emergency report was made for Units 1 and 2 on June 25, 1992, at 1808 PDT, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

The four conditions that were determined not to be reportable are:

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*
6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*
7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*
8. *Emergency Lighting*

B. Background

PG&E began an Appendix R Design Basis Documentation Enhancement Project in June 1991. The Project was initiated in part to resolve some previously identified weaknesses in documentation and to provide a consistent level of supporting documentation. The Project scope included a detailed review and verification of Appendix R post-fire safe shutdown (SSD) required equipment, cable (CBL) identification, cable routing, fire area SSD analysis, SSD timeline, and emergency lighting (FH).

As a result of investigations leading to the Project, investigations during the Project, and other reviews now in progress, eight plant conditions have been identified to be not in conformance with Appendix R criteria. In addition to four reportable conditions, four conditions PG&E believes to be not reportable also were identified. Each of these conditions is discussed in Section II.C.

C. Event Description:

1. *DG 2-1 and 2-2 Field Circuitry*

As described in FSAR Update, Appendix 9.5A, Fire Area 22-C is a corridor outside the DG rooms in the Unit 2 turbine building (NM) at the 85 foot elevation. Fire Area 22-C contains control circuitry related to the DGs. A deviation from 10 CFR 50, Appendix R, Section III.G.2, was required for this fire area due to a lack of an area-wide fire detection system (IC). The deviation was approved in Supplemental Safety Evaluation Report (SSER) 31 on the basis of features that adequately mitigated the effects of the design basis fire and assured the capability to achieve safe shutdown. These features included an automatic wet pipe sprinkler system (KP) with remote annunciation (IC), manual fire fighting equipment (KQ) in the area, and circuit separation via 2-hour rated fire barriers for redundant safe shutdown circuits.

FSAR Update, Appendix 9.5A, states that control and backup control circuitry for the DGs in Fire Area 22-C is enclosed in 2-hour rated fire barriers to provide separation for redundant circuits. On February 13, 1992, a potential error was noted in the Fire Area 22-C post-fire SSD analysis with respect to DG 2-1 and 2-2 field circuits G05H02 and H07H02 that are routed in conduits within this fire area. The field circuits were not enclosed in rated fire barriers. The Appendix R SSD analysis did not have an evaluation of the impact to the DGs with respect to these circuits and the design basis fire for this area.

The corresponding Unit 1 fire area was reviewed and was determined to not have a condition similar to that discovered in Unit 2. A continuous fire watch was established in Fire Area 22-C as a prudent measure until the potential impact of the lack of 2-hour rated fire barriers for the field circuits could be evaluated.

On February 14, 1992, PG&E determined that a postulated design basis fire for Fire Area 22-C could potentially disable the DG 2-1 and 2-2 field circuits, which could result in the inability of the DGs to develop and sustain rated voltage. These potential circuit losses, combined with a postulated loss of offsite power, could result in the inability to energize Unit 2 vital busses G and H (EB)(BU) from their

respective DGs, leaving only DG 1-3 (vital bus F) in an operable status. As noted in FSAR Update, Table 9.5G-2, "Equipment Required for Safe Shutdown," Diablo Canyon is analyzed to have two out of three DGs operable following a loss of offsite power coincident with a design basis fire. Therefore, PG&E determined that the lack of proper enclosures for the field circuits represented a condition outside the design basis of the plant. On February 14, 1992, at 1350 PST, a one-hour, non-emergency report was made for Unit 2 in accordance with 10 CFR 50.72(b)(1)(ii)(B).

2. *SG and RCS Indication Circuitry*

As described in FSAR Update, Appendix 9.5A, the Units 1 and 2 Fire Zones 1-A and 9-A are the containment annular areas. The circuitry for SG narrow range level and RCS temperature (both T_{hot} and T_{cold}) indication pass through these annular areas. FSAR Update, Table 9.5G-2, notes that the indication required to enable performance of a natural circulation cooldown following an Appendix R design basis fire coincident with a loss of offsite power consists of SG narrow range level, SG pressure (AB)(PI), and RCS T_{hot} and T_{cold} indication for one RCS loop. This instrumentation is relied upon as the primary means of monitoring cooldown, and for these indications to be meaningful the RCS temperature indications must be on the RCS loop associated with the SG providing the cooling. Section 9.5A of the FSAR Update states: "Only one steam generator is required for safe shutdown and the circuitry is separated so that one steam generator remains available," and that the RCS temperature indication circuits "...are provided with a 1-hour fire barrier where they are within 20 feet of redundant circuitry."

On June 2, 1992, during the Appendix R Design Basis Documentation Enhancement Project, PG&E determined that not all SG and RCS circuitry was in compliance with the FSAR Update statements. For Unit 1, the SG 1-1 and 1-2 narrow range level indication circuitry was separated such that the minimum distance between these and the RCS T_{hot} and T_{cold} circuitry associated with SGs 1-3 and 1-4 was approximately 12 feet. For Unit 2, the SG 2-1 and 2-2 narrow range level indication circuitry was separated such that the minimum distance between these and the RCS T_{hot} and T_{cold} circuitry associated with SGs 2-3 and 2-4 was approximately 14 feet.

On June 8, 1992, PG&E determined that the condition identified on June 2 meant that Appendix R separation requirements for redundant circuitry had not been met, and therefore that an Appendix R design basis fire in containment potentially could disable circuitry such that SG narrow range level indication and RCS temperature indication for a given RCS loop would not be available. Although not specifically credited in the FSAR Update, natural circulation cooldown

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6"

also could be monitored by use of indication from core exit thermocouples (IM)(TT) and SG wide range level circuitry, but PG&E determined that circuitry for this instrumentation was routed in the containment annulus and could not be postulated to withstand the design basis fire. PG&E therefore determined that lack of proper SG level and RCS temperature circuit separation represented a condition outside the design basis of the plant. On June 8, at 1638 PDT, a one-hour, non-emergency report was made for Units 1 and 2 in accordance with 10 CFR 50.72(b)(1)(ii)(B).

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*

As described in FSAR Update, Appendix 9.5A, the DCPP Fire Protection Program SSD analysis meets the requirements of Appendix R, Sections III.G.3 and III.L, by providing the capability to isolate SSD circuits from the effects of a fire in the control room or cable spreading rooms, and by providing an alternative location (the HSP) to perform post-fire SSD actions independent of a fire in the control room or cable spreading room. Transfer of SSD equipment control from the control room to the HSP is enabled by switches (JE)(33), which isolate all control room or cable spreading room circuit faults to allow operation using control switches at the HSP.

On June 19, 1992, PG&E identified a potential error in the Units 1 and 2 SSD analysis with respect to the fuse configuration for alternative shutdown circuitry for several components required to achieve Mode 3. Circuit analysis determined that a fire in the control or cable spreading rooms could potentially damage the 125 V dc control circuitry for breaker control of the 4 kV pumps (P) if the actions at the HSP and switchgear to transfer to local control are not completed prior to fire damage of the circuits. If operator actions to transfer control to the HSP are not completed prior to fire damage to the circuits, the fire could potentially blow the fuses common to the control room, the control room/cable spreading room transfer isolation, 4 kV switchgear, and HSP circuits and disable breaker operation. This damage could disable the ability to isolate circuits in the fire area and electrical operation of the breakers. The affected components are:

- Centrifugal Charging Pumps 1-1, 1-2, 2-1 and 2-2 (CB)(P)
- Component Cooling Water Pumps 1-1, 1-2, 1-3, 2-1, 2-2, and 2-3 (CC)(P)
- Auxiliary Saltwater (ASW) Pumps 1-1, 1-2, 2-1, and 2-2 (BI)(P)
- Auxiliary Feedwater Pumps 1-2, 1-3, 2-2, and 2-3 (BA)(P)

On June 19, 1992, at approximately 1200 PDT, PG&E determined that lack of adequate fuse design to provide circuit separation for the components described above required to achieve Mode 3, in conjunction

with the Appendix R design basis fire for the control room or cable spreading rooms, could potentially result in an inability to immediately have control of these pumps when plant shutdown functions are transferred from the control room to the HSP.

To restore operability, operators must either replace the fuse or manually close the individual component breakers at the 4 kV switchgear. However, the NRC Letter dated July 2, 1982, considers replacement of fuses to be a repair action, and such actions generally are not accepted by the NRC in order to achieve Mode 3. Also, while the capability exists to manually close the individual breakers (and mechanical breaker operation instructions are posted in the breaker cubical), the current SSD analysis did not take credit for this capability; the SSD analysis apparently assumed that the action to transfer control to the HSP would be completed prior to fire damage to the circuits. The potential need to manually close individual breakers is not proceduralized and no analysis existed to show that the time required for operators to re-establish control of the equipment was acceptable in order to meet plant design bases. Therefore, the potential for disabling these circuits represented a condition outside the design basis of the plant with respect to Appendix R criteria. A one-hour, non-emergency report was made for Units 1 and 2 on June 19, 1992, at 1230 PDT, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

4. *DG Control Circuitry*

As described in the FSAR Update, Section 9.5A, Fire Area CR-1 is the Units 1 and 2 control room complex. The FSAR Update discussion for Fire Area CR-1 notes that the requirements of Appendix R, Sections III.G.3 and III.L, are met in part by providing an alternate location to perform post-fire safe shutdown actions independent of a fire in the control room or cable spreading rooms. This alternate shutdown capability includes the ability to start the DGs at their local control panels (ED)(PL).

On June 25, 1992, as part of the followup investigation initiated following identification of Condition 3 above regarding breaker design for safe shutdown equipment control circuitry, PG&E identified a potential error in the design of the DG control circuitry. Due to the potential for a fire in the control room or cable spreading rooms, hot shorts and shorts to ground are assumed for the DG control circuits. Each DG has two redundant 125 V dc control power sources (normal and backup). Circuits associated with both the control power sources are located in the control room and cable spreading rooms. The DG remote control circuits in the control room and the local control circuits in the control panels near the DG rooms are connected to the same 20 Amp control power fuses (ED)(FU). A postulated Appendix R design basis

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fire could result in a hot short or short to ground on the positive leg of each control power source circuit in conjunction with a short to ground on a circuit connected to the negative leg of the same power source. These circuit faults could cause the 20 Amp power fuses to blow and result in loss of the ability to locally start the DGs.

On June 25, 1992, at approximately 1730 PDT, PG&E determined that lack of adequate fuse design for DG control circuits in Units 1 and 2, in conjunction with the Appendix R design basis fire for the control room or cable spreading rooms, could potentially result in an inability to operate the DGs from the local control panels. In the event of a control room or cable spreading room Appendix R design basis fire and with a loss of offsite power and subsequent evacuation of the control room, the operators must have alternate capability for safe shutdown of the plant. FSAR Update, Section 9.5, states that two DGs are necessary for safe shutdown in the event of a design basis fire. Since a postulated control room or cable spreading room fire could potentially prevent start of the DGs from the local control panels, the potential for disabling these circuits represented a condition outside the design basis of the plant with respect to Appendix R criteria. A one-hour, non-emergency report was made for Units 1 and 2 on June 25, 1992, at 1808 PDT, in accordance with 10 CFR 50.72(b)(1)(ii)(B).

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

As described in FSAR Update, Appendix 9.5A, Fire Zone 30-A-5 is the circulating water pump (KE)(P) room in the intake structure (MK)(NN). Conduits containing control circuits for ASW Pumps 1-1, 1-2, 2-1, and 2-2 and conduits containing the power circuits for the ASW pump exhaust fans (E-101 and 103 for Unit 1 and E-102 and 104 for Unit 2) (UA)(FAN) pass through this area. One ASW train (pump and exhaust fan) are required to be operable for safe shutdown. 3-hour fire wrap on one train of circuits per unit is provided to ensure availability of one ASW train per unit in the event of an Appendix R design basis fire.

On April 21, 1992, during the Appendix R Design Basis Documentation Enhancement Project, PG&E determined that a 3-foot long section of the circuits for ASW Pump 1-1 and ASW Pump Exhaust Fan E-103 for Unit 1, and ASW Pump 2-1 and ASW Pump Exhaust Fan E-104 for Unit 2, was not protected with a 3-hour fire wrap. This section is from the point where the circuits exit the concrete floor embedment and travel three feet up to Junction Box BJZ-114 (ED)(JBX). The junction box is protected with a 3-hour fire wrap, but the conduits entering the box are not protected.

ASW Pump 1-1 and 2-1 circuits located in Fire Zone 30-A-5 are required

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for auto start of the pump on low ASW pressure. Fire-induced circuit damage to one train of ASW pump circuits could blow the pump's dc control circuit fuse and prevent an idle pump from automatically starting on low pressure, but will not trip a running pump. Loss of the pump's dc control power due to the blown fuse will alarm in the control room. The circuits for the alarm are not located in Fire Zone 30-A-5 and will not be affected by the fire.

ASW Pump Exhaust Fan E-103 and E-104 circuits located in Fire Zone 30-A-5 are required to supply power for the exhaust fans. Fire-induced circuit damage to one train of exhaust fan circuits could result in loss of power to the fan. The loss of an ASW fan will alarm in the control room. The circuits for the alarm are not located in Fire Zone 30-A-5 and will not be affected by the fire.

On April [illegible], 1992, PG&E determined that, while this condition was not in strict compliance with Appendix R, Section III.G.[illegible] the condition did not significantly reduce the level of safety and therefore was not reportable in accordance with 10 CFR 50.72. The basis for this determination is discussed further in Section IV, "Analysis of Event."

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

As described in the FSAR Update, Fire Areas 11-D and 22-C are corridors outside the DG rooms at the 85 foot elevation in the Units 1 and 2 turbine buildings, respectively. The DG emergency stop switches (ED)(HS) are located outside the DG rooms in these corridors. FSAR Update, Appendix 9.5A states that the DG 1-1, 1-2, and 2-1 stop switches are enclosed in 1-hour rated fire barriers. Fire Area TB-7/Zone 14-A and Fire Area TB-7/Zone 19-A are the main condenser (SG)(COND), feedwater (SJ) and condensate (SD) equipment areas in the Units 1 and 2 turbine building at the 85 foot elevation. The manual actuation switches (LW)(HS) for the DG room CO_2 fire suppression system (LW) are located in these areas. These switches likewise are to be enclosed in 1-hour rated fire barriers. However, as discussed below, anomalies were identified with the Thermo-Lag enclosures used to provide the fire barriers for these switches.

FSAR Update, Section 9.5.1, states that two DGs are required for safe shutdown in the event of a fire concurrent with a loss of offsite power. Thermo-Lag 1-hour fire barrier enclosures were provided for the DG 1-1, 1-2, and 2-1 emergency stop switches to preclude a fire in Area 11-D or 22-C from causing spurious actuations of the switches and thereby disabling more than one DG. Similarly, Thermo-Lag 1-hour fire barriers were provided for the CO_2 fire suppression system manual actuation switches to preclude a fire in Zone 14-A or 19-A from disabling more than one DG; spurious actuation of the CO_2 system manual actuation switch would result in automatic closure of a DG room

roll-up door (NM)(DR), which would result in loss of cooling to the DG and thereby potentially render the DG inoperable.

On November 7, 1991, PG&E determined that vendor information for Thermo-Lag had been inappropriately applied when approving the proposed enclosure configurations, in that screws and subliming compound had been used for construction of the enclosures to hold the prefabricated Thermo-Lag panels together in lieu of steel bands or wires. This method of construction had not been tested and approved by the vendor, and therefore the enclosure configuration was potentially not adequate to provide a 1-hour fire barrier.

On November 15, 1991, PG&E determined that, while the Thermo-Lag enclosures could not be depended upon to provide a 1-hour fire barrier, the condition did not significantly reduce the level of safety and therefore was not reportable in accordance with 10 CFR 50.72. The basis for this determination is discussed further in Section IV, "Analysis of Event."

During repair activities to provide adequate fire barriers for the DG and CO_2 switches, personnel who approved the work orders to implement the design changes assumed that the compensatory measures in place for the "degraded" enclosures also would apply when the enclosures were removed. Consequently, the enclosures were removed without the proper evaluations having been performed.

Upon identification of this condition, PG&E reviewed Generic Letter (GL) 86-10, "Implementation of Fire Protection Requirements," for further Appendix R guidance regarding spurious actuation. As discussed further in Section IV, through application of the guidance in GL 86-10, PG&E determined that absence of the Thermo-Lag enclosures likewise did not reduce the level of safety and therefore the condition was not reportable in accordance with 10 CFR 50.72.

7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

As described in FSAR Update, Appendix 9.5A, control circuits for power-operated relief valves (PORVs) PCV-474, PCV-455C, and PCV-456 (AB)(RV) and Auxiliary Spray Valves 8145 and 8148 (AB)(PZR)(INV) are routed in conduit through the following Units 1 and 2 Fire Areas:

1	Containment (Unit 1)
3-BB	Containment Penetration Area (Unit 1)
3-CC	Containment Penetration Area (Unit 2)
6-B-4	Reactor Trip Switchgear (Unit 2)
9	Containment (Unit 2)

The PORVs are 2-inch, pneumatically-opened, spring-closed, reverse-

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acting globe valves. The PORVs fail closed on loss of actuating gas pressure. Instrument air (LD) is the normal actuating gas for all three PORVs. For two of the PORVs (PCV-455C and PCV-456), normal instrument air is backed up by nitrogen accumulators (LK)(ACC). Each of the two valves has its own nitrogen accumulator. The only motive power supply for PCV-474 is instrument air.

Units 1 and 2 also each have auxiliary spray for pressurizer (AB)(PZR) pressure control. The charging flow stream in the chemical and volume control system (CB) at the outlet of the regenerative heat exchanger (CB)(HX) is the source for auxiliary spray. The auxiliary spray line contains two air-operated valves installed in parallel: the auxiliary spray control valve (8145) and the auxiliary spray bypass control valve (8148). These valves are redundant, and each one has a separate nitrogen back-up supply to allow opening during loss of instrument air to the containment. Both valves fail to the closed position upon loss of actuating fluid or electrical power.

Appendix R, Section III.G, requires the capability to achieve and maintain Mode 5 (Cold Shutdown) conditions using either equipment protected from the effects of a fire or equipment that can be repaired following a fire, and describes the fire protection requirements for the necessary equipment. This equipment includes components required for a controlled RCS depressurization prior to initiation of the residual heat removal system (BP).

Following an Appendix R design basis fire and loss of offsite power, at least one of the PORVs or auxiliary spray valves is necessary for RCS depressurization to achieve and maintain Mode 5 (Cold Shutdown) since the reactor coolant pumps (RCPs) (AB)(P) and, hence, normal pressurizer spray would be unavailable. Therefore, to comply with the requirements of Appendix R, Section III.G.1.b, it must be shown that these valves will remain free from fire damage or can be repaired within 72 hours.

On January 14, 1992, during the Appendix R Design Basis Documentation Enhancement Project, PG&E identified an error in the SSD analysis for Fire Area 6-B-4. Control circuits for Auxiliary Spray Valves 8145 and 8148 and for PORVs PCV-455C and PCV-456 are routed in conduit through Fire Area 6-B-4, and do not meet Appendix R minimum separation criteria. The SSD analysis took credit for the availability of PCV-474 to achieve Mode 5 in the event of a fire in this Area since no control circuitry for PCV-474 is routed through this Area. However, the motive power supply for PCV-474, instrument air, cannot be postulated to be available following a loss of offsite power. Therefore, the post-fire ability to operate PCV-474 could not be assured.

Similar analysis and routing errors were identified in Unit 1 Fire

Areas 1 (containment) and 3-BB (containment penetration area) and Unit 2 Fire Areas 3-CC (containment penetration area) and 9 (containment). The control circuits for 8148 and PCV-455C are routed within the same conduit through the 100 foot elevation of Fire Area 3-CC. The control circuits for PCV-456 and 8145 are routed in separate conduits that cross either directly above or below the conduit containing 8148 and PCV-455C. Horizontal separation between the conduit containing circuits for 8148 and PCV-455C and the conduit containing circuits for PCV-456 ranges from 0 feet (where the conduits cross) to approximately 12 feet. Horizontal separation between the conduit containing circuits for 8148 and PCV-455C and the conduit containing circuits for 8145 ranges from 0 feet (where the conduits cross) to approximately 12 feet. Horizontal separation between the conduit containing circuits for 8145 and the conduit containing circuits for PCV-456 ranges from 0 feet (where the conduits cross) to approximately 9 feet.

For Fire Area 3-BB, a minimum separation of approximately 13 feet between redundant circuits exists on the 115 foot elevation of the containment penetration areas. This minimum separation occurs at the containment penetration Junction Boxes BTG 12E and BTG 19E which are provided with 1-hour fire resistive enclosures. Redundant circuits are routed in rigid conduit throughout the area.

For Fire Areas 1 and 9, the minimum separation between PORV and auxiliary spray valve circuits occurs at Containment Penetrations 12E and 19E. Penetration Termination Box BTX 12E contains circuits for auxiliary spray valve 8145 and PORV PCV-456. Penetration Termination Box BTX 19E contains circuits for Auxiliary Spray Valve 8148 and PORV PCV-455C. The minimum separation (approximately 16 feet) occurs between conduits containing circuits for 8145 and PCV-455C at BTX 12E and BTX 19E.

On January 15, 1992, PG&E determined that, while these conditions were not in strict compliance with Appendix R requirements, the conditions did not significantly reduce the level of safety and therefore were not reportable in accordance with 10 CFR 50.72. The basis for this determination is discussed further in Section IV, "Analysis of Event."

B. *Emergency Lighting*

As described in FSAR Update, Appendix 9.5D, the DCPP Fire Protection Program SSD analysis indicates that the requirements of Appendix R, Section III.J, "Emergency lighting units with at least an 8-hour battery power supply shall be provided in all areas needed for operation of safe shutdown equipment and in access and egress routes thereto," have been met by providing battery-operated lights (FH) in the appropriate plant locations in conjunction with credit for vital

ac (FG) and dc (FH) lights in certain areas. This method of compliance was described in PG&E's Appendix R submittals, which also requested deviations from the specific Appendix R, Section III.J, requirements for use of only battery-operated lights. The battery-operated light configuration and deviation requests were reviewed and approved by the NRC as documented in SSERs 23 for Unit 1 and 31 for Unit 2.

In December 1990, PG&E identified several potential errors in the Units 1 and 2 SSD analysis with respect to Emergency Procedure (EP) M-10, "Fire Protection of Safe Shutdown Equipment," which provides analyzed corrective actions to take following a fire in plant areas containing safe shutdown equipment; EP M-10 references Abnormal Operation Procedures (OPs) AP-8A, "Control Room Inaccessibility - Establishing Hot Standby," and AP-8B. "Control Room Inaccessibility - Hot Standby to Cold Shutdown." These potential analysis errors involved the adequacy of battery-operated lighting as follows:

(a) EP M-10 and OPs AP-8A and AP-8B identified several plant areas that required access and/or manual actions, but these areas had no installed emergency lighting;

(b) OPs AP-8A and AP-8B specified operator actions for several components that had not been identified in the SSD as equipment used in the event of a fire;

(c) Time requirements for manual actions specified in the procedures had not been clearly defined in supporting analyses.

PG&E determined that, while these conditions were not in strict compliance with Appendix R requirements, the conditions did not significantly reduce the level of safety and therefore were not reportable in accordance with 10 CFR 50.72. The basis for this determination is discussed further in Section IV, "Analysis of Event."

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

E. Dates and Approximate Times for Major Occurrences:

1. February 13, 1992: Condition 1 identified. Review of potential impact on SSD analysis begun. Continuous fire watch posted in the area as a prudent measure.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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2. February 14, 1992, at 1330 PST: Condition 1 Discovery/Event date.

3. February 14, 1992, at 1350 PST: One-hour, non-emergency report for Condition 1 made to NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

4. June 2, 1992: Condition 2 identified. Further investigation of actual plant conditions and potential impact on SSD analysis begun.

5. June 8, 1992, at 1610 PDT: Condition 2 Discovery/Event date.

6. June 8, 1992, at 1638 PDT: One-hour, none-emergency report for Condition 2 made to NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

7. June 19, 1992: Condition 3 identified. Investigation of potential impact on SSD analysis begun.

8. June 19, 1992, at 1200 PDT: Condition 3 Discovery/Event date.

9. June 19, 1992, at 1230 PDT: One-hour, none-emergency report for Condition 3 made to NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

10. June 25, 1992: Condition 4 identified. Investigation of potential impact on SSD analysis begun.

11. June 25, 1992, at 1730 PDT: Condition 4 Discovery/Event date.

12. June 25, 1992, at 1808 PDT: One-hour, non-emergency report for Condition 4 made to NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

These conditions were identified either during investigation that led to initiation of the Appendix R Design Basis Documentation Enhancement Project and during the investigations conducted in support of the Project or referral to the Project from other reviews now in progress.

H. Operator Actions:

None.

I. Safety System Responses:

None.

III. Cause of the Event

A. Immediate Cause:

The conditions described in this LER are the result of several immediate causes. The conditions are grouped below by cause.

1. *DG 2-1 and 2-2 Field Circuitry*
2. *SG and RCS Indication Circuitry*
7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

The immediate cause of these conditions was that the early 1980s Appendix R SSD analysis did not adequately evaluate all of the circuits with respect to the required post-fire functions of the affected components.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*
4. *DG Control Circuitry*

The immediate cause of these conditions was determined to be inadequate fuse design.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

The early 1980s Appendix R SSD analysis required both the conduits and the associated Junction Box BJZ-114 to be protected with a 3-hour fire wrap. However, the design change that implemented this requirement did not clearly communicate this requirement, and therefore only the junction box was protected

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with a 3-hour fire wrap.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

The basis for the design of the Thermo-Lag enclosures referenced only one section of the vendor instructions instead of all applicable sections.

8. *Emergency Lighting*

(a) Manual operator actions and access/egress routes described in EP M-10 and OPs AP-8A and AP-8B were not provided with emergency lighting.

(b) A clear distinction in OPs AP-8A and AP-8B and the supporting SSD analysis was not made as to which manual operator actions required area emergency lighting. Also, a clear description of the screening criteria used in the original SSD analysis to determine which manual operator actions required area emergency lighting was not documented.

(c) No distinction was made in the SSD analysis or in EP M-10 and OPs AP-8A and AP-8B regarding time requirements for manual actions. Therefore, it was not clear which actions were to be completed within eight hours after a fire concurrent with a loss of offsite power and therefore for which emergency lighting may have been required.

B. Root Cause:

The conditions described in this LER are the result of several root causes. The conditions are grouped below by cause.

1. *DG 2-1 and 2-2 Field Circuitry*
2. *SG and RCS Indication Circuitry*
7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

The root cause of these conditions was determined to be personnel error (cognitive) due to a lack of attention to detail by PG&E engineers during performance of the early 1980s Appendix R SSD analysis. The rationale for this as applied to each condition follows:

For Condition 1, the corresponding Unit 1 DG field circuits are contained in the room with their respective DGs, and are not

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routed into the corresponding Unit 1 corridor. For reasons that could not be determined, the Unit 2 DG 2-1 and DG 2-2 field circuits are routed out of their respective rooms, into the Fire Area 22-C corridor, and then back into their respective rooms. Investigation indicates that the early 1980s SSD analysis most likely assumed that DG circuits having both endpoints within the DG room did not exit that room.

For Condition 2, separation of the SG narrow range level and RCS temperature indication circuitry in containment was provided. However, the SSD analysis failed to superimpose the availability of the subject SG and RCS indications for various fire locations inside containment and therefore did not ensure sufficient available indication for a given RCS loop in the event of a fire.

For Condition 7, the SSD analysis did not properly assess the effects of a concurrent fire and loss of offsite power on the air supply to PCV-474. The SSD analysis also did not adequately assess the post-fire availability of components required for RCS depressurization following a design basis fire in containment or the containment penetration areas.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*
4. *DG Control Circuitry*

Investigation indicates that the root cause for the inadequate fuse design was an assumption made during system design that transfer of equipment control (to the HSP for Condition 3 and to the DG local control panels for Condition 4) was completed prior to damage of the circuits by the fire.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

A review of the design change initiated to implement Appendix R requirements for wrapping of circuits in the plant indicates that the requirement to wrap the subject ASW circuits was inadequately communicated by Nuclear Engineering and Construction Services (NECS) Engineering in the design change to personnel implementing the requirement. While the junction box associated with the subject circuits was wrapped, a 3-foot long section of the circuits was not protected with a 3-hour fire wrap.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

A review of the design changes initiated to implement Appendix R requirements for installation of the Thermo-Lag enclosures indicates that the design changes were ambiguous and did not provide adequate guidance for proper construction and installation of the enclosures.

8. *Emergency Lighting*

a. Requirements for access/egress routes and manual actions and the emergency lighting requirements have not been clearly defined and documented in the SSD analysis or in plant procedures.

b. There was no process that ensured that EP M-10 and OPs AP-8A and AP-8B were updated to be current with respect to the SSD analysis in the FSAR Update.

C. Contributing Causes:

1. *DG 2-1 and 2-2 Field Circuitry*

The original Appendix R SSD analysis performed in the early 1980s did not use as rigorous criteria as is currently required by procedure. Also, the Nuclear Engineering Manual Procedure (NEMP) 3.3, "Design Calculations," requirements for incorporation of material such as the SSD analysis results into design calculations were not a strict in the early 1980s as they have been since revision to NEMP 3.3 in 1986.

2. *SG and RCS Indication Circuitry*

None.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*
4. *DG Control Circuitry*

IE Information Notice 85-09, "Isolation Transfer Switches and Post-Fire Shutdown Capability," suggested that licensees review isolation transfer switches installed outside the control room for potential deficiencies in electrical design regarding lack of redundant fusing. PG&E's original review of the Notice incorrectly concluded that proper circuit isolation was provided at DCPP and therefore that no action for the Notice was

required. Though no documentation could be found, interviews with involved personnel indicate that this conclusion was based on a assumption that multiple circuit faults would not occur prior to transfer of equipment control. However, current PG&E safe shutdown methodology conservatively assumes that multiple circuit faults occurring prior to equipment transfer could result in blowing of control fuses and loss of control of equipment from a remote control station.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

None.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

None.

7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

None.

8. *Emergency Lighting*

None.

IV. Analysis of the Event

The following analyses for the first four conditions provide evaluations for impact to the health and safety of the public. The remainder of the analyses provide the rationale used to determine safety significance and reportability.

1. *DG 2-1 and 2-2 Field Circuitry*

A postulated design basis fire for Fire Area 22-C could potentially disable the DG 2-1 and DG 2-2 field circuits, which could result in the inability of the DGs to develop and sustain rated voltage. These potential circuit losses, combined with a postulated loss of offsite power, could result in the inability to energize the Unit 2 vital busses G and H from their respective DGs. However, the minimum distance between the generator field circuits in the corridor is approximately 10 feet, and the circuits are in separate conduits. Additionally, the normal in situ and transient combustible loading is minimal, with a fire severity of less than ten

minutes. Hourly fire patrols are provided in this area to monitor transient combustibles. Therefore, it is likely that even with a fire in the corridor, at least one of these two DGs would have been available if required. Therefore, this condition did not adversely affect the health and safety of the public.

2. *SG and RCS Indication Circuitry*

A postulated design basis fire for either Fire Zone 1-A or 9-A could potentially disable SG narrow range level and RCS temperature indication circuitry such that both these indications would not be available on a single RCS loop. These potential circuit losses, combined with a postulated loss of offsite power, could result in an inability to properly monitor natural circulation cooldown.

However, the combustible loadings in the containment annular areas where the subject SG and RCS circuitry is routed are less than 10 minutes, and the most significant contributor to these loadings is non-Class 1E cable insulation (EC)(ISL). The major combustible loading in containment, the RCPs, is not considered to be a concern for the annular areas because each RCP has automatic wet pipe sprinkler protection, smoke detection (IC), shield walls, and a lube oil collection system (AB)(LL). Also, containment is a high radiation area, and materials (including potential combustibles and ignition sources) brought into containment are strictly controlled. The subject SG and RCS circuits are inside rigid metal conduits, such that an electrically induced fire in one conduit should not impact any adjacent conduits. Lastly, the annular areas have automatic smoke detection that alarms in the control room, and manual fire suppression, hose reels, and extinguishers are readily available for fire brigade use. Therefore, this condition did not adversely affect the health and safety of the public.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*

A postulated design basis fire in either the control room or the cable spreading rooms could potentially disable circuitry for control of components from the HSP, which then could impede the ability to achieve Mode 3. However,

- The cable spreading room is provided with smoke and heat detection (IC), and smoke detectors also are provided in the control panels in the control room for the components of concern.

- The cable spreading room is provided with a total-flooding CO_2 suppression system that can be actuated by the heat detectors, or that can be manually actuated by plant personnel during periods when the CO_2 system automatic actuation is disabled.

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- The control and cable spreading rooms are supplied with portable fire extinguishers, and fire hose stations are available.

- The control room is continuously manned, and the cable spreading rooms have been provided with an hourly roving fire watch since the beginning of commercial operation.

- Redundant cabling is separated, sized, and protected to preclude a cable fault-initiated fire. The possibility of a non-electrical fault-initiated fire is very remote due to lack of fixed ignition sources and administrative control on transport of temporary ignition sources into the control room or cable spreading rooms.

Therefore, in the event of a design basis fire in the either the control room or cable spreading rooms, the ability to achieve Mode 3 was not adversely impaired. Therefore, this condition did not adversely affect the health and safety of the public.

4. *DG Control Circuitry*

A postulated design basis fire in either the control room or the cable spreading rooms could potentially disable the DG control circuitry, which then could impede the ability to achieve safe shutdown. However,

- The cable spreading room is provided with smoke and heat detection, and smoke detectors also are provided in the control panels in the control room.

- The cable spreading room is provided with a total-flooding CO_2 suppression system that can be actuated by the heat detectors, or that can be manually actuated by plant personnel during periods when the CO_2 system automatic actuation is disabled.

- The control and cable spreading rooms are supplied with portable fire extinguishers, and fire hose stations are available.

- The control room is continuously manned, and the cable spreading rooms have been provided with an hourly roving fire watch since the beginning of commercial operation.

- Redundant cabling is separated, sized, and protected to preclude a cable fault-initiated fire. The possibility of a non-electrical fault-initiated fire is very remote due to lack of fixed ignition sources and administrative control on transport of temporary ignition sources into the control room or cable spreading rooms.

Therefore, in the event of a design basis fire in the either the control room or cable spreading rooms, the ability to achieve safe shutdown was not adversely impaired. Therefore, this condition did not adversely affect the health and safety of the public.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

As noted in Section II.C.5., PG&E determined that this condition was not reportable in accordance with 10 CFR 50.72. The basis for this determination was that PG&E believed there was adequate assurance that it was unlikely that a fire would damage both trains of ASW (pumps and pump exhaust fans) and, therefore, at least one ASW train would be available in the event of a fire because:

- Fire Zone 30-A-5 contains in situ combustible loading equivalent to a fire duration of 14 minutes, with an additional allowable transient combustible loading of 5 minutes. The majority of the in situ combustible loading consists of the cable insulation and lube oil for the circulation water pumps, which are located in a concrete housing. The entrance to the concrete housing is the only significant opening from the enclosure to the room containing the ASW circuits and is "sunk" into the concrete floor from which the circuits emerge. Therefore, the housing would serve to contain any oil spill since it is unlikely that the lube oil would travel out through the entrance, up the short approximately 2-foot flight of stairs, and then out into the room.

- There is a high pressure, heat-activated CO_2 flooding fire suppression system in the concrete housing for the circulating water pumps. Also, there are smoke detectors at the entrance of the ASW pump vault. Although these do not constitute area-wide detection, they do annunciate in the control room. Fire extinguishers and hose reels are available in this fire zone for use by the fire brigade.

- There is no intervening combustible material between the redundant ASW circuits.

- Assuming a fire damaged one ASW train, the fire would have to propagate along a torturous path to damage the other train. This path involves traveling around three, 3-hour rated walls and alongside another 3-hour rated wall. Propagation of a fire along this path is considered even less likely based on the lack of intervening combustibles between the redundant circuits.

Therefore, given the remote probability a fire disabling both ASW circuits of Unit 1 or of Unit 2, this condition did not significantly reduce the level of safety. Since the condition of the plant was not seriously degraded, this condition therefore was determined not to be reportable in

accordance with 10 CFR 50.72, and the condition did not adversely affect the health and safety of the public.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

As noted in Section II.C.6., PG&E determined that this condition was not reportable in accordance with 10 CFR 50.72. Prior to removal of the Thermo-Lag enclosures, this determination was based on the following points that PG&E believes give adequate assurance that a fire would not disable more than one DG:

- While the ability of the enclosures to provide a 1-hour fire barrier was indeterminate, the enclosures still could have functioned as radiant energy shields.

- The DG emergency stop switches are spaced approximately 20 feet apart, and also are separated by DG room roll-up doors and normal access doors. Section III.G.2.b of Appendix R states that physical separation of 20 feet or more measured horizontally, in conjunction with no intervening combustible or fire hazards, fire detectors, and an automatic fire suppression system, is also a means of fire protection for safe shutdown equipment. Although the DG corridor is not provided with fire detectors, the corridor is provided with automatic suppression and the switches were separated and provided with the Thermo-Lag enclosures.

  Although the physical separation point can not be used for the CO_2 manual actuation switches since they are separated by less than three feet, and the Unit 2 switches additionally are mounted vertically, all three switches in Unit 1 and two of the three switches in Unit 2 were located in their own Thermo-Lag enclosure.

- The normal in situ and transient combustible loading for the DG corridors is minimal, with a fire severity of less than ten minutes. Transient combustibles are kept to a minimum and controlled in accordance with AP C-13, "Fire Loss Prevention." Also, the corridors are high traffic areas, and it is highly unlikely that there would be sufficient transient combustibles stored such that a fire could affect more than one switch.

  The normal in situ and transient combustible loading for the areas in which the CO_2 manual actuation switches are located is approximately 13 minutes; the transient portion of this loading is approximately three minutes, and storage of transient combustibles near the switches is unlikely given their location (along a narrow access path for Unit 1, and near structural supports for Unit 2). The area in the immediate vicinity of the Unit 1 switches is essentially void of combustibles. The area in the immediate vicinity of the Unit 2

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switches also is void with the exception of potential leakage of lube oil from the nearby condensate booster pumps (SD)(P). However, the turbine building floor near the Unit 2 lube oil reservoirs (LL)(RVR) slopes away from the switches, and therefore it is unlikely that a fire involving the lube oil would disable the switches.

- Hourly roving fire watches have been in effect for the subject areas since beginning of commercial operation, which is consistent with Technical Specification requirements for surveillance of impairment to penetrations in fire area boundaries. These areas also are high traffic areas.

- The subject areas have automatic, area-wide wet pipe sprinkler systems, and manual hose stations and portable fire extinguishers. If the sprinkler system is activated, a water flow alarm is received in the control room. Upon receipt of a water flow alarm, an operator is sent to the area of indication; if a fire is found, the fire alarm is sounded and the fire brigade is summoned.

Following this original determination, the Thermo-Lag enclosures were mistakenly removed and the following basis was developed regarding reportability:

- GL 86-10 states that a single spurious actuation should be postulated in the event of fire in a given fire area. The failure mode for the subject switches in the event of a fire is a hot short, and is considered to be a spurious actuation. Therefore, a fire in the vicinity of the unprotected DG or CO_2 switches would result in only one spurious actuation and, therefore, disable no more than one of the three DGs. Therefore, even with no Thermo-Lag enclosures, the plant design basis may be considered to have been met.

Since the level of plant safety was not reduced and the condition of the plant was not seriously degraded, this condition was determined not to be reportable in accordance with 10 CFR 50.72 and this condition did not adversely affect the health and safety of the public.

7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

As noted in Section II.C.7., PG&E determined that this condition was not reportable in accordance with 10 CFR 50.72. This determination was based on the following points that PG&E believes give adequate assurance that the ability to transition to Mode 5 was not significantly affected:

- The likelihood of spurious opening of a PORV or auxiliary spray valve is unaffected by the lack of circuit separation due to design features and existing procedural guidance. The lack of circuit separation only impacts the ability to operate the PORVs or auxiliary spray valves

during a controlled RCS depressurization in the transition from Mode 3 to Mode 5.

- To be in accordance with Item 1.b of Appendix R, Section III.G., it must be shown that the valves will remain free from fire damage or can be repaired within 72 hours in order to enable transition to Mode 5.

The ability to cycle Auxiliary Spray Valves 8145 or 8148 can be established through the use of a temporary air jumper arrangement. Abnormal Operating Procedure (OP) AP-8B, "Control Room Inaccessibility - Hot Standby to Cold Shutdown," Appendix D, describes how to use air jumpers to enable closure of Valves 8146 and 8147 to isolate diversion paths for auxiliary spray flow (these are fail-open valves that must be closed to establish the proper lineup for auxiliary spray initiation). With minor modifications, this same jumper arrangement can also allow the cycling of Valves 8145 or 8148, which are located close to 8146 and 8147, to provide auxiliary spray if the control circuits for the PORVs and the auxiliary spray valves were damaged during a fire. The charging valves should be closed using the jumpers (or control room switch, if available) and an air jumper should be used to open and close valve 8145 or 8148.

Though actions to restore auxiliary spray valve or PORV operability were not proceduralized at the time of discovery of the condition, PG&E believes that operators had sufficient capability to determine the cause of the postulated valve inoperability and determine the actions necessary to regain valve operability in order to achieve Mode 5.

- For Areas 3-BB and 3-CC, transient combustible loading is minimal and in situ loading consists primarily of cable. Smoke detection is provided for the cable trays (FA), and these Areas have been provided with hourly fire watches during periods when safe shutdown equipment has been required to be available. Cables associated with the PORVs and auxiliary spray valves are routed in rigid metal conduits. Additionally, a wet pipe sprinkler system is provided.

For Area 6-B-4, transient combustible loading is minimal and in situ loading consists primarily of cable. The redundant PORV and auxiliary spray cables are routed through separate junction boxes and rigid metal conduits. The Area is provided with smoke detection, and has been provided with an hourly fire watch since the beginning of commercial operation.

For Areas 1 and 9, the major combustible loading, the RCPs, is considered not to be a concern for the annular areas because each RCP has automatic wet-pipe sprinkler protection, smoke detection, shield walls, and a lube oil collection system. Also, containment is a high radiation area, and materials (including potential combustibles)

brought into containment are strictly controlled. The subject circuits are inside rigid metal conduits, such that an electrically induced fire in one conduit should not impact any adjacent conduits. Lastly, the annular areas have automatic smoke detection that alarms in the control room, and manual fire suppression, hose reels, and extinguishers are readily available for fire brigade use.

Therefore, given the remote possibility a fire disabling the circuits, and given the 72-hour time frame available to operators to implement the above repairs in conjunction with procedures and equipment available for operation of the adjacent auxiliary spray valves, this condition did not significantly reduce the level of safety. Since the condition of the plant was not seriously degraded, this condition was determined not to be reportable in accordance with 10 CFR 50.72, and the condition did not adversely affect the health and safety of the public.

B. *Emergency Lighting*

As noted in Section II.C.8., PG&E determined that this condition was not reportable in accordance with 10 CFR 50.72. This determination was based on the following points that PG&E believes give adequate assurance that the ability to perform safe shutdown functions was not significantly impaired:

- Most of the actions in the procedures that were identified not to have adequate emergency lighting were actions for which the SSD analysis had not taken credit. Therefore, these actions were not considered essential to achieve safe shutdown and there was no requirement for these actions to have emergency lighting.

  Although emergency lighting may not be available for some post-fire manual actions, the ability to achieve safe shutdown in the event of a fire and concurrent loss of offsite power would still be available due to sound operational practices and alternative means of ensuring operator access and egress. Operators would use flashlights, if required, to perform required manual actions. Steps in procedures required to place the plant in a safe condition would not be bypassed by operators due to a lack of emergency lighting.

- Flashlights have always been available for operator use.

- Hourly roving fire watches have been in effect for the subject areas since the beginning of commercial operation.

Therefore, since only a limited number of required manual actions in EP M-10 and OPs AP-8A and AP-8B did not have adequate emergency lighting, and given that flashlights were available and operators therefore had the ability to complete the actions satisfactorily, this condition did not significantly reduce the level of safety. Since the condition of the plant was not

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seriously degraded, this condition was determined not to be reportable in accordance with 10 CFR 50.72, and the condition did not adversely affect the health and safety of the public.

V. Corrective Actions

A. Immediate Corrective Actions:

1. *DG 2-1 and 2-2 Field Circuitry*

a. A continuous fire watch was posted in Fire Area 22-C.

b. The corresponding Unit 1 fire area was reviewed and was determined not to have a condition similar to that discovered in Unit 2.

2. *SG and RCS Indication Circuitry*

All plant operators were advised regarding the strategy for performing a natural circulation cooldown in the event of loss of SG narrow range level and RCS temperature indication postulated during an Appendix R design basis fire in containment coincident with a loss of offsite power. This strategy involves maintaining the auxiliary feedwater flow (for which indication is not damaged by a containment fire) to all SGs and maintaining the main steam flow (SB) (for which control room control likewise is not damaged by a containment fire) from all the SGs matched as closely as possible. This would allow the level indication on one of the SGs to be used as a relative indication of the level in the SGs with temperature indication but without level indication.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*
4. *DG Control Circuitry*

A continuous fire watch was posted in the Units 1 and 2 cable spreading rooms. The control room is continuously manned by operators, and a Shift Order was issued to identify that the Unit 1 Control Operator would provide the continuous fire watch function for the control room area.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

Transient combustibles present at the time of discovery were removed from the fire zone, smoke detectors were determined to

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be operable, and an hourly fire watch was posted.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

   Hourly fire watch tour routes were reviewed to ensure that affected fire areas were being appropriately covered.

7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

   a. Hourly fire watches were verified to be in place for affected areas outside containment.

   b. Information was sent to all shift supervisors and shift foremen that described the use of air jumpers to enable remote control of auxiliary spray in the event that control of the auxiliary spray valves and PORVS is not available from the control room.

   c. EP M-10 and OPs AP-8A and AP-8B were revised to incorporate the potential need to effect the repair.

8. *Emergency Lighting*

   a. A Shift Order was issued to describe the problem.

   b. An on-the-spot change was issued to OPs AP-8A and AP-8B to inform operators of the potential need to use flashlights in areas where emergency lighting might not be adequate. Similar guidance was added to EP M-10.

   c. The action to perform a quarterly inventory of the HSP equipment locker in accordance with OP AP-8A was revised to include inventory of flashlights.

B. Corrective Actions to Prevent Recurrence:

1. *DG 2-1 and 2-2 Field Circuitry*

   a. A design change will be implemented to provide adequate fire barriers to provide circuit separation and obviate the need for a continuous fire watch.

   b. A memorandum was issued to NECS electrical and mechanical fire protection personnel regarding this condition and the importance of attention to detail with respect to Appendix

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R assumptions and implementation.

c. Since 1986, Appendix R calculations have been performed in accordance with NEMP 3.3, which requires that these calculations be prepared checked, approved, and documented in a thorough and consistent manner.

d. A review of all DG circuits that could potentially disable a DG due to fire-induced circuit failure was performed. No further unprotected circuits with this capability were identified. There is a possibility that this type of condition could exist elsewhere in the plant; however, the Appendix R Design Basis Documentation Enhancement Project under which this condition was identified is substantially complete and to date no other similar condition has been identified.

2. *SG and RCS Indication Circuitry*

a. A design change will be implemented to provide adequate Appendix R instrumentation separation.

b. A memorandum was issued to NECS electrical and mechanical fire protection personnel regarding this condition and the importance of attention to detail with respect to Appendix R assumptions and implementation.

c. Since 1986, Appendix R calculations have been performed in accordance with NEMP 3.3, which requires that these calculations be prepared checked, approved, and documented in a thorough and consistent manner.

d. No further unprotected circuits with this capability were identified. There is a possibility that this type of condition could exist elsewhere in the plant; however, the Appendix R Design Basis Documentation Enhancement Project under which this condition was identified is substantially complete and to date no other similar condition has been identified.

3. *Fuse Design for Safe Shutdown Equipment Control Circuitry*

a. A design change will be implemented to provide adequate fuse isolation.

b. A memorandum will be issued to NECS electrical and mechanical fire protection personnel regarding this

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condition and the importance of attention to detail with respect to Appendix R assumptions and implementation for fuses.

c. NECS electrical and mechanical fire protection personnel will be trained on Appendix R fuse requirements for design changes as part of the training for E3.6 DC, "Diablo Canyon Power Plant Design Changes."

d. Procedure EE-2, "Electrical Engineering Procedure For the Review of Electrical DCNs For Impact on 10 CFR Appendix R Electrical Analysis," will be revised to include details of the level of circuit analysis to be performed for Appendix R safe shutdown components.

e. No further fuses with this capability were identified. There is a possibility that this type of condition could exist elsewhere in the plant; however, to date no other similar condition has been identified.

f. A review of circuit design for all safe shutdown components credited for operation from remote stations will be performed as a part of the Appendix R Project.

4. *DG Control Circuitry*

a. A design change will be implemented to provide adequate fuse separation.

b. A memorandum will be issued to NECS electrical and mechanical fire protection personnel regarding this condition and the importance of attention to detail with respect to Appendix R assumptions and implementation for fuses.

c. NECS electrical and mechanical fire protection personnel will be trained on Appendix R fuse requirements for design changes as part of the training for E3.6 DC.

d. Procedure EE-2 will be revised to include details of the level of circuit analysis to be performed for Appendix R safe shutdown components.

e. No further fuses with this capability were identified. There is a possibility that this type of condition could exist elsewhere in the plant; however, to date no other similar condition has been identified.

TEXT (17)

f. A review of circuit design for all safe shutdown components credited for operation from remote stations will be performed as a part of the Appendix R Project.

5. *Auxiliary Saltwater Pump and Exhaust Fan Circuitry*

a. A design change will be implemented to provide 3-hour fire wrap for the subject circuits.

b. A memorandum will be issued to NECS electrical and mechanical fire protection personnel regarding this condition and the importance of attention to detail with respect to implementation of Appendix R commitments in design changes.

c. A review of previous Appendix R modifications will be performed to verify that Appendix R commitments were properly implemented.

6. *DG Emergency Stop and CO_2 Switch Circuitry Thermo-Lag Enclosures*

a. The subject DG emergency stop and CO_2 switch enclosures will be replaced with adequate fire retardant enclosures.

b. Procedures for evaluation of non-tested Thermo-Lag configurations are now in place which specify requirements for detailed review and documentation of such configurations.

7. *Power-Operated Relief and Auxiliary Spray Valve Circuitry*

a. A memorandum was issued to NECS electrical and mechanical fire protection personnel regarding this condition and the importance of attention to detail with respect to Appendix R assumptions and implementation.

b. Since 1986, Appendix R calculations have been performed in accordance with NEMP 3.3, which requires that these calculations be prepared checked, approved, and documented in a thorough and consistent manner.

c. No further SSD analysis assumption errors involving air-operated valve circuits were identified. There is a possibility that this type of assumption has been made elsewhere in the SSD analysis; however, the Appendix R Design Basis Documentation Enhancement Project under which

this condition was identified is substantially complete and to date no other similar condition has been identified.

8. *Emergency Lighting*

    a. A design change will be implemented to install emergency lighting in areas determined to be deficient.

    b. EP M-10 and OPs AP-8A and AP-8B were cross-checked against the SSD analysis. Permanent emergency lighting will be provided in areas identified not to have adequate lighting where SSD actions are required.

    c. A detailed emergency lighting review has been initiated that will specifically identify manual operator actions which credit emergency lighting and subsequently verify adequacy of lighting of plant areas and access/egress routes for those actions.

    d. NECS review of revisions to OPs AP-8A and AP-8B and Operations Department review of revisions to NECS Calculation M-680 (Appendix R SSD Equipment List) are now required as noted in these documents.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Problems:

None.

50-275/323-OLA-2 I-MFP-F-11

"NOT ADMITTED"

MFP Exhibit F-11

RELATED CORRESPONDENCE

U. S. NUCLEAR REGULATORY COMMISSION

REGION V

'93 OCT 28 P6:54

Report Numbers: 50-275/92-21 and 50-323/92-21

Docket Numbers: 50-275 and 50-323

License Numbers: DPR-80 and 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: June 29 through July 2, and July 20 through July 29, 1992

Inspectors: D. Acker, Reactor Inspector

Approved By: M. Royack, Acting Chief, Engineering Section — 8/12/92 Date Signed

Summary:

Inspection on June 29 through July 2, and July 20 through July 29, 1992 (Report Nos. 50-275/92-21 and 50-323/92-21)

Areas Inspected:

The areas inspected in this routine engineering inspection included the installation of the new emergency diesel generator in Unit 2 and follow-up of previously identified items. Construction Modules 51051, 51053, 51065, 70300, and 70312 and Inspection Procedures 37700 and 92701 were used as guidance for this inspection.

Results:

Conclusions and Specific Findings:

The inspector concluded that:

The new (sixth) emergency diesel generator electrical systems were being installed in accordance with engineering requirements.

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Q PDR

The craft personnel had adequate knowledge of electrical testing criteria.

Th.. there was adequate quality assurance overview of this project in the areas examined.

Significant Safety Matters:

None

Summary of Violations:

None

Open Items Summary:

The inspector closed two unresolved items during this inspection.

DETAILS

1. Persons Contacted

   Pacific Gas and Electric Company

   *M. Angus, Manager, Technical Services
   M. DeWitt, Quality Assurance Engineer
   *B. Goelzer, System Engineer
   J. Griffin, Senior Compliance Engineer
   *M. Hicks, Startup Engineer
   D. Miklush, Acting Plant Manager
   *R. Ricks, Engineering Test Coordinator
   *D. Shelly, Senior Plant Engineer
   *D. Sisk, Compliance Engineer
   *S. Szuch, Quality Engineer

   *Denotes those attending the telephone exit meeting on July 29, 1992.

   The inspector also held discussions with other licensee personnel during the course of the inspection.

2. Previously Identified Items

   a. (Closed) Unresolved Item 50-275, 50-323/91-07-01: 4 Kilovolt Switchgear Fault Current Rating

      The Electrical Distribution System Functional Inspection identified that calculated fault current exceeded 4 kilovolt (kV) switchgear ratings during certain plant operations. Calculated fault current exceeded switchgear ratings when one or more emergency diesel generators (EDGs) were operated in parallel with the main generator.

      The licensee took action to minimize the tests which required parallel operation of the main generator and one or more EDGs, and performed a calculation which showed that a maximum (bolted) fault was a low probability event during the limit ' time the main generator was operated in parallel with an EDG.

      The inspector reviewed the licensee's actions and calculation and concluded that:

      o The actions t mini ize the risk from a bolted fault were adequate.

      o The licensee's calculation adequately demonstrated that a bolted fault during parallel operation of the main generator and an EDG was a low probability event.

      Based on the licensee's evaluation and independent NRC evaluations the inspector concluded that the core damage frequency for the

bolted fault condition was low and had little safety significance.

This item is closed.

b. (Closed) Unresolved Item 50-323/92-06-01: Adequacy of Conduit Supports

During a previous inspection, the inspector had noted a new conduit installation which, although not yet in use, did not appear to be installed in accordance with the Updated Final Safety Analysis Report (UFSAR).

Sections 3.10.2.12 and 8.3.1.4.7 of the UFSAR required that no unsupported span (of conduit) shall exceed 8 feet 6 inches. The inspector had identified that new EDG conduit in the turbine building visually appeared to have support spacing which exceeded 8 feet 6 inches. The licensee determined that the installation in question was installed in accordance with sheet 4 of Field Change E-15127, Revision 0, dated March 6, 1991. This Field Change allowed a maximum distance between supports of 10 feet.

The licensee determined that the actual installation did exceed the UFSAR 8 feet 6 inch criteria, but was within the 10 feet criteria of Field Change E-15127. The licensee concluded that the support for the conduit in question was technically adequate and that the UFSAR would be revised to incorporate the new criteria.

The inspector reviewed Field Change E-15127 and the licensee's evaluation that the conduit supports were technically adequate. The inspector concluded that the licensee's evaluation was acceptable since the conduit was not yet in use and the UFSAR was being changed to support the installation.

This item is closed.

No violations or deviations from NRC requirements were identified in the areas reviewed.

3. Design Changes: New Emergency Diesel Generator (37700)

The inspector reviewed the progress being made on the new (sixth) emergency diesel generator (EDG). The inspector walked down the work areas with licensee personnel and independently witnessed testing in progress. The inspector reviewed quality assurance and quality control involvement for this project.

a. <u>Cable, Raceway and Conduit Installation</u>

The licensee had installed cables, raceways and conduit in accordance with Diablo Canyon Procedures (DCPs) 301, Revision 3, "Wire and Cable Installation," and 304, Revision 3, "Installation of Electrical Raceway and Raceway Supports." The inspector walked down the cable runs between the cable spreading room and the new EDG room and compared these installations to the DCP requirements. The inspector reviewed cable installation and certification documents.

The inspector found three locations in the cable spreading areas in the turbine building where one conduit support was used for mutually redundant Class 1E circuits. The inspector noted that the UFSAR, Section 8.3.1.4.7 stated that:

> "Class 1 supports are not normally shared by mutually redundant Class 1E circuits."

The inspector discussed cable supports with the licensee. The licensee noted that most mutually redundant Class 1E circuits in the turbine building cable spreading areas had separate supports. The licensee reverified that the supports in question were seismically qualified. The licensee concluded that the UFSAR commitment was being met.

The inspector reviewed approximately 75 Class 1E conduit supports in the cable spreading areas of the turbine building found three Class 1E circuits that did not have independent supports. The inspector concluded that the installation met the UFSAR commitment.

b. <u>New EDG Room</u>

The inspector monitored work taking place in the new EDG room. The EDG had been leveled and installed on its foundation. Shaft alignment had been completed. The inspector reviewed the alignment data and found the data acceptable.

The licensee had removed the protective covering from the new EDG skid. The inspector noted that all mechanical openings on the diesel generator skid were covered. Some electrical equipment was open, but the room was being continuously cleaned. The inspector concluded that cleanliness controls in the new EDG room were adequate.

c. <u>Quality Assurance Oversight of Work</u>

The inspector reviewed the quarterly reports issued by the quality assurance organization specifically for the new EDG project. The inspector toured the construction areas with quality assurance personnel. Quality Assurance personnel had identified problems with day tank cleanliness, problems with as-built details for skid instrument tubing installed by the licensee, and problems with

electrical separation.

Based on a review of the quarterly report and discussions with quality assurance personnel the inspector concluded that the quality assurance organization was providing an effective review of ongoing and completed work for the new EDG.

d. Testing of EDG Systems

The inspector witnessed performance of part of Test Procedure TP M-44405-02E, Revision 0, "Diesel Generator 23 Control Circuitry." The inspector also reviewed additional parts of this procedure and preliminary procedures PMT 21.04, Revision 0, "Sixth Diesel 2-3 Test of Starting Air and Turbo Air System," PMT 21.06, Revision 0, "Diesel Generator (D/G) 2-3 Engine Fuel Oil System Operational Test," and PMT 21.08, Revision 0, "Diesel Generator (D/G) 2-3 Lube Oil System and Miscellaneous Equipment Operational Test."

*Craft Understanding of Procedure TP-M44405-02E:

Based on observation of the work, the inspector found that the craft personnel performing Procedure TP M-44405-02E understood the test and had all the necessary electrical drawings to verify the procedure steps.

*Procedure TP-M44405-02E Adequacy and Electrical Safety:

The inspector found that Procedure TP M-44405-02E did not specify how to make electrical CONTACT checks. The procedure directed craft personnel to verify that contacts were "Open" or "Closed," without noting whether the contacts would be energized or de-energized. Craft personnel had to review the system drawings in order to determine whether each contact was energized or de-energized. Craft personnel had to check energized contacts with a voltmeter and de-energized contacts with an ohmmeter.

The inspector considered that personnel injury or equipment damage could occur if craft personnel mistakenly tried to measure resistance with an ohmmeter across an open energized contact.

The inspector also considered that if craft personnel used a voltmeter to verify a closed contact they could mistake a de-energized open contact for an energized closed contact, since the voltmeter would indicate no voltage for both situations. The inspector concluded that lack of directions for the type of measurement required was a procedure weakness.

Procedure TP M-44405-02E, Step 9.3.3.5.a verified that relay ESR1-23 was de-energized and contacts numbered 3 and 4 were closed. The inspector reviewed Drawing SK 496276, Revision 1A,

"Schematic Diagram, 4160V Diesel Generator No. 23 and Associated Circuit Breaker." This drawing showed that a parallel closed contact existed across terminals 3 and 4 of relay ESR1-23 for the test conditions of Step 9.3.3.5.a. The inspector concluded that Step 9.3.3.5.a did not verify that contacts 3 and 4 of relay ESR1-23 were operating properly. The inspector reviewed this conclusion with the licensee. The licensee noted that contacts 3 and 4 of relay ESR1-23 were correctly verified to be open when relay ESR1-23 was energized. However, the licensee determined that Step 9.3.3.5.a did not properly verify contacts 3 and 4 were closed when the relay was de-energized. The licensee rechecked these contacts for proper operation with the relay de-energized.

The inspector concluded that TP M-44405-02E was adequate to verify proper operation of the equipment being tested based on:

1) Observation of personnel performing TP M-44405-02E who recognized the procedural weaknesses and by "skill of the craft" adequately assured proper operation of the equipment and assured personnel safety;

2) A review of associated electrical schematics; and

3) The licensee actions to recheck relay ESR1 contact operation.

- Procedures PMT 21.08, PMT 21.06, PMT 21.04:

  The inspector found the parts of these preliminary procedures reviewed to be adequate.

No violations or deviations from NRC requirements were noted in the areas inspected.

4. <u>Walkdown of Plant Equipment</u>

The inspector walked down the electrical equipment on the 115 foot level of the auxiliary building, including the Class 1E battery rooms, inverter/battery charger rooms and rod control motor generator set areas. Procedure NPAC C-10, Revision 10, "Housekeeping - General," defined these areas as Zone 4 housekeeping. Zone 4 included a ban on eating, drinking and smoking.

The inspector noted gum, candy wrappers, sunflower seeds and/or smoked cigarettes in 12 different locations in the auxiliary building 115' elevation electrical rooms. Most of this eating and smoking material was located on fire barriers located around vertical cable trays. The inspector also noted heavy metal wedges and a large portable electrical tool on vertical cable tray fire barriers in three locations.

The licensee removed the eating and smoking material, the electrical tool, and metal wedges from the identified areas. The licensee also discussed the requirements for maintaining proper housekeeping and material control in construction areas with plant and construction personnel.

The inspector concluded that the licensee's housekeeping control, required increased attention and that it would be reviewed in future inspections.

No violations or deviations from NRC requirements were identified in the areas reviewed.

5. Exit Meeting

The inspector conducted a telephone exit meeting on July 29, 1992, with members of the licensee staff as indicated in Section 1. During this meeting, the inspector summarized the scope of the inspection activities and reviewed the inspection findings as described in this report. The licensee acknowledged the concerns identified in the report. During this inspection, the licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector.

50-275/323-OLA-2
I-MFP-112
"NOT ADMITTED"

RELATED CORRESPONDENCE

MFP EXHIBIT S 112

DCS

Pacific Gas and Electric Company

415/973-4684

James D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

'93 OCT 28 P6:54

March 12, 1990

PG&E Letter No. DCL-90-070

Director, Office of Enforcement
U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to Notice of Violation
NRC Enforcement Action 89-241

Gentlemen:

On February 13, 1990, NRC Region V issued Enforcement Action 89-241 that included a Notice of Violation and proposed imposition of a civil penalty in the amount of $50,000 associated with NRC Inspection Report Nos. 50-275/89-31 and 50-323/89-31. The Enforcement Action contained a Notice of Violation citing a Severity Level III problem regarding the Diablo Canyon Units 1 and 2 containment recirculation sumps. PG&E's response to the Notice of Violation is enclosed, including a check for full payment of the civil penalty payable to the Treasurer of the United States. The response incorporates discussions and corrective actions described in previous PG&E correspondence to the NRC and PG&E-NRC meetings regarding containment recirculation sump issues. PG&E recognizes the importance and significance of the problems and has taken appropriate measures to improve performance in these areas.

As discussed in past correspondence with the NRC and in PG&E-NRC management meetings, PG&E has and will continue to place emphasis on management and supervisory oversight of maintenance and surveillance activities, personal accountability and problem ownership, and increased involvement by the quality and engineering organizations in plant activities. PG&E will continue to require that all matters be addressed using sound judgment, with particular emphasis on the identification, timely resolution, and appropriate followup of potential safety concerns and problems.

PG&E believes that its ongoing programs in the area of configuration management are appropriate for identifying and correcting discrepancies and inconsistencies at the plant. PG&E's System Engineer Program, including the quarterly system walkdowns, has been implemented and is continually being strengthened. PG&E's enhanced Design Criteria Memoranda (design basis documentation) program is proving to be both useful and effective in clarifying the design bases and identifying discrepancies and inconsistencies. PG&E's Safety System Functional Audit and Review Program is also proving to

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ENCLOSURE

RESPONSE TO NOTICE OF VIOLATION - ENFORCEMENT ACTION 89-241 REGARDING NRC INSPECTION REPORT NOS. 50-275/89-31 AND 50-323/89-31

On February 13, 1990, as followup to an Enforcement Conference held with PG&E on December 19, 1989, NRC Region V issued Enforcement Action 89-241 that included a Notice of Violation associated with NRC Inspection Report Nos. 50-275/89-31 and 50-323/89-31. Enforcement Action 89-241 cited three violations that were categorized in the aggregate as a Severity Level III problem applicable to Diablo Canyon Units 1 and 2 related to the containment recirculation sumps. Potential degradation of the sumps due to inadequate procedures and personnel error was reported by PG&E to the NRC in Licensee Event Report (LER) 1-89-014-01, dated January 19, 1990 (DCL-90-018). PG&E recognizes the importance and significance of these concerns and has taken appropriate measures to improve performance in these areas. A discussion of the sump problems and PG&E's corrective actions are provided below.

STATEMENT OF VIOLATION A:

A. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires in part, that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

FSAR Section 6.2.3.2.2.1, Containment Recirculation Sump, states in part, that a baffle arrangement surrounds the sumps to prevent floating debris or anything larger than 3/16-inch from entering the sumps. FSAR Figure 6.2-11 shows the configuration.

Contrary to the above, on August 2, 1985, the licensee identified a condition adverse to quality related to gaps in the Unit 1 recirculation sump in excess of the dimensions described in the FSAR. The licensee's corrective actions were inadequate to identify and correct all of the nonconforming conditions. Additional gaps in excess of the dimensions described in the FSAR were discovered on November 26, 1989.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

During the Unit 1 third refueling outage (which commenced October 6, 1989), a walkdown verification of the containment recirculation sump (sump) identified a 1-inch vertical gap in the upper grating assembly between the screen sections and other gaps around a concrete column pedestal in the inclined section of the upper grating assembly (see Figures 1, 2, and 3). PG&E acknowledges that the gaps in the sump screen assembly identified in 1985 and again in 1989 were not in accordance with the intended design configuration of

the sump as described in the FSAR Update, and that the corrective actions taken in 1985 were inadequate to identify and correct the nonconforming conditions. The reasons are as follows:

1. The critical construction parameter related to the maximum gap anywhere on the surface of the sump screens was not clearly defined by Engineering until December 15, 1986, when Revision 8 of sump Drawing 443259 was issued. The drawing revision was issued at that time to reflect the Unit 2 design changes that were made in 1985 to eliminate the gaps greater than 3/16-inch in the sump screen assembly. The apparent failure to specify adequate construction acceptance criteria for the sump screen gaps led to the Unit 1 as-built screen configuration described in the violation, i.e., screen gaps in excess of the dimensions described in the FSAR Update.

2. The 1985 problem report for Unit 1, which was based on a similar problem with the Unit 2 sump screens, identified potential deficiencies (gaps greater than 3/16-inch) in the unscreened portions only of the upper grating assembly. Two gaps were found and corrected in addressing the problem report. However, the inspection was not expanded to look for gaps in the screened portions of the upper grating assembly since the problem report did not identify that the screened portions might also be deficient.

3. The Unit 1 screen gaps were not identified during containment inspections since the procedures governing walkdowns and inspections of the sump lacked specific guidance regarding integrity of the sump screen assemblies.

As discussed at the Enforcement Conference and in LER 1-89-014-01, PG&E believes with a high degree of confidence that the emergency core cooling system (ECCS), even with the identified gaps in the sump screen assembly, would have been capable of performing its intended safety function in the event of a design basis loss-of-coolant-accident (LOCA) requiring containment recirculation. This conclusion is based on safety evaluations and supporting studies, which were documented in LER 1-89-014-01, that considered both the nature of the accident conditions and the conservative design of the sump with its relatively large screen areas, concrete baffle, curb, and multiple layers of screen and grating. These evaluations considered the unique and advantageous location of the sump in the annulus area of the containment structure where it is separated from a postulated pipe break by the concrete crane wall, the shielding labyrinths, and the locked wire mesh personnel doors. These evaluations also considered the nature of the debris created by postulated accidents (insulation debris and larger size paint particles) and PG&E's conclusion that this debris would sink and not be carried to the sump and the residual heat removal (RHR) inlet piping due to the low velocity of the flow.

STATEMENT OF VIOLATION B.

B. Diablo Canyon Technical Specification 3.5.2 states in part that:

"Two Emergency Core Cooling System (ECCS) subsystems shall be OPERABLE with each subsystem comprised of: ...e. An OPERABLE flow path capable of taking suction from the Refueling Water Storage Tank on a Safety Injection signal and manually transferring suction to the containment sump during the recirculation phase of operation."

Technical Specification 1.21, in defining the terms OPERABLE and OPERABILITY, provides in part: "a system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety-related function(s). Implicit in this definition shall be the assumption that all necessary...auxiliary equipment that are required for the system, subsystem, train, component or device to perform its safety-related function(s) are also capable of performing their rated support function(s)."

With more than one ECCS subsystem inoperable, Technical Specification 3.0.3 applies, which states:

"When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within 1 hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in

a. At least HOT STANDBY within the next 6 hours,
b. At least HOT SHUTDOWN within the following 6 hours, and
c. At least COLD SHUTDOWN within the subsequent 24 hours."

Contrary to the above, two emergency core cooling system subsystems were inoperable for period of about 10 to 12 hours each while Unit 2 was in Mode 1 operation on October 12, 1987 and August 23, 1988 and while Unit 1 was in Mode 1 operation on September 7, 1988, and May 11, 1989. On those dates, the containment recirculation sump was rendered inoperable because the screened access hatch was opened to allow the addition and pumpdown of borated water with hoses for calibration of the sump level detectors. With the sump access hatch open, the screening structure was not fully capable of performing its rated support function. During the stated periods, no action was initiated to reduce the reactor power to enter a lower mode of operation.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

PG&E acknowledges that the sump access hatch on the Units 1 and 2 upper grating assembly had been opened (for up to 12 hours) at various times during power operation without adequate consideration of the effect on operability of the sump. The primary reason for opening the hatch was for calibration of the sump level narrow-range instrumentation, LT-940 and -941. The calibration was performed using Temporary Procedure (TP) TO-8706, which did not include limitations on the time that the access hatch is permitted to be oper or other guidance regarding sump operability considerations during at-power calibration activities. The safety evaluation performed for TP TO-8706 was inadequate since it did not address operability of the sump.

As discussed at the Enforcement Conference and in LER 1-89-014-01, PG&E believes that opening of the sump access hatch on the upper grating assembly did not render the sump inoperable. The evaluation presented in the LER discussed the low likelihood that debris would enter the sump (with the access hatch open) and the risk significance of unavailability of the containment sump during power operation. It was concluded that it was highly unlikely, considering the physical arrangement and location of the sump structure, that debris would enter the sump should a LOCA occur when the access hatch was open. Using extremely conservative assumptions, the risk significance study concluded that the increase in the total core damage frequency was approximately 0.05 percent for each hour that the sump was not available. If more realistic assumptions were used to account for the physical configuration of containment, the remote location of the sump, and the nature of the potential debris, it is judged that the risk would be reduced by at least an order of magnitude.

PG&E concludes that opening of the access hatch in the upper grating assembly during power operation did not render the containment recirculation sump inoperable as stated in the violation. Furthermore, even if the assumption is made that opening the hatch renders the sump inoperable, the risk significance is very low. Therefore, the health and safety of the public were not adversely affected by this event. However, since the safety evaluation for performance of TP TO-8706 did not adequately address sump operability, PG&E has taken the actions described below to ensure critical evaluation prior to future sump access hatch openings during power operation.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A shift night order was issued requiring management review of any intended at-power openings of the access hatch on the upper grating assembly of the Unit 1 or Unit 2 sump. If management determines that opening the hatch at power is acceptable, concurrence will be sought from the NRC Resident Inspector.

2. Nuclear Plant Administrative Procedure C-19/NPG 4.3, "Safety Evaluation Guidelines," was recently revised and extensive training is being given to plant personnel to increase their sensitivity to the requirements for performing safety evaluations in accordance with 10 CFR 50.59.

STATEMENT OF VIOLATION C.

C. Technical Specification 4.5.2.c requires in part that a visual inspection be performed of all accessible areas in the containment prior to establishing containment integrity to verify that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restrictions of the pump suctions during a LOCA condition.

Contrary to the above, on May 11, 1989, the licensee performed an inadequate inspection of the Unit 1 containment sump for loose debris which could be transported within the containment sump and cause restrictions of the sump suctions during a LOCA condition. Even though containment integrity had been established, there was debris in the sump from at least the time of the last licensee inspection of May 11, 1989, until October 17, 1989 when the debris was discovered and removed.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

PG&E acknowledges that inadequate sump inspections were performed. This resulted in failure to detect debris inside the upper grating assembly of the Unit 1 sump. The debris was found by the NRC Resident Inspector relatively early in the Unit 1 third refueling outage before the PG&E System Engineer had performed a planned ECCS walkdown. The engineer had planned to inspect the sump during the first week of the outage, but a primary system valve flange leak resulted in contaminated boric acid crystals on the top and inside of the sump. Thus, the walkdown was delayed pending decontamination of the sump area. At the request of the NRC Resident Inspector, sump decontamination was expedited and acceptable entry conditions were obtained.

The primary reason for debris in the sump was failure to follow STP M-45, "Containment Inspection," for containment inspections following maintenance activities. Also, the procedure was not explicit in defining inspection activities. In addition, plant management did not ensure that foreign material exclusion principles controlled recirculation sump activities.

An extensive evaluation of the effects of the debris on recirculation operability was performed. This evaluation was discussed at the Enforcement Conference and documented in LER 1-89-014-01. PG&E concluded that because of the nature of the debris and the design features of the sump, it is highly unlikely that the debris would have been drawn into the RHR inlet piping, and thus, it would not have impaired operation of the ECCS or the containment spray system.

DCS

February 8, 1990
EN 90-015

OFFICE OF ENFORCEMENT
NOTIFICATION OF SIGNIFICANT ENFORCEMENT ACTION

Licensee: Pacific Gas & Electric Company (EA 89-241)
Diablo Canyon
Docket Nos. 50-275 and 50-323

Subject: PROPOSED IMPOSITION OF CIVIL PENALTY - $50,000

This is to inform the Commission that a Notice of Violation and Proposed Imposition of Civil Penalty in the amount of $50,000 will be issued on or about February 13, 1990 to Pacific Gas & Electric Company. This action is based on three violations relating to Containment Sump operability. The violations concerned the failure to take adequate corrective actions for gaps in the sumps trash screens identified in 1985, opening sump access hatches on a number of occasions for time periods exceeding technical specification limits and the failure to do adequate surveillance inspection resulting in operation with debris inside the sump screens. The civil penalty was escalated 50% because the NRC identified the problem of debris in the Unit 1 sump and raised questions concerning the as-built screen configuration. Due to the licensee's good overall past performance, the civil penalty was mitigated 50%. No other factors were deemed applicable to this case.

It should be noted that the licensee has not been specifically informed of the enforcement action. The schedule of issuance and notification is:

Mailing of Notice	February 13, 1990
Telephone Notification of Licensee	February 13, 1990

The State of California will be notified.

The licensee has thirty days from the date of the Notice in which to respond. Following NRC evaluation of the response, the civil penalty may be remitted, mitigated, or imposed by Order.

Contact: W. Troskoski, OE, 23281 J. Lieberman, OE, 20741

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63B

NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTY

Pacific Gas and Electric Company
Diablo Canyon Nuclear Power Plant
Units 1 and 2

Docket Nos. 50-275 and 50-323
License Nos. DPR 80 and DPR 82
EA 89-241

During an NRC inspection conducted from October 17 through December 11, 1989, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1989), the Nuclear Regulatory Commission proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (Act), 42 U.S.C. 2282, and 10 CFR 2.205. The particular violations and the associated civil penalty are set forth below:

A. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires in part, that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

FSAR Section 6.2.3.2.2.1, Containment Recirculation Sump, states in part, that a baffle arrangement surrounds the sumps to prevent floating debris or anything larger than 3/16 inch from entering the sumps. FSAR Figure 6.2-11 shows the configuration.

Contrary to the above, on August 2, 1985, the licensee identified a condition adverse to quality related to gaps in the Unit 1 recirculation sump in excess of the dimensions described in the FSAR. The licensee's corrective actions were inadequate to identify and correct all of the nonconforming conditions. Additional gaps in excess of the dimensions described in the FSAR were discovered on November 26, 1989.

B. Diablo Canyon Technical Specification 3.5.2 states in part that:

"Two Emergency Core Cooling System (ECCS) subsystems shall be OPERABLE with each subsystem comprised of: ... e. An OPERABLE flow path capable of taking suction from the Refueling Water Storage Tank on a Safety Injection signal and manually transferring suction to the containment sump during the recirculation phase of operation."

Technical Specification 1.21, in defining the terms OPERABLE and OPERABILITY, provides in part: "a system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety-related function(s). Implicit in this definition shall be the assumption that all necessary ... auxiliary equipment that are required for the system, subsystem, train, component or device to perform its safety-related function(s) are also capable of performing their rated support function(s)."

With more than one ECCS subsystem inoperable, Technical Specification 3.0.3 applies, which states:

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PDR ADOCK 05000275
Q PNU

"When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within 1 hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in

a. At least HOT STANDBY within the next 6 hours,
b. At least HOT SHUTDOWN within the following 6 hours, and
c. At least COLD SHUTDOWN within the subsequent 24 hours."

Contrary to the above, two emergency core cooling system subsystems were inoperable for periods of about 10 to 12 hours each while Unit 2 was in Mode 1 operation on October 12, 1987 and August 23, 1988 and while Unit 1 was in Mode 1 operation on September 7, 1988, and May 11, 1989. On those dates, the containment recirculation sump was rendered inoperable because the screened access hatch was opened to allow the addition and pumpdown of borated water with hoses for calibration of the sump level detectors. With the sump access hatch open, the screening structure was not fully capable of performing its rated support function. During the stated periods, no action was initiated to reduce the reactor power to enter a lower mode of operation.

C. Technical Specification 4.5.2.c requires in part that a visual inspection be performed of all accessible areas in the containment prior to establishing containment integrity to verify that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restrictions of the pump suctions during a LOCA condition.

Contrary to the above, on May 11, 1989, the licensee performed an inadequate inspection of the Unit 1 containment sump for loose debris which could be transported within the containment sump and cause restrictions of the pump suctions during a LOCA condition. Even though containment integrity had been established, there was debris in the sump from at least the time of the last licensee inspection of May 11, 1989, until October 17, 1989 when the debris was discovered and removed.

Violations A through C have been categorized in the aggregate as a Severity Level III problem (Supplement 1).

Civil Penalty - $50,000 (assessed equally between the violations).

Pursuant to the provisions of 10 CFR 2.201, Pacific Gas and Electric Company (licensee), is hereby required to submit a written statement or explanation to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission within 30 days of the date of this Notice. This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each alleged violation: (1) admission or denial of the alleged violation, (2) the reasons for the violation if admitted, (3) the corrective steps that have been taken and the results achieved, (4) the corrective steps that will be taken to avoid further violations, and (5) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked or why such other action as may be proper should not be

50-275/323-OLA-2
I-MFP-113

RELATED CORRESPONDENCE

MFP Exhibit 113

"NOT ADMITTED"

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94106
415/972-7000
415/973-4684

James D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

'93 OCT 28 P6:54

March 12, 1990

PG&E Letter No. DCL-90-070

Director, Office of Enforcement
U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

ACTS
LOG NUMBER
2273

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to Notice of Violation
NRC Enforcement Action 89-241

Gentlemen:

On February 13, 1990, NRC Region V issued Enforcement Action 89-241 that included a Notice of Violation and proposed imposition of a civil penalty in the amount of $50,000 associated with NRC Inspection Report Nos. 50-275/89-31 and 50-323/89-31. The Enforcement Action contained a Notice of Violation citing a Severity Level III problem regarding the Diablo Canyon Units 1 and 2 containment recirculation sumps. PG&E's response to the Notice of Violation is enclosed, including a check for full payment of the civil penalty payable to the Treasurer of the United States. The response incorporates discussions and corrective actions described in previous PG&E correspondence to the NRC and PG&E-NRC meetings regarding containment recirculation sump issues. PG&E recognizes the importance and significance of the problems and has taken appropriate measures to improve performance in these areas.

As discussed in past correspondence with the NRC and in PG&E-NRC management meetings, PG&E has and will continue to place emphasis on management and supervisory oversight of maintenance and surveillance activities, personal accountability and problem ownership, and increased involvement by the quality and engineering organizations in plant activities. PG&E will continue to require that all matters be addressed using sound judgment, with particular emphasis on the identification, timely resolution, and appropriate followup of potential safety concerns and problems.

PG&E believes that its ongoing programs in the area of configuration management are appropriate for identifying and correcting discrepancies and inconsistencies at the plant. PG&E's System Engineer Program, including the quarterly system walkdowns, has been implemented and is continually being strengthened. PG&E's enhanced Design Criteria Memoranda (design basis documentation) program is proving to be both useful and effective in clarifying the design bases and identifying discrepancies and inconsistencies. PG&E's Safety System Functional Audit and Review Program is also proving to

be effective for identifying inconsistencies in both documentation and operational practices and improving system operation.

In addition, numerous improvements have been made since 1981 in PG&E's processes for design control, drawing revisions, FSAR updating, and preliminary walkdowns of proposed plant modifications. Finally, a theme that is being stressed is the significance of an individual's signoff that an activity has been correctly accomplished. PG&E is confident that aggressive pursuit of these programs and their betterment will enable us to identify conditions such as those associated with the sump, and that these programs will significantly reduce the likelihood of recurrence. While continuous reemphasis is warranted, PG&E believes significant progress has been made in the above areas.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Subscribed to in San Francisco, California this 12th day of March 1990.

Respectfully submitted,

Pacific Gas and Electric Company

By J. D. Shiffer
J. D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

Howard V. Golub
Richard F. Locke
Attorneys for Pacific
Gas and Electric Company

By Richard F. Locke
Richard F. Locke

Subscribed and sworn to before me
this 12th day of March 1990

B. E. Zelnik
Bianca E. Zelnik, Notary Public
for the City and County of San Francisco
State of California

My commission expires July 30, 1991.

OFFICIAL SEAL
BIANCA E. ZELNIK
NOTARY PUBLIC - CALIFORNIA
San Francisco County
My Commission Expires July 30, 1991

cc: A. P. Hodgdon
J. B. Martin
M. M. Mendonca
P. P. Narbut
H. Rood
CPUC
Diablo Distribution

Enclosure

DCO-89-EN-N025

3043S/0080K/DWO/2237

956967

Pacific Gas and Electric Company | 77 Beale Street San Francisco, CA | WELLS FARGO BANK 464 CALIFORNIA STREET SAN FRANCISCO, CA 94120 | 11-24 1210

Date MARCH 8, 1990 Check Number 09003249 Pay $50,000.00

PAYABLES PROCESSING

To The Order Of

TREASURER OF THE UNITED STATES
C/O U.S. REGULATORY COMMISSION
WASHINGTON, DC 20555

TREASURER
York
TREASURER

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PAYEE NUMBER 9377102 PAY DATE 030890 CHECK NO 09003249

INVOICE NUMBER	INVOICE DATE			PAYMENT REQ NO	DISCOUNT AMOUNT	AMOUNT PAID
	03	06	90	26117564		50 000 00
					CHECK TOTAL:	50 000 00*

COMMENTS: %CATHY HUBBARD AT 3-9653

Pacific Gas and Electric Company 77 Beale Street, San Francisco, CA 94106 Not Negotiable

ENCLOSURE

RESPONSE TO NOTICE OF VIOLATION - ENFORCEMENT ACTION 89-241 REGARDING NRC INSPECTION REPORT NOS. 50-275/89-31 AND 50-323/89-31

On February 13, 1990, as followup to an Enforcement Conference held with PG&E on December 19, 1989, NRC Region V issued Enforcement Action 89-241 that included a Notice of Violation associated with NRC Inspection Report Nos. 50-275/89-31 and 50-323/89-31. Enforcement Action 89-241 cited three violations that were categorized in the aggregate as a Severity Level III problem applicable to Diablo Canyon Units 1 and 2 related to the containment recirculation sumps. Potential degradation of the sumps due to inadequate procedures and personnel error was reported by PG&E to the NRC in Licensee Event Report (LER) 1-89-014-01, dated January 19, 1990 (DCL-90-018). PG&E recognizes the importance and significance of these concerns and has taken appropriate measures to improve performance in these areas. A discussion of the sump problems and PG&E's corrective actions are provided below.

STATEMENT OF VIOLATION A.

A. 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires in part, that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

FSAR Section 6.2.3.2.2.1, Containment Recirculation Sump, states in part, that a baffle arrangement surrounds the sumps to prevent floating debris or anything larger than 3/16-inch from entering the sumps. FSAR Figure 6.2-11 shows the configuration.

Contrary to the above, on August 2, 1985, the licensee identified a condition adverse to quality related to gaps in the Unit 1 recirculation sump in excess of the dimensions described in the FSAR. The licensee's corrective actions were inadequate to identify and correct all of the nonconforming conditions. Additional gaps in excess of the dimensions described in the FSAR were discovered on November 26, 1989.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

During the Unit 1 third refueling outage (which commenced October 6, 1989), a walkdown verification of the containment recirculation sump (sump) identified a 1-inch vertical gap in the upper grating assembly between the screen sections and other gaps around a concrete column pedestal in the inclined section of the upper grating assembly (see Figures 1, 2, and 3). PG&E acknowledges that the gaps in the sump screen assembly identified in 1985 and again in 1989 were not in accordance with the intended design configuration of

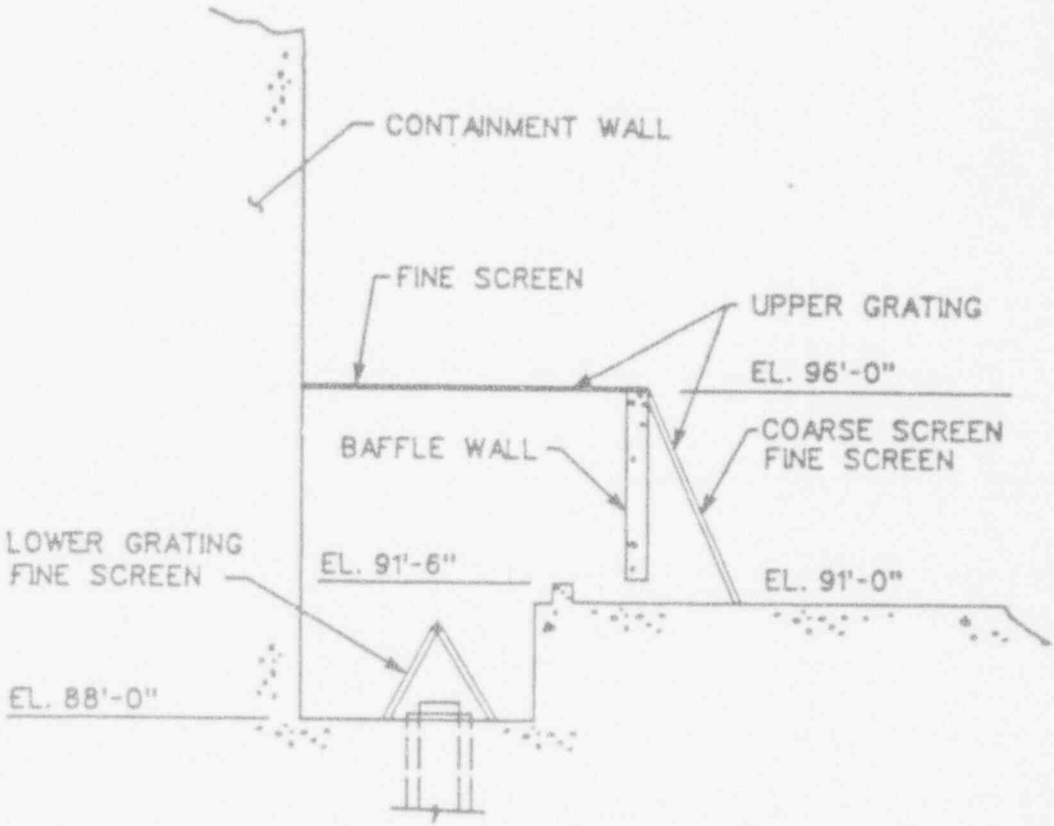
the sump as described in the FSAR Update, and that the corrective actions taken in 1985 were inadequate to identify and correct the nonconforming conditions. The reasons are as follows:

1. The critical construction parameter related to the maximum gap anywhere on the surface of the sump screens was not clearly defined by Engineering until December 15, 1986, when Revision 8 of sump Drawing 443259 was issued. The drawing revision was issued at that time to reflect the Unit 2 design changes that were made in 1985 to eliminate the gaps greater than 3/16-inch in the sump screen assembly. The apparent failure to specify adequate construction acceptance criteria for the sump screen gaps led to the Unit 1 as-built screen configuration described in the violation, i.e., screen gaps in excess of the dimensions described in the FSAR Update.

2. The 1985 problem report for Unit 1, which was based on a similar problem with the Unit 2 sump screens, identified potential deficiencies (gaps greater than 3/16-inch) in the unscreened portions only of the upper grating assembly. Two gaps were found and corrected in addressing the problem report. However, the inspection was not expanded to look for gaps in the screened portions of the upper grating assembly since the problem report did not identify that the screened portions might also be deficient.

3. The Unit 1 screen gaps were not identified during containment inspections since the procedures governing walkdowns and inspections of the sump lacked specific guidance regarding integrity of the sump screen assemblies.

As discussed at the Enforcement Conference and in LER 1-89-014-01, PG&E believes with a high degree of confidence that the emergency core cooling system (ECCS), even with the identified gaps in the sump screen assembly, would have been capable of performing its intended safety function in the event of a design basis loss-of-coolant-accident (LOCA) requiring containment recirculation. This conclusion is based on safety evaluations and supporting studies, which were documented in LER 1-89-014-01, that considered both the nature of the accident conditions and the conservative design of the sump with its relatively large screen areas, concrete baffle, curb, and multiple layers of screen and grating. These evaluations considered the unique and advantageous location of the sump in the annulus area of the containment structure where it is separated from a postulated pipe break by the concrete crane wall, the shielding labyrinths, and the locked wire mesh personnel doors. These evaluations also considered the nature of the debris created by postulated accidents (insulation debris and larger size paint particles) and PG&E's conclusion that this debris would sink and not be carried to the sump and the residual heat removal (RHR) inlet piping due to the low velocity of the flow.

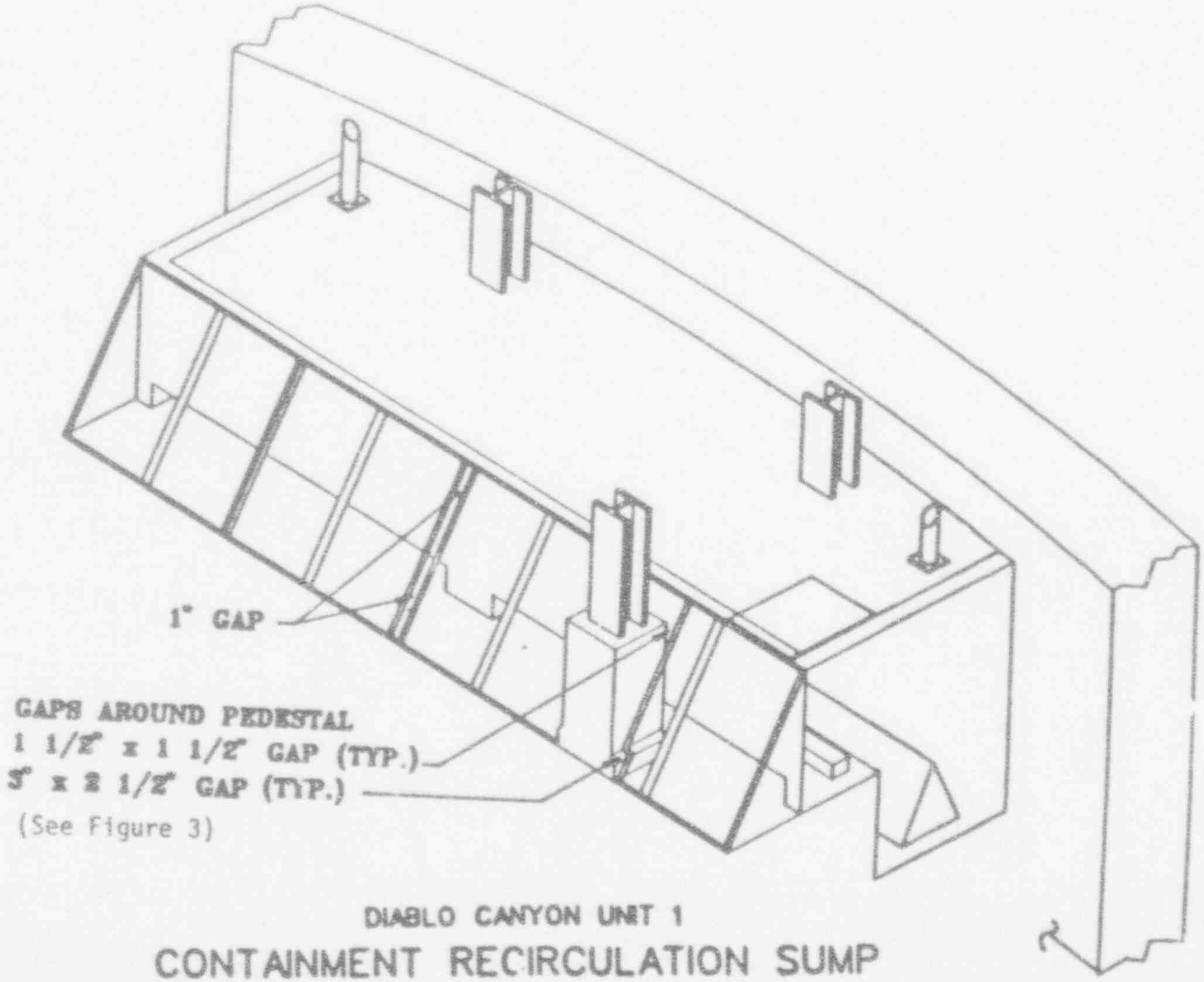


SECTION

DIABLO CANYON

CONTAINMENT RECIRCULATION SUMP

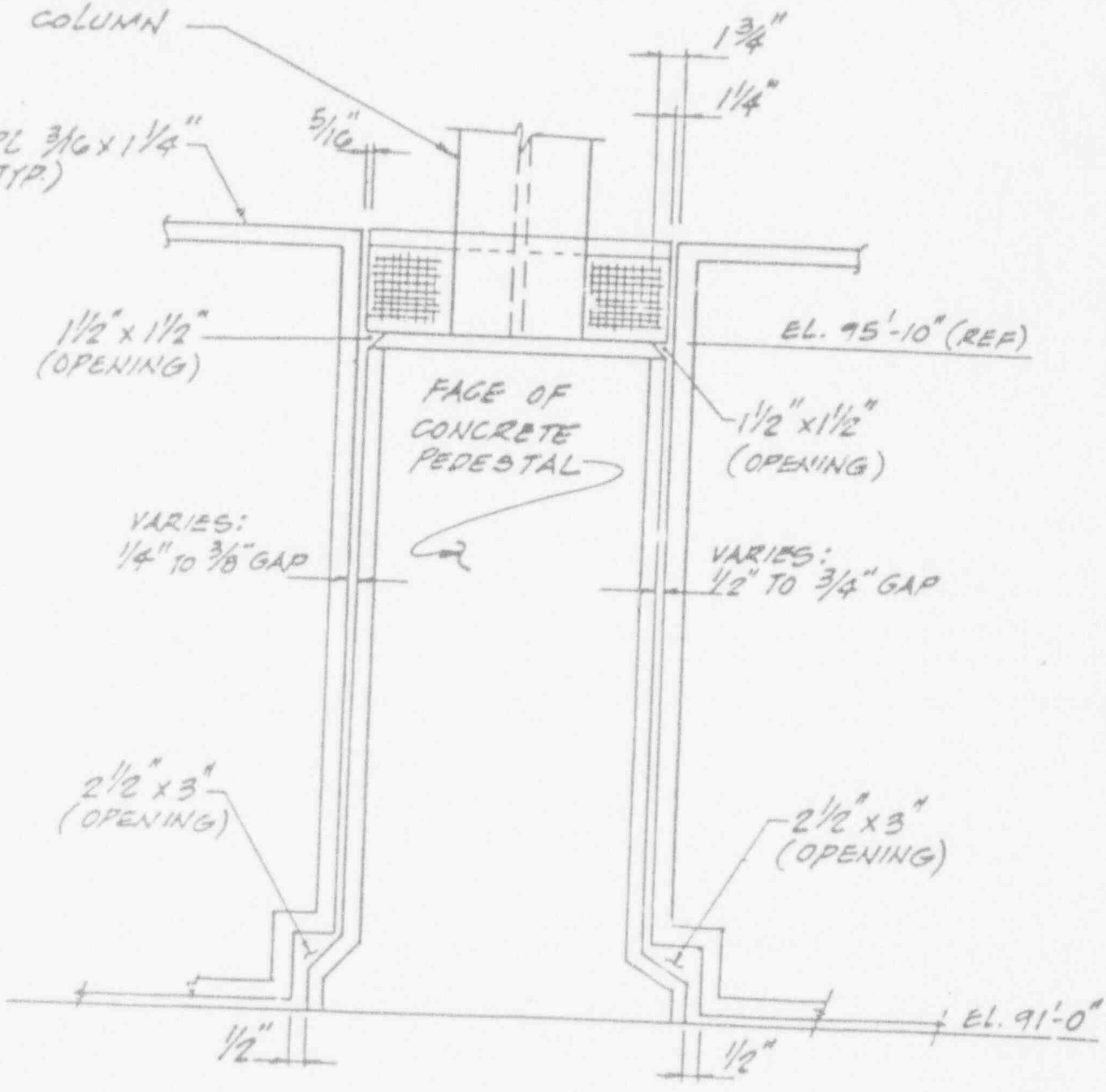
FIGURE 1



DIABLO CANYON UNIT 1
CONTAINMENT RECIRCULATION SUMP

FIGURE 2

30435/0080K



COLUMN
1 3/4"
1 1/4"
5/16"
PL 3/16 x 1 1/4"
(TYP.)
1 1/2" x 1 1/2"
(OPENING)
EL. 95'-10" (REF)
FACE OF
CONCRETE
PEDESTAL
1 1/2" x 1 1/2"
(OPENING)
VARIES:
1/4" TO 3/8" GAP
VARIES:
1/2" TO 3/4" GAP
2 1/2" x 3"
(OPENING)
2 1/2" x 3"
(OPENING)
EL. 91'-0"
1/2"
1/2"

FIGURE 3

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. Design Change Notice (DCN) DC1-EC-43762 was issued to repair the deficiencies of the Unit 1 sump, including the gaps in the upper grating assembly screen. The DCN identified the repairs necessary to assure that the sump is configured to meet design and functional requirements. This DCN has been closed out. A similar DCN was issued for as-building and repair of Unit 2 sump deficiencies, if any, during the current Unit 2 third refueling outage. The FSAR Update will be revised to reflect the Unit 1 and 2 as-built sump configurations.

2. Nuclear Engineer Manual Procedures 3.5, "Drawing Preparation and Approval," 3.6 ON, "Operating Nuclear Power Plant Design Changes," and 3.7, "As-built Documents," have been revised on numerous occasions since the origination of the sump configuration problems. These procedures ensure that sufficient detail is provided for design changes to eliminate incorrect interpretation. As a result of the sump configuration problems, these procedures, as well as the drafting procedures, were reviewed and determined to be adequate to preclude configuration problems similar to the sump screen gaps.

3. Surveillance Test Procedure (STP) M-45A, "Containment Inspection Prior to Establishing Containment Integrity," was revised to assure special attention be given to sump cleanliness. The revised procedure includes inspection of the sump screens for gaps, structural distress, and corrosion, as well as inspections of the sump and RHR suction lines for debris. The revised procedure was used for the recent Unit 1 refueling post-outage containment inspection.

4. PG&E has several ongoing programs to review plant systems that will significantly improve the probability that problems, such as the sump configuration problems, will be identified in a timely manner. These programs are:

   a. System Engineer Program: The plant System Engineers, in conjunction with their counterparts in Nuclear Engineering and Construction Services (NECS), perform quarterly walkdowns of the systems for which they are responsible.

   b. Safety System Functional Audit and Review (SSFAR) and Safety System Outage Modification Inspection (SSOMI) Programs: These programs provide for independent, detailed reviews of plant systems, including the design bases and the as-built configuration.

   c. Design Basis Documentation Enhancement Program: DCMs for the plant systems are being enhanced or prepared to provide a detailed design basis for each plant system. Other enhancements to improve the understanding of and access to design bases information include (1) a Design Basis Document Source Reference Guide (DBDSRG), (2) a DCM Writer's Guide, (3) a Plant System Engineer/System Design Engineer matrix to improve design interface and identify system responsibilities, and (4) design bases training in major topical design areas and in use of the DBDSRG.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

1. The DCM for containment function, DCM T-16, has been rescheduled for completion in 1990 instead of 1991. The DCM will include a detailed description of the design basis for the containment recirculation sump.

2. PG&E is performing a study of the containment recirculation sump to optimize its design and operation. This study includes consideration of accident conditions as well as inspection, maintenance, ALARA, and operational issues. PG&E has targeted completion of this study for mid-1990 and implementation of any appropriate modifications during the fourth refueling outage for each unit.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

Any needed changes or repairs identified during the as-built walkdown of the Unit 2 sump will be completed during the third refueling outage. The FSAR Update, Revision 6 (September 1990) will include updated information on the as-built configuration of the Unit 1 and 2 sumps. The containment function Design Criteria Memorandum T-16 will be completed by December 31, 1990. Appropriate sump modifications resulting from the recirculation sump study are targeted for implementation during the fourth refueling outage for each unit.

STATEMENT OF VIOLATION B.

B. Diablo Canyon Technical Specification 3.5.2 states in part that:

"Two Emergency Core Cooling System (ECCS) subsystems shall be OPERABLE with each subsystem comprised of: ...e. An OPERABLE flow path capable of taking suction from the Refueling Water Storage Tank on a Safety Injection signal and manually transferring suction to the containment sump during the recirculation phase of operation."

Technical Specification 1.21, in defining the terms OPERABLE and OPERABILITY, provides in part: "a system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety-related function(s). Implicit in this definition shall be the assumption that all necessary...auxiliary equipment that are required for the system, subsystem, train, component or device to perform its safety-related function(s) are also capable of performing their rated support function(s)."

With more than one ECCS subsystem inoperable, Technical Specification 3.0.3 applies, which states:

"When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within 1 hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in

a. At least HOT STANDBY within the next 6 hours,
b. At least HOT SHUTDOWN with the following 6 hours, and
c. At least COLD SHUTDOWN within the subsequent 24 hours."

Contrary to the above, two emergency core cooling system subsystems were inoperable for period of about 10 to 12 hours each while Unit 2 was in Mode 1 operation on October 12, 1987 and August 23, 1988 and while Unit 1 was in Mode 1 operation on September 7, 1988, and May 11, 1989. On those dates, the containment recirculation sump was rendered inoperable because the screened access hatch was opened to allow the addition and pumpdown of borated water with hoses for calibration of the sump level detectors. With the sump access hatch open, the screening structure was not fully capable of performing its rated support function. During the stated periods, no action was initiated to reduce the reactor power to enter a lower mode of operation.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

PG&E acknowledges that the sump access hatch on the Units 1 and 2 upper grating assembly had been opened (for up to 12 hours) at various times during power operation without adequate consideration of the effect on operability of the sump. The primary reason for opening the hatch was for calibration of the sump level narrow-range instrumentation, LT-940 and -941. The calibration was performed using Temporary Procedure (TP) TO-8706, which did not include limitations on the time that the access hatch is permitted to be open or other guidance regarding sump operability considerations during at-power calibration activities. The safety evaluation performed for TP TO-8706 was inadequate since it did not address operability of the sump.

As discussed at the Enforcement Conference and in LER 1-89-014-01, PG&E believes that opening of the sump access hatch on the upper grating assembly did not render the sump inoperable. The evaluation presented in the LER discussed the low likelihood that debris would enter the sump (with the access hatch open) and the risk significance of unavailability of the containment sump during power operation. It was concluded that it was highly unlikely, considering the physical arrangement and location of the sump structure, that debris would enter the sump should a LOCA occur when the access hatch was open. Using extremely conservative assumptions, the risk significance study concluded that the increase in the total core damage frequency was approximately 0.05 percent for each hour that the sump was not available. If more realistic assumptions were used to account for the physical configuration of containment, the remote location of the sump, and the nature of the potential debris, it is judged that the risk would be reduced by at least an order of magnitude.

PG&E concludes that opening of the access hatch in the upper grating assembly during power operation did not render the containment recirculation sump inoperable as stated in the violation. Furthermore, even if the assumption is made that opening the hatch renders the sump inoperable, the risk significance is very low. Therefore, the health and safety of the public were not adversely affected by this event. However, since the safety evaluation for performance of TP TO-8706 did not adequately address sump operability, PG&E has taken the actions described below to ensure critical evaluation prior to future sump access hatch openings during power operation.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. A shift night order was issued requiring management review of any intended at-power openings of the access hatch on the upper grating assembly of the Unit 1 or Unit 2 sump. If management determines that opening the hatch at power is acceptable, concurrence will be sought from the NRC Resident Inspector.

2. Nuclear Plant Administrative Procedure C-19/NPG 4.3, "Safety Evaluation Guidelines," was recently revised and extensive training is being given to plant personnel to increase their sensitivity to the requirements for performing safety evaluations in accordance with 10 CFR 50.59.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

Although there is no reason to make "routine" entries into the sumps at power, the primary reason for past entries during Modes 1 through 4 was to perform maintenance on the sump level narrow-range instrumentation. This maintenance was primarily due to capillary air in-leakage and boric acid crystallization on the level transmitters. To reduce the susceptibility of the level instrumentation to these problems and thus improve reliability, design change packages J-41715 and J-42715 are being issued to replace the differential pressure level transmitters in the Units 1 and 2 sumps with RTD thermal differential level indicators. This modification will allow the level instruments to be serviced without sump entry at power. Implementation of design change packages J-41715 and J-42715 is targeted for the fourth refueling outage of each unit.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

PG&E is in full compliance with the Technical Specifications.

STATEMENT OF VIOLATION C.

C. Technical Specification 4.5.2.c requires in part that a visual inspection be performed of all accessible areas in the containment prior to establishing containment integrity to verify that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restrictions of the pump suctions during a LOCA condition.

Contrary to the above, on May 11, 1989, the licensee performed an inadequate inspection of the Unit 1 containment sump for loose debris which could be transported within the containment sump and cause restrictions of the sump suctions during a LOCA condition. Even though containment integrity had been established, there was debris in the sump from at least the time of the last licensee inspection of May 11, 1989, until October 17, 1989 when the debris was discovered and removed.

ADMISSION/DENIAL AND REASON FOR VIOLATION IF ADMITTED

PG&E acknowledges that inadequate sump inspections were performed. This resulted in failure to detect debris inside the upper grating assembly of the Unit 1 sump. The debris was found by the NRC Resident Inspector relatively early in the Unit 1 third refueling outage before the PG&E System Engineer had performed a planned ECCS walkdown. The engineer had planned to inspect the sump during the first week of the outage, but a primary system valve flange leak resulted in contaminated boric acid crystals on the top and inside of the sump. Thus, the walkdown was delayed pending decontamination of the sump area. At the request of the NRC Resident Inspector, sump decontamination was expedited and acceptable entry conditions were obtained.

The primary reason for debris in the sump was failure to follow STP M-45, "Containment Inspection," for containment inspections following maintenance activities. Also, the procedure was not explicit in defining inspection activities. In addition, plant management did not ensure that foreign material exclusion principles controlled recirculation sump activities.

An extensive evaluation of the effects of the debris on recirculation operability was performed. This evaluation was discussed at the Enforcement Conference and documented in LER 1-89-014-01. PG&E concluded that because of the nature of the debris and the design features of the sump, it is highly unlikely that the debris would have been drawn into the RHR inlet piping, and thus, it would not have impaired operation of the ECCS or the containment spray system.

To further assure the absence of sump debris, proper conduct of inspections, and implementation of acceptable housekeeping and foreign material exclusion principles, PG&E has taken the steps listed below.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

1. The debris found in the Unit 1 sump was removed.

2. PG&E inspected the Unit 1 sump RHR intake piping during the recent third refueling outage. The video probe inspection included the 8982 gate valves, the vertical piping section, and approximately 20 feet into the horizontal piping section of both A and B suction trains. No debris was found.

3. STP M-45A for containment inspections was revised to assure additional attention is given to recirculation sump cleanliness. The revised procedure includes a greater level of detail and inspection criteria and was used for the recent Unit 1 post-outage containment inspection.

4. Preventive maintenance activities have been established to require that foreign material exclusion area covers be installed on the sump suction piping on a recurring basis immediately following entry into Mode 5 during refueling outages.

5. Administrative Procedure (AP) C-10S4, "Foreign Materials Exclusion Area Controls," was revised to assure the application of foreign material exclusion controls to any recirculation sump activities.

6. To reemphasize the importance of and provide guidance for verification signatures, AP A-56, "Signatures and Signature Responsibilities," has been developed and will be issued in the near term.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

PG&E believes that the steps taken are adequate to ensure that the sump will be adequately inspected in accordance with the Technical Specifications.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

With the above completed actions, PG&E is in full compliance with the Technical Specification requirement for sump inspections.

50-275/323-OLA-2
I-MFP-116 RELATED CORRESPONDENCE — MFP Exhibit

"NOT ADMITTED" UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

USNRC

November 23, 1992 '93 OCT 28 P6:54

Docket No. 50-275

LICENSEE: Pacific Gas and Electric Company (PG&E)

FACILITY: Diablo Canyon Nuclear Power Plant, Unit 1

SUBJECT: SUMMARY OF OCTOBER 20, 1992 PUBLIC MEETING TO DISCUSS STEAM GENERATOR FEEDWATER NOZZLE CRACKING

On October 20, 1992, the NRC staff met with the Pacific Gas and Electric Company (PG&E or the licensee) in Rockville, Maryland to discuss the issue stated above. Attendees at the meeting are listed in Enclosure 1. Slides shown by PG&E at the meeting are presented in Enclosure 2. The PG&E presentation summarized their analysis and long-term plans regarding the cracks associated with the steam generator nozzles.

PG&E discussed their analysis which included findings of nozzle-to-pipe weld cracks, thermal sleeve erosion, and elbow pipe cracks. Their actions to analyze and/or to resolve these problems consisted of replacing the piping and analyzing the thermal sleeve condition for (1) erosion gap growth, (2) waterhammer implications, and (3) nozzle implications.

The licensee presented their nondestructive examination (NDE) results. Ultrasonic testing (UT) examinations were scheduled for the first days of the outage. UT examinations were used to detect the presence of flaws in the piping. The UT manual and automatic testing results did verify indications of cracking. The possibility of cracking was also indicated by visual examinations. However, no cracks were indicated with the use of radiography.

From the results of the metallurgical analysis, the UT examination results were shown to be quite conservative (approximately by a factor of 10). The NDE testing of the samples, sectioned from the nozzle area, showed 0.35-inch-deep indications; whereas, from the metallurgical analysis, the actual samples showed indications no deeper than 0.037 inches. The metallurgical results also indicated evidence of microcracking in the spools.

As a result of the NDE testing, PG&E's action plans included: (1) reviewing the NDE assignment methods to ensure that the proper welds were clearly designated for exams and (2) analyzing the UT data and metallurgical results to determine methods for accurate sizing of thermal fatigue cracking.

The licensee also discussed the likelihood of waterhammer during draining and filling of the feedline with cold water. PG&E stated that waterhammer would not occur during draining because, by design, the J-tubes and thermal sleeve

allow steam to replace the water as the feedline drains. The licensee also stated that the possibility of waterhammer during filling is very unlikely due to the J-tubes; however, waterhammer could still be possible due to wave action. The licensee concluded the following: (1) due to Diablo Canyon's geometric configuration, a steam volume collapse waterhammer is very unlikely, (2) plant inspections indicate no evidence of waterhammer to date, and (3) in the unlikely event of occurrence, there would be insufficient energy to affect the piping system.

PG&E discussed the probable causes of thermal sleeve erosion. These causes include: (1) erosion/corrosion due to increased velocities and (2) turbulence as a result of the complex geometric configuration between the nozzle and the thermal sleeve.

The licensee stated that initiation of fatigue cracks in the steam generator nozzle at Indian Point were the result of a significant environmental effect (water chemistry) However, this was not a problem at Diablo Canyon because the water chemistry control at Diablo Canyon decreased the likelihood of the environmental influences.

In addition, the licensee stated that initiation of fatigue cracks in the knuckle region of the feedwater nozzle is not as likely at Diablo Canyon as it is at similarly designed facilities. PG&E also stated that fatigue cracks in the knuckle region are not predicted for Diablo Canyon. This is based on the following factors: (1) low fatigue usage, (2) the severity of thermal stratification loads being much less than at the plant where cracking was found, and (3) a recent UT inspection of a nozzle revealing no indications of cracking. PG&E stated, however, that if cracks were to exist in the nozzle region, the predicted size would be acceptable under Section XI of the ASME Code. The licensee demonstrated that the future growth of worst case cracks were found to be relatively small for the next 4 years or 100 days in Modes 2 or 3. Therefore, PG&E concluded that the integrity of the feedwater nozzles would be maintained through the next several years of service.

PG&E's long-term plans include installing resistance temperature detectors (RTDs) and scratch gages, and reviewing correlations between algorithms and operating data. The licensee's inspection plans consist of factoring in lessons learned from outage 1R5, performing a UT analysis every outage until a permanent fix is installed, and baselining the permanent fix after installation.

The NRC staff stated that PG&E had completed a reasonable analysis on the feedwater nozzle crack issues. In addition, the NRC staff asked the licensee to keep them informed on their feedwater nozzle crack status and future plans.

Sheri R. Peterson

Sheri R. Peterson, Project Manager
Project Directorate V
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

Enclosures:
As stated

cc w/enclosures:
See next page

cc:
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Diablo Canyon Nuclear Power Plant
c/o U.S. Nuclear Regulatory Commission
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San Francisco, California 94177

50-275/323-OLA-2
I-MFP-125

RELATED CORRESPONDENCE

MFP Exhibit 125
179945
026.1429

Pacific Gas and Electric Company

"NOT ADMITTED"

DOCKETED
USNRC

'93 OCT 28 P6:54

November 1, 1991

PG&E Letter No. DCL-91-268

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-323, OL-DPR-82
Diablo Canyon Unit 2
Licensee Event Report 2-91-006
Momentary Loss of Power to Radiation Monitor RM-26 Causes Control Room Ventilation System Mode Shift (ESF Actuation) Due to Personnel Error

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(iv), PG&E is submitting the enclosed Licensee Event Report (LER) regarding the Control Room Ventilation System transfer from normal mode to pressurization mode, an Engineered Safety Feature (ESF) actuation.

This event has in no way affected the health and safety of the public.

Sincerely,

Greg Rueger

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution
INPO

DC2-91-OP-N089

Enclosure

55395/85K/JHA/2246

RECEIVED
NOV 04 1991
PFS
Corresp. Control Center

LICENSEE EVENT REPORT (LER) 179945

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3	1 OF 5

TITLE (4): MOMENTARY LOSS OF POWER TO RADIATION MONITOR RM-26 CAUSES CONTROL ROOM VENTILATION SYSTEM MODE SHIFT (ESF ACTUATION) DUE TO PERSONNEL ERROR

EVENT DATE (5) MON	DAY	YR	LER NUMBER (6) YR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MON	DAY	YR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER (S)
10	03	91	91	- 0 0 6 -	0 0	11	01	91		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73(a)(2)(iv)

OTHER -

(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
MARTIN T. HUG, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4005

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (if yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

Abstract (16)

On October 3, 1991, at 1256 PDT, with Unit 2 in Mode 5 (Cold Shutdown) at 0 percent power, the Control Room Ventilation System (CRVS) shifted from normal mode to pressurization mode. This mode change constitutes an Engineered Safety Feature (ESF) actuation.

While removing instrument AC inverter IY-24 from service in accordance with procedure OP J-10:III, "Instrument AC System-Shutdown and Clearing," a senior licensed operator and a non-licensed operator inadvertently opened the output breaker for inverter IY-23 instead of the intended breaker for inverter IY-24. This resulted in a momentary loss of power to the control room ventilation intake radiation monitor RM-26, which caused the CRVS to shift from normal mode to pressurization mode.

On October 3, 1991, at 1427 PDT, a four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

The root cause of this event was personnel error (inattention to detail). The operators involved failed to perform an adequate pre-job review of the operating procedure. They did not notice that specific attachments to the procedure had been provided.

To prevent recurrence, (1) the operators involved were counseled, (2) an Operations Incident Summary has been issued, (3) OP J-10:III will be revised, and (4) Operations Policy A-6 was revised.

I. Plant Conditions

Unit 2 was in Mode 5 (Cold Shutdown) at 0 percent power.

II. Description of Event

A. Event:

Summary:

On October 3, 1991, at 1256 PDT, the Control Room Ventilation System (CRVS)(VI) shifted from normal mode to pressurization mode, an Engineered Safety Feature (ESF) actuation. This event occurred when a senior licensed operator and a non-licensed operator inadvertently opened the output breaker (BKR) for instrument AC inverter (INVT) 23 (IY-23) instead of the intended breaker for instrument inverter IY-24.

Chronology:

Two operators were preparing to remove instrument AC inverter IY-24 from service. Prior to starting this job, they had reviewed DCPP Unit 2 Operating Procedure OP J-10:III, "Instrument AC System-Shutdown and Clearing," which provides guidance for performing this task. During this procedure review, they noted that Section 6.1 was the appropriate section that lists the generic steps to shutdown and remove the inverter from service. Section 6.1.1 of the procedure states "All IY panels are similar. Use the appropriate procedure checklist attachment for individual panels." The detailed attachments provide specific switch numbers that correspond to switch numbers on the inverter panels.

After reviewing the procedure, the two operators proceeded to remove inverter IY-24 from service using the generic steps of Section 6.1.1 instead of the more detailed procedure attachments. Instrument panel 24 (PY-24) was successfully placed on its backup power source. The operators then performed the first step to remove inverter IY-24 from service by attempting to open the AC output breaker for inverter IY-24. Following this step, the operators noted that the potential light for instrument panel 23 (PY-23) had gone out, indicating that panel PY-23 had been de-energized. The operators then discovered that they had inadvertently opened the AC output breaker for inverter IY-23 instead of the intended breaker for inverter IY-24. A momentary loss of power to panel PY-23 de-energized control room ventilation intake radiation monitor RM-26, causing the CRVS to shift to the pressurization mode, an ESF actuation.

On October 3, 1991, at 1258 PDT, the operators returned inverter IY-23 to service and re-energized panel PY-23. The CRVS was reset and returned to its normal operating mode. A four-hour, non-emergency

TEXT (17)

report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii), at 1427 PDT.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times for Major Occurrences:

1. October 3, 1991, at 1256 PDT: Event/Discovery date - Instrument AC panel PY-23 was de-energized and the CRVS shifted from normal mode to pressurization mode.

2. October 3, 1991, at 1258 PDT: Panel PY-23 was re-energized and the CRVS was returned to its normal status.

3. October 3, 1991, at 1427 PDT: A four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

This event was detected by the operators attempting to remove instrument AC inverter IY-24 from service. They noted that the potential light for instrument AC panel PY-23 had gone out, indicating that panel PY-23 had been de-energized.

F. Operators Actions:

The operators returned inverter IY-23 to service by re-energizing panel PY-23. The CRVS was reset and returned to the normal operating mode.

G. Safety System Responses:

1. Control room ventilation radiation monitor RM-26 alarmed due to loss of power.

2. Both trains of the CRVS shifted from normal mode to pressurization mode.

TEXT (17)

report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii), at 1427 PDT.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times for Major Occurrences:

1. October 3, 1991, at 1256 PDT: Event/Discovery date - Instrument AC panel PY-23 was de-energized and the CRVS shifted from normal mode to pressurization mode.

2. October 3, 1991, at 1258 PDT: Panel PY-23 was re-energized and the CRVS was returned to its normal status.

3. October 3, 1991, at 1427 PD : A four-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(2)(ii).

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

This event was detected by the operators attempting to remove instrument AC inverter IY-24 from service. They noted that the potential light for instrument AC panel PY-[illegible] had gone out, indicating that panel PY-23 had been de-energized.

F. Operators Actions:

The operators returned inverter IY-23 to service by re-energizing panel PY-23. The CRVS was reset and returned to the normal operating mode.

G. Safety System Responses:

1. Control room ventilation radiation monitor RM-26 alarmed due to loss of power.

2. Both trains of the CRVS shifted from normal mode to pressurization mode.

III. Cause of the Event

A. Immediate Cause:

Operators inadvertently opened the output breaker for instrument AC inverter IY-23 instead of the intended output breaker for inverter IY-24, causing an ESF actuation.

B. Root Cause:

The root cause of this event was personnel error (inattention to detail). The operators involved failed to perform an adequate pre-job review of the operating procedure. They did not notice that specific attachments to the procedure had been provided.

IV. Analysis of the Event

The shifting of the CRVS from the normal mode to pressurization mode places the system in a more conservative mode of operation All plant equipment functioned as designed. Therefore, no adverse safe y consequences or implications resulted from this event and at no time was the health and safety of the public affected.

V. Corrective Actions

A. Immediate Corrective Actions:

The operators returned inverter IY-23 to service by re-energizing panel PY-23. The CRVS was reset and returned to the normal operating mode.

B. Corrective Actions to Prevent Recurrence:

1. The operators involved were counseled regarding the necessity to adequately review procedures prior to starting a job.

2. Operating procedure J-10:III will be revised for both units to delete the generic procedure steps and emphasize the detailed attachments.

3. Operations Policy A-6, "Use of Operations Department Procedures," was revised to require that, prior to using an operating procedure that contains generic instructions, an on-the-spot-change (OTSC) be issued to add specific component numbers to the procedure.

4. An Operations Incident Summary on this event has been issued, stressing the importance of a proper pre-job procedure review.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs on Similar Events:

LER 1-89-012-00, Fuel Handling Building Ventilation System Transfer to the Iodine Removal Mode Due to Personnel Error.

This event is essentially identical to this recent event in that operators inadvertently opened the output breaker on instrument AC inverter IY-13 instead of instrument AC inverter IY-13A, de-energizing instrument AC panel PY-13. This action de-energized radiation monitor RM-59, causing the Fuel Handling Building Ventilation System to transfer from normal mode to the iodine removal mode of operation, an ESF actuation. The root cause of this event was personnel error due to inattention to detail. The operator performing the switching operation and the second operator acting as concurrent verifier overlooked the fact that they were opening the output breaker of IY-13 instead of IY-13A. The corrective actions included (1) upgrading of all instrument inverters to ensure that the inverter number is clearly stated near each switch or circuit breaker of the inverter, (2) installation of caution signs on PY-13A, PY-23A, IY-13A, and IY-23A to warn plant workers that the associated inverter distribution panel is located in a different room than normally expected, (3) OP J-10:III was revised to provide specific instructions for removing each inverter from service, and (4) an Operations Incident Summary was issued to review the event with all shift operations personnel.

If the operators had followed the detailed instructions provided in the attachment to OP J-10:III, this current event would have been prevented.

RELATED CORRESPONDENCE 179944 MFP EXHIBIT 127 026.1429

Pacific Gas and Electric Company

50-275/323-OLA-2 I-MFP-127
"NOT ADMITTED

'93 OCT 28 P6:54

November 1, 1991

PG&E Letter No. DCL-91-267

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-323, OL-DPR-82
Diablo Canyon Unit 2
Licensee Event Report 2-91-007-00
Inadvertent Safety Injection While in Mode 5 Due to Personnel Error

Gentlemen:

Pursuant to 10 CFR 50.73(a)(2)(iv), PG&E is submitting the enclosed Licensee Event Report (LER) concerning an inadvertent Safety Injection during a surveillance test caused by personnel error.

This event has in no way affected the health and safety of the public.

Sincerely,

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
Howard J. Wong
CPUC
Diablo Distribution
INPO

DC2-91-TI-N088

Enclosure

5532S/85K/JHA/2246

RECEIVED
NOV 04 1991
PFS
Corresp. Control Center

LICENSEE EVENT REPORT (LER)

179944

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3	1 OF 5

TITLE (4) INADVERTENT SAFETY INJECTION WHILE IN MODE 5 DUE TO PERSONNEL ERROR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MON	DAY	YR	YR	SEQUENTIAL NUMBER	REVISION NUMBER	MON	DAY	YR	FACILITY NAMES	DOCKET NUMBER (S)
										0 5 0 0 0
10	06	91	91	- 0 0 7 -	0 0	11	01	91		0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73(a)(2)(iv)

OTHER - (Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
MARTIN T. HUG, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4005

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR

ABSTRACT (16)

On October 6, 1991, at 0008 PDT, with Unit 2 in Mode 5 (Cold Shutdown) during the fourth refueling outage, two safety injection (SI) signals occurred due to technicians operating Solid State Protection System (SSPS) control switches out of sequence with the surveillance test procedure (STP) they were performing. A four-hour, non-emergency report required by 10 CFR 50.72(b)(2)(ii) was made on October 6, 1991, at 0218 PDT.

The cause of the SIs was personnel error. The technicians failed to utilize STP I-16D4, "Reconfiguring An SSPS Train In Modes 5 or 6," during the switch operating sequence. STP I-16D4 requires the SSPS Input Error Inhibit switch to be repositioned from "Normal" to "Inhibit" and the Mode Selector switch from "Test" to "Operate," in that order. The technicians repositioned the switches in reverse order on SSPS Trains A and B. Each train produced an SI signal.

All equipment performed as expected in Mode 5 during the SI. Unit 2 was returned to normal Mode 5 alignment on October 6, 1991, at 0015 PDT. Since emergency core cooling pumps were secured for maintenance, there was no water injection into the reactor coolant system.

The technicians involved in this event were counseled in accordance with PG&E's positive discipline program. A memorandum has been issued from the Vice President, Diablo Canyon Operations and Plant Manager, emphasizing the need for procedural compliance and verification.

I. Plant Conditions

Unit 2 was in Mode 5 (Cold Shutdown) at 0 percent power during the fourth refueling outage.

II. Description of Event

A. Event:

On October 5, 1991, two Instrument and Control (I&C) technicians were assigned to reconfigure Trains A and B of the Solid State Protection System (SSPS)(JE) from "Inputs In Normal/Outputs In Test" to "Inputs Inhibited/Outputs In Operate" per Surveillance Test Procedure (STP) I-16D4, "Reconfiguring an SSPS Train in Modes 5 or 6." Since the SSPS was removed from service and both technicians had previously been tailboarded and had successfully performed the same STP earlier in the week, no additional detailed tailboard was conducted. The technicians were informed there was no rush to complete this job. The two technicians then proceeded to the control room and obtained permission from the Shift F reman to reconfigure SSPS Trains A and B.

On October 6, 1991, at 0008 PDT, the following sequence of events took place within 30 seconds:

The "SSPS General Warning Train B" alarm cleared when the senior technician repositioned the Train B Mode Selector switch to the "Operate" position prior to placing the Input Error Inhibit switch in the "Inhibit" position. This sequence is opposite the required sequence of STP I-16D4. The senior technician did not have a copy of STP I-16D4 in his possession when repositioning the switches. The repositioning of this switch created a safety injection (SI) signal with SSPS Train B "Outputs in Operate" and "Inputs in Normal" and the Unit in a Mode 5 condition.

An "SSPS General Warning Train B" alarm occurred when the senior technician placed the Train B Input Error Inhibit switch in the "Inhibit" position. This placed SSPS Train B in the intended configuration per STP I-16D4.

The "SSPS General Warning Train A" alarm cleared when the junior technician, acting independently of the senior technician, placed the SSPS Train A Mode Selector switch in the "Operate" position prior to placing the Input Error Inhibit switch in the "Inhibit" position. The junior technician did have a copy of the STP I-16D4 summary sheet with him at the time but failed to utilize the procedure while repositioning the switches. This placed SSPS Train A "Outputs in Operate" and "Inputs in Normal" and created a second SI signal with the Unit in a Mode 5 condition.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

179944

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3	91	- 0 0 7 -	0 0	3 OF 5

TEXT (17)

An "SSPS General Warning Train A" alarm occurred when the junior technician placed the Train A Input Error Inhibit switch in the "Inhibit" position. This placed SSPS Train A in the intended configuration per STP I-16D4.

Following these events, the two technicians then verified that each train was properly configured per STP I-16D4 and initialled the summary sheet. Upon entering the control room, the technicians were informed by Operations that the activities they had performed had caused SIs. The technician who had reconfigured SSPS Train A retraced his steps and realized he had operated the switches in the incorrect order and informed his supervisor.

On October 6, 1991, at 0015 PDT, Operations personnel reset the SI and returned the plant to normal Mode 5 alignments.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

C. Dates and Approximate Times for Major Occurrences:

1. Oct. 6, 1991, at 0008 PDT: Event/discovery date. SSPS Train B and Train A SI signals occur, respectively.

2. Oct. 6, 1991, at 0015 PDT: All equipment and valves returned to normal Mode 5 alignments.

4. Oct. 6, 1991, at 0218 PDT: A four-hour, non-emergency report required by 10 CFR 50.72 (b)(2)(ii) was made.

D. Other Systems or Secondary Functions Affected:

None.

E. Method of Discovery:

The event was immediately apparent to plant operators due to alarms and indications received in the control room.

F. Operators Actions:

Operations personnel reset the SI and returned all equipment and valves to normal Mode 5 alignments.

G. Safety System Responses:

The following Engineered Safety Features (ESF) actuations occurred:

- Safety injection (BQ)
- Vital 4kV busses transferred to startup power (EK)
- Phase "A" containment isolation (JM)
- Feedwater isolation (JB)
- Auxiliary saltwater pump 2-1 (BI)(P) started
- Main steam line isolation (JI)
- Diesel generators 1-3 and 2-2 started (EK)
- Residual heat removal pump 2-1 (BP)(P) started

III. Cause of the Event

A. Immediate Cause:

The immediate cause of the event was improper configuration of the SSPS while in Mode 5 operation (i.e., inputs in "Normal", outputs in "Operate").

B. Root Cause:

The root cause of the event is personnel error. The senior technician did not use the procedure and the junior technician did not follow the sequence of steps in STP I-16D4.

C. Contributory Cause:

1. The technicians did not practice self-verification in accordance with I&C Department policy memorandum, "Policy For Unit/Channel/Component Self Verification," dated June 30, 1988.

2. The technicians did not practice concurrent verification in accordance with NPAP C-104, "Independent Verification Of Operating Activities."

IV. Analysis of the Event

Unit 2 was in Mode 5 when this event occurred with the reactor coolant system (RCS)(AB) temperature less than 200°F and the RCS not pressurized.

All ESF equipment functioned as intended, as listed in paragraph II.G. above.

No water was injected into the RCS since emergency core cooling system pumps were secured for refueling outage maintenance.

Thus, the health and safety of the public were not adversely affected by this event.

V. Corrective Actions

A. Immediate Corrective Actions:

After determining the cause of the event was personnel error, Operations returned the plant to normal Mode 5 alignments.

B. Corrective Actions to Prevent Recurrence:

1. An I&C Department tailboard was held on October 7, 1991, by the I&C Section Director and General Foreman, r emphasizing the importance of verbatim compliance, self-ver.fication and concurrent verification.

2. A memorandum has been issued by the Vice President, Diablo Canyon Operations and Plant Manager, emphasizing the need for procedural compliance, self-verification, concurrent verification, and independent verification.

3. The technicians responsible for this event were counseled in accordance with the PG&E Positive Discipline Program.

VI. Additional Information

A. Failed Components:

None.

B. Previous Similar Events:

None.

RELATED CORRESPONDENCE 196002

026.1429

MFP Exhibit 131

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

'93 OCT 28 P6:54

September 11, 1992

50-275/323-OLA-2
I-MFP-131
"NOT ADMITTED"

PG&E Letter No. DCL-92-198

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Licensee Event Report 1-92-015-00
Inadequate Maintenance of Hosgri Report Commitments

Gentlemen:

PG&E is submitting the enclosed voluntary Licensee Event Report (LER) concerning inadequate maintenance of Hosgri Report commitments. This report is submitted for information purposes only as described in Item 19 of Supplement 1 to NUREG-1022.

PG&E met with NRC Region V personnel on June 22, 1992, to discuss Hosgri Report commitments related to seismic qualification of equipment at Diablo Canyon Power Plant. At this meeting, PG&E stated that it would submit the enclosed voluntary LER.

The events discussed in this LER did not affect the health and safety of the public.

Sincerely,

Greg Rueger

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
CPUC
Diablo Distribution
INPO

DCO-90-EN-N027

Enclosure

5853S/85K/MWZ/2246

LICENSEE EVENT REPORT (LER)

196002

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	1 OF 12

TITLE (4) INADEQUATE MAINTENANCE OF HOSGRI REPORT COMMITMENTS

EVENT DATE (5) MON	DAY	YR	LER NUMBER (6) YR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MON	DAY	YR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
11	12	90	92	- 0 1 5 -	0 0	09	11	92	DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

____ 10 CFR ______
__X__ OTHER - VOLUNTARY
(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
DAVID SOKOLSKY, SENIOR NUCLEAR GENERATION ENGINEER	415	973-9717

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (if yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

ABSTRACT (16)

This voluntary LER is submitted for information purposes only as described in Item 19 of Supplement 1 to NUREG-1022.

On November 12, 1990, PG&E determined that the boric acid tank level transmitters in place at that time did not have a seismic qualification file as required by the Hosgri Report.

The Hosgri Report and equipment seismic qualification files were reviewed to determine if other equipment files were similarly deficient. Discrepancies were found in some active valve, instrument, and electrical qualification files, in the methodology used for passive valve qualification, and with battery operated light (BOL) qualification. PG&E has performed analysis or testing which verifies that the identified components are capable of performing their required functions following a Hosgri earthquake.

The root causes of these findings were determined to be: (1) the classification system that defines component design requirements did not in all cases convey Hosgri Report requirements; and (2) thorough design reviews and 10 CFR 50.59 safety evaluations were not performed for revisions to certain design documents.

Corrective actions include: (1) revising certain seismic qualification files; (2) implementing a program to control special qualification requirements of Design Class II equipment; and (3) revising design documents and the UFSAR to reflect Hosgri Report seismic qualification requirements.

I. Plant Conditions

Units 1 and 2 have been in various modes and at various power levels with the conditions described below.

II. Description of Event

A. Summary:

On November 12, 1990, PG&E determined that the boric acid tank (BAT)(CA)(TK) level transmitters (CA)(LT) in place at that time did not have a documented seismic qualification as required by PG&E licensing commitments. Further review identified additional components lacking seismic qualification documentation.

This event and subsequent findings were not considered to be reportable because engineering assessments indicated that seismic qualification files could be prepared for all components without the need for plant modifications.

B. Background:

The original design basis for Diablo Canyon required consideration of a design earthquake (DE) and double design earthquake (DDE), which correspond to the operating basis earthquake (OBE) and safe shutdown earthquake (SSE) as defined in 10 CFR 100, Appendix A.

A subsequent reevaluation of the plant to a different magnitude earthquake was documented in the Seismic Evaluation for Postulated 7.5M Hosgri Earthquake (Hosgri Report), submitted as amendments to the Diablo Canyon operating license application during the period from June 1977 through June 1980. The Hosgri reevaluation was performed using criteria and methodology that were different from the original seismic design basis. As a result, variations exist between the DE/DDE analysis and the Hosgri analysis regarding the scope of qualification, load combinations, and allowable stresses.

With respect to safe shutdown, the original seismic design basis for Diablo Canyon required capability to achieve hot shutdown conditions. During the Hosgri reevaluation, additional components were identified and seismically qualified to demonstrate the capability to achieve cold shutdown and maintain the plant in a safe condition after a postulated Hosgri earthquake, assuming a single active failure and loss of offsite power. Some of the identified components qualified to this new criteria, including the BAT level transmitters, were Design Class II components that normally do not require seismic qualification.

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The NRC review of PG&E's Hosgri reevaluation is documented in Diablo Canyon Supplemental Safety Evaluation Reports (SSERs) 7, 8, and 9.

C. Event Description:

On November 12, 1990, PG&E determined that the files for the Design Class II BAT level transmitters did not contain analyses or test results to demonstrate the required seismic qualification for the Hosgri earthquake.

Previously installed transmitters had been qualified for Hosgri loads, but replacement transmitters were installed by design changes performed in 1987 (Unit 2) and 1988 (Unit 1) without confirming qualification for Hosgri loads.

As a result, PG&E initiated Nonconformance Report DCO-90-EN-N027 and performed investigative actions to determine if additional components existed that required seismic qualification as a result of Hosgri Report commitments, but whose qualification had not been maintained. This investigative action identified the following findings and issues.

Other Instrumentation

* Seismic qualification files had not been maintained for the steam generator pressure indicators (SB)(PI), charging pump (CB)(P) discharge header flow transmitter (CB)(FT), and firewater storage tank (KP)(TK) level indicator (KP)(LI). This instrumentation was listed as requiring qualification to the Hosgri earthquake. Files have been revised to document qualification for the Hosgri earthquake; no plant modifications were required.

Battery Operated Lights

* The seismic qualification of battery operated lighting units (BOLs)(FH)(LF) was not maintained in accordance with Hosgri Report commitments. Seismic testing has verified that these BOLs will remain functional following the Hosgri earthquake.

Valve Qualification

* Twenty-one active valves (V) per unit were identified for which the Hosgri load case qualification had not been fully maintained. The valves were modeled in the piping system analysis for the DE, DDE, and Hosgri earthquake load cases; however, valve qualification to active valve stress limits for the Hosgri earthquake was not documented. The files have been verified and revised where necessary to document qualification

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to active valve stress limits; no plant modifications were required.

- Eleven containment HVAC valves (VA)(V) per unit were identified for which formal seismic qualification files had not been maintained. The files have been revised to document qualification; no plant modifications were required.

- Two reactor coolant system (RCS) sample valves (AB)(SMV) per unit were identified that had been designated as passive valves, but are required to be active to meet Hosgri Report commitments. The files have been revised to document qualification; no plant modifications were required.

- The Hosgri Report established stress criteria to be applied to the extended upperstructures of passive valves. Valves in accident mitigating systems that are passive for the Hosgri earthquake were qualified by modeling the valves in the piping analysis and demonstrating compliance to pipe stress criteria. This was consistent with industry practice at that time and was believed to be sufficient to assure passive qualification. Additional analysis has been performed and files have been revised where necessary to document qualification to passive stress criteria for these 127 valves. No plant modifications were required, which validates the original approach.

- During review of the Hosgri Report, certain ambiguities in the Hosgri Report and the SSERs regarding qualification requirements for valves in accident mitigating systems were identified. Table 7-1 of the Hosgri Report defines active components as "Mechanical equipment which is needed to go from normal full power operation to cold shutdown following the earthquake and which must perform mechanical motions during the course of accomplishing its design function." Tables 7-7 and 7-7A of the Hosgri Report list valves required to be qualified to active valve criteria for cold shutdown of the plant. SSER 7 refers to Table 7-7 in describing those valves required to be qualified as active valves. These specific statements are consistent with what was done in the PG&E, NSSS, and other contractor valve qualification files and calculations.

  However, other parts of the Hosgri Report and SSERs make general statements regarding valve qualification. These general statements can be construed as implying that remotely operated accident mitigating system valves were also qualified to active valve criteria for the Hosgri earthquake, as was the case for the DE (OBE) and DDE (SSE). This indicates that the specific criteria established during the Hosgri reevaluation and reflected in associated SSERs, along with the engineering

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actions taken during that period, were not clearly reflected in the licensing documentation.

To provide increased conservatism, qualification files for these valves will be revised to document qualification to active criteria for the Hosgri earthquake (see Section V.C.1.).

Other Issues

- Three switches (JL)(IS), two fuses (JL)(FU), and a fuse block (JL)(FUB) that require seismic qualification for Class 1E circuit integrity were identified in the dedicated shutdown panel (JL)(PL). The panel, its anchorage, and the electrical devices had not been seismically analyzed. The necessary qualification files for this equipment have been prepared and no plant modifications were required. The root cause analysis of this finding will be addressed by the Regulatory Guide (RG) 1.97 Review Program presently being performed by PG&E as a part of Nonconformance DCO-91-EN-N005. This issue is not discussed further in this LER as it is not related to Hosgri Report commitments.

- Position switches (JL)(33) internal to various safety-related valve motor-operators were inappropriately designated as Design Class II. However, this finding has had no adverse impact on design, procurement, and maintenance of the devices since the valves and operators are designated as Design Class I and internal parts have been managed as safety-related components. Drawing changes are being initiated to reclassify these components. This issue is not discussed further in this LER as this finding does not impact the seismic qualification of these components.

- Remote valve operators on some Design Class I valves have been designated as Design Class II. These valves: (1) have a passive function; (2) are only relied upon for manual handwheel operation in accident analyses; or (3) are in the designated cold shutdown flowpath that was evaluated for the Hosgri earthquake. Appropriate seismic analyses had been performed for these valves. However, the Class II designation for the valve operators does not assure configuration control of plant maintenance activities for this unique situation. Therefore, drawing changes are being initiated to reclassify the valve operators to Design Class I. As part of the design change process, PG&E will verify that appropriate maintenance activities have been performed on these valve operators. This issue is not discussed further in this LER as there is no evidence that maintenance practices have impacted the seismic qualification of these operators.

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

E. Dates and Approximate Times for Major Occurrences:

June 3, 1977:	Hosgri Report issued as Amendment 50 to the operating license application. The report was amended numerous times, with the last amendment issued in June 1980.
June 22, 1987:	Event Date. Design change failed to maintain evidence of seismic qualification for BAT level transmitter in Unit 2.
January 14, 1988:	Event date. Design change failed to maintain evidence of seismic qualification for BAT Level transmitter in Unit 1.
November 12, 1990:	Discovery Date: PG&E determined that Units 1 and 2 BAT level transmitter files did not include evidence of qualification for the Hosgri earthquake. PG&E initiated Nonconformance DCO-90-EN-N027.
July 3, 1991:	Review of Hosgri Report and equipment qualification files identified additional potential inconsistencies.
May 26, 1992:	Investigative actions completed and scope of corrective actions defined.
June 22, 1992:	PG&E met with NRC Region V to discuss the nonconformance on Hosgri Report commitments. PG&E agreed to submit a voluntary LER.

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

During review of a design change to replace the BAT level transmitters, Hosgri Report seismic qualification requirements for the transmitters were identified.

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When the design change was reviewed for Seismically Induced System Interaction (SISI) considerations, it was identified that the SISI Program considers the Design Class II BAT level transmitters as targets (which indicates that they are required for safe shutdown after an earthquake). This led to a review of the Hosgri Report, which lists the BAT level transmitters as requiring seismic qualification for the Hosgri earthquake. The transmitters installed at that time did not have a seismic qualification file.

Subsequent review of the Hosgri Report identified additional seismic qualification commitments that had not been maintained.

H. Operator Actions:

None.

I. Safety System Response:

None.

III. Cause of the Event

A. Immediate Cause:

The conditions that directly affect the seismic qualification of equipment within the scope of this LER are the result of several immediate causes. The causes are listed by equipment type as follows.

BAT level transmitters: PG&E implemented design changes in 1987 and 1988 to replace the original, seismically qualified BAT level transmitters. The Hosgri Report seismic qualification requirement for the transmitters was not recognized because the requirement was not reflected in design documents.

Other instrumentation: PG&E implemented design changes to reclassify instrumentation to conform with RG 1.97 requirements that were inconsistent with the seismic qualification requirements of the Hosgri Report.

The firewater storage tank level indicator was seismically qualified to maintain system pressure boundary integrity; however, the requirement for functional qualification was not recognized because the requirement was not reflected in design documents.

Battery operated lights: The BOLs were installed as a result of the pre-10 CFR 50, Appendix R fire protection review and were seismically qualified as documented in the Hosgri Report in response to an NRC verbal request. When additional units were installed to comply with 10 CFR 50, Appendix R fire protection requirements, the seismic

qualification requirement for the BOLs was deleted because Appendix R does not require seismically qualified lighting units.

Valve qualifications: Requirements for Hosgri active qualification of 21 valves per unit were eliminated in a design criteria revision. The basis for this revision could not be determined.

Passive valve qualifications for the Hosgri earthquake were not established based on extended upperstructure stress allowables as stated in the Hosgri Report. Instead, valves were modeled in the piping system and accepted based on compliance with piping stress allowables. This methodology was consistent with industry practice and was considered to be appropriate for passive valve qualification.

Eleven containment HVAC system valves per unit were not included in the valve list for identifying valves requiring qualification. As a result, qualification files verifying that actual valve accelerations were less than allowables were not established for these valves.

Two RCS sample valves were improperly listed on the valve list as passive instead of active.

B. Root Cause:

The following two root causes have been identified for these findings.

A specific configuration control system was not established to identify Hosgri seismic qualification commitments for equipment whose classification would not normally require seismic qualification. This applies to the BAT level transmitters and the other instrumentation.

Seismic qualification requirements for BOLs were deleted as the result of a design document revision that did not receive a thorough design review and 10 CFR 50.59 safety evaluation. Similarly, seismic qualification requirements for valves were incomplete and inappropriately modified as the result of design basis documents that did not receive thorough design reviews and 10 CFR 50.59 safety evaluations. At that time, design basis documents were not considered to be within the scope of 10 CFR 50.59.

IV. Analysis of the Event

The event analysis for each equipment type is as follows.

BAT level transmitters: The non-qualified level transmitters installed in 1987 and 1988 have been evaluated and no failure modes were identified that could have prevented boration from occurring or adversely impacting any other safety functions. The transmitters had no moving parts and seismically induced failure of the transmitters was unlikely. PG&E believes

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that the transmitters could have been seismically qualified if necessary; however, other unrelated design considerations warranted their replacement in the fourth refueling outages for both units. The replacement transmitters are seismically qualified.

Therefore, installation of the non-qualified transmitters did not result in any safety or operability issues.

Other instrumentation: The Hosgri Report required that additional instrumentation required for cold shutdown be seismically qualified. Seismic qualification file revisions to document the qualification of these devices have been completed; no plant modifications were required. No safety or operability concerns exist.

Battery operated lights: The commitment to seismically qualify the BOLs exceeds regulatory requirements for fire protection. The BOL units presently installed at Diablo Canyon are similar to the original units that were seismically tested in 1978, but utilize lead-acid batteries (FH)(BTRY) instead of the nickel-cadmium batteries (FH)(BTRY) installed in the original units. To comply with the commitment in the Hosgri Report, seismic testing of the BOL units was performed to qualify the lead-acid batteries. Rather than identifying and qualifying only those BOLs in specific areas requiring lighting for post-earthquake shutdown, PG&E chose to qualify all BOLs located in the plant (the quantity of BOLs in the plant is substantially greater today than when the original test was performed). A seismic test spectra was developed that enveloped all plant locations with BOLs. This spectra resulted in a test condition substantially more severe than the original qualification test. Two different mounting rack configurations were used to envelope all BOL support conditions.

Because the BOL units were subjected to a more severe seismic test spectra than in 1978, during the second front-to-back and vertical test, excessive buckling deformation of the sheet metal mounting rack occurred. However, the BOLs remained functional during and after the test. In order to complete the test in accordance with IEEE-344 requirements, the BOL mounting racks were stiffened using aircraft cable and gusset plates. The seismic test was resumed and successfully completed. The seismic testing confirmed that the lead-acid batteries are capable of withstanding the Hosgri earthquake. Upon completion of the seismic testing, functional tests for the BOLs were successfully completed. Therefore, no safety or operability concerns exist.

Mounting racks for the BOL units in those locations where the required response spectra exceeds the 1978 test spectra will be modified to conform to the tested configuration (see Section V.C.2).

Valve qualifications: PG&E has reestablished the Hosgri valve qualification for those valves considered to be active valves for the Hosgri earthquake.

B. Corrective Actions to Prevent Recurrence:

1. Specific controls are being implemented to ensure that configuration control of Design Class II components that require seismic qualification will be maintained. These include:

   * Design Class II components with seismic qualification requirements specific to the Hosgri earthquake will be reclassified to assure qualification requirements are maintained.

   * Plant modification and replacement part evaluation procedures have been revised to assure seismic configuration control.

2. Design documents are being revised to incorporate appropriate Hosgri Report seismic qualification requirements. The design change to revise these documents is expected to be issued by October 15, 1992.

3. The Updated Final Safety Analysis Report (UFSAR) will be revised to reflect Hosgri Report seismic qualification requirements. Revisions will be included in the annual updates issued in 1992 and 1993.

4. A review of the valve requalification effort will be performed by PG&E's Quality Assurance Department to ensure compliance with design documents. The review is expected to be completed by October 15, 1992. Verification of all corrective actions is routinely performed by the QA Department as part of nonconformance closure.

5. Procedures governing design criteria document revision have been revised over the past several years to require thorough technical review, design/safety review, independent verification, and 10 CFR 50.59 safety evaluation. Personnel performing safety evaluations receive documented training based on the content of NSAC 125, "Guidelines for 10 CFR 50.59 Safety Evaluations."

C. Additional Actions:

1. Seismic qualification files will be revised to demonstrate active qualification for the accident mitigating system valves currently designated as passive for the Hosgri earthquake. This effort, which is outside the scope of the nonconformance corrective action, will provide increased conservatism. Engineering analysis will be completed in 1993 and plant modifications, if required, are anticipated to be completed

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PG&E has completed the analyses for the valves that require passive qualification for the Hosgri earthquake. No plant modifications were required. Therefore, no safety or operability concerns exist.

Additional evaluations, currently in progress, have the potential to affect these valve qualifications. These evaluations are: (1) incorporation of Generic Letter 89-10 motor-operator thrust loads in valve qualification analyses; (2) evaluation of the effect of revised vendor supplied valve weight data; and (3) a reevaluation of valves that utilize cast iron in non-pressure retaining applications. These issues are being addressed independently of the issues in this LER.

PG&E performed additional seismic evaluations and analyses that were documented in the Diablo Canyon Long Term Seismic Program (LTSP) Final Report submitted to the NRC in July 1988. The NRC review of the LTSP is documented in SSER 34. The findings in this LER do not affect the conclusions from the LTSP. The Diablo Canyon LTSP established fragility estimates for air and motor-operated valves from a sampling of valves required for safe shutdown. The allowable acceleration level for these valves as identified in the design criteria document was taken to correspond to the acceptable level of stress of 1.8S ("S" is the ASME Section III membrane stress allowable), which is the criterion for active valves. On the basis of this assumption, the high-confidence-of-low-probability-of-failure (HCLPF) capacity, when compared to the LTSP demand, provided a seismic margin of 2.21 (reference LTSP Final Report, Table 7-2). Valves considered as passive components for the Hosgri earthquake have an allowable stress criteria of 2.4S. For the LTSP study, the HCLPF seismic margin for valves qualified as passive instead of active, in those few situations which may approach the worst case, would be reduced to 1.65. This seismic margin is still in excess of the 1.4 margin established in the LTSP deterministic seismic margin assessment (PG&E letter DCL-90-226). Therefore, the findings in this LER do not affect the conclusions from the LTSP.

V. Corrective Actions

A. Immediate Corrective Actions:

1. The BAT level transmitters were replaced with seismically qualified transmitters.

2. The Hosgri Report was reviewed to identify any other seismic qualification commitments that had not been maintained.

3. Files demonstrating qualification to the Hosgri earthquake have been established or updated as necessary to document the seismic qualification of the identified components, except for the BOLs. Seismic qualification files are expected to be completed for the BOLs by October 15, 1992.

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during the sixth refueling outage in each unit (scheduled in 1994).

2. Mounting racks for the BOL units in those locations where the required response spectra exceeds the 1978 test spectra will be modified to conform to the tested configuration. Plant modifications will be completed during the sixth refueling outage in each unit (scheduled in 1994).

3. Seismic qualification files have been prepared to document the qualification of the dedicated shutdown panel and the required electrical devices within the panel. No plant modifications were required.

4. Design changes will be initiated to reclassify (1) position switches internal to safety-related valve motor-operators and (2) valve operators on Design Class I valves that were identified as a result of the nonconformance investigative action.

VI. Additional Information

A. Failed Components:

None.

B. Previous LERs:

None.

50-275/323-OLA-2
I-MFP-133
"NOT ADMITTED"

MFP Exhibit 133

RELATED CORRESPONDENCE

U.S. NUCLEAR REGULATORY COMMISSION

'93 OCT 28 P6:54

REGION V

Report No:	50-275/92-20 and 50-323/92-20
Docket Nos:	50-275 and 50-323
License Nos:	DPR-80 and DPR-82
Licensee:	Pacific Gas and Electric Company 77 Beale Street, Room 1451 San Francisco, California 94106
Facility Name:	Diablo Canyon Units 1 and 2
Inspected at:	Diablo Canyon Site, San Luis Obispo County, California
Inspection Conducted:	June 2 through July 13, 1992
Inspectors:	P. Morrill, Senior Resident Inspector M. Miller, Resident Inspector D. Corporandy, Reactor Inspector

Approved by: W. P. Ang for
P. Johnson, Chief
Reactor Projects Section 1

8-13-92
Date Signed

Summary:

Inspection from June 2 through July 13, 1992 (Report Nos. 50-275/92-20 and 50-323/92-20)

Areas Inspected: The inspection included routine inspections of plant operations, maintenance and surveillance activities, followup of onsite events, open items, and licensee event reports (LERs), as well as selected independent inspection activities. Inspection Procedures 2515/115, 41701, 61726, 62703, 71707, 71710, 90711, 92700, 92703, 93702, and 94600 were used as guidance during this inspection.

Safety Issues Management System (SIMS) Items: None

Results

General Conclusions on Strengths and Weaknesses

Strengths:

The licensee's immediate response to the chemical spill on June 20, 1992, was prompt and comprehensive. It appeared that Fire Brigade

training and related training had been effective in preparing Operations personnel to deal with emergency evacuation and rescue operations.

Weaknesses:

The NRC determined that the Unit 1 and 2 positive displacement charging pumps (PDPs) have been deemed by the licensee to have been inoperable, "for emergency use only," during the past two years. The inspectors also identified a weakness in the licensee's assumption that Abnormal Procedure AP A-17, "Loss of All Charging," could be assumed usable for safe shutdown in the event of a fire in the centrifugal charging pump (CCP) room. The licensee's engineering organization had previously concluded that operation of the positive displacement charging pump (PDP) could cause cracking in the charging system. However, the licensee had not conducted a circuit analysis to determine whether AP A-17 could be used following a fire in the CCP room, nor had the licensee informed the operators of when, how, and how long the PDPs could be safely used to back up the CCPs.

Significant Safety Matters: None.

Summary of Violations: Two Severity Level IV violations were identified, applicable to both Units 1 and 2:

1. The first violation was failure to provide adequate instructions for the use of the PDP.

2. The second violation involved failure to comply with 10 CFR 50.72.(b)(1)(ii)(B) after three fire protection deficiencies outside the design basis of the plant were identified. The regulation requires that conditions outside the design basis of the plant be reported to the NRC within one hour.

Open Items Summary:

Five items were opened. Two items were closed.

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
   D. B. Miklush, Manager, Operations Services
   M. J. Angus, Manager, Technical Services
   *B. W. Giffin, Manager, Maintenance Services
   W. G. Crockett, Manager, Support Services
   J. E. Molden, Instrumentation and Controls Director
   *W. D. Barkhuff, Quality Control Director
   R. P. Powers, Mechanical Maintenance Director
   H. J. Phillips, Electrical Maintenance Director
   J. A. Shoulders, On site Project Engineer
   *S. R. Fridley, Operations Director
   R. Gray, Radiation Protection Director
   J. V. Boots, Chemistry Director
   *T. A. Moulia, Assistant to Vice President, Diablo Canyon Operations
   *R. Kohout, Safety, Health and Emergency Services Director
   *T. L. Grebel, Regulatory Compliance Supervisor
   J. J. Griffin, Senior Engineer, Regulatory Compliance
   *D. P. Sisk, Regulatory Compliance Engineer
   D. R. Stermer, Power Production Engineer
   M. R. Tresler, Project Engineer
   R. Clark, Assistant Project Engineer
   R. Gagne, Acting Radwaste Foreman
   U. A. Farradj, Fire Protection Engineer
   *R. A. Waltos, Mechanical Maintenance Supervisor
   S. F. Shrefler, Mechanical Maintenance Engineer
   B. D. Pogue, System Engineer
   R. Ortega, System Engineer
   R. Watson, Quality Assurance Engineer
   *F. J. Bosseloo, OPEG Project Engineer
   *D. A. Moon, Regulatory Compliance Engineer
   *M. Burgess, Systems Engineering Director
   *J. S. Bard, Quality Control Specialist

   Independent Safety Oversight Committee

   William Kastenberg, Professor of Engineering & Applied Science, UCLA
   Warren Owen, Executive Vice President of Duke Power, Power Group Operations

U.S. Nuclear Regulatory Commission, Region V

*R. A. Scarano, Director, Division of Radiation Safety and Safeguards

*Denotes those attending the exit interview.

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

2. Operational Status of Diablo Canyon Units 1 and 2

Both units operated at 100% power during the inspection period except for Unit 2, which curtailed power to 50% on June 13 to clean the condenser and perform testing of main feed-water pumps.

3. Operational Safety Verification (71707)

a. General

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 sample 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 to observe the following:

(1) General plant and equipment conditions

(2) Fire hazards and fire fighting equipment

(3) Conduct of selected activities for compliance with the licensee's administrative controls and approved procedures

(4) Interiors of electrical and control panels

(5) Plant housekeeping and cleanliness

(6) Engineered safety features equipment alignment and conditions

(7) Storage of pressurized gas bottles

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.

b. Radiological Protection

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors verified that health physics supervisors and professionals conducted frequent plant tours to observe activities in progress and were aware of significant plant activities, particularly those related to radiological conditions and/or challenges. ALARA considerations were found to be an integral part of each RWP (Radiation Work Permit).

c. Physical Security

Security activities were observed for conformance with regulatory requirements, implementation of the site security plan, and administrative procedures, including vehicle and personnel access screening, personnel badging, site security force manning, compensatory measures, and protected and vital area integrity. Exterior lighting was checked during backshift inspections.

No violations or deviations were identified.

4. Onsite Event Followup (93702)

a. Through-Wall Corrosion and Leakage of Auxiliary Salt Water Piping

On June 18, 1991, a leak of about 50 gallons per minute occurred in the annubar riser on the 2-2 auxiliary salt water (ASW) system. The annubar riser, used for ASW system flow measurements, is a 4-inch diameter PVC-lined carbon steel pipe rising about five feet above the buried ASW piping traveling under the turbine building. The riser travels up through a covered trench before it extends above ground. The leak occurred in the portion of the piping in the trench. The licensee clamped a pipe patch around the pipe as a temporary measure to stop the leak.

The leak appeared to have been caused by through-wall corrosion initiated on the outer wall of the piping, in the trench. Later ultrasonic testing indicated that significant corrosion had also occurred on the 1-1 ASW riser. The licensee's preliminary evaluation determined that the corrosion was due to degradation of the coal tar epoxy coating on the carbon steel piping combined with alternate wetting and drying. Once any moisture got under the coal tar epoxy, the pipe rusted and flaked off additional coal tar epoxy. The alternate wetting and drying caused the exposed pipe to rust rapidly. The licensee plans to replace all four annubar risers with corrosion resistant material.

Chronology of Events:

The inspectors examined the licensee's documents listed below and discussed the corrosion problems with licensee engineering and maintenance personnel.

Action Requests: A0269002, A0269111, A0269118, A0269152, A0269215

Work Orders: C0101129, C0101131

NCR: DC2-92-TN-N028, Rev. 00

Operability Evaluation: 92-14, Rev. 0

The inspector observed that, starting with the annubar leak, the following chronology of recent events had occurred.

June 18 --	The leak in the 2-2 annubar pipe was found by the licensee. A temporary soft patch was installed and a prompt operability evaluation (POA) was completed.
June 19 --	Licensee engineering confirmed the POA. Other annubar piping was visually inspected.
June 20 --	Significant corrosion of annubar 1-1 was documented. An event response plan (ERP 92-6) and nonconformance report (NCR DC2-92-TN-N028) were initiated. An acid and caustic spill occurred in the buttress area of Unit 2. Some overflow appears to have entered the trench containing carbon dioxide fire suppression (CARDOX) and diesel fuel oil (DFO) piping. The annubars also go through this trench approximately 70 feet from the acid/caustic spill.
June 21 --	While cleaning up the acid/caustic spill, licensee personnel found significant corrosion on the CARDOX piping.
June 22 --	One of the pipes thought to be CARDOX with significant corrosion was identified as diesel fuel oil transfer piping. The preliminary inspection plans for the CARDOX lines were developed.
June 23 --	DFO line 4537 was removed from service at 5:45 a.m. to allow tie-in to the new emergency diesel generator (EDG 2-3). The corroded spot on DFO train 0-2 was examined and found to be approximately 120 mils (nominal pipe wall is 203 mils). The minimum wall requirement for this location was calculated by the licensee to be 75 mils.

No leakage was observed during a pressure test to 68 psig.

June 24 -- Detailed plans were prepared to inspect DFO lines. At 1220 the 0-2 DFO line was returned to service.

June 25 -- DFO 0-1 line was taken out of service at 5:05 a.m. for tie-in to EDG 2-3. Visual inspection of 0-1 piping was conducted, and areas of concern were identified. At 7:15 a.m., 0-1 piping was returned to service.

July 2 -- DFO 0-1 was taken out of service for ultrasonic examination. One portion was found to be less than or equal to 40 mils thickness. Because this was below required minimum wall, a twelve foot portion of pipe was replaced.

July 4 -- 0-1 DFO piping was placed back in service at 2:00 p.m..

July 5 -- DFO 0-2 was taken out of service from 4:00 to 11:00 a.m. to conduct ultrasonic examinations on the Unit 2 side. No areas were found below minimum wall thickness.

July 6 -- DFO 0-2 was taken out of service from 4:00 a.m. to noon to conduct ultrasonic examinations on the Unit 1 side. No areas were found below minimum wall.

July 8-13 -- CARDOX piping visual and ultrasonic examinations were conducted. No areas were found below minimum wall.

ASW Operability Determination: The license determined that the 2-2 ASW train was operable during the leak, because the leak flow rate was about 50 gpm, while the ASW flow rate allowed about 200 gpm design margin (OE 92-14, Revision 1). The licensee initiated a conditional surveillance to monitor ocean temperature to ensure continued design margin.

Replacement of ASW Annubar Piping: The licensee plans to replace the piping during plant operation. At the time of writing this inspection report, the annubar connections to the main ASW line had been unburied, and the 1-1 and 2-2 annubar piping had been removed and capped with flanges.

Diesel Fuel Oil Piping: The licensee determined that the corrosion of the DFO piping in train 0-1 was not immediately reportable, but was reportable as a licensee event report. The licensee's preliminary evaluation concluded that the corrosion of the DFO piping was most likely due to incomplete application of coal tar

epoxy on the underside of the pipe, combined with an environment where moisture could condense and accumulate on the underside of the pipe. At the end of the reporting period the licensee was evaluating how long the existing piping would be satisfactory and how to replace the DFO piping with more corrosion resistant material. The inspector asked licensee personnel if they had considered the prudence of taking the 0-2 fuel oil train out of service during the period June 23 - 24, 1992, to complete the tie-in to a new emergency diesel generator. The inspector also asked if the licensee had recognized that, due to the finding six days later that part of the 0-1 train was below minimum wall, both trains of fuel oil were out of service at that time.

Licensee personnel stated that events were developing rapidly when the corrosion problems were found and that they had to have time to formulate inspection plans. Taking the 0-2 piping out of service was consistent with the need to examine and repair this line if the highly rusted spot found on June 22 was below minimum wall thickness. Since visual inspections had already been completed, licensee personnel believed they had found the worst case of corrosion. After the completion of this inspection, the licensee completed an engineering analysis which concluded that the as-found wall thickness for the DFO piping would have been acceptable.

Carbon Dioxide Suppression (Cardox) System Piping: The licensee inspected the Cardox system with ultrasonic test equipment, and found no locations below minimum required wall thickness. However, significant corrosion was observed, and the licensee is reviewing the frequency of inservice inspection.

Fasteners on Main ASW Piping: The licensee uncovered portions of the buried ASW piping to support annubar replacement. The fasteners on both the four-inch and 24-inch piping flanges showed significant corrosion. The licensee determined that further inspection was required, and is currently determining the appropriate scope of investigation.

Scope of Corrosion Investigation: In addition to the piping and fasteners discussed above, the licensee is reviewing additional buried and entrenched piping and components, including electrical connections in covered trenches. The review is being tracked by NCR DC2-92-TN-N028.

Summary: Since licensee actions are not complete, the inspectors will continue to follow the licensee's corrective actions (Followup Item 50-275/92-20-01).

b. Chemical Spill and Noxious Gases in the Turbine Building

On June 20, at 5:35 p.m., the licensee declared a Notice of Unusual Event as a result of a spill of hazardous material and associated noxious gases entering the turbine building.

Caustic and acid tanks in the 85 foot elevation condensate polisher

area adjacent to the Unit 2 side of the turbine building were inadvertently overfilled. About 300 gallons of 93% sulfuric acid and 500 gallons of 50% sodium hydroxide were simultaneously discharged to a common drain line, to an approximately 10 ft by 25 ft bermed area containing chemical transfer equipment. The resulting exothermic reaction splashed caustic liquid and released a cloud of acidic vapor which operators observed expanding above the bermed area.

Operators recognized the tanks were overfilling and shut off the pumps. The fire brigade responded and determined that the spill had stabilized. Search and rescue activities were performed immediately, which determined that no personnel had been injured in the spill. Assistance was requested from California Department of Forestry hazardous waste response personnel.

The hot gases had entered the turbine building and traveled up the crane bay to the 140 foot elevation. Operators promptly shifted the control room and technical support center ventilation to the pressurization mode. Vital equipment in the turbine area was verified to be accessible by operators and security personnel using self-contained breathing apparatus.

By about 10:30 p.m., initial testing of some of the turbine building areas showed reduction of noxious gas concentrations to safe habitability levels. Final confirmation of habitability for all turbine building areas was completed at 2:10 a.m. on June 21, at which time the Unusual Event was secured.

The resident inspector responded to the site. It appeared that licensee response activities were carried out in a timely and conservative manner.

Cleanup of the bermed area and the other areas where the gas cloud deposited acidic precipitates was initiated June 21, and was essentially completed by the end of the report period.

The licensee initiated NCR DC2-92-OP-N029 and an investigation (ERP 92-7) to determine the cause of the spill. The spill was initiated by an operator who violated procedures by filling both the acid and caustic day tanks simultaneously.

The licensee initiated corrective actions to prevent recurrence, including counseling the operator who filled both tanks at once, circulating an Incident Summary to other operators, making design improvements in the condensate demineralizer regeneration system, determining if other areas of the plant were vulnerable to similar events, and evaluating whether this event was covered by the plant design basis.

The inspector questioned the licensee regarding the design basis of the three chemical storage tanks (sulfuric acid, sodium hydroxide, and ammonia) located in the Unit 2 turbine building buttress area. Licensee personnel stated that the tanks were not safety related and

had been designed to the Uniform Building Code requirements using the Design Earthquake (0.2 G horizontal and 0.13 G vertical accelerations). The ammonia tank had been design to slightly higher standards of 0.3 and 0.2 G respectively. An analysis of the effects of the failure of each tank had been done. The installation of the ammonia tank (DCP M-39122) had been completed after a 10 CFR 50.59 safety evaluation was completed. This safety evaluation considered the complete rupture of the ammonia tank. The inspector questioned whether the design was adequate to preclude rupture of all three tanks at once during a large earthquake and whether this effect had been considered in accident planning.

Licensee personnel stated that the safety factors to design allowable stresses in the tanks varied from 1.5 to 2.2 for the Design Earthquake, and that the factor of safety to failure from the allowable stresses was at least 2.2, which would make simultaneous tank ruptures very unlikely. The inspector asked the licensee if they had considered the effects on accessibility to the Technical Support Center, which is in the same plant area. The inspector and the licensee will review existing documentation of the tanks' design bases before reaching a final conclusion.

c. Earthquake Felt at the Site on June 28, 1992

On June 28, 1992, at approximately 4:59 a.m., plant personnel felt seismic activity and declared an Unusual Event. It was subsequently determined that the event was an earthquake measuring 7.4 on the Richter scale, approximately 260 miles southeast of the plant.

The Senior Resident Inspector responded to the site. The licensee's seismic monitoring instrumentation registered a horizontal acceleration of 0.002 G at the containment base. The only other indication was a one-inch level oscillation in the pressurizer relief tank for a period of several minutes. Licensee and inspector walk-downs did not identify any other effects on the plant.

5. Maintenance (62703)

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. These activities included:

Work Order C0100716, Investigate High D/P Indication on CCW Heat Exchanger 2-1

Work Order C0100647, Clean Saltwater Side, CCW Heat Exchanger 2-1

Work Order C0100669, Implement DCP E-47538 (Remove Surge Protectors from HVAC air solenoids in Auxiliary Building)

Work Order C0101129, Remove Tar and Inspect Piping (Cardox)

Work Order C0101131, Inspect Unit 2 Diesel Fuel Oil Header Line 4534

The inspector observed that CCW Heat Exchanger 2-1 was taken out of service for cleaning on June 8, 9, 10, and 11. Licensee personnel stated that this was intended and expected due to sea growth being killed by continuous chlorination of that ASW train. The licensee had previously eliminated sea growth (barnacles and mussels) from the 1-1 ASW train using continuous chlorination and felt this was a prudent measure to preclude unexpected unavailability of the CCW heat exchangers. The inspector asked if the licensee had considered the level of plant risk associated with taking the CCW heat exchanger out of service so frequently.

Licensee personnel subsequently determined that the increase in risk was dependent upon how the CCW heat exchanger was taken out of service, and reportedly, that the increase was noteworthy and warranted consideration. In the meantime, the licensee had stopped continuous chlorination due to the leak found in the 2-2 annubar piping and did not plan to restart chlorination until the annubar piping was repaired.

The inspector asked what measures would be used to minimize the core damage risk for cleaning the 1-2 and 2-2 ASW system piping. Licensee personnel stated that Operations had been consulted on this issue, but no final decision on how to proceed had been reached. The inspector stated that he would follow up this item during a subsequent inspection.

No violations or deviations were identified.

6. Failure of Motor Operated Valve Caused by Loose Set Screw (90711)

a. Background

On June 2, 1992, motor operated valve (MOV) SI-2-8923A failed to open fully during surveillance testing. The license inspected the Limitorque SMB-00 actuator and found that the worm cartridge bearing locknut setscrew was loose, and the locknut had unscrewed from the worm. This caused the torque switch to displace to its contact open setpoint even though the spring pack had not deflected. The limit switch, which bypasses the torque switch, opened as required at approximately 30% of the open stroke. This enabled the open torque switch, hence tripping the motor and stopping valve motion at 30% of open stroke. (Refer to NCR DC2-92-EM-N026).

The licensee reviewed plant maintenance history and found that a similar failure had occurred on MOV SI-2-8805B during post-maintenance testing during Unit 2's fourth refueling outage. MOV SI-2-8805B also has an SMB-00 operator.

b. Determination of Scope

The licensee determined that a loose worm cartridge bearing locknut could only cause premature torque switch actuation in an SMB-00

operator. Furthermore, the licensee determined that only the opening direction was affected.

For the closing direction, the licensee determined that a loose locknut could cause the torque switch on the SMB-00 operator to actuate late or not at all. This type of failure would not prevent a valve from closing but could potentially overtorque or overthrust MOVs. Furthermore, failure of the torque switch to actuate could cause the motor to stall and overheat at the end of the valve stroke.

The licensee reviewed the other types of Limitorque actuators used in their two units and determined that torque switch operation would not be adversely affected by a loose worm cartridge bearing locknut. Consequently, the licensee focused their investigation on the SMB-00 operators.

c. Sampling

Units 1 and 2 contain 98 MOVs with SMB-00 operators. The licensee inspected locknut tightness on 18 of these. The 18 MOVs were selected, in part, based on safety significance and vulnerability in the opening direction. Of the inspected MOVs, five Unit 2 MOVs were found to have loose worm cartridge bearing locknuts. Work on all five MOVs had been performed by one particular craftsman. The licensee accounted for work performed by this craftsman. In addition, 13 assemblies, which had previously been in service in the plant, and later replaced, were inspected and found to have tight locknuts.

d. Root Cause Evaluation

The licensee concluded that the premature actuation of the MOV SI-2-8923A torque switch had resulted from the loose worm cartridge bearing locknut. The licensee was able to duplicate this failure mechanism in their laboratory. The licensee identified three potential causes:

(1) lack of specific instructions for tightening the locknut and locknut setscrew; i.e., a reliance on skill of the craft.

(2) inadequate locknut and setscrew tightening by one particular individual.

(3) harder material in replacement worm gear shafts possibly exacerbating the problem of setting the locknut setscrew.

Because the actuator vendor had supplied harder worm gear replacement shaft material without prior notification to the licensee, the licensee also considered 10 CFR Part 21 reportability. After discussions with their vendor, the licensee concluded that the form, fit, and function of the part had not changed and that it was not reportable under 10 CFR Part 21.

e. Operability Considerations

The SMB-00 MOVs inspected were determined operable by verifying that the locknut was tight. SMB-00 MOVs that were not inspected were reviewed by the licensee as follows:

Operating procedures, emergency operating procedures (EOPs) and functional recovery procedures (FRPs) were reviewed to determine which direction(s) was required to perform each valve's safety function(s). MOVs with a closing safety function were checked to ensure that maximum torque and thrust conditions would not exceed valve and operator limits for a single application of the load. MOVs with a safety function to close were also verified to have thermal overload protection.

For valves with an opening safety function, motor trip at the point at which the limit switch no longer bypassed the torque switch was assumed. If flow was inadequate at this position, the licensee performed a temporary modification to jumper out the torque switch in the opening direction. The licensee also verified that their SMB-00 MOVs had sufficient capability at degraded voltage conditions to unseat a valve disk which might have been wedged into the seat at maximum overthrust conditions. Valves which were locked open in the required safety position with power removed did not undergo any further operability evaluations.

f. Conclusions

The inspectors considered the licensee's determination of scope, sampling, and root cause evaluations to be adequate. The licensee's operability considerations appeared to progress in a logical sequence to address major concerns. However, at the time of the inspection, the licensee had not addressed the ability of SMB-00 MOVs with loose locknuts to recover from inadvertent valve mispositioning. Consideration of valve mispositioning is a recommendation of Generic Letter 90-10 to which the licensee has committed.

No violations or deviations were identified.

7. Surveillance (61726)

By direct observation and record review of selected surveillance testing, the inspectors checked compliance with TS requirements and plant procedures. The inspectors verified that test equipment was calibrated, and that test results met acceptance criteria or were appropriately dispositioned. These tests included:

- STP V-3J1, Revision 7, Exercising Block Valves to the Pressurizer PORVS, Valves RCS-8000A, RCS-8000B, and RCS-8000C.
- STP G-15B, Revision 2, Determination of Valve Stroke Times with Equipment Timers.

No violations or deviations were identified.

8. Engineering Safety Feature Verification (71710)

During the inspection period, selected portions of the residual heat removal system for Units 1 and 2 were inspected to verify that system configuration, equipment condition, valve and electrical lineups, and local breaker positions were in accordance with plant drawings and Technical Specifications.

No violations or deviations were identified.

9. Verification of Plant Records (TI 2515/115)

The objective of this Temporary Instruction (TI) is to determine whether practices of individuals performing surveillance and log entries are such that there is a potential for record falsification to occur.

The inspector utilized the subject TI and NRC Information Notice 92-3, Falsification of Plant Records, to conduct this inspection effort. The inspector determined that the licensee had implemented two self-monitoring programs to audit daily and shiftly surveillance test procedures (STPs) and radiological surveys associated with entry into various areas of the plant. The inspector discussed the scope and progress of the audits with licensee QA personnel, who were scheduled to finish by September 1992.

a. Operator Readings Verification

The licensee's Quality Assurance Surveillance (QP&A 92-0020, Operator Readings Verification) examined 55 STPs and the associated 168 area entries made during the month of March 1992. Five apparent findings were identified wherein the assigned individual did not enter the required zone for one step of the subject STP.

In three of the five identified findings a different member of the crew did enter the required area. The auditors observed that in the past it has been accepted practice for someone on watch in an area where known checks are to be made, to offer to perform those checks. This practice is not currently required to be documented in any way.

In one of the five identified findings, subsequent investigation revealed that the necessary observations (observe backup air bottle pressure to the 10% atmospheric dump valves in the pipe rack) could be and on occasion were made without entering the area.

The last discrepancy found was for a verification of no leakage from the Unit 2 reactor vessel level indication system, which is only required for Unit 2 until a design change is implemented. The licensee also found that the individual responsible for that reading entered what would have been the correct data for the same area for Unit 1. At the end of the report period, the licensee was evaluating whether this could have been a case of looking at the wrong unit.

The licensee also investigated the time that operators spent in the area for six activities which required 95 observations. Based on timed runs for completing these activities, the time licensee personnel spent in the subject areas appeared acceptable.

The audit team's initial conclusions were that there was no generic problem of falsifying records at Diablo Canyon, but that additional auditing should be conducted to determine if some individuals may not be completing activities properly. The licensee anticipated that additional future audits of plant activities would be conducted. The Operations Director had determined that the surveillance test procedures (STPs) needed to be revised to ensure that specific individuals are accountable for STP check-offs. The licensee is tracking this activity through action request A0264320.

b. Radiological Surveys in Security Zones

The licensee's Quality Assurance Surveillance (QP&A 92-0022, Radiological Surveys in Security Zones) was scheduled to be completed in July 1992. This audit's objective was to verify that radiological surveys had been performed. In May 1992, licensee personnel had identified an individual who had falsified surveys. That individual was suspended and subsequently dismissed. As of the end of the reporting period, no other examples of record falsification had been identified.

c. Conclusions

The inspector concluded that the licensee has an adequate plan to determine whether logs and surveys were being falsified. The licensee appeared to be dealing with the preliminary findings in an appropriate manner. This item will remain open until the subject audits are concluded and the licensee has determined any necessary corrective actions. (50-275/92-20-02)

No violations or deviations were identified.

10. Lack of Criteria for Locked Valves Other Than Those Listed In Technical Specifications (92700)

The inspector noted that the valves in the EDG air start system were not sealed valves, nor was there indication of the valve position. These valve's positions appear to be important to safety, since EDG start during a design basis event could be prevented by mispositioned valves. The inspector noted that valves listed in TS appeared to be sealed. However, no criteria existed for selection of other valves which should be sealed. The licensee agreed to review and document the criteria for determining which valves should be sealed, and initiated an Action Request.

No violations or deviations were identified.

11. Inadequate Operability Evaluation for Charging Capability During Safe Shutdown (41700)

a. Background

Both centrifugal charging pumps (CCPs) are located in the same fire area, with about seven feet of separation. The Fire Hazards Analysis requires that, if a fire were to occur in the CCP room, the positive displacement charging pump (PDP) be used as a source of charging to achieve safe shutdown.

In 1989, the licensee determined that operation of the PDP caused cracking of its piping, and performed extensive troubleshooting and maintenance work on the PDPs in both units, without recognizing the safe shutdown function of the pump. As a result of the pumps' extended time out of service, the NRC issued a Notice of Violation (Inspection Report No. 89-33), which addressed the lack of administrative controls on the PDP operability, since the PDP would have been required to operate during a fire in the centrifugal charging pump (CCP) room.

b. Current Findings

On August 29, 1990, the licensee issued Revision 1 of JCO 90-17, which stated that the PDPs were inoperable, and that Abnormal Procedure AP A-17, "Loss of Charging" could be used for plant shutdown and cooldown if a fire occurred in the CCP room. Five additional revisions to the JCO have been made as a result of inadequacies identified by the NRC and by the licensee.

Revision 6 of JCO 90-17 relied on:

1. The Use Of the PDP for Safe Shutdown. At the time of this inspection, the positive displacement charging pumps had been declared inoperable for nearly two years. Plant Operations was informed that the PDPs are available for emergency use only. At high speeds, the PDP suction lines have exhibited high vibration, resulting in pipe cracking. The suction lines have been replaced; however, the vibration can still occur. Quarterly surveillances (STP P17-B) have been run to demonstrate that the pumps produced rated pressure and flow. However, the length of time at high speed before pipe cracking will occur has not been established. This is significant because the design basis fire, involving loss of offsite power, will cause the PDP speed control to fail high.

2. Hourly Fire Watches, Suppression and Detection, and Limited Combustibles in the CCP Room. The centrifugal charging pumps and their associated circuits are not separated by 20 feet distance or by a fire barrier. The licensee has stated that temporary compensatory measures in place comply with the intent of a fire barrier impairment. The inspectors noted that between June 18 and July 6, 1992, 2 bags containing anti-contamination clothing were placed between the Unit 2 CCPs,

thereby providing intervening combustibles which could propagate an oil fire.

3. Use of OP AP-17, (Plant Shutdown During) Loss of All Charging. Revision 6 and earlier revisions of JCO 90-17 stated that, in the event all charging pumps were unavailable, AP-17 would be used. The inspector determined that a circuit analysis had not been accomplished to determine whether circuits associated with the safe shutdown equipment required by that procedure were protected from the effects of a design basis fire in the CCP fire area. Additionally, OP AP-17 noted that level may be lost in the pressurizer during shutdown, and required a reactor trip in that case. This appeared inconsistent with 10 CFR 50, Appendix R, Section L.2.b. which requires that the reactor coolant makeup function be capable of maintaining level within the indicating band of the pressurizer. The licensee revised AP-17 based on using the procedure during this particular fire scenario. Later, the licensee stated that AP-17 would not be referenced by the next revision of JCO 90-17, since the JCO would rely on prevention of a fire in the CCP room by the compensatory hourly fire watch.

NRC Inspection Report 92-05 documented that the licensee planned to issue Revision 7 of the JCO by April 1992. The revision had not been issued as of the end of this inspection, raising concern about the continuing lack of resolution of this issue.

c. Conclusions

The licensee has established neither that the PDP will operate to fulfill its design basis fire protection function, nor that any charging will be available in the event of a fire in the CCP room. Additionally, no circuit analysis has been conducted to demonstrate that AP-17 could be used to complete a safe shutdown after a fire in the CCP room. The licensee had initiated temporary compensatory measures, however, have now been in effect for nearly 2 years. The inspector concluded that the licensee had failed to provide adequate instructions to the operators regarding the use of the PDP. Although the PDP was tagged for emergency use only, no instructions were provided regarding precautions to take to prevent pipe cracking or the circumstances under which it should or should not be used. This is considered a violation (50-275/92-20-03).

12. Simulator Observation (41701)

On June 11, 1992, the inspectors reviewed simulator scenarios for annual operator licensing requalification testing, observed operator examinations at the simulator, and attended the associated critiques by the licensee. The scenarios used included (1) steam break with inadvertent containment spray, (2) gas decay tank rupture, (3) letdown heat exchanger leak with steam generator tube rupture, and (4) bus G undervoltage with LOCA. The four accident scenarios for the simulator appeared to have

been well prepared and appropriately challenging to the operators. The operators appeared to complete required actions, communicated effectively, and performed well as a team. The associated evaluator critiques appeared factual and adequately critical. The licensee's Operations Director observed the evaluations and provided an appropriate verbal critique to the operators and the evaluators at the conclusion of the testing.

No violations or deviations were identified.

13. Licensee Event Report Followup (92700)

10 CFR 50, Appendix R, Safe Shutdown Circuit Separation Deficiencies, (LER 50-323/92-01, Revision 1), Closed

In addition to Unit 2 EDG field circuit separation concerns identified in Revision 0 of this LER, the licensee identified eight additional conditions of inadequate circuit separation. Each appear to have adequate temporary compensatory measures in place, and appropriate corrective action scheduled or under review. Four of these were reported as one-hour non-emergency reports, and four conditions of lesser significance were only documented in the LER, but were not reported as one-hour non-emergency reports. The lack of the latter four being reported as one-hour non-emergency reports according to 10 CFR 50.72 is discussed below in Unresolved Item 50-275/91-01-01.

14. Open Item Followup (92703)

a. Inadequate Determination of Reportability Of Licensee-Identified Fire Protection Deficiencies (50-275/91-01-01), Open

This open item follows ongoing actions by the licensee to review safe shutdown circuit separation and other fire protection requirements. As a result of this effort, eight deficiencies have been identified which the licensee considers outside design basis. The licensee reported four of the items with 1-hour non-emergency reports, discussed earlier in the Follow-up of Licensee Event Reports section of this inspection report. However, the licensee determined that the other four conditions were not reportable, because they were of low safety significance. The inspector concluded that three of those items are significant to safety, and meet the requirements of 10 CFR 50.72 to perform a one-hour non-emergency report to the NRC. These are as follows:

(1) Auxiliary Saltwater Pump and Associated Ventilation Circuitry

The licensee identified that circuits from both of the auxiliary salt water (ASW) pumps, as well as circuits of the associated ventilation systems, did not have the required three-hour fire barrier, although they were located in the same fire area. The redundant circuits are on opposite sides of a vault, in the same fire area. There is no area-wide suppression or detection. However, combustible loading near the circuits is light, and the main combustible loading in the fire

area, the circulating water pump oil supply, has a cardox suppression system in a partially enclosed area, and is at a slightly lower elevation. Also, smoke detectors are installed at the ASW pump vault entrance.

The licensee considers the likelihood of a fire in the area which would travel around the vault to destroy both trains to be unlikely.

(2) Diesel Generator Emergency Stop and CO_2 Switch Thermolag Enclosures

Background: Both the EDG emergency stop switches and the Cardox actuation switches, each of which can disable an EDG, were enclosed in Thermolag without the required structural support for this type of fire barrier. On November 15, 1991, the licensee recognized the deficiency, and initiated work to correct the fire barrier.

Removal of Fire Barrier: After portions of the inadequate fire barrier were removed during corrective actions, technicians stopped work because materials were not available to finish the job. The circuits were left without a fire barrier, and without an evaluation of the safety of the condition. The licensee later recognized the removal of the fire barrier.

The CO_2 switches are separated by less than three feet. The EDG emergency stop switches are separated by about 20 feet. Hourly fire watches have been in place since commercial operation. The combustible loading of the area is light, and suppression, but not detection, is installed. These switches control redundant EDGs used for safe shutdown, and therefore are not in compliance with Appendix R.

The licensee considers that the basis for reportability is Generic Letter 86-10, requiring postulation of only a single spurious actuation in a given fire area, since the failure mode is a hot short. The licensee considers that, according to GL 86-10, a fire near the unprotected EDG or CO_2 switches would result in only one spurious actuation, and therefore disable no more than one of the three EDGs. Therefore, the licensee considers that even without fire wrap enclosures, the plant design basis has been met, and therefore the condition is not reportable.

The inspector noted that the rationale above would imply that no circuit separation deficiency involving hot short vulnerability would be reportable.

(3) Power Operated Relief Valve and Auxiliary Spray Valve Circuitry

The licensee determined that safe shutdown equipment required for transition from hot shutdown to cold shutdown may be vulnerable to fire damage if a fire occurs in containment or in

the motor generator set room. Specifically, circuits for the PORV and auxiliary spray valves do not have required protection in four fire areas, one being containment.

Combustible loading in the areas outside containment consists mostly of cable. Two areas are provided with detection and automatic suppression, and the other two areas (one being containment) have detection only, and PORV and auxiliary spray cables routed in metal conduit. All areas except containment have had hourly fire watches.

The licensee considers that the vulnerability would have been recognized, and repairs could have been successfully developed using similar temporary jumper procedures while the plant was in hot shutdown, before attempting transition to cold shutdown.

For each of these above conditions outside design basis, the inspector considers that the lack of appropriate circuit separation, and the need for previously unidentified operator actions, are outside the design basis. Therefore, this appears to be a violation of the requirements to make a 1-hour non-emergency report pursuant to 10 CFR 50.72.(b)(2)(ii)B (50-275/92-20-04). Continuing followup of the licensee's program to identify Appendix R deficiencies and evaluation of the significance of the findings will be tracked under Unresolved Item 50-275/91-01-01.

b. Corrosion of Outdoor Components (50-323/89-21-05), Closed

This item was opened to follow the licensee's action concerning the corrosion of components in outdoor environments. As a result of the corrosion discovered on ASW and EDG fuel oil system piping, and the associated followup item 50-275/92-20-01, the licensee's actions concerning corrosion of outdoor components will be followed as part of the routine resident inspection activities associated with Unresolved item 50-275/92-20-01. Therefore, Followup Item 50-323/89-21-05 is closed.

c. Corroded Auxiliary Saltwater Train Crosstie Valves (Unresolved Item 50-275/90-30-02), Closed

This unresolved item addressed the degradation of the auxiliary saltwater (ASW) train crosstie valves due to corrosion and the licensee's failure to take adequate corrective actions to prevent recurring degradation.

The inspector reviewed the nonconformance report associated with this issue (NCR DC1-EM-009) and the licensee's design basis for the ASW valves.

The inspector noted that the licensee has taken action to ensure that the reliability of the ASW crosstie valves has improved. However, NCR DC1-EM-N009 did not address the timeliness of corrective action or missed opportunities. In addition, the inspector asked questions regarding the use of a non-safety related

actuator on a safety related valve. The licensee committed to address the questions, which will be reviewed in a future inspection.

History

Each unit has two ASW pumps and two ASW heat exchangers which supply normal and ultimate heat sink cooling for the component cooling water system. The two ASW trains are crosstied at the pump discharge. Each crosstie line has two normally open motor operated isolation valves (1-FCV-495, 1-FCV-496, 2-FCV-495, and 2-FCV-496). Between crosstie valves is a line which crossties the units. The unit crosstie valve 0-FCV-601 is normally closed.

The crosstie valves were designed as safety related for purposes of maintaining ASW system integrity. The crosstie valves are required in the Emergency Operating Procedures (EOPs) to be closed to isolate ASW trains in the event of the failure of the pressure boundary of one train. However, the licensee concluded in their design analysis that there is no design basis failure of one train which would require that the trains be isolated. Therefore, the crosstie valve motor operators were considered non-safety related.

On May 23, 1989, 1-FCV-496 would not close when operated from the control room and could not be manually operated due to excessive corrosion. A quality evaluation (QE, a lower level of non-conformance review) was initiated (when it was recognized that the EOPs required the valve to be operated) to provide root cause review and initiate corrective action (Inspection Report No. 50-275/89-14).

In June 1990, the licensee again discovered that the valve could not be manually operated. After an initial attempt to free the handwheel, the job was put on hold. In January 1991, the inspector noted the action request tag on the valve and questioned why maintenance had not been performed and whether the corrective actions following the May, 1989 event had been adequate.

The licensee was able to free the handwheel using lubrication and considerable force. Non-conformance report NCR-DC1-91-EM-09 was initiated to review this problem.

NCR-DC1-91-EM-09

The inspector reviewed non-conformance report (NCR) DC1-91-EM-09. The resolution of the NCR provided two corrective actions to prevent recurrence:

- The quarterly crosstie valve surveillance tests (STP V-3F1 and V-3F2) were revised to require that the handwheel be rotated.

- The frequency of preventive maintenance was increased.

These actions should increase the reliability of the crosstie valve operators. However, the inspector did not find any action which would have addressed the untimely licensee action to resolve the degradation of the operators.

* The NCR did not address why the QE initiated in 1989 did not provide for timely action to prevent recurrence. Inspection Report No. 90-30 stated that the NCR chairman would include a review of the 1989 QE in the NCR review.

* The NCR did not provide any administrative means to ensure that corrective maintenance would be performed in a timely manner.

  The inspector reviewed this issue with the individual in work planning responsible for establishing the priority of corrective maintenance. Since January 1991, the licensee has initiated two administrative procedures for ensuring that important equipment receives priority attention. Neither procedure was applied to the ASW crosstie valves.

  * The Equipment Control Guidelines, (Administrative Procedure A-58) required priority attention for equipment which was required for system operability but which was not specifically called out in the Technical Specifications. In 1991, the inspector was informed that the ASW system crosstie valves would be considered under this program.

  * The balance-of-plant reliability program (AP C-55) listed important non-safety related equipment that should receive quality review and priority assignment. The ASW crosstie valves were not included in this list.

* The NCR failed to address why an operations policy regarding the maintenance of equipment called out in Emergency Operating Procedures was not implemented. Operations Policy C-9, "Control of Safety Related Equipment Not Required By Technical Specifications," stated that this equipment would be treated the same as Technical Specification equipment.

The inspector discussed these findings with the licensee on July 10, 1992. Although the resolution of the NCR provided increased reliability of the ASW valve operators, it did not thoroughly address why they had not received higher priority attention. The licensee committed to review these issues.

<u>Design Analysis</u>

The inspector reviewed the crosstie valve operator design analysis. The inspector raised the following questions:

* FSAR chapter 3.6.1 discussed the moderate energy pipe crack analysis for the ASW system. It indicated that the ASW system could withstand a moderate energy pipe crack and that the consequences were mitigated by ASW pump room floor drains. The

inspector observed on a walk down that the room floor drains were small and only slightly larger in diameter than the ASW pump seal leakoff line hose which ran through it. The inspector also noted that the ASW Design Criteria Memorandum did not discuss design for a moderate energy pipe break.

* The inspector questioned whether an analysis had been performed to determine if the crosstie operators, which were not seismically qualified, could stroke to a non-conservative position during a seismic event. Additionally, he questioned whether this had been analyzed for other non-safety related operators on safety related valves.

* The inspector determined, through discussions with a licensee motor-operated valve specialist, that the auxiliary crosstie valve operator, with its torque and limit switch settings misadjusted, could not malfunction in a way which would breach the ASW pressure boundary. The inspector questioned if this was the case for other non-safety related operators on safety related valves.

The licensee indicated that these issues would be reviewed (Followup Item 50-275/92-20-05).

15. Information Meeting With the Independent Safety Review Committee (94600)

On June 25, the resident inspectors attended the meeting of the Independent Safety Review Committee in Arroyo Grande, CA. The purpose of attending the meeting was to ensure that the resident inspectors were aware of the issues discussed by the committee.

16. Management Meeting to Discuss Resolution of Nonconformance Report (NCR)

On June 22, 1992, members of licensee management met with NRC management representatives in the Region V Office to discuss their resolution of deficiencies involving qualification of equipment for an earthquake on the Hosgri fault. The following persons were in attendance:

Pacific Gas & Electric Company

W. Fujimoto, Vice President, Nuclear Technical Services
M. Tresler, Diablo Canyon Project Engineer
J. Tompkins, Nuclear Safety and Regulatory Affairs Director

NRC Region V

R. Zimmerman, Director, Division of Reactor Safety and Projects
S. Richards, Chief, Reactor Projects Branch
L. Miller, Chief, Reactor Safety Branch
P. Johnson, Chief, Reactor Projects Section 1
W. Ang, Project Inspector
D. Corporandy, Reactor Inspector

NRC Office of Nuclear Reactor Regulation (by phone conference)

H. Rood, Project Ma.ager
G. Bagchi, Chief, Structural and Geosciences Branch

The licensee representatives stated that the extensive review was including an update of documentation relating to Hosgri commitments to ensure document clarity and compatibility. They stated that the review, which would be completed by the end of 1992, had identified no findings which involved safety significance or which required plant modifications. A copy of the materials provided by the licensee during the meeting is enclosed with this inspection report.

17. Exit Meeting

An exit meeting was conducted on July 15, 1992, with the licensee representatives identified in Paragraph 1. 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 the inspection.

Enclosure: Copy of discussion materials provided by the licensee during the June 22, 1992 meeting (paragraph 16).

RELATED CORRESPONDENCE MFP Exhibit 134. 026.1432

194091

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684

Gregory M. Rueger
Senior Vice President and
General Manager
Nuclear Power Generation

'93 OCT 28

REISSUED
DATE 8-20-92 because Enclosure 2 was omitted

August 5, 1992

PG&E Letter No. DCL-92-179

50-275/323-OLA-2
I-MFP-134
"NOT ADMITTED"

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to Notice of Violation in NRC Inspection Report 50-275/92-16 and 50-323/92-16

Gentlemen:

NRC Inspection Report (Report) 50-275/92-16 and 50-323/92-16, dated July 7, 1992, contained a Notice of Violation citing one Severity Level IV violation regarding the incorrect use of chainfalls while lifting primary and secondary lids of a radwaste container. PG&E's response to the Notice of Violation is provided in Enclosure 1.

The Report also expressed a concern that the violation indicates a weakness in PG&E's control of lifting and rigging devices for heavy loads, particularly in light of a rigging problem last year involving a loss of offsite power. PG&E's response to this concern is provided in Enclosure 2.

Sincerely,

Greg Rueger

Gregory M. Rueger

cc: Ann P. Hodgdon
John B. Martin
Philip J. Morrill
Harry Rood
CPUC
Diablo Distribution

DCO-92-MM-N034

Enclosures

1042S/85K/PGD/2237

(3) is a complicated lifting task. The tailboard included communications, crane operations, rigging in accordance with Maintenance Procedure (MP) M-50.23, "Loading Pre-loaded Liners into the NUPAC 10-142 Radwaste Shipping Cask," and ALARA. A Mechanical Maintenance (MM) foreman supervised this rigging activity while the radioactive material was being placed in the cask and until the rigging was attached to the cask lids, at which time he left.

The cask lids were initially lifted by three slings and placed on the cask. The clearance between the cask and the cask primary lid was very tight and required some alignment. In an attempt to align the cask primary lid, the rigging crew decided to change the rigging to two chainfalls and a sling. The rigging crew then mistakenly chose one-ton chainfalls, rather than two-ton chainfalls, which would be required to lift the 7,330 pounds load. The decision by the rigger to use one-ton chainfalls was based on his recollection that the lids weighed less than 6000 pounds, for which one-ton chainfalls would have been adequate; this, in fact, was only approximately the weight of the cask primary lid. The lid was then raised approximately two inches to remove wooden blocks that had been installed to support the lid, then lowered using the chainfalls to level the load.

PG&E's investigation concluded that the cause of this incident was personnel error. The seating of the primary cask lid using chainfalls was: (1) outside of the job scope discussed on the pre-job tailboard; and (2) in violation of AP C-702, "Rigging and Load Handling." PG&E policy dictates that when activities are required which are outside the scope of those discussed in the pre-job tailboard, they should be stopped and another tailboard conducted with the foreman involved. A contributing cause was weakness of rigging instructions in MP M-50.23, which does not provide guidance for manipulating the load in place and subsequently seating the cask lid.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

The MM general foreman discussed with the responsible foreman the Plant Manager's previous policy memo regarding tailboard requirements. This policy emphasizes stopping work when difficulties are encountered and reviewing the steps to be taken to adequately complete the job. The MM general foreman conducted a meeting with MM craft personnel stressing the importance of tailboards and stopping work when outside the scope of a tailboard.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

The Maintenance Services Manager will discuss industrial safety with the riggers to further emphasize the importance of proper rigging, personnel safety practices, and the stopping of work when required activities are outside the pre-job tailboard scope.

MP M-50.23 will be revised to enhance the steps to be taken in the preplanning and control of lifting and rigging activities to give specific guidance for manipulating loads and seating lids on casks to ensure that the correct equipment is used on the job.

Quality Control will evaluate in-process rigging of heavy loads.

ENCLOSURE 2 194091

REPLY TO NRC CONCERN REGARDING WEAKNESS IN
CONTROL OF LIFTING AND RIGGING DEVICES FOR HEAVY LOADS

NRC Inspection Report 50-275/92-16 and 50-323/92-16, dated July 7, 1992, expressed a concern that the Notice of Violation indicates a weakness in PG&E's control of lifting and rigging devices for heavy loads, particularly in light of a rigging problem last year involving a loss of offsite power (LOOP).

PG&E's understanding of this concern is whether the violation may have any commonality to the March 1991 LOOP event, which was caused by a mobile cra... boom that came too close to the 500 KV lines. PG&E's investigation of the 1991 LOOP event determined that it was caused by personnel errors made by the crane operator and foreman, in that they did not follow accident prevention rules and did not recognize electrical safety issues during job planning and execution. As described in DCL-91-079, dated April 8, 1991, corrective actions taken included:

- Training appropriate plant and construction personnel on the electrical safety portions of PG&E's accident prevention rules
- Issuance of a memorandum by the Plant Manager reemphasizing the importance of conducting thorough tailboards

PG&E understands and agrees with the NRC concerns regarding the importance of proper crane operation. However, PG&E believes that the radwaste container rigging violation does not represent a weakness in our program for lifting and rigging of heavy loads program. This belief is based on the following:

- DCPP rigging crews are adequately trained on personnel safety on rigging.
- An extensive pre-job tailboard was conducted for the radwaste container activity, which included a discussion on rigging.
- The foreman was directly involved in the job during the period when he considered that critical activities were being performed.
- The 1991 LOOP event was caused by personnel failing to understand the implications of crane operations on plant safety. The evolution of adjusting the cask lid using chainfalls, while not in compliance with procedures, did not present a threat to personnel safety. If the chainfalls had failed, the lid would have dropped a maximum of two inches and could not have slipped off the lip of the container or affected the stability of the container. In addition, there was no potential for plant equipment to be adversely affected.

In summary, PG&E believes that the LOOP event does not have any commonality with the current rigging incident. However, as discussed in the corrective steps of Enclosure 1, PG&E will use this violation of plant procedures to further reemphasize management's expectations.

MFP Exhibit 141

U. S. NUCLEAR REGULATORY COMMISSION

RELATED CORRESPONDENCE

REGION V

'93 OCT 28 P6:54

Report Nos. 50-275/92-13 and 50-323/92-13

Docket Nos. 50-275 and 50-323

License Nos. DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

50-275/323-OLA-2
I-MFP-141

Facility Name: Diablo Canyon Units 1 and 2

Meeting at: San Luis Obispo, California

"NOT ADMITTED"

Meeting Conducted: April 2, 1992

Report Prepared by: FOR
M. H. Miller, Resident Inspector

4-15-92
Date Signed

Approved by: FOR
P. H. Johnson, Chief
Reactor Projects Section 1

4-15-92
Date Signed

Summary: An announced periodic management meeting was held to discuss recent Diablo Canyon events and issues, and to review progress of licensee programs.

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PDR ADOCK 05000275
Q PDR

DETAILS

1. Meeting Attendees

   a. Licensee Attendees

      R. Anderson, Manager, Nuclear Engineering and Construction Services (NECS)
      M. Angus, Manager, Technical Services
      J. Blakley, Sr. Licensing Engineer, Nuclear Safety Assessment and Regulatory Affairs (NSARA)
      J. Castner, Regulatory Compliance
      M. Davido, Senior Engineer, NECS
      R. Domer, Vice President, General Engineering and Construction
      W. Fujimoto, Vice President, Nuclear Technical Services
      J. Gisclon, Acting Manager, Nuclear Operations Support
      W. Goelzer, System Engineering
      T. Grebel, Supervisor, Regulatory Compliance
      B. Giffin, Manager, Maintenance Services
      K. Herman, Supervisor, Instrumentation and Controls Engineering
      J. Hoch, Manager NSARA
      P. Lang, Senior Engineer, Quality Control
      T. Leserman, Nuclear Operations Support
      N. Malenfant, Corporate Communications
      T. Nelson, Nuclear Operations Support
      H. Phillips, Director, Electrical Maintenance
      J. Phipps, Systems Engineering
      R. Powers, Director, Mechanical Maintenance
      G. Rueger, Sr. Vice President, Nuclear Power Generation
      J. Sexton, Manager, Quality Assurance
      J. Shiffer, Executive Vice President
      J. Shoulders, Onsite Project Engineering, NECS
      D. Sokolsky, Nuclear Regulatory Affairs
      H. Thailer, Supervisor, Piping Engineering, NECS
      J. Tompkins, Director, NSARA
      J. Townsend, Vice President, Diablo Canyon Operations
      M. Tresler, DCPP Project Engineer
      R. Webb, NCES Engineering

   b. NRC Region V Attendees

      J. Martin, Regional Administrator
      L. Miller, Chief, Reactor Safety Branch
      M. Miller, Resident Inspector
      P. Morrill, Chief, Reactor Projects Section 1
      K. Perkins, Deputy Director, Division of Reactor Safety and Projects
      R. Scarano, Director, Division of Radiation Safety and Safeguards
      H. Wong, Senior Resident Inspector

c. NRC Headquarters Attendees

C. Regan, Assistant Project Manager, Project Directorate - V
H. Rood, Project Manager, Project Directorate - V

d. Other Attendees

Jeff Neal
June Von Ruden, Mothers for Peace

2. Details

Mr. Martin opened the meeting, stating that this was a periodic meeting to review topics of general interest and concern. He observed that several management meetings had been conducted at or near the Diablo Canyon site, and future meetings would be conducted at locations open for public attendance.

a. Containment Fan Cooler Unit Backdraft Dampers

PG&E presented their evaluation of recent containment fan cooler unit (CFCU) problems. Several of the CFCUs were found to have backdraft dampers that did not fully close when the fan was secured. This event is described in Licensee Event Report 50-275/91-19. PG&E also demonstrated a mechanical model of a backdraft damper to illustrate the various technical concerns.

Mr. Giffin noted that a contributing cause of inadequate maintenance of the CFCUs, which led in part to the problems, was underestimating the safety significance of the backdraft dampers. He added that during the troubleshooting process, although there was a concern that the dampers were open, no one initially thought to verify that the dampers would fully close when the associated fan was shut down. Mr. Morrill commented that in meetings with PG&E in February 1992, the NRC had urged visual verification to determine if CFCU counter rotation was occurring.

Mr. Rueger stated that the NECS organization was involved early in the CFCU concerns. This was due to processes put in place after issues concerning Regulatory Guide 1.97 occurred in late 1991. Mr. Fujimoto added that a methodology to establish an integrated problem response team had been established. A team had been formed and had met to resolve the CFCU issues.

The NRC questioned the licensee regarding why indications of broken bolts on backdraft dampers in March of 1991 were not adequately followed up. Mr. Perkins considered that the system engineer should have been involved in determining the cause of broken bolts since system problems may have been the root cause. In addition, management should better communicate expectations to system engineers to identify system initiated problems and the need to evaluate system history. Mr. Townsend agreed that system

engineering has the responsibility for tracking the history of these kinds of problems, however he felt that the component engineers should have resolved the cause of the broken bolts.

Mr. Fujimoto noted that, after evaluation of industry and historical experience, the integrated problem response team identified that adequate safety margin remained in the dampers, in that the CFCUs contained around 800 bolts, and that only about 20 had been found broken.

Mr. Martin observed that the March 1991 failure to evaluate the broken bolt issue illustrated a lack of basic engineering instincts. Mr. Martin closed the discussion of this issue by stating that the attitude should be that if any bolts are broken, there is a problem. He restated the NRC concern that licensee management needed to communicate the right expectations for resolving problems to all engineering groups and to organizations performing the quality assurance functions.

b. Feedwater Pump Trip

The licensee has experienced several feedwater pump problems due to the failure of an associated control system power supply. The licensee presented a discussion of technical and historical information concerning this issue. Mr. Rueger stated that PG&E may have been too narrowly focused on the issue, causing PG&E to fix the existing equipment, rather than to question the adequacy of the design after repeated failures. Mr. Fujimoto noted that since the equipment had been redesigned in February, 1989, there was a tendency to continue to try to make the new design work, rather than reassess the design.

Mr. Martin observed that it was not typical of a strong engineering organization to wait for several failures to fix a deficient design, particularly in the case of these failures, which resulted in challenges to operators and the plant. He noted that the December 3, 1991, failure should have raised serious concerns, and should have been dealt with more forcefully. Each action PG&E took may have appeared reasonable when considered individually, but not in perspective with the whole issue. Although these particular components were not safety-related, there is a need to come to terms with timely corrective action for these situations before problems arise with higher safety significance.

Mr. Rueger agreed, noting that he had used this issue as an example of an area requiring improvement.

c. Equipment Unavailability

The licensee presented summaries of availability data for key safety systems. Data indicated that system availability at Diablo Canyon was in the highest quarter of the industry.

d. Design Basis Document Program

Mr. Tresler presented the status of this program, and noted that the documents were being used and updated by individuals throughout the organization Mr. Martin stated that retention of design basis information was very important, particularly when considering the loss of knowledge of the plant design due to personnel losses.

e. Individual Plant Examination (IPE)

Mr. Gisclon presented the status and results of the program. The licensee confirmed that actual system availability data was being factored into the IPE. As a result of identifying principle sources of risk, plant improvements have been made which increase plant safety. In response to NRC questions, PG&E noted that changes had been made to the preventive maintenance program, and shut down risk was being examined through an EPRI study.

Mr. Martin asked if PG&E was communicating with industry concerning risks of mid-loop operations. Mr. Townsend replied that PG&E has taken an active part in industry meetings discussing the risks of mid-loop operations.

f. Piping Erosion/Corrosion Control

Mr. Martin expressed concern that many industry erosion/corrosion prediction and monitoring programs were quite extensive, but relied on computer programs which had limiting assumptions. He questioned how PG&E was addressing the limitations of industry computer codes.

Mr. Shiffer replied that PG&E was actively dealing with the issue. PG&E does not rely on only one source of expertise or analysis, but rather on industry experience, Diablo Canyon experience, and EPRI computer programs. PG&E has identified situations where computer algorithms do not correlate with field measurements.

3. Conclusion

Mr. Shiffer stated his concern that this meeting covered many of the same programmatic issues discussed in past meetings and indicated his understanding that engineering needs to more quickly resolve indications of problems with systems. He also noted that the system engineers had many examples of success to contrast with the problems discussed in this meeting.

Mr. Martin stated that there was a need to work on basic engineering instincts and that the areas discussed may be representative of problems which have not yet been discovered. Of particular concern are problems where everyone involved appeared to do their job, but the problem was

not successfully resolved because of lack of overall perspective. Mr. Martin concluded that management expectations should direct technical organizations to seek out these types of problems. Mr. Shiffer agreed.

Mr. Martin stated that items on the agenda which were not covered in this meeting should be covered in the next management meeting. The meeting was adjourned.

50-275/323-OLA-2 I-MFP-142 MFP EXHIBIT 142

26-286 (3/89)

"NOT ADMITTED"

RELATED CORRESPONDENCE

QAP-15.B
Revision: 10/24/90
ATTACHMENT A
Page 1 of 3
Effective Date: 12/31/90

NONCONFORMANCE REPORT

'93 JUL 28 P6:54

INITIATION

1. NCR No. Plant DC1 - Year 91 - Dept. II - Number N045 Rev. 1

2. Quality Problem Report No. (if applicable)

3. Item/Activity S/G 1-3 Level Control

4. Reference A0228887

5. Description of Nonconformance:
Unit 1 Reactor Trip due to P-14 actuation (High Level S/G 1-3). This condition in considered a nonconformance by Senior Management in accordance with OAP 15.B, paragraph 2.1.2.

6. Initiated By (p/s)	7. Organization	8. Date	9. Designated Mgmt. (p/s)	10. Organization	11. Date
RC Washington	I&C	04/24/91	BW Giffin	APM Maint. Svcs.	04/24/91

TECHNICAL REVIEW

ANALYSIS

12. NCR Evaluation Attached on the NCR Text Continuation Sheets
I. Plant Conditions
II. Description of Problem
III. Cause of Problem
IV. Analysis of Problem
V. Corrective Actions
VI. Additional Information

13. Trend Codes	Other	14. Estimated Completion Date	15. Responsible Organization
X X - 0 C 7 - -	N/A	07/01/91	I & C

REPORTABILITY

16. 10CFR50.73 Reportable	17. Potentially 10CFR21 Reportable	18. 10CFR50.9 Reportable	19. Reference Other Reportable, if app.
Yes [X] No [ ]	Yes [ ] No [X]	Yes [ ] No [X]	N/A

20. Basis 50.73(a)(2)(iv) refer to attached

Initial Report	21. Time Limit	22. Method	23. Notified By	24. Time	25. Date
	4 hours	telephone	Shift Supervisor	1015 PDT	04/23/91

Followup Report	26. Required	27. Time Limit	28. LER No.	29. Date
	Yes [X] No [ ]	30 days	1-91-007-00	~~5/23/91~~ 5/21/91

30. Other Agencies Notified none

GROUP

31. Remarks

APPROVAL

	Date		Date
32. Chairman (p/s) WGCrockett	33. 6-20-91	40. Other (p/s)	41.
34. QA (p/s) CTLewis C. T. Lewis	35. 6/21/91	42. Other (p/s)	43.
36. QC (p/s) JEBonner	37. 6-21-91	44. Other (p/s)	45.
38. Reg. Comp. for DCPP NCRs only (p/s) DDMalone	39. 6/21/91	46. Other (p/s)	47.

PSRC Review	48. Meeting Date: 7/3/91	49. GONPRAC Notification Date: 6/21/91

Corrective Action	50. Complete - TRG Chairman (p/s) WD Crockett	51. Date 7/18/91	52. QA Verification by (p/s)	53. Date

Distribution

NPG
Manager, QA
Plant Manager, DCPP
GONPRAC Secretary
Engineering

Materials
Station/Hydro Construction
TES
Authorized Inspector, if applicable_____

PSRC Secretary_____
Initiator_____
Appropriate QC_____
Other_____
Other_____

UNIT 1 FEEDWATER TRANSIENT 4-23-91
SUMMARY OF FEEDWATER SYSTEM RESPONSE

The initiating event for the transient was a failure of operational amplifier U1 in the 'track and hold board' of the Lovejoy speed control system for Main Feedwater Pump 1-1. MFW pump 1-1 rapidly increased speed to approximately 6100 rpm, and stabilized. As a result of the rapid increase in feedwater flow, Digital Feedwater Control System responded by backing MFW pump 1-2 down, and closing down on reg valves FCV-510, FCV-520, and FCV-540. The bypass valves for these three Steam Generators were in manual and closed. FCV-530 was in manual with its bypass valve open and in AUTO. DFWCS closed the bypass valve for Steam Generator 1-3, but this did not significantly reduce total feedwater flow to the SG. Consequently, both feedwater flow channels for SG 1-3 had signals that were higher than the normal range due to the excessive flow from MFW pump 1-1. DFWCS interpreted this input as a failure of two feedwater flow channels, and a "fail to manual" signal for FCV-530 and FCV-1530 was initiated. (This also brought in an annunciator, PK09-10, DIGITAL FEEDWATER CONTROL SYSTEM FAIL TO MANUAL). However, since FCV-1530 was closed, and FCV-530 was already in manual, this did not affect the transient.

As MFW pump 1-2 reduced speed due to the DFWCS signal, MFW pump 1-1 discharge pressure decreased. The operators responded to the transient by manually increasing MFW pump 1-2 demand, and manually decreasing turbine load to 50% power (In Turbine Manual on DEH), which caused a slight increase in MFW pump 1-1 discharge pressure. As SG 1-3 level was rapidly increasing, the operators manually closed off on FCV-530. This caused the discharge pressure on MFW pump 1-1 to spike up to the trip setpoint, and MFW pump 1-1 tripped. As a result of MFW pump 1-1 tripping, all SG levels decrease rapidly. DFWCS responds by opening FCV-510, FCV-520 and FCV-540. MFW pump 1-1 is relatched from VB3, and the demand signal is increased using the startup station. The pump responds to the startup station signal. However, as feedwater flow increases, and the SGs swell from the rapid power decrease, DFWCS closes off on FCV-510, FCV-520 and FCV-540 again, resulting in another trip of MFW pump 1-1 on high discharge pressure. MFW pump 1-1 is relatched again, and the demand is brought up to a minimum on the startup station (approximately 3000 rpm).

All SGs continued to swell from the previous excessive feedwater flow, the SG levels approached the Hi-Hi level trip (P-14, 2/3 levels > 67% on 1/4 SGs). Plant operators took manual control of the reg valves to reduce flow. SG 1-3 level increased more rapidly than the others (possibly because it was overfed more than the others), and the trip setpoint was exceeded in spite of the fact that feedwater flow had been reduced by manually closing FCV-530. P-14 actuated, causing a Main Turbine trip, trip of both MFW pumps, and Reactor trip. The motor driven AFW pumps started on loss of both MFW pumps.

UNIT 1 FEEDWATER TRANSIENT 4-23-91
SUMMARY OF FEEDWATER SYSTEM RESPONSE

The initiating event for the transient was a failure of operational amplifier U1 in the 'track and hold board' of the Lovejoy speed control system for Main Feedwater Pump 1-1. MFW pump 1-1 rapidly increased speed to approximately 6100 rpm, and stabilized. As a result of the rapid increase in feedwater flow, Digital Feedwater Control System responded by backing MFW pump 1-2 down, and closing down on reg valves FCV-510, FCV-520, and FCV-540. The bypass valves for these three Steam Generators were in manual and closed. FCV-530 was in manual with its bypass valve open and in AUTO. DFWCS closed the bypass valve for Steam Generator 1-3, but this did not significantly reduce total feedwater flow to the SG. Consequently, both feedwater flow channels for SG 1-3 had signals that were higher than the normal range due to the excessive flow from MFW pump 1-1. DFWCS interpreted this input as a failure of two feedwater flow channels, and a "fail to manual" signal for FCV-530 and FCV-1530 was initiated. (This also brought in an annunciator, PK09-10, DIGITAL FEEDWATER CONTROL SYSTEM FAIL TO MANUAL). However, since FCV-1530 was closed, and FCV-530 was already in manual, this did not affect the transient.

As MFW pump 1-2 reduced speed due to the DFWCS signal, MFW pump 1-1 discharge pressure decreased. The operators responded to the transient by manually increasing MFW pump 1-2 demand, and manually decreasing turbine load to 50% power (In Turbine Manual on DFH), which caused a slight increase in MFW pump 1-1 discharge pressure. As SG 1-3 level was rapidly increasing, the operators manually closed off on FCV-530. This caused the discharge pressure on MFW pump 1-1 to spike up to the trip setpoint, and MFW pump 1-1 tripped. As a result of MFW pump 1-1 tripping, all SG levels decrease rapidly. DFWCS responds by opening FCV-510, FCV-520 and FCV-540. MFW pump 1-1 is relatched from VB3, and the demand signal is increased using the startup station. The pump responds to the startup station signal. However, as feedwater flow increases, and the SGs swell from the rapid power decrease, DFWCS closes off on FCV-510, FCV-520 and FCV-540 again, resulting in another trip of MFW pump 1-1 on high discharge pressure. MFW pump 1-1 is relatched again, and the demand is brought up to a minimum on the startup station (approximately 3000 rpm).

All SGs continued to swell from the previous excessive feedwater flow, the SG levels approached the Hi-Hi level trip (P-14, 2/3 levels > 67% on 1/4 SGs). Plant operators took manual control of the reg valves to reduce flow. SG 1-3 level increased more rapidly than the others (possibly because it was overfed more than the others), and the trip setpoint was exceeded in spite of the fact that feedwater flow had been reduced by manually closing FCV-530. P-14 actuated, causing a Main Turbine trip, trip of both MFW pumps, and Reactor trip. The motor driven AFW pumps started on loss of both MFW pumps.

NCR DC1-91-TN-N045
Unit 1 Reactor Trip from Turbine Trip Due to P-14 (S/G 1-3)

I. Plant Conditions

Unit 1, was in Mode 1 (Power Operation) at 100% percent power. All main feedwater (MFW) control components in automatic except Steam Generator (SG) 1-3 feedwater regulating val-- (FCV-530) which was in manual control mode with feedwater regulating bypass valve (FCV-1530) in automatic control mode. All other SGs feedwater regulating bypass valves were manually closed.

II. Description of Event

A. Event:

Each of the below listed events occurred on April 23, 1991, at:

08:34:07 Control Room receives a "MFW Pp 1-1 Oil Filter dP High alarm. This was the first indication of a problem with the 1-1 MFW Pump. FCV-530 was in MANUAL prior to and during the event due to earlier valve sticking problems.

08:34:18 The following alarms are received in the Control Room:
DFW Control System Trouble
MFW Pump 1-1 Thrust Bearing Wear
MFW Pump 1-1 Temp P-250

08:38:11 "Digital Feedwater Control System fails to MANUAL" alarm received due to Bypass Valve FCV-1530 failing to the manual mode of operation. The high RPM of 1-1 MFW Pump with both FCV-530 and FCV-1530 in MANUAL causes the 1-3 SG to be over fed.

08:38:44 The 1-1 Main Feedwater Pump trips. Shortly before this time, operators begin running the Unit back to approximately half load in anticipation of a possible MFW Pump trip.

08:39:34 "Main Steam Line High Rad" alarm received in the control room.

08:39:50 Operators relatch the 1-1 MFW Pump to make it available should it be needed. The operator runs the RPM up to approximately 4000 RPM on the Startup Station.

08:40:37 "Pressurizer Low Pressure" alarm received

08:41:17 "Main Steam Line High Rad" alarm clears.

08:41:23	MFW Pump 1-1 trips again. Shift Foreman approves the turbine to be relatched one additional time. Turbine RPM is run up to approximately 3500 RPM.
08:44:03	"Pressurizer Low Pressure" alarm clears.
08:46:11	The level in the 1-3 SG reaches the P-14 setpoint. The main turbine and both MFW Pump turbines trip as required. Reactor power is above the P-9 setpoint and the Reactor trips from the main turbine trip as designed.
08:46:12	"Seismic Inst Sys Strong Motion - Terra Tech" alarm received.
08:46:13	Both motor driven Auxiliary Feedwater pumps start on the trip of both main feedwater pumps.
08:46:14	"Pressurizer Low Pressure" alarm received.
08:46:20	"Low Tavg" alarm received. Main Feedwater Isolation automatically initiated.
08:46:41	Unit Trip initiated.
08:46:52	"Lo-Lo Tavg" alarm received. Plant cooldown rate appears to be in excess of normal.
08:48:20	"Pressurizer Low Pressure" alarm received. Pressure at the reactor trip setpoint of 1950 psig.
08:49:14	Auxiliary Feedwater Pump 1-1 auto starts on low steam generator level contributing to the cooldown. Operators manually close the main steam isolation valves due to the plant cooldown. Shift Foreman gives the order to break condenser vacuum due to the loss of gland sealing steam once the MSIVs are closed.
08:50:43	Operators shut down the 1-1 Auxiliary Feedwater Pump to reduce total AFW flow the steam generators.
08:58:34	Lo-Lo Tavg alarm clears as the plant heats up following the isolation of the main steam lines.
09:03:18	Operators shut down the 1-1 and 1-3 Reactor Coolant Pumps to minimize heat input into the primary system. RCS temperatures have returned to the no-load setpoint.
09:13:04	Operators complete electrical power alignments to backfeed the

Unit from the 500 KV system. Primary system stable at normal operating temperature and pressure.

On April 23, 1991, at 1015 PDT, the 4-hour non-emergency report required by 10 CFR 50.72(b)(2) was made via phone to NRC Operations Center.

B. Inoperable Structures, Components, or Systems that Contributed to the Event:

FCV-530 was maintained in the manual mode of control due to known operational problem (the valve would oscillate at full load).

C. Dates and Approximate Times for Major Occurrences.

1. On April 23, 1991, at 0846:11 PST: Event date; Unit 1 Reactor Trip from Turbine Trip.

D. Other Systems or Secondary Functions Affected:

Steam dump valve PCV-2 was found with the valve stem separated from the plug inner shaft. This problem has been referred to the Steam Dump Valve "HIT" Team for further evaluation and resolution. (See DCO-90-TI-N091).

E. Method of Discovery:

The event was immediately known to plant operators due to alarms received in the control room.

F. Operators Actions:

Plant operators responded as described above in Section I, Event.

G. Safety System Responses:

Upon receipt of the P-14 (high steam generator level) coincident 2 out of 3 on SG 1-3, the SSPS initiated a Turbine Trip, which coincident with P-9 (power above setpoint) initiates a Reactor Trip. The P-14 also tripped all main feedwater pumps and tripped closed all main and bypass feedwater regulating valves. Both motor driven auxiliary feedwater pumps started and delivered water to all SGs. Following the trip control operators identified an unusual cooldown and manually closed the Main Steam Isolation Valves (MSIV).

III. Cause of the Event

A. Immediate Cause:

FWP 1-1 pump speed rapidly increased to approximately 6100 RPM. This sudden increase in feedwater pump speed initiated a feedwater transient resulting in a SG 1-3 high level P-14 actuation causing a turbine trip and reactor trip.

B. Root Cause:

A component failure (operational amplifier U1) on the "Track and Hold" circuit board of the Lovejoy feedwater pump control system caused the pump speed to increase until "low selected" at the preset (6100 RPM) level of the manual start up station. This sudden increase in feedwater pump speed overfeed steam generator 1-3 due to the selected mode of valve control resulting in a high level P-14 actuation causing a turbine trip and reactor trip.

C. Contributory Cause:

Feedwater regulating valve FCV-530 was in manual during this event and therefore was unable to respond as anticipated by the DFWCS (and plant operations personnel).

IV. <u>Analysis of the Event</u>

A. Safety Analysis:

The initiation of a turbine trip (and resultant reactor trip) due to high steam generator level is a FSAR Condition II fault previously evaluated in Chapter 15.2.10, "Excessive heat removal due to feedwater system malfunctions." This event is bound by the analysis presented which evaluates common feedwater control system malfunctions such as feedwater valve control malfunction or valve failure.

"The reactivity insertion rate that occurs at no-load following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition. Also, the DNBRs encountered for excessive feedwater addition at power are well above the safety analysis limit DNBR values."

Based upon the previous FSAR analysis the health and safety of the public were not adversely effected, and there were no adverse consequences or safety implications resulting from this event.

B. Reportability:

1. The described event is nonconforming in accordance with section 2.1.2. of QAP 15B.

2. This event is reportable under 10 CFR 50.72 and 50.73(a)(2)(iv) in accordance with NUREG 1022.

3. Reviewed in accordance with NUREG 0302 and determined not to require a 10 CFR 21.21 report.

4. This event is not reportable under 10 CFR 50.9, since this event will be reported in accordance with 10 CFR 50.73(a)(2)(iv).

5. This event does not require an INPO Network entry.

V. Corrective Actions

A. Immediate Corrective Actions:

Plant management initiated Event Response Plan 91-04 to identify and document the immediate corrections necessary for this event, therefore ERP 91-04 is entered as part of this NCR. ERP items of note are; repair of the FWPT control "track and hold" board, repair of FCV-530 positioner and repair and testing of the steam dump valves.

B. Investigative Actions:

1. Provide additional information regarding sequence of events that lead to lovejoy failure.

RESPONSIBILITY: Jim Whitehead ECD: COMPLETE
Tracking AR: A0229188, AE 01# DEPARTMENT: PTES
Outage Related? No
JCO Related? No
NRC Commitment? No
CMD Commitment? No

2. Provide operational experience summary of Lovejoy failures and application of track and hold boards. Input based on NPRDS failure search provided by DCPP. Review and recommend replacement of the track and hold board with new and improved board.

RESPONSIBILITY: John Heffler ECD: COMPLETE
Tracking AR: A0229188, AE 02# DEPARTMENT: NECSIE
Outage Related? No
JCO Related? No
NRC Commitment? No
CMD Commitment? No

C. Corrective Actions to Prevent Recurrence:

1. Provide an Operations Incident Summary of the event.

RESPONSIBILITY: Steve Fridley ECD: COMPLETE
Tracking AR: A0229188, AE 03# DEPARTMENT: PGOM
Outage Related? No
JCO Related? No
NRC Commitment? No
CMD Commitment? No

D. Prudent Further Actions:

As a result of previous problems relating to the Lovejoy "track and hold" board upgraded circuit boards have been purchased, and upon resolution of questions regarding the configuration requirements for the new boards, will be installed during the next refueling outage. (Refer to AT EWR A0230541) Also, new digital regulation boards are being installed under DCP-J-45051/46051 to reduce calibration effort (decrease analog calibration setting difficulty).

The TRG further recommended to the DCPP and GO system engineer that a long term replacement for the Lovejoy speed control system be considered to improve overall plant reliability. (This is being pursued under funding provided by BLI A701A & A701B)

VI. Additional Information

A. Failed Components:

Lovejoy feedwater pump controller "track and hold" card operational amplifier U1.

B. Previous Similar Events:

On May 30, 1990, a near miss occurred due to a similar "track and hold" card failure as documented in AR A0193614.

C. Operating Experience Review:

1. NPRDS:

An NPRDS search revealed that similar occurrences have happened at Zion 2, LaSalle 2 and Indian Point 2.

2. NRC Information Notices, Bulletins, Generic Letters:

Not applicable.

3. INPO SOERs and SERs:

No vendor specific items were identified, however, the MFWP system performance improvement has been investigated by the Westinghouse Owners Group (WOG) in WCAPs 11125, 11126, 11135, 11156 and Trip Reduction and Assessment Program Task 2-5.

D. Trend Code:

Responsible group is the vendor, and the root cause is failure of operational amplifier U1 on the 'track and hold' board due to undetermined root cause (cause code XX-OC7).

E. Corrective Action Tracking:

The tracking action request is A0229188.

F. Footnotes and Special Comments:

None.

G. References:

1. Administrative Procedure (AP) A-105 Report for reactor trip of April 23, 1991.

2. Event Response Plan 91-04, Reactor Trip - April 23, 1991.

3. Final Safety Analysis Report Update, Chapter 15.2.10.

4. Initiating Action Request A0228887.

5. Licensee Event Report (LER) 1-91-007-00.

H. TRG Meeting Minutes:

The initial TRG convened April 29, 1991, and reviewed the actions taken as part of ERP 91-04. Further investigative actions were assigned to review possible causes of the MFWP 1-2 speed increase noted early in the event, to have NECS review the failures with the vendor and users. Plant operations department will initiate an operations incident summary regarding this event for review by all plant operators.

The TRG reconvened on 05/09/91, reviewed LER 1-91-007, finalized root cause, corrective actions and accepted further prudent actions.

I. Remarks:

50-275/323-OLA-2 MFP EXHIBIT 117 176574 026.1460
I-MFP-179
"NOT ADMITTED"

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

NSARA
1455Z
SEP 10 '91

RELATED CORRESPONDENCE

AUG 23 1991

'93 OCT 28 P6:54

		FYI	FYA
LCPP	- VP	☒	☐
~~HBPP~~	~~- MGR~~	☐	☐
NECS	- MGR	☒	☐
NOS	- MGR	☒	☐
NRA	- DIR	☒	☐
NSARA	- MGR	☒	☐
NPG	- VP ASST	☒	☐
NPG	- SR VP	☒	☐
QA	- MGR	☒	☐

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MEMORANDUM FOR: Thomas M. Novak, Director
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

FROM: Jack E. Rosenthal, Chief
Reactor Operations Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

SUBJECT: HUMAN FACTORS STUDY REPORT - DIABLO CANYON 1 (5/17/91)

On May 17, 1991, at 6:28 a.m., Diablo Canyon 1 tripped from 100% power because of an error by an instrumentation and controls technician. The technician took a nuclear instrumentation channel out of service with another channel already out of service, and this satisfied the necessary 2-out-of-4 trip logic. Following the reactor trip, multiple steam dump valves failed open causing an excessive cooldown and depressurization of the primary system, which initiated a low pressurizer pressure safety injection.

As part of the AEOD program to study the human factors aspects of operational events, a team was sent to the site May 29. The team leader was George Lanik of AEOD; other team members were Gene Trager of AEOD, and Harold Blackman and Bill Steinke of Idaho National Engineering Laboratory. The team was at the site for two days and gathered data from discussions, plant logs, strip chart recordings, and interviews of plant operators.

Enclosed is the report prepared by INEL of the results of the human factors study. Specific human performance aspects of this event are addressed in this memorandum.

Teamwork

This event provided an example of effective teamwork and factors contributing to effective teamwork. The control room crew worked quickly and effectively in responding to the trip and the safety injection, in spite of the fact that a normal member of the team was missing. The abnormal cooldown was identified and an appropriate response determined considering input from a number of team members. Decision making was not involved in terminating the safety injection, because that action was directed by the emergency operating procedure. The response was aided by team training in the use of the procedures.

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Shift Structure

The shift structure and manning were adequate to respond well to this event, primarily because of good teamwork. The control room crew members quickly assumed their emergency roles and made adjustments to perform the activities normally performed by the utility senior control operator (licensed SRO). The licensed control room operators felt their performance was adversely effected by the limited capabilities of the unlicensed assistant control operator, who does not receive reactor operator training and does not train with the crew on the simulator.

Human Factors of Surveillance Testing

A number of factors contributed to the error by the shift control technician that resulted in the reactor trip. The calibration procedure did not follow guidelines that would have made the error less likely, the technician had not completed training in self-verification, and the goal of completing the surveillance before shift change may have created a time-based stress. In addition, the technician was without direct supervision although still in training. This is another example of how factors such as procedures, training, stress, and supervision can adversely effect on-line surveillance testing.

Man-machine Interface

The control room annunciator system acknowledge circuit causes all blinking annunciator tiles to go to solid illumination and silences the alarm. There is pressure to silence the annunciator, because the sound can be irritating and distracting and can interfere with communications. Since the single acknowledge circuit effects all the alarms, there is an increased possibility that an incoming alarm may not be detected. Alternate annunciator system designs divide the alarms into groups that have separate audible signals and acknowledge circuits. San Onofre is considering a control room annunciator system redesign.

EOPs Complicated by Equipment Problems

Equipment problems can complicate the decision making and actions necessary to carry out an effective emergency response. However, equipment problems should be anticipated and provided for in emergency operating procedures and in training. This can help ensure effective operator performance.

Post Trip Event Review Process

At the conclusion of the event, the operators and other involved personnel were required to give written individual statements on what they recalled. However, the statements were sometimes quite terse, perhaps because they were written following shift turnover at 0800 am. The statements contained notes on observations, but did not comment on how the event might have been avoided or how the response might have been improved.

This report is being sent to Region V for appropriate distribution within the region.

Earl J. Brown for

Jack E. Rosenthal, Chief
Reactor Operations Analysis Branch
Division of Safety Programs
Office for Analysis and Evaluation
of Operational Data

Enclosure: As stated

cc: John Townsend, Station Manager
Diablo Canyon Nuclear Power Plant
Avila Beach, CA 93424

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EGG-HFRU-9476

TRIP REPORT:
ONSITE ANALYSIS OF
THE HUMAN FACTORS OF AN EVENT
AT DIABLO CANYON 1
ON MAY 17, 1991

(REACTOR TRIP AND SAFETY INJECTION)

ORVILLE MEYER

On-Site Analysis Team:
* George Lanik, NRC/AEOD
Eugene Trager, NRC/AEOD
Harold Blackman, INEL
William Steinke, INEL

* Team Leader

Published August 1991

Idaho National Engineering Laboratory
EG&G Idaho, Inc.
P. O. Box 1625
Idaho Falls, ID 83415

Prepared for the
Office for Analysis and Evaluation of Operational Data
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
Under DOE Contract No. DE-AC07-76ID01570

EXECUTIVE SUMMARY

At 6:23 a.m., on May 17, 1991, an instrument technician at Diablo Canyon 1 was completing the calibration of one of four power range nuclear instrument channels. He was attempting to complete the calibration before the shift turnover at 8:00 and inadvertently disconnected a fuse on a second channel rather than the channel under calibration. This initiated a reactor trip. The failures of six out of twelve steam dump valves (SDVs) to close caused the reactor coolant system to cool and depressurize rapidly which led to a safety injection (SI) initiation. The operators.responded promptly by closing the main steam isolation valves to stop the cooldown and by reducing the SI flow to prevent overpressurization of the reactor coolant system. As part of the AEOD program to study the human factors of operating events AEOD formed a team to conduct an onsite analysis. The team leader was George Lanik, AEOD/ROAB. Other team members were Eugene Trager, Jr., AEOD/ROAB, Harold Blackman, INEL, and William Steinke, INEL. The team was at the Diablo Canyon site on May 29 and 30, 1991.

Both units at Diablo Canyon were at 100% power on the morning of May 17 prior to the reactor trip. As designed, the reactor trip caused a turbine trip and this activated the steam dump control system to remove stored energy and decay heat to return the reactor average temperature to its no load valve. However, two of the twelve SDVs failed open due to separation of the actuator from the valve stem and four other SDVs had control circuit failures which left them partly open. The failures were such that the SDV position indicators in the control room indicated that these SDVs were closed. However, the operators deduced that there was excess steam flow and closed the main steam isolation valves (MSIVs).

The reactor coolant pressure continued to decrease and reached the SI setpoint (1850 psig) before the MSIVs were closed. The SI initiation isolated the letdown system from the reactor coolant system and initiated charging flow from the centrifugal charging pumps. The operators understood that the SI initiation was due to cooldown and shrinkage of the reactor coolant and not due to a loss of coolant. They therefore reduced the charging flow and re-

established reactor coolant letdown. The pressurizer pressure was prevented from reaching the setpoint for the power operated relief valves.

The analysis of this event disclosed that the operators' response was prompt and effective despite the equipment failures. Causal factors for this response were the abnormal and emergency procedures, training, and sound knowledge of reactor coolant system thermal-hydraulics. Their response was carried out through efficient teamwork even though the utility senior control operator was absent. Decision making was not involved in terminating the safety injection because that was directed by a step in the emergency operating procedures.

This was not the first event involving failures of the SDVs and coping with these anticipated failures has prompted the station to consider closing the MSIVs after a reactor trip whenever Tav decreases to 530°F. This could occur after most trips and would prevent use of the main condenser for decay heat removal.

Several factors contributed to the instrument technician error that resulted in the reactor trip. The calibration procedure did not follow human factors principles, e.g. providing a caution preceding steps that may trip the reactor, that would have made the error less likely, the technician had not completed training in self-verification, the goal of completing the calibration before shift change created a time-based stress, and the technician was without direct supervision although still in training.

The control room annunciator has a single acknowledge circuit rather than separate acknowledge circuits for different groups of main control panels which are found in other control room annunciator designs. This makes it more difficult for operators to silence the audible alarm while also assuring that they have not missed any incoming alarms.

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ACKNOWLEDGEMENTS

We express appreciation to the Diablo Canyon staff for their cooperation in providing information necessary to analyze the human factors of the operating event. We particularly thank the operators and instrument and control technicians who were on duty during the event for their cooperation during the interviews.

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CONTENTS

Figures

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ACRONYMS

ACO	assistant control operator
AEOD	Office for Analysis and Evaluation of Operational Data
AFW	auxiliary feedwater
CCP	centrifugal charging pumps
CO-1	Unit 1 control operator
CRA	control room assistant
EC[illegible]	emergency operating procedure
INEL	Idaho National Engineering Laboratory
MSIV	main steam line isolation valve
NRC	Nuclear Regulatory Commission
PPS	plant protection system
PWR	pr[illegible] water reactor
RCS	reacto[illegible]olant system
SCT	shift control technicians
SCO-1	senior control operator for Unit 1
SCO-2	senior control operator for Unit 2
SCT	shift control technician
SDV	ste[illegible] dump valve
SFM-1	Uni[illegible] shift foreman
SFM-2	Unit 2 shift foreman
SI	safety injection
SPDS	safety parameter display system
SS	shift supervisor
STA	shift technical advisor
Tav	average temperature
T-cold	cold leg temperature
T-hot	hot leg temperature
USCO	utility senior control operator

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1. INTRODUCTION

1.1 Purpose

The Nuclear Regulatory Commission, Office for Analysis and Evaluation of Operational Data (NRC/AEOD) formed a team to conduct an onsite analysis of the human factors of an operating event at Diablo Canyon 1 that occurred May 17, 1991. The event was initiated when the fuse for a power range nuclear instrument channel was inadvertently disconnected while another channel was in the test position. This coincidence made up the two-out-of-four logic that initiated a reactor trip from 100% power. The failures of six out of twelve steam dump valves (SDVs) to close caused the reactor coolant system (RCS), to cool and depressurize, which initiated a safety injection (SI). The operators promptly mitigated the transient and returned the plant to a stable, hot standby condition such that no pressure or temperature limits were exceeded and the pressure setpoints for the pressurizer power operated relief valves were not approached.

1.2 Scope

The analysis focused on the human factors aspects of the May 17, 1991, event including the causal factors for the disconnection of the fuse on the wrong nuclear instrument channel, which initiated the event and the subsequent actions of the control room operators. Data were acquired from instrument recordings, plant logs, discussions, and interviews with control room operators, technicians, and other station staff such as operations, maintenance management, and training instructors. Idaho National Engineering Laboratory (INEL) provided technical assistance for the onsite analysis as part of the AEOD program to study the human factors of operating events.

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1.3 On-site Analysis

The analysis team was at the Diablo Canyon site on May 29 and May 30, 1991. The team consisted of

- George Lanik, NRC/AEOD, team leader
- Eugene Trager, NRC/AEOD
- Harold Blackman, INEL, Human Factors Research
- William Steinke, INEL, Reactor Operations and Performance Evaluations.

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2. DESCRIPTION OF THE EVENT ANALYSIS

2.1 Background

The Diablo Canyon Power Plant is located on the Pacific Coast near San Luis Obispo, California. The plant consists of twin, 4-loop, Westinghouse pressurized water reactors (PWRs), each of which is rated at 1080 MWe nominal capacity. Unit 1 was placed in commercial operation in May 1985; Unit 2, in March 1986. Both units are operated from a common control room.

Both units were at 100% power on the morning of May 17, 1991. Surveillance test procedure STP I-2D had been performed on power range nuclear instrument channel N-41 of Unit 1, and a shift control technician (SCT) was preparing to remove test equipment and reconnect the high voltage and detector signal cables. The reactor trip bistables for channel N-41 were in the tripped positions. Before reconnecting the cables, the SCT had to remove the instrument power fuses from channel N-41 per procedure STP I-2D. Instead, he inadvertently disconnected one instrument power fuse momentarily from channel N-42. Since channel N-41 was already removed from service this made up the 2-out-of-4 coincidence in the plant protection system (PPS) logic, and the Unit 1 reactor tripped. The trip was recorded as caused by a high neutron flux signal at 6:28:38 a.m.

As designed, the reactor trip caused a turbine trip and it actuated the steam dump control system to remove stored energy and decay heat to return the reactor average temperature (Tav) to its no-load value. However, all of the steam dump valves (SDVs) did not reclose when Tav decreased to its no-load value. Two of the 12 SDVs failed in the fully opened position because the actuator mechanisms disconnected from the valve stems, creating a steam demand of approximately 8%. In addition, the controls for the actuators of four other SDVs failed, leaving those valves partially open. The failures were such as to leave the position indications in the control room for all six valves in the closed position such that the open condition of the six SDVs was not directly detectable by the control room operators. Reactor cooldown

continued below the no-load setpoint although the cooldown was at a reduced rate since the six operable SDVs closed.

The shrinkage of the reactor coolant from the cooldown caused a reduction in pressurizer water level and pressure. RCS letdown isolation was automatically initiated from low pressurizer level (17%) and a safety injection (SI) was initiated from low pressurizer pressure (1850 psig). The reactor operators were challenged by excessive reactor cooldown (caused by the failed-open SDVs) and increasing pressurizer pressure and water level (caused by the SI). The operators correctly diagnosed that the basic problem was one of excessive steam demand, probably from failure of SDVs since this had occurred during previous plant operations. They closed the main steam isolation valves (MSIVs), which stopped the reactor cooldown, and reduced the charging flow to the RCS. (The RCS pressure had not fallen below the 1650 psig shut-off head of the intermediate pressure SI pumps). The failed SDVs were manually isolated and the MSIVs were re-opened to establish decay heat removal from the RCS. The RCS pressure, hot leg temperature (T-hot), and cold leg temperature (T-cold) are shown in Figure 1.

The normal control room manning is shown in Figure 2. At the time of the event the utility senior control operator (USCO) position was not filled on that shift. The USCO normally enters the plant after a reactor trip to supervise local operations. The senior control operator for Unit 2 (SCO-2) entered the plant after this reactor trip to supervise local operations. The senior control operator for Unit 1 (SCO-1) became the "EOP reader" in accordance with station procedure and directed execution of the emergency operating procedures (EOPs). All Unit 1 operations were under the supervision of the Unit 1 shift foreman (SFM-1). The assistant control operator (ACO) assisted the Unit 1 control operator (CO-1) but his activities were limited by station procedure to those that would not directly or indirectly affect reactivity. The SFM-1 from the oncoming shift made the telephone communications to the state and to the NRC and directed the control room assistant (CRA) in making the remainder of the notifications.

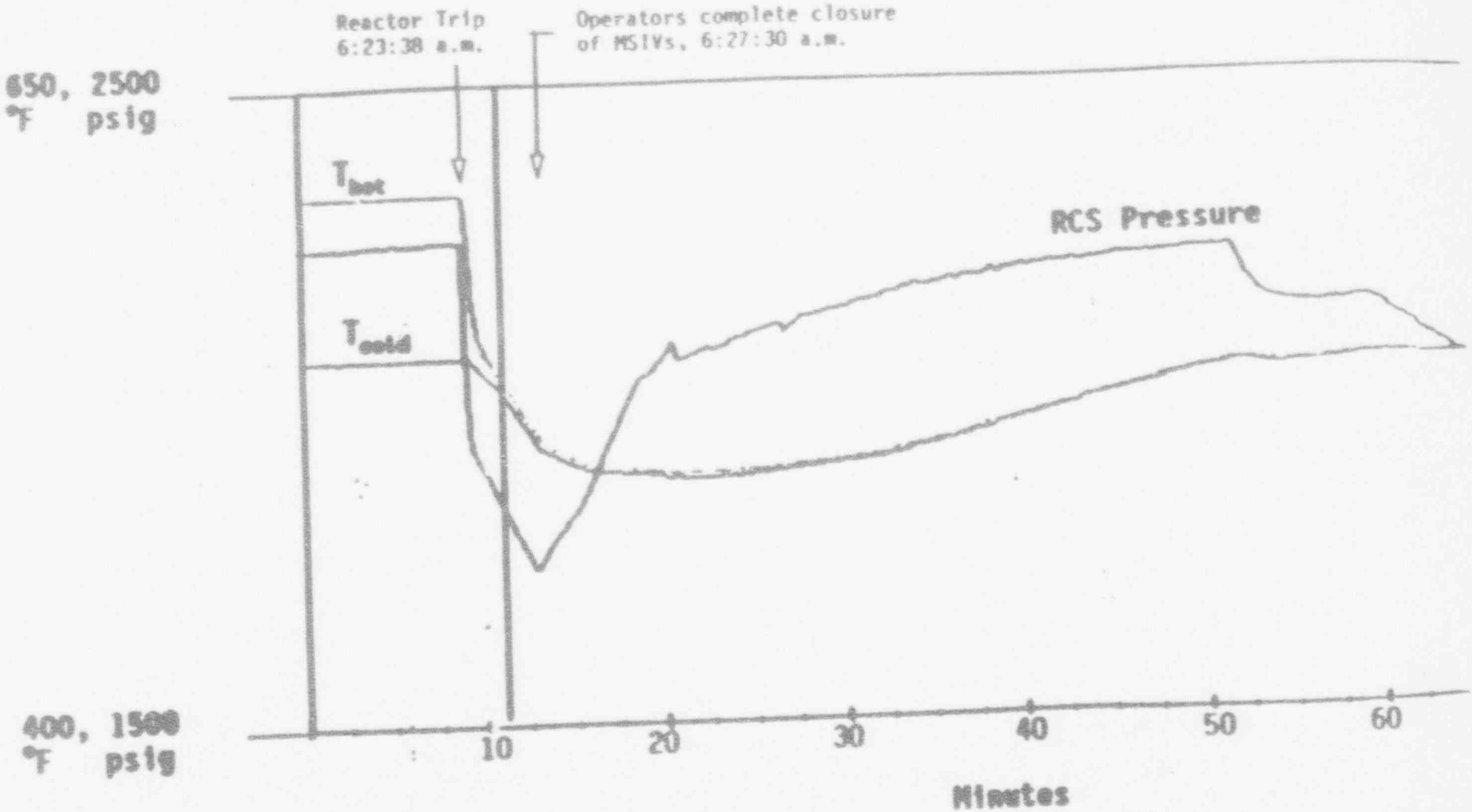

Figure 1 - RCS pressure and temperatures

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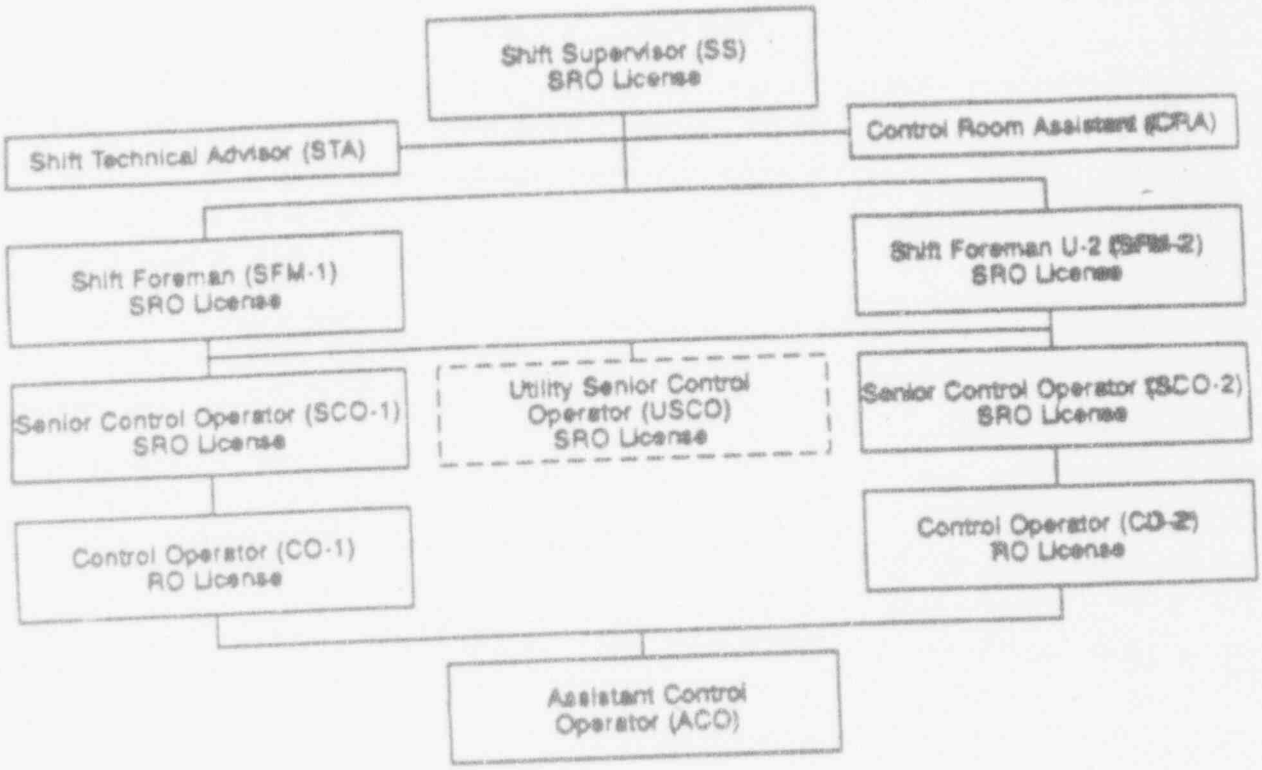

Figure 2. Diablo control room shift structure

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Shift Supervisor (SS), SFM-1, and SFM-2 are management positions and per station procedure, the people in these positions do not operate controls.

The SS and the SCO-1 had approximately 10 years experience at Diablo Canyon. The SFM-1 had approximately 5 years licensed operator experience at Diablo Canyon and previous experience as a licensed operator at McGuire, which is a similar twin unit, 4 loop Westinghouse PWR site. The CO-1 had approximately one year experience at Diablo Canyon as a licensed operator. These individuals had been trained as a crew. The ACO is not licensed, does not receive reactor operator training and does not train with the crew on the simulator. The shift technical advisor (STA) during this event was not normally assigned to the crew, had received simulator training with different crews, and did not hold a reactor operator's license. This was his first experience as an STA during a reactor trip. This control room operations crew was on their first 12 hour night shift, starting at 7:00 p.m., May 16, 1991.

The shift control technicians (SCTs) were completing the fifth and last of a series of graveyard shifts, with on-duty hours from midnight to 8:00 a.m. Initially there were three SCTs assigned to STP I-2D. SCT-1 was the most experienced, with approximately 10 years at Diablo Canyon. SCT-3 was the least experienced. He had worked as a contractor at Diablo Canyon for several years and had transferred to the utility about six months previously. He had been assigned as a SCT during the second week of April and was considered to be in an on-the-job training status. SCT-2 left work at about 6:15 a.m. to attend to other business.

2.2 Time Line of the Event

The following event time line sequence was developed from interviews with the control room operators and SCT-1 and -3, from the plant process computer recordings and control room logs, and from other data derived by the Diablo Canyon Staff.

5/17/91 Units 1 and 2 were at 100% power

6:15 a.m. • SCT-1 and -3 had just completed a full calibration on power range nuclear instrument channel N-41 per STP I-2D and its referenced procedures. There was a 24 hour time limit on calibrating the NIS and N-41 was the last channel to be calibrated. SCT-2 had been at the PPS cabinets in the cable spreading room to assist in this calibration. At this time SCT-2 left on personal leave. The instrument and control general foreman had come by on his morning review of work status and asked SCT-1 whether N-41 would be calibrated before the end of the shift and whether SCT-1 was "keeping an eye" on SCT-3, the less experienced SCT. SCT-1 then left to go to the PPS cabinets.

Note:

Figure 3 is a front view of the nuclear instrument cabinets. Each of the four power range channels has two detectors, A and B. Figure 4 is a front view of the drawers for each channel. There is a pair of A and B drawers for each channel N-41, N-42, N-43, and N-44. The detector and high-voltage coax cables enter at the rear of the cabinets. These had been disconnected from channel N-41. The power range B drawer for channel N-41 was in the withdrawn position but still energized. Test leads were attached to test points within the drawer.

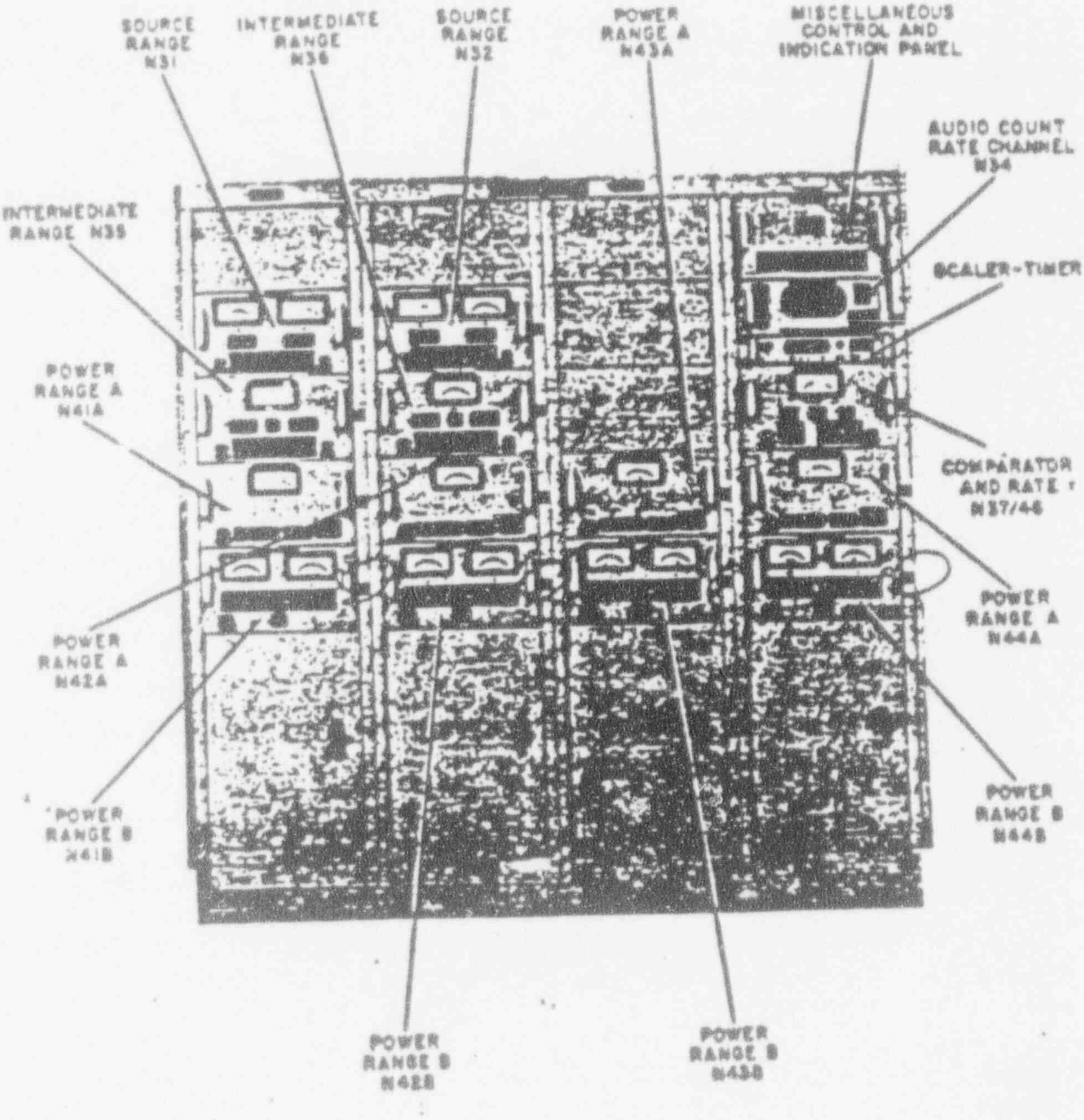

Figure 3. Front view of NI cabinets

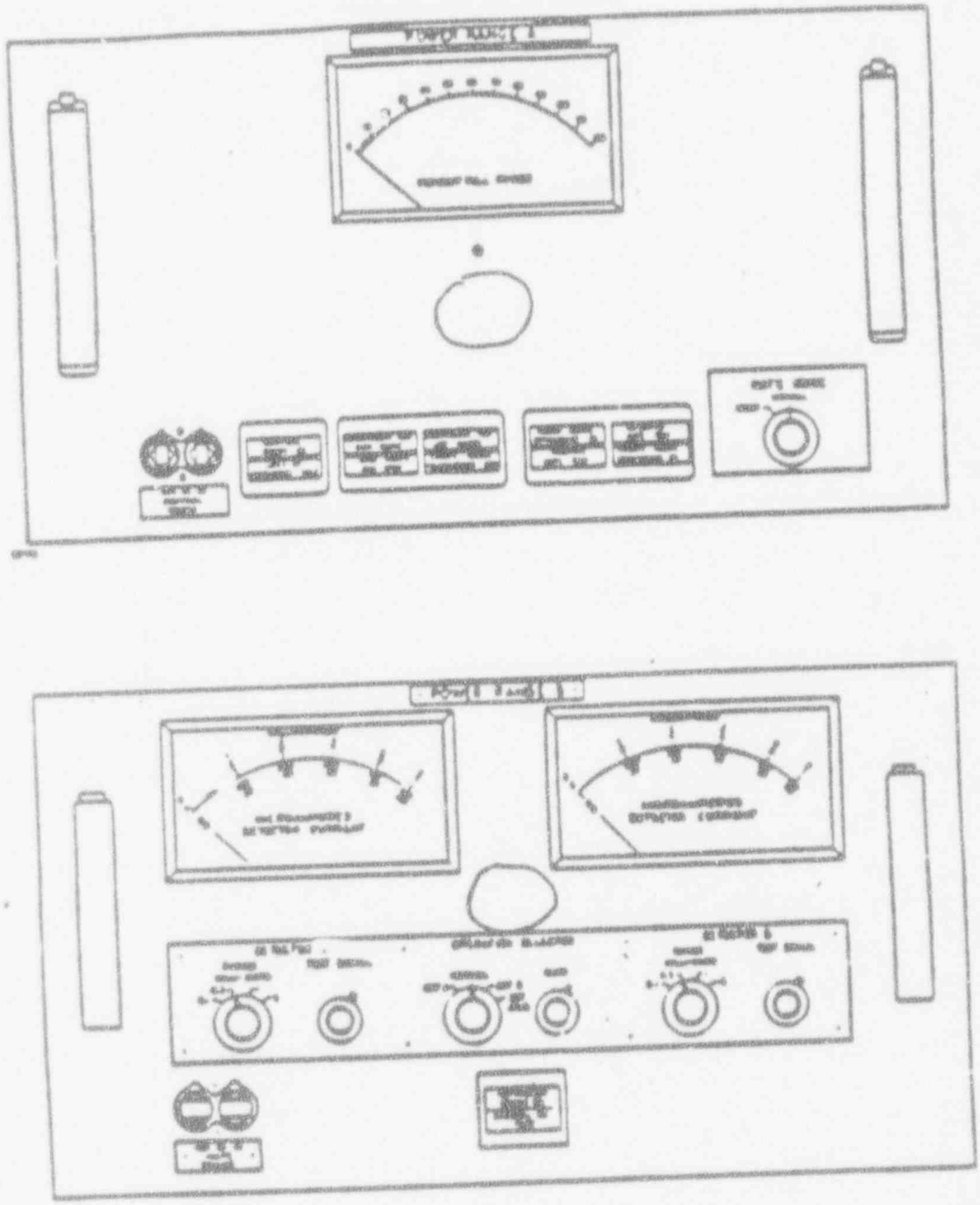

Figure 4. Front view of Power Range Drawers A and B
(identical for all four channels N-41, N-42, N-43, N-44)

- SCT-3 was restoring channel N-41. He was about to pull the instrument power fuse on drawer B that he had removed during an earlier procedure step while the instrument drawer was closed. SCT-3 first went to the rear of the cabinets and when he returned to the front placed his hand on the fuse for channel N-42, which was adjacent to channel N-41 and which had its drawer closed. As SCT-3 rotated the fuse he realized his error, but this momentary interruption of power to channel N-42 caused its reactor trip bistables to go to the tripped state. Because channel N-41 was already removed from service this resulted in a reactor trip.

6:23:38 a.m. • Reactor trip annunciated. The CO began immediate actions as recalled from EP E-0, "Emergency Procedure Reactor Trip or Safety Injection." (The first twelve steps of EP E-0 had been memorized and could be performed before opening the control room copy of EP E-0).

6:23:46 • Pressurizer pressure reached the reactor trip set point.

6:23:51 • Motor driven auxiliary feedwater (AFW) pumps started as initiated by low steam generator water level.

• Tav reached the "low" setpoint (554°F), which initiated isolation and trip of the main feedwater pumps.

6:24:02 • Tav reached the "low low" setpoint (543°F), at which point the SDVs should have been closed by the steam dump control system.

6:24:09 • Generator trip initiated. (Main generator breaker was tripped through an interlock with reactor trip after a 30-second delay). The Unit 1 12 and 4 buses were transferred automatically to the startup transformers.

6:24:10 • Diesel generator 1-1 started automatically as initiated by the above bus transfer, but its generator output breaker did not close because offsite power was being supplied to the bus.

6:24:27 • Pressurizer low level setpoint (17%) was reached and the letdown system was automatically isolated from the RCS.

6:25:17 • Pressurizer low pressure safety inspection setpoint (1850 psig) was reached, and SI was initiated.

• Diesel-generators 1-2 and 1-3 started on SI signal and remained running with generator output breakers open.

6:23:38 to 6:25:17 • Summary of activities of control room operators during time from reactor trip to SI initiated: (elapsed time 1 min 39 sec):

• Control room operators heard the turbine stop valves close and the reactor trip annunciations.

• CO-1 began to perform the immediate action steps of EOP E-0. SFM-1 wheeled the EOP cart to the CO-1 desk for use by SCO-1. SCO-1 pulled the control room copy of EOP E-0 and began reading aloud and confirming the steps. CO-1 performed steps as directed by SCO-1. SCO-1 transferred to ES-0.1 per E-0, step 5, because an SI had not occurred.

• CO-1 advised SCO-1 that the plant was cooling down too fast and SCO-1 acknowledged this. SS went to the alarm printout approximately 30 seconds after the reactor trip to verify the hypothesis that an NI trip had initiated the reactor trip and also observed that a low pressure reactor trip signal had occurred about 10 seconds after reactor trip. (This was an unusually short time interval and was a symptom of the rapid

cooldown in progress.) SS and SFM-1 discussed the rapid decrease in RCS temperature and pressure and SFM-1 directed SCO-1 to close the MSIVs.

- CO-1 closed two of the four MSIVs when directed by SFM-1 and the remaining two were closed by ACO per specific direction of SFM-1. A safety injection (SI) trip occurred (because of the low RCS pressure) while the MSIVs were being closed and SCO-1 re-entered EOP E-0.

- STA observed the SPDS display and checked it against the control room indicators and concluded that a red path (inadequate heat sink) was erroneous since control room indicators showed full flow for both turbine and motor driven AFW pumps.

- After the reactor trip SCO-2 entered the turbine building to carry out the duties normally performed by the USCO (USCO was absent).

6:27:30 • Operators completed closing the MSIVs and their bypass valves, which stopped the RCS cooldown (minimum RCS temperature approximately 500°F).

6:28 and later • The operators verified that the conditions in EOP E-0 for SI termination were satisfied and entered EOP E-1.1, SI termination. During the plant recovery from the cooldown, operators walked down the SDVs and noted no obvious problems. To control the heatup, operators began repressurizing the main steam lines but again isolated them when it appeared that there was a steam leak to the condenser. The SDVs were checked by the System Engineer and it appeared that two had failed. These valves were manually isolated and the main steam lines repressurized normally. At approximately 8:00 a.m., the plant

had been returned to normal operating temperature and pressure. It was determined later that four additional SDVs had failures of the actuators, which left them partially open but with their position indications in the control room indicating closed.

2.3 Analysis

2.3.1 Teamwork (Command, Control, and Communications)

The response of the control room operators to the reactor trip, which was complicated by the rapid RCS cooldown, demonstrated effective teamwork. Their actions were prompt and proper, and tasks were appropriately distributed among the team members. Examples are the CO and SCO-1 execution of the EOPs, the overview and joint decision on closure of the MSIVs by the SS and SFM-1, the assumption by the SCO-2 of the duties of the absent USCO, and the STA overview of the status of the safety functions. The operators recognized and were prepared for a proper response to the rapid cooldown because they had received training on SDV failures during various plant modes. Decision making was not involved in terminating the safety injection because that action was directed by the emergency operating procedures. Their performance reflected effective procedures and training and also indicated that the operators had confidence in their knowledge and capabilities both as individuals and as a team.

2.3.2 Shift Structure

The absence of the USCO emphasized the role of the assistant control operator (ACO). The SCO-2 assumed the duties of the absent USCO and went into the plant to supervise local operations. Normally, the SCO from the other unit would be available to assist the SCO in the unit that was in need of operational assistance, although this reduces the operator staff on the other unit. In this event since SCO-2 was in the plant, the SFM-1 and the SS attempted to use the ACO to assist SCO-1. However, the limited training of the ACO and the station procedure's restrictions on his activities resulted in the ACO performing only specific actions under direct order from the SS or SFM-1. The SCO-1 and CO-1 were of the opinion that the recovery of the plant,

especially the restoration of charging and letdown to normal line up, took appreciably longer with the ACO assisting than otherwise.

2.3.3 Human Factors of Surveillance Testing

The momentary disconnect of the fuse for NI channel N-42 rather than channel N-41 is the type of human error that is sometimes classified as a "sl.," rather than a "mistake". A mistake implies an error of intention, while a slip implies an error in execution. Exact causes and means of prevention of slips are not well understood, although training in self-verification appears to provide a specific defense (the dictum of "measure twice and cut once" is a clear example). SCT-3 had not yet completed the training in self-verification at the station.

There are several other factors that may have been relevant to the slip. The calibration procedure STP I-2D does not follow human factors principles for procedures for on-line operations. Descriptive or instructive information is intermingled with instructions for specific steps. A single paragraph may contain instructions for several steps to execute. There are no cautions preceding steps that may trip the reactor, such as disconnecting fuses. Because SCT-3 had worked at the site many years and was considered capable, SCT-1 may have thought, inappropriately, that SCT-3 did not need close supervision. In addition SCT-3 was under some stress at the time of the fuse disconnection since he was aware that he was performing this online calibration for the first time and was operating without direct supervision. The fact that SCT-3 was working the early morning hours of a graveyard shift (the last of five scheduled graveyard shifts) may also have been relevant. These factors were aggravated by the pressure of time limits stemming both from the 24 hour time limit for the calibration process and from the approaching end of his shift.

2.3.4 Man-machine Interface

The control room annunciator system has an acknowledge circuit that when manually activated will silence the annunciator and change all flashing

windows (incoming alarms) to a constant illumination. Other control room annunciator system designs divide the annunciators into several groups, each of which has its own audible signal and acknowledge button. This has been shown to reduce the noise problem (distraction, annoyance, and interference with oral communications) and at the same time to reduce the frequency of undetected incoming alarms. The operators were consciously aware of the noise and possibility of undetected alarms during this event.

A new display system for the plant process computer was undergoing trial use by the operators and was not programmed fully. Consequently, the displays were not used by the operators during this event.

2.3.5 EOPs Complicated by Equipment Problems

Problems with the steam dump valves failing open in the past and anticipated future failures had led the station management to issue a station policy authorizing the closure of the MSIVs after a reactor trip in advance of the sequence of operations in EOP E-0. This event prompted the station to consider modifying EOP E-0 to close the MSIVs after a trip whenever Tav reaches 530°F, which is possible after every reactor trip. Closure of the MSIVs prevents use of the main condenser for decay heat removal. This would lead to use of the atmospheric steam relief valves, the attendant release of secondary coolant to the atmosphere, and loss of condensate.

The history of SDV failures had led the control room operators to expect problems with secondary system heat removal. The station staff stated that other equipment problems (main generator output breakers, RHR pumps, auxiliary seawater system, and component cooling water capacities) had also made the normal and emergency operating procedures more complex. This number of equipment problems may not be excessive considering the number of systems and components, especially in the balance-of-plant. However, equipment problems should be anticipated and provided for in the procedures and training. The equipment problems did not prevent an effective response by the operators in this event and they are under continuing review by management.

2.3.6 Post Trip Event Review Process

At the conclusion of this event, the operators and other involved personnel were asked to give individual written statements regarding their recollection on the event. The statements were frequently brief and gave little insight into how it could have been prevented or how the response to the event could have been improved.

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3. SUMMARY OF FINDINGS

3.1 Teamwork

This event provides an example of effective teamwork and the factors contributing to effective teamwork. Decision making was not involved in terminating the safety injection since the emergency operating procedures directed the termination.

3.2 Shift Structure

The capabilities and limitations of the ACO position were tested by this event due to the absence of the USCO. Otherwise, the structure was shown to be effective by virtue of the effective teamwork.

3.3 Human Factors of Surveillance Testing

The slip by the SCT-3 provides an opportunity to review the human factors of on-line surveillance testing, specifically, procedures, on the job training supervision, self-verification training, and stress.

3.4 Man-machine Interface

The single circuit f.. acknowledging any control room alarm is a source of undesirable noise and possible undetected incoming alarms. An upgrade is being considered by station management.

3.5 EOPs Complicated by Equipment Problems

The EOPs and normal operating procedures were complicated by equipment problems. However, equipment problems can be anticipated and provided for by the procedures and training. The problems did not prevent effective response by the operators during this event and are under continuing review by station management.

3.6 Post Trip Event Review Process

The operators and other involved personnel were required to give individual written statements on what they recalled. However the statements did not comment on how it might have been prevented or how the response could have been improved.

50-275/323-OLA-2
I-MFP-185
"NOT ADMITTED"

MFP Exhibit 185

RELATED CORRESPONDENCE

INITIAL SALP BOARD REPORT

U.S. NUCLEAR REGULATORY COMMISSION

REGION V

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

INSPECTION REPORT NOS. 50-275/91-19 and 50-323/91-19

PACIFIC GAS & ELECTRIC COMPANY

DIABLO CANYON POWER PLANT

JANUARY 1, 1990, THROUGH JUNE 30, 1991

TABLE OF CONTENTS

I. INTRODUCTION

The Systematic Assessment of Licensee Performance (SALP) is an integrated NRC staff effort to collect available observations and data on a periodic basis and to evaluate licensee performance on the basis of this information. The program is supplemental to normal regulatory processes used to ensure compliance with NRC rules and regulations. It is intended to be sufficiently diagnostic to provide a rational basis for allocating NRC resources and to provide meaningful feedback to the licensee's management regarding the NRC's assessment of their facility's performance in each functional area.

An NRC SALP Board, composed of the staff members listed below, met on July 30, 1991, to review observations and data on performance, and to assess licensee performance in accordance with NRC Manual Chapter 0516, "Systematic Assessment of Licensee Performance."

This report is the NRC's assessment of the licensee's safety performance at the Diablo Canyon Power Plant for the period January 1, 1990, through June 30, 1991.

The SALP Board for Diablo Canyon was attended by:

Board Chairman

R. Zimmerman, Director, Division of Reactor Safety and Projects, RV

Board Members

J. Dyer, Project Director V, Division of Reactor Projects, NRR
K. Perkins, Deputy Director, Division of Reactor Safety and Projects, RV
H. Rood, Project Manager, PDV, NRR
G. Yuhas, Chief, Reactor Radiological Protection Branch, RV
D. Kirsch, Chief, Reactor Safety Branch, RV
S. Richards, Chief, Reactor Projects Branch, RV
P. Morrill, Chief, Reactor Projects Section I, RV
P. Narbut, Senior Resident Inspector, RV

Other Attendees

R. Huey, Chief, Engineering Section, RV
J. Reese, Chief, Safeguards, Emergency Preparedness and Non-Power Reactor Branch, RV
G. Good, Emergency Preparedness Analyst, RV
B. Olson, Project Inspector, RV
D. Schaefer, Safeguards Inspector, RV
M. Cillis, Radiation Specialist, RV
K. Johnston, Project Inspector, RV
H. Resides, Radiation Specialist, RV
A. Dummer, Reactor Inspector, NRR

II. SUMMARY OF RESULTS

Overview

The licensee's overall performance level during this assessment period was acceptable in all areas. Examples of particularly good performance were demonstrated by relatively event-free operation, low occupational radiation exposure, completion of the Long Term Seismic Program, and your performance based audits.

The strengths observed in the Operations, Radiological Controls, Engineering/Technical Support and the Safety Assessment/Quality Verification functional areas resulted in these areas being rated as Category 1. The Board deliberated at length for the functional area of Safety Assessment/Quality Verification as a result of instances where problems were not aggressively resolved but concluded that the licensee's overall performance and corrective actions outweighed earlier problems.

In rating the functional area of Emergency Preparedness as Category 2, the Board noted that problems from past assessment periods resurfaced again, resulting in five repeat findings during the October 1990 exercise. Based on this and other findings, the Board reached the Category 2 conclusion. Likewise, the number of enforcement actions in the functional area of Security did not demonstrate superior performance. Security was rated as Category 2, Improving, in recognition that the licensee had reduced the number of events involving improper entry into vital areas in the latter portion of the evaluation period.

Maintenance management appears to need to improve the timeliness of dealing with problems. In rating the functional area of Maintenance/Surveillance as Category 2, the Board discussed various problems that were allowed to exist until the plant was undesirably affected or high level management involvement was required to resolve the problem. It appeared that Maintenance could improve their interaction with Engineering in an effort to reduce the time that problems remain unresolved.

Overall, the Board recommends that problems need to be aggressively pursued in all functional areas. This emphasizes the continuing need for management involvement and oversight when issues first develop.

The performance ratings during the previous assessment period and this assessment period according to functional areas are given below:

Functional Area	Rating Last Period	Rating This Period
A. Plant Operations	1	1
B. Radiological Controls	1	1
C. Maintenance/Surveillance	2 Improving	2
D. Emergency Preparedness	1	2
E. Security	2 Improving	2 Improving
F. Engineering/Technical Support	2 Improving	1
G. Safety Assessment/Quality Verification	2 Improving	1

III. PERFORMANCE ANALYSIS

A. Plant Operations

1. Analysis

Evaluation of this area was primarily based on the results of 13 routine inspections by the resident inspectors and the observations of the operator licensing staff. Twenty-nine percent of the total inspection effort was expended in this functional area. The licensee's strengths in this area included relatively event-free operation and a knowledgeable and generally well-trained staff. Weaknesses identified were associated with untimely operability determinations and occasional reluctance to involve plant management when problems arise.

Licensee performance in this functional area during the previous SALP period was rated as Category 1 with relatively few events attributed to operational causes. Superior performance on the part of operations continued throughout this assessment period. Although four Unusual Events were declared during this period, the causes were not associated with operations. Additionally, operators managed the plant well after events, such as when steam dump valves failed open following reactor plant trips in December 1990 and April 1991. Operator actions following plant trips appeared to be consistently superior.

The licensee demonstrated strength in their short term analysis and review of operating events. The licensee's "event response plans" continued to provide a formal identification of plant problems following events. Additionally, corporate management exhibited a commitment to the assurance of quality, as demonstrated when they risked a record Unit 2 run to reduce power and repair a feedwater control valve oscillation problem.

Additional strengths observed in this functional area include the conservative management of plant conditions during outages, specifically the minimization of mid-loop operations, and the development of equipment control guidelines for plant equipment not covered by Technical Specifications. Also, during this assessment period, an examination of the fire protection program found that there was strong management support for the program.

Escalated enforcement action was taken during the previous SALP period regarding the licensee's failure to take timely corrective actions in response to repeated equipment lineup problems. During this period, the licensee's corrective actions have proven to be effective with only an occasional lineup problem: the one exception was when an auxiliary operator disabled two residual heat removal pumps due to not following written instructions. This event was immediately detected and corrected by the licensee.

The previous SALP noted some inconsistency in the ability to recognize and address problems in a timely manner. During the current period, some weaknesses in operability determinations were observed. Less than conservative action resulted from untimely operability decisions pertaining to the vibration and loose parts monitors, the auxiliary feedwater pump steam supply stop valve, and the ventilation supply for the auxiliary feedwater pump rooms. The concerns regarding the operability determinations appear to be a result of a lack of formality in the decision making process.

Another apparent weakness observed during this assessment period was a reluctance on the part of shift management to contact plant management when addressing operational problems. This reluctance was not widespread, but did occur twice on the backshift. In one instance, during a plant startup, a high steam generator water level tripped the main feedwater pumps. The operators restored the plant conditions and continued the startup without informing their management of the occurrence. In the other instance, an RHR pump tripped while filling the refueling cavity. The operators restored RHR and concluded that the event was not reportable. After plant management was informed of the event the next morning, the event was classified as reportable.

The licensee's operations training program continues to be well-defined and implemented with dedicated resources. The overall pass rate on both initial qualification and requalification exams was 100 percent. While inadequate training was rarely the cause of an event, operator performance during the October 1990 emergency preparedness exercise, where offsite dose assessments were not made in a timely manner, demonstrated an isolated training weakness. Additionally, during an Unusual Event on May 17, 1991, a non-licensed auxiliary operator performed several activities in the control room that may require either a license or additional training. This is being evaluated by the NRC. This occurrence late in the SALP period may point to the need for increased operating crew training and coordination.

The single violation in this functional area during this assessment period concerned a lack of administrative controls to ensure operability of the positive displacement charging pump. Five of the 14 Licensee Event Reports (LERs) attributed to operations involved personnel errors associated with either poor communications or not following procedures. Three of the LERs pertained to equipment failures. The remaining LERs did not point to any single concern.

2. Performance Rating

Performance Assessment - Category - 1

3. Recommendations

Management should ensure that their operations staff involves them in complex decisions and should increase the formality and timeliness with which operability decisions are made. Operations staff should involve management when equipment is not performing properly or is inoperable, such as the vibration and loose parts monitor and the feedwater regulating valves. Operations management should raise these issues to a higher level when they persist. Operating crew training and coordination should be assessed to ensure operational effectiveness.

B. Radiological Controls

1. Analysis

Inspections conducted during this SALP period found that the licensee has been proactive in assuring quality and innovative in their approach to reducing occupational dose and radioactive effluents. Approximately five percent of the total inspection effort was devoted to this functional area by the regional inspectors during this assessment period.

The licensee's performance in this functional area during the previous SALP period was a Category 1. The previous SALP board recommended that the licensee continue their aggressive approach towards ALARA and improve the quality of health physics and work practices during outages.

Management has been consistently involved in assuring quality. They implemented a positive incentive program which included time off for achieving ALARA goals. The 1990 site occupational dose was 352 person-rem. The volume of solid radioactive waste shipped for disposal was reduced to 2935 cubic feet in 1990, and liquid and gaseous effluents were maintained at a small fraction of the Technical Specification limits. These are substantial improvements over previous years' activities.

Corporate involvement was evidenced by frequent site visits and thorough reviews of outage activities. Decision-making has involved appropriate levels of management as noted in the licensee's response to leaks in the letdown piping, containment entries at power, and a major upgrade of radiation monitoring and analytical support equipment. Radiation protection and chemistry policies were well documented, goals were realistically established and well publicized, and workers were familiar with management expectations.

Some minor weaknesses were identified. These involved the number of personnel contamination events, the backlog of fixed and portable radiation detection instruments needing calibration, maintaining administrative control of keys providing access to very high radiation areas, and training of dosimetry clerks and those personnel involved in the preparation of radioactive waste for shipment.

The licensee's approach to the resolution of technical issues was conservative, timely, and technically sound. Examples included proactive efforts to minimize corrosion in the steam generators by removal of ionic impurities in the steam generator tube crevices, testing the use of hydrazine to further reduce dissolved oxygen in the condensate and feedwater system, and the installation of an on-line ion chromatograph as well as an on-line sodium monitor to immediately identify which polisher beds have high sodium and sulfate content in their effluent. Another technical issue involved the development of methods to improve the effectiveness of the liquid radwaste processing system (LPR) to reduce effluent activity. Failure of a solidification process to produce a stable product that met burial site criteria was thoroughly researched and the root cause was identified as a manufacturing defect. Another project taken on by the licensee involves a comprehensive program to upgrade the radiation monitoring system (RMS). This very significant effort is expected to take approximately two years to complete. The first channel of the new RMS is scheduled for installation in the fall of 1991. Detailed analysis of each outage by the licensee has revealed opportunities for additional dose reductions and improved goals.

Licensee management has supported training programs for the chemistry and radiation protection technicians, supervisory personnel, and the technical staff with state-of-the-art training facilities and dedicated resources. Programs include training to further develop the knowledge and skills of staff members by participating at onsite and offsite educational opportunities such as: steam generator owners group meetings, EPRI conferences, low-level radwaste user group meetings, and periodic rotational assignments of the radiation protection technician staff at other nuclear facilities. Examples also include a five week supervisory development course for foremen and supervisory personnel and participation of the training staff in outage activities as a means of determining areas that can be improved in the training program. The licensee has initiated training for their staff on the new 10 CFR Part 20 requirements.

The licensee has well staffed site and corporate chemistry and radiological protection groups. Staffing includes an active and experienced chemistry and radiation protection ALARA work planning group. Authorities and responsibilities were defined by management and understood by the staff. Key positions were generally filled on a priority basis. All site departments communicate effectively with the health physics and chemistry organizations.

One Severity Level IV violation and six Licensee Event Reports (LERs) were identified in this functional area during the assessment period. The violation concerned a failure to perform leak checks of two licensed sources. Neither the violation nor the LERs indicated a programmatic breakdown of the radiation protection program. The licensee's root cause and corrective actions were prompt and effectively implemented as evidenced by lack of repeated events.

2. Performance Rating

Performance Assessment - Category - 1

3. Board Recommendations

Management should continue to provide their full support to site and corporate staff initiatives to maintain and improve the present performance level. Some additional emphasis seems appropriate towards correcting minor weaknesses in controlling personnel contamination, reducing the backlog of non-Technical Specification radiation monitoring equipment needing calibration, and training of dosimetry clerks and radioactive waste handlers.

C. Maintenance/Surveillance

1. Analysis

The maintenance and surveillance functional area was observed routinely during the assessment period by resident and regional inspection personnel. Twenty-one percent of the inspection resources were devoted to this functional area.

Licensee performance in the maintenance and surveillance functional area during the previous SALP period was rated as Category 2, Improving. The previous SALP recognized licensee advancements in proceduralization, control of backlog, and effective outage management. The previous SALP also noted

that the licensee was slow to address some concerns, including plant material condition, such as the intake structure. The previous SALP recommendations to licensee management included a need for stronger management oversight. The major issues of the previous SALP included the use of excessive overtime without management awareness and improper maintenance of the containment sumps and the auxiliary feedwater pump trip valve.

The maintenance and surveillance area during this SALP period has been slow to show consistent improvement. This conclusion is based largely on examples of a lack of management aggressiveness in the resolution of problems and examples of a lack of maintenance management oversight. The most notable indication of lack of oversight was the failure to resolve long-standing mechanical maintenance measuring and test equipment problems. These problems were the subject of several licensee audits and surveillances. Subsequently, the NRC made this area the subject of three special inspection reports, including an enforcement conference. The end result of this problem was that the licensee decided to close their mechanical maintenance measuring and test equipment shop and assign these duties to the instrument and control shop. A second example dating back to the previous SALP was water intrusion and component corrosion in the intake structure. Conditions in the intake have continued to worsen and now include concrete spalling, reinforcing bar corrosion, and component corrosion wastage.

Management of maintenance and surveillances to minimize equipment out-of-service times has been improving. Several errors were made in taking equipment out of service, but were identified by the licensee. Likewise, outage management has generally been superior and has minimized mid-loop operations while maximizing the availability of electrical power supplies.

Management assurance of quality has generally been shown to be acceptable in attributes such as prior planning, assignment of priorities, and procedures for the control of activities. These policies are adequately stated and generally understood but not always practiced. For example, maintenance personnel signed off work steps before they were performed during the installation of an auxiliary feedwater pump governor, maintenance personnel failed to follow administrative procedures by not identifying spring pack relaxation of important motor operated valves, and a fire pump was repeatedly misassembled. Decision-making appears to be done at a level which ensures management review, but that review is sometimes non-conservative. A March 7, 1991, loss of offsite power event was caused by maintenance personnel using a crane in close proximity to high voltage energized electrical lines despite the licensee's specific review of a similar event at the Vogtle power plant. Other examples of a lack of conservatism and inquisitive attitudes were shown by followup after the December 24, 1990, reactor trip and safety injection in which a pressurizer spray valve failed open due to a missing locking device, and a steam dump valve failed open due to a broken stem. Licensee maintenance management did not thoroughly investigate the steam dump valve problem prior to restarting. Subsequently, during a plant trip, on May 17, 1991, another steam dump valve failure caused a safety injection and excessive reactor cooldown. After this event adequate attention was given to resolve problems with the steam dump valves.

Staffing in maintenance appears to be adequate although work hour changes for maintenance staff have left Mondays and Fridays more lightly

staffed. Training and qualification in the maintenance area appear to be well defined and implemented. Licensee audits have identified, however, that untrained and uncertified personnel have sometimes been utilized due to a lack of discipline by supervisory maintenance personnel in assigning work. In January 1991, Instrumentation and Controls (I&C) personnel removed the wrong Unit's power range nuclear instrument due to not following self-verification policy. In May 1991, the wrong power range instrument was removed again, resulting in a reactor trip. These examples show that although the licensee has adequate training, procedures, and policies in the maintenance area, they have not been consistently followed by working and middle level management personnel. Maintenance management does not appear to have emphasized these issues sufficiently.

During the SALP period, the licensee has improved visibility in some pump rooms through painting the rooms white. In general, the licensee has instituted an energetic painting program which is an important element in maintaining plant material condition. In response to industry and NRC initiatives, the licensee has started to trend important safety equipment out-of-service times and has started to consider programs for utilizing probabilistic risk assessment to perform risk evaluations of preventive maintenance activities. Additionally, a predictive maintenance group has been formed, and the licensee is moving towards a reliability centered maintenance program.

The licensee's surveillance test program has generally been adequately conducted. Procurement control and storage of components has been examined and found to be well controlled and executed. Likewise inservice inspection and testing have been examined and found to be generally well performed. One area that requires improvement is a reduction in the backlog of radiation detecting instruments that require calibration. The backlog appears to have developed as a result of I&C not fully supporting the health physics organization.

There were nine Level IV violations and 16 Licensee Event Reports (LERs) associated with this area. Fifteen of the LERs were attributed to personnel error and point out, as previously discussed, that training, procedures, and policies are not always consistently followed.

2. Performance Rating

Performance Assessment - Category - 2

3. Recommendations

Management should provide more timely attention to preventing and correcting degradation of the plant material condition. The licensee should ensure that maintenance management develops an inquisitive attitude toward plant hardware anomalies such that root causes of hardware problems are identified and resolved. The timeliness of dealing with problem areas should be improved. The licensee is encouraged to continue to develop their initiatives regarding preventive maintenance risk assessment, predictive maintenance, and outage management strategies.

D. Emergency Preparedness

1. Analysis

The licensee's performance in this functional area during the previous SALP period was rated as Category 1. The previous SALP Board recommended that problems related to emergency preparedness (EP) be corrected in a more timely manner, and that licensee management take the necessary steps to strengthen the engineering support in the Technical Support Center (TSC) and Emergency Operations Facility (EOF). During the current SALP period, weaknesses were identified in the effectiveness of the licensee's EP corrective action program, the control of the drill program, and the effectiveness of the EP training program as demonstrated by performance during drills and exercises. The licensee's actions to address NRC concerns about on-shift dose assessment capabilities and their initial actions to address recurring inspection findings was considered to be a strength. The licensee's EP program was observed by both the regional and resident inspectors during three routine inspections, an annual emergency exercise, and several operational events. Approximately five percent of the total inspection effort was devoted to this functional area.

Inspections conducted during this SALP period identified weaknesses in licensee management's oversight and control of the implementation of the EP corrective action program, and the drill and exercise portion of the EP training program. Many of these weaknesses were reflected in the licensee's declining performance during the October 1990 annual exercise. During the 1990 exercise, five issues were identified as repeat findings from prior years (1987-1989). These issues involved: 1) the coordination of protective action recommendations at the EOF, 2) the failure to establish measures to control contamination within the TSC, 3) the ability of the TSC engineering staff to support the Control Room (CR), 4) the identification of inconsistencies in General Emergency class requirements in procedures used to classify emergency events, and 5) the potential missile hazard associated with storage of unsecured iodine monitors in the TSC ventilation room. The repeat findings demonstrated that the licensee did not have a corrective action program fully effective in preventing the recurrence of issues identified during drills, exercises, and NRC inspections. Once the repeat findings were identified by the NRC at the conclusion of the 1990 annual exercise, the licensee initiated a nonconformance report (NCR) to track the resolution of the matter. The licensee's actions in response to the NCR appeared thorough; however, the effectiveness of the licensee's corrective actions could not be determined since they were initiated toward the end of the SALP period. Additional findings from the 1990 exercise that indicated a decline in performance are discussed in subsequent paragraphs.

The inspections also showed that the licensee did not have sufficient procedural controls to govern the implementation of its drill program. As a result, some drills did not fully meet the scope of the emergency plan requirements. For example, radiological (environmental) monitoring drills were conducted, but environmental samples were not collected. Air samples were simulated during some inplant health physics drills and post accident sampling system drills were conducted, but samples were not analyzed.

As described above, one exception involving the effectiveness of the licensee's EP corrective action program was identified. The licensee's

approach to the resolution of technical issues from a safety standpoint was generally sound, thorough, and timely. Based on the CR's inability to demonstrate that offsite dose calculations could be completed in a timely manner to support emergency classification during the 1990 annual exercise, the licensee immediately initiated dose calculation training for onshift CR staff members and incorporated dose calculations into recurring operator training.

The licensee implemented its emergency plan on several occasions during this SALP period. All of the events were correctly classified as Unusual Events. The most notable example occurred as a result of the March 7, 1991, loss of offsite power during Unit 1's refueling outage. In general, all of the events were classified in a timely manner; however, the timeliness of the March 7, 1991, Unusual Event declaration was slow. Notifications to local offsite authorities were made in a timely manner.

Staffing for the EP program appeared sufficient during this SALP period. Due to rotational assignments and a reorganization, several changes have occurred in EP's management reporting chain at the site during the current SALP period. The licensee has established a new, permanent position to provide management oversight for EP, safety, and health. The management position above and the position below the newly established permanent position are considered to be rotational assignments. During this SALP period, the individuals in these two positions were changed due to a shift in rotational assignments. Both of the new individuals have strong EP backgrounds which should benefit the management of the EP program. Establishing the permanent position was viewed as a positive step to maintain stability. The effectiveness and continuity of the management could not be fully determined because two of the position changes occurred toward the end of the SALP period. Organizational changes to the emergency response staff (engineering support) at the EOF were made as a result of NRC concerns identified during the 1989 exercise.

Several weaknesses in the effectiveness of the licensee's EP training program were identified during this SALP period. The most significant example was the inability of the CR staff to complete dose calculations in a timely manner to support accident classification during the 1990 emergency exercise. Although the licensee took prompt corrective action, as previously described, the problems experienced during the exercise indicated that the previous level of training/practice was not adequate to accomplish the assigned responsibilities.

The weakness in the level of training/practice was also evident during the 1990 exercise as indicated by the findings discussed earlier and the observation that personnel from the Operations Support Center (OSC) did not fully adhere to radiation protection procedures during simulated emergencies. Toward the end of the SALP period, the licensee initiated steps to improve its EP training program. More drills were scheduled and drill/exercise findings will be incorporated into the training. The effectiveness of these actions could not be determined since they were initiated toward the end of the SALP period.

An in-office inspection was conducted to evaluate changes to the licensee's emergency classification procedure and the emergency action levels (EALs)

contained therein. A change to the Diablo Canyon emergency plan was also reviewed during this appraisal period. The changes to the emergency plan and EALs were acceptable and continued to meet NRC requirements. No cited violations or Licensee Event Reports were identified in this functional area during this appraisal period.

2. Performance Rating

Performance Assessment - Category - 2

3. Board Recommendations

Licensee management should ensure that an effective corrective action plan for drill and exercise findings is established and carried out. Licensee management should evaluate the adequacy of classroom training provided to emergency response personnel and ensure that personnel are given an adequate number of opportunities to practice their assigned tasks during periodic drills. The additional dose assessment training provided to CR personnel should continue. The need to adhere to radiation protection procedures under simulated emergency conditions should also be stressed during classroom training and during drill conduct. Administrative procedures should be enhanced to ensure that drills and exercises consistently meet emergency plan requirements. Simulating sample collection during drills and exercises should be avoided to enhance realism and increase the training value.

E. Security

1. Analysis

During this assessment period, Region V conducted three physical security inspections which comprised approximately four percent of the total inspection effort. In addition, Region V conducted one enforcement conference pertaining to an escalated enforcement action. Further, the resident inspectors provided continuing observations in this area.

The previous SALP report rated the licensee as Category 2, Improving, and recommended that licensee management resolve the identified weakness with the closed circuit television (CCTV) alarm assessment capability, plus finalize measures to correct identified inadequacies with portions of vital area barriers. As discussed below, these issues are scheduled for completion, or have been completed. During this SALP period, the licensee's weaknesses pertained to an escalated enforcement action that primarily focused on personnel access control to vital areas, plus additional enforcement actions involving failed compensatory security measures. The strengths identified this SALP period included the licensee's construction of a new Central Alarm Station, and their improvements related to strengthening the readiness posture of the security contingency response force.

The previous SALP report encouraged the licensee to resolve the identified weakness in CCTV alarm assessment capability, involving the manner in which the integrated security systems (barrier, perimeter alarms and CCTV cameras) are used. To resolve this weakness, the licensee has scheduled installation of a video-capture system by September 1991. This new system, in conjunction with the CCTV cameras and security alarms, should provide the capability for

instant assessment of the cause for perimeter alarms. The previous SALP report also encouraged the licensee to finalize measures to correct identified inadequacies with portions of vital area barriers at the Units' 1 and 2 pipe galleries. This action has been completed. The licensee's approach to the resolution of these two technical issues has been sound and thorough.

With regard to management's involvement in assuring quality, corporate and plant management continued to review the operation of the overall security program. They have implemented generally sound and thorough remedial measures to correct deficiencies and weaknesses identified in the course of both internal and NRC security inspections.

During this SALP period, the licensee reported seven incidents in which unauthorized employees had gained access to plant vital areas. In most of these instances, the unauthorized employee had been previously authorized access only to the protected area, and had entered the vital area based upon the card-key authority of another employee. The licensee's corrective actions have emphasized to plant employees the importance of following required procedures when seeking access to vital areas, thus the frequency of these incidents have been reduced by approximately 80 percent.

Additionally, multiple incidents of failed compensatory measures were identified by the licensee during this SALP period. In each instance, an officer had been assigned the required duty of monitoring a degraded piece of security equipment, and for one of several reasons, the equipment was not properly monitored. In two instances, the compensatory officer was discovered inattentive, and in other instances, the compensatory officer had either been provided inadequate instructions by his supervisor, or had been involved in a miscommunication with other members of the security force. The majority of these incidents involving failed compensatory measures occurred during the second half of the SALP period, and the overall effectiveness of the licensee's corrective actions have not been evaluated by the NRC.

During this period, the licensee's overall security program has been enhanced in several areas. A newly constructed Central Alarm Station provides an improved "nerve center" for security operations. The licensee's responsiveness to the design basis threat (10 CFR Part 73) has been increased through implementation of defensive choke-point positions, prepositioning of response equipment to expanded locations throughout the plant, and improved weaponry and uniforms for members of the security force. Additionally, the licensee effectively upgraded the capability of their security emergency power supply.

The enforcement history for this period includes issuance of one Level-III violation, four Level-IV violations, and ten non-cited violations. The Level-III violation, plus one Level-IV violation focused primarily upon the entry of unauthorized employees into plant vital areas. Two of the Level-IV violations, plus three of the non-cited violations pertained to situations of failed compensatory security measures. A separate portion of the aggregate Level-III violation, plus one non-cited violation pertained to situations involving the licensee's failure to properly protect safeguards information. In response to these enforcement actions, the licensee's corrective actions have been thorough and generally effective.

During the SALP period, each of the licensee's fourteen safeguards events were reported in the Licensee Event Report (LER) format. These events related to: failed compensatory measures(5); problems encountered with the security power system(3); and miscellaneous events(6). Nine (64%) of these safeguards events were caused by personnel errors and were attributed to causes under the licensee's control. The five LERs pertaining to failed compensatory measures were caused by: inadequate compensatory instructions to security officers, miscommunication between security personnel, and inattentive security officers.

During the previous SALP period, the greatest number of LERs pertained to degraded operation of the alarm stations, and Region V determined that the alarm station operators had been rarely observed during the performance of duty by their supervisors. To correct this situation, the licensee required each shift supervisor to visit both alarm stations once per shift. This appears to have improved the overall operation of the alarm stations.

Key positions and responsibilities within the Security Department were well defined. The licensee's security training program supported the overall increased readiness posture of the security force.

The licensee's Fitness-For-Duty (FFD) program appears to meet the requirements of 10 CFR Part 26. Though not formally inspected during this SALP period, reviews of required FFD reports plus informal reviews of FFD staff and facilities indicate that the FFD program is comprehensive and well understood by the general site population.

2. Performance Rating

Performance Assessment - Category - 2, Improving

3. Board Recommendations

Licensee security management should reduce the number of situations involving failed compensatory security measures. Licensee management should emphasize adherence to site security procedures in order to reduce the types of enforcement actions and reportable events identified during this SALP period, or licensee management should implement other techniques for positive control over door entries.

F. Engineering/Technical Support

1. Analysis

This functional area was examined by regional and resident inspectors and was also examined by NRC headquarters evaluators. Approximately 18 percent of the inspection resources were used in evaluating this functional area.

The previous SALP rated licensee performance in this functional area as Category 2, Improving. The licensee was encouraged to place emphasis on the system engineering and configuration management programs and to focus on the formal resolution of plant problems. The licensee was also encouraged to be self-critical, to promote early identification of problems, and to establish aggressive schedules for corrective actions. The licensee received a specific

board recommendation to aggressively assess the issue of plant material condition.

Generally, during this SALP assessment period, engineering/technical support at Diablo Canyon has been very good in the areas where attention has been focused. Engineering involvement at the site has noticeably increased and has generally had a positive effect on operations and the quality of modification work. In addition, licensee management involvement shows consistent evidence of prior planning and assignment of priorities. Most engineering evaluations have been found to be technically adequate.

The licensee's design basis reviews were productive in identifying problems in the original construction. The licensee has been forthright in addressing these problems as nonconformances and dealing with them appropriately. One design problem that was quickly resolved involved a seismic concern regarding water that had not been drained from containment spray piping. Plant and corporate personnel worked closely together to resolve the problem. Likewise, corporate engineering's setpoint reverification program was productive in identifying problems with electrical thermal overload design margins throughout the plant.

Corporate engineering established a proactive program with Westinghouse to maintain up-to-date communications with Westinghouse's study of potential generic issues. This program enabled PG&E to respond to Westinghouse Part 21 reports very quickly. In addition there were cases where corporate engineering interest and involvement in long-standing plant problems resulted in comprehensive action and correction of problems. Such was the case in the investigation of breaking steam dump valves and in the case of determining why the steam admission valve to the auxiliary feedwater pump was sticking closed. Currently, the quality of engineering work on masonry walls is good.

Towards the end of the assessment period, an electrical distribution system functional inspection (EDSFI) was conducted. The inspection, conducted by NRC regional and headquarters staff members, found the engineering technical performance to be generally very good. In particular, the team found that the licensee had implemented a number of proactive measures to address problems at Diablo Canyon based on their own review of EDSFI findings at other facilities. Also, the team noted that Diablo Canyon had implemented an aggressive vendor interface program to maintain up-to-date information on equipment installed at the plant. The primary engineering weaknesses noted by the team involved several instances of incomplete technical work and a weak sense of ownership of some plant problems. This latter concern appeared to manifest itself in the form of a lack of timely identification and resolution of some problems.

Engineering personnel were found to be well qualified in a January 1990 team inspection of the corrective action program. The staffing levels, both at the site and in the corporate office are very good. The licensee is currently developing comprehensive training initiatives including a job task analysis for engineers.

Despite the previous observations, improvements can still be made in the thoroughness of engineering activities. One example involves a design change to remove the boron injection tank in Unit 2. The planned design change was aborted when licensee QA audits found that additional equipment qualification was required. Likewise, engineering exhibited other examples where work could

have been more thorough such as providing improper blowdown settings for Unit 2 relief valves, utilizing the wrong unit steam dump data for justification of a technical specification change, and providing inaccurate wiring schematics for a diesel generator droop relay design change. Some examples where engineering personnel did not always promptly assess site occurrences were observed. Equipment problems like motor operated valve spring pack relaxation, out-of-service hardware, and frequent alarms on the reactor vibration and loose parts monitor received little attention by responsible plant engineering personnel. Additionally, about 50 minor deviations to the licensing basis for fire protection have not been fully resolved.

The results of a Vendor Branch assessment of PG&E's procurement practices indicated that PG&E had made a significant effort to upgrade its commercial-grade dedication program since its inception in July 1986, and that their program description was generally consistent with the dedication philosophy described by the Electric Power Research Institute (EPRI). PG&E's engineering and technical support related to commercial-grade dedication was seen as a strength by the assessment team. Personnel related to the program were found to be knowledgeable and aware of current issues and concerns. PG&E's involvement in industry groups has benefited both the engineering staff and the overall commercial-grade dedication program. Especially noteworthy was the fact that PG&E's commercial-grade dedication program was initiated 16 months prior to the initiative commitment date of January 1, 1990. One negative aspect of the procurement and dedication program was that a licensee internal audit found that communication and interaction between site and corporate personnel appeared to be lacking.

During the SALP period, the NRR staff was involved in a number of in-depth reviews pertaining to engineering activities. Principal among these was the staff's review of the Long Term Seismic Program (LTSP). The material presented demonstrated thorough and comprehensive engineering analysis. Overall, the staff found that the geological, seismological, and geophysical investigations and analyses conducted by the licensee for the LTSP were the most thorough and complete ever conducted for a nuclear facility in this country and have advanced the state of knowledge. As part of the LTSP, the licensee developed a comprehensive, Level 1 PRA model for the plant which includes external accident initiating events such as fires and earthquakes, as well as internal events such as LOCAs. The engineering staff expects to use the PRA as a tool to assist the maintenance, operations, and planning organizations in scheduling outages and preventive maintenance activities.

The violations and Licensee Event Reports associated with this functional area did not point to any single concern.

2. Performance Rating

Performance Assessment - Category - 1

3. Board Recommendation

The licensee should provide additional emphasis in early identification, effective engineering involvement, and timely correction of plant problems. The licensee should continue to build a strong interface between corporate and plant engineering and consider continued involvement of corporate engineering

in a leadership role in plant problem resolution. The licensee is encouraged to continue to develop their innovative corporate engineering training program.

G. Safety Assessment/Quality Verification

1. Analysis

Evaluation of this functional area was based on regional and resident based inspections. Eighteen percent of the NRC's inspection effort at Diablo Canyon was used in this functional area.

During the previous SALP period, this functional area was rated as Category 2, Improving. Licensee strengths in performance based Quality Assurance (QA) inspections were recognized. The Board recommendations encouraged the licensee to maintain emphasis on performance based audits and to increase emphasis on the identification of problems.

The general conduct of QA audits continued to be performance based and effective. When necessary, expert technical personnel were called in to augment the audit team. In addition, the licensee formulated a group called the Nuclear Excellence Team (NET) to evaluate problem areas as requested by senior management. One product of the NET was a meaningful examination of fire protection program implementation. The licensee has also demonstrated committed involvement and leadership in the area of industry initiatives.

During the SALP period the licensee reorganized the QA organization. The QA organization now reports directly to the Senior Vice President and General Manager for the Nuclear Power Generation Business Unit instead of the corporate President. No adverse effects from the QA reorganization were noted during the reporting period.

Near the middle of the SALP period, the Senior Vice President required that an event investigation team (EIT) be conducted to address NRC concerns related to the timeliness and ownership of actions following an auxilary feedwater pump overspeed event and a weld crack in the positive displacement charging pump piping. The EIT concluded that the untimely problem resolution was caused by (1) a lack of problem ownership and (2) a lack of requirements for the allowed time to initiate a nonconformance report. The licensee implemented organization and procedural changes as a result of the EIT. These actions appeared to provide some improvement in the assignment of responsibility for multi-department problems. The licensee also began to monitor the time limits for nonconformance decisions. The decision level for nonconformance resolution was also elevated to the plant manager when necessary.

It was observed during the first part of the assessment period that organizations such as Quality Assurance, Quality Control, (QC) and the Onsite Safety Review Group performed little critical assessment of Operations. Problems identified by the NRC through the review of control room logs had been overlooked. In response to this assessment, Quality Control began to perform critical reviews of control room logs with some positive results. In the area of Radiological Controls, the licensee developed a program to perform thorough reviews of radiological protection using peer experts.

As discussed in the maintenance area of this SALP report, in one significant case when a problem area was recognized by oversight groups their actions to pursue and resolve the problem was not sufficiently aggressive. Such was the case when inadequate control of measuring and test equipment had been identified by both QC and QA but had not been resolved, even though the problem had been elevated to upper management.

In some instances, the licensee's organizations were slow to understand and solve repetitive component failures and problems. For example, steam dump valves have had internal failures since May 1990 and were not systematically addressed until May 1991. Likewise, letdown welds have been cracking in Unit 2 since June of 1989 and the root cause was not aggressively pursued and resolved until 1991. Finally, the repetitive NRC findings from Emergency Preparedness exercises also indicate the need to aggressively correct problems before they recur. Once the licensee's attention was focused on these problems, resolution appeared thorough and timely.

Licensee staffing in the quality oversight groups appears good. It was noted that the licensee utilizes outside expertise when determined to be necessary and has extended this policy to include a non-PG&E expert member on its General Office Nuclear Plant Review and Audit Committee (GONPRAC).

During this assessment period, it was observed that when the Vice Presider , Diablo Canyon Operations and Plant Manager was away from the site, a department head was designated to act as the Plant Manager. The effect of this was that department heads, with their specific areas of responsibility, may not have the broad scope perspective necessary when designated as acting plant manager. An example of this situation was the Maintenance Manager's decision to restart from the pressurizer spray valve event (on December 24, 1990) without fully investigating the problem.

During the SALP period the NRR staff reviewed a large number of safety analyses performed by the licensee. The licensee replies to generic letters and bulletins were timely, responsive, and of generally high quality. The submittals for licensee amendment requests were technically adequate and generally complete.

The most significant violation attributed to this functional area pertained to the control of mechanical maintenance measuring and test equipment. The Licensee Event Reports in this area did not point to an, significant concern.

2. Performance Rating

Performance Assessment - Category - 1

3. Board Recommendations

The licensee should promptly deal with emerging technical issues to prevent them from affecting the plant as was the case with steam dump valve failures and cracking of charging piping. Management should involve themselves in timely resolution of outstanding issues to prevent the slow action that occurred in addressing concerns with measuring and test equipment. Increased attention should be focused on repeat problems.

IV. SUPPORTING DATA AND SUMMARIES

A. LICENSEE ACTIVITIES

UNIT 1

Diablo Canyon Unit 1 was at 100% power at the start of this reporting period. On February 6, 1990, an Unusual Event was declared when a moderate seismic event was detected, but an inspection of both units indicated no abnormalities.

On February 20, 1990, Unit 1 was manually tripped due to a loss of flow from both main feedwater pumps. Two logic cards from the SSPS were tested and replaced. The cause of this event was unknown. Unit 1 was returned to 100% power on February 22, 1990.

On June 14, 1990, Unit 1 tripped on a Power Range Nuclear Instrument high positive rate trip signal due to an increase in reactor coolant pump speed caused by a loss of load. Unit 1 entered Mode 1 on June 19, 1990.

On July 26, 1990, the NRC Senior Resident identified a through wall crack on a four-inch diameter piping elbow, upstream of the suction stabilizer for the positive displacement charging pump. The licensee calculated that as a result of the crack, control room radiation doses could have exceeded the 10 CFR Part 50 requirements for control room habitability in the event of a LOCA. Compensatory measures were taken to allow continued operation, and a weld repair of the crack was performed on August 1, 1990.

On December 5, 1990, a reactor trip followed a turbine trip. The turbine tripped after a runback did not reduce generator load below a required limit. The licensee discovered that the runback limit setpoint was improperly set. The runback was caused by a stuck low flow switch for the main generator stator cooling water system. After repairs, Unit 1 returned to 100% power on December 9, 1990.

On December 24, 1990, an Unusual Event was declared after a reactor trip and safety injection occurred due to low pressurizer pressure, caused by the failure of a pressurizer spray valve. Following the reactor trip, the Technical Specification maximum cooldown rate of 100° F in one hour was exceeded. The pressurizer spray valve failed open due to the feedback linkage becoming disconnected because of a missing elastic stop nut. Failure of a main condenser steam dump valve also contributed to the overcooling. Following repairs, Unit 1 returned to power operation on December 28, 1990.

On January 18, 1991, Unit 1 commenced its End of Life (EOL) coastdown for the fourth refueling outage (1R4).

On February 1, 1991, the reactor tripped due to steam generator low level coincident with steam flow/feedwater flow mismatch after the feedwater regulating valves to two steam generators closed. This occurred when instrument air was accidentally isolated during scaffolding erection. On February 2, 1991, it entered Mode 5. On February 6, 1991, Unit 1 entered Mode 6 and fuel unloading commenced. On February 10, 1991, fuel unloading was

completed, and on March 6, 1991, Unit 1 re-entered Mode 6 and commenced refueling.

On March 7, 1991, a loss of offsite power to Unit 1 occurred when a mobile crane approached too closely to the 500 kv power lines, causing an arc to ground. Following the loss of offsite power, the emergency diesel generators started and loaded to the vital buses. Offsite power was restored five hours later. An Unusual Event was declared as a result of the loss of offsite power, and an NRC Augmented Inspection Team (AIT) investigated the event. Also on March 7, 1991, the fuel reloading was completed, and the reactor entered Mode 5 (cold shutdown) on March 12, 1991.

On March 27, 1991, Unit 1 entered Mode 4, and Mode 3 was entered on March 29, 1991. Unit 1 entered Mode 2 on April 2, 1991, and on April 4, 1991, entered Mode 1.

On April 23, 1991, a reactor trip resulted from a high steam generator level. The level transient was caused by a loss of the main feedwater pump 1-1 due to a speed controller failure. Operator action was required to mitigate an unanticipated primary cooldown due to a failed open main condenser steam dump valve.

On April 24, 1991, during a reactor startup, a manual reactor trip was initiated following a rod control urgent alarm. The alarm was due to a failed fuse in the rod control power supply. On April 25, 1991, Unit 1 re-entered Mode 1.

On May 17, 1991, a reactor trip occurred after an I&C technician inadvertently deenergized a second power range instrument while performing a surveillance test on a different instrument. Subsequent to the trip, two main condenser steam dump valves failed open, resulting in low pressurizer pressure and a safety injection. Additionally, the Technical Specification maximum cooldown rate of 100° F in one hour was exceeded. An Unusual Event was declared as a result of initiating safety injection. The unit returned to 100% power on May 21, 1991, and remained at power through the end of this assessment period.

Unit 2

Diablo Canyon Unit 2 was at 100% power at the start of this reporting period, and remained in Mode 1 until March 3, 1990, when it commenced a ramp down in power in preparation for the third refueling outage.

On March 9, 1990, Unit 2 entered Mode 6, and completed fuel off-loading on March 14, 1990. On March 26, 1990, Unit 2 re-entered Mode 6 and completed fuel reloading on March 31, 1990. On April 4, 1990, Unit 2 entered Mode 5, and on April 22, 1990, Mode 4 was entered. Unit 2 entered Mode 3 on April 23, Mode 2 on April 28, 1990, and on April 30, 1990, returned to power operation.

Unit 2 remained at power through the end of the assessment period, a record run of greater than 400 days at power.

B. Inspection Activities

Fifty-two routine and special inspections were conducted during this assessment period (January 1, 1990, through June 30, 1991). Significant inspections are listed in Section IV.B.2.

1. Inspection Data

Facility Name: Diablo Canyon Units 1 & 2, Docket numbers: 50-275 & 50-323, Inspection Reports: 89-33, 89-34, 90-01 through 90-09, 90-11 through 90-32, 91-01 through 91-14, 91-16 through 91-18, 91-21 and 91-23. Five of these reports summarized management meetings, two reports documented enforcement conferences, and one documented a meeting about the Quality Assurance program.

2. Special Inspection Summary

a. From January 1 through February 2, 1990, a special inspection was conducted to assess the effectiveness of the licensee's corrective action program. (Inspection Report 50-275 & 50-273/91-01)

b. From April 17 through May 25, 1990, a special inspection was conducted to review licensee activities in response to spring pack relaxation in Limitorque actuators for certain MOVs. (Inspection Report 50-275 & 50-323/90-16)

c. From November 27, 1990, through January 11, 1991, a special inspection was conducted to review the licensee's mechanical maintenance measuring and test equipment program. (Inspection Report 50-275 & 50-323/90-29)

d. From February 11 through February 14, 1991, a followup inspection was conducted to review the licensee's mechanical maintenance measuring and test equipment program. (Inspection Report 50-275 & 50-323/91-04)

e. From March 8 through March 13, 1991, an Augmented Inspection Team (AIT) was formed to review the licensee's actions in response to the loss of offsite power to Unit 1. (Inspection Report 50-275 & 50-323/91-09)

f. From April 22 through May 24, 1991, a special inspection was conducted to perform an electrical distribution system functional inspection. (Inspection Report 50-275 & 50-323/91-07)

C. Enforcement Activity

Unit 1

The inspections during this assessment period identified 16 cited violations, 1 deviation, and 13 non-cited violations. One of the cited violations was a Severity Level III with no civil penalty, and was issued for failing to prevent unauthorized access to vital areas, not properly recording entries into vital areas, and for failing to protect safeguards information (Inspection Report 50-275/90-02).

UNIT 2

The inspections during this enforcement period identified 4 cited violations, 1 deviation, and 1 non-cited violation. All of the cited violations were Severity Level IV.

D. Confirmatory Action Letters

None

E. Licensee Event Reports

Unit 1 LERs

Unit 1 issued 49 LERs during this reporting period. The LERs were: 83-37, 83-38, 84-42 through 84-45, 89-15, 89-16, 89-17, 89-19, 90-01 through 90-07, 90-10, 90-12 through 90-15, 90-17 through 90-19, and 91-01 through 91-10 (91-10 was a voluntary LER). Fourteen security LERs were issued.

Unit 2 LERs

Unit 2 issued 13 LERs during this reporting period. The LERs issued were: 88-27, 89-11, 89-12, and 90-01 through 90-10 (90-08 was a voluntary LER).

50-275/323-OLA-c
I-MFP-203

SLOMFP Exhibit 203

"NOT ADMITTED"

RELATED CORRESPONDENCE

'93 OCT 28 P6:55

PACIFIC GAS & ELECTRIC COMPANY
DIABLO CANYON POWER PLANT

Onsite Safety Review Group (OSRG)
March 1993 Monthly Report

SUMMARY

The following items summarize the OSRG's observations and concerns from the meetings for this month. A more detailed description follows, and all items that were reviewed are listed in Attachment 1.

2. The bonnet bolts of two CVCS valves in the post-LOCA recirculation path were torqued without work orders. The OSRG is concerned that the valves may have been damaged or the torques may be unacceptable. For example, to preclude diaphragm damage, such valves must be slightly open during torquing of the bonnet bolts.

DESCRIPTION

The following items were discussed by the OSRG. Generally, where concerns exist, they have been discussed with the appropriate TRG Chairman or responsible department head and an AR has been initiated, if applicable.

2. AR A0297791: Unauthorized Bolt Torquing

CONCERNS: The bonnet bolts of two CVCS valves in the post-LOCA recirculation path were torqued without work orders. Mechanical Maintenance notification and authorization of this work were not received per maintenance procedures. Additionally, the unauthorized torquing, documented in an AR written for another purpose, bypassed the QE initiation process. Thus, the adequacy of the work could be evaluated only after the fact.

RESOLUTION: The OSRG issued AR A0297791 to identify these concerns. The AR also requested an assessment of the acceptability of the torquing. The requirements of the appropriate maintenance procedure may not have been followed (for example, to preclude diaphragm damage, the valves must be slightly open when torquing the bonnet bolts).

DISCUSSION: AR A0291914 tracked a prudent action for NCR DC2-91-TN-N047. The action regarded improvements to CVCS valve leakage control based on refueling outage 1R5 lessons learned. The AR states that "two valves" (CVCS-1-547 and CVCS-1-548) were identified to have seat leak-by and, subsequently, to have bonnet-to-body diaphragm leakage.

ARs A0281298 and A0281300 were issued to correct seat leak-by of these valves. Work orders C0105772 and C0105773 were issued to adjust the travel stops to stop the seat leak-by. Torquing the bonnet bolts to stop the bonnet-to-body leakage also was performed. However, this was beyond the scope of the work orders.

The following concerns were identified:

1. No additional work orders were issued to torque the bonnet bolts.

2. Neither the work planning section nor Mechanical Maintenance Engineering was notified prior to torquing.

3. The as-left torque value for valve 548 was not documented in the work order summary.

4. Prior to torquing, MP M-51.7 step 7.1.24 required the valves to be a quarter turn open to prevent diaphragm damage. It is not known whether this step was performed.

5. A new AR should have been used to document the failures both to notify Maintenance Engineering and to issue work orders for torquing the bonnet bolts. Since the early text of AR A0291914 had already concluded that a QE was not required for an NCR prudent action, the opportunity to issue a QE for these leakage problems was missed.

6. A leak-type AR could not be found which documented the diaphragm leakage of valve 548. AR A0281357 was, however, issued for the diaphragm leakage of valve 547.

The OSRG issued AR A0297791 to request an assessment of the acceptability of the work performed on valves 547 and 548. The AR also requests the initiation of at least one QE to address the above concerns. The AR further notes that work performed beyond the scope of existing work orders, and the failure to issue ARs for new problems, are recurrent issues that have received past NRC scrutiny.

This item will be included in the OSRG's Open Item 90-08 regarding work without approval.

During the OSRG meetings for this month, the Chairman or his alternate was present and a quorum was established and maintained. Detailed information on any item included in this report can be obtained by reviewing the referenced document or by contacting the OSRG.

The OSRG continues to monitor Plant activities by conducting Plant tours and surveillances, reviewing the daily Shift Foreman/Control Operator's logs, all significant Action Requests/Quality Evaluations and by attending appropriate Plant TRG, PSRC, Staff, NRC Exit and Scheduling meetings. In addition, DCNs are screened and those having a significant potential impact upon operations are identified for a more thorough review.

PACIFIC GAS & ELECTRIC COMPANY
DIABLO CANYON POWER PLANT

Onsite Safety Review Group (OSRG)
April 1993 Monthly Report

SUMMARY

The following items summarize the OSRG's observations and concerns from the meetings for this month. A more detailed description follows, and all items that were reviewed are listed in Attachment 1.

1. The failure of a steam supply valve to the turbine-driven auxiliary feedwater pump on 1/31/93 was attributed to a sticking valve stem initially. Later, in March, it was found that the valve failure was due to rusted bearings in the operator and not sticking of the stem. Therefore, the valve had been declared operable on 2/1/93 without determining and fully correcting the actual failure mechanism.

3. Design Criteria Memoranda (DCMs) issued by NES contain "Category 1" maintenance and surveillance requirements that are beyond those in Technical Specifications. An NCR was issued in early 1993 to address these requirements not always being performed by the plant. Thus safety related equipment may not meet all design bases requirements. This may impact operability. This NCR should receive elevated management attention.

DESCRIPTION

The following items were discussed by the OSRG. Generally, where concerns exist, they have been discussed with the appropriate TRG Chairman or responsible department head and an AR has been initiated, if applicable.

1. NCR DC2-93-EM-N014: Turbine Driven Auxiliary Feedwater Pump (TDAFWP) Steam Supply Valve Failed to Close

   CONCERN: The failure of 2-FCV-37 on 1/31/93 was attributed to a sticking valve stem initially. Later, in March, it was found that the valve failure was due to rusted bearings in the operator and not sticking of the stem. Therefore, the valve had been declared operable on 2/1/93 without determining and fully correcting the actual failure mechanism.

   RESOLUTION: The TRG concluded that future failures of MOVs, for which the cause is not certain, should be evaluated. The plant should assess the consequences of subsequent failure and the basis for returning the MOV to service. The OSRG believes that similar action should be taken for any safety related plant equipment. However, since the documented NCR action only was to consider such requirements for other plant equipment, the OSRG will track other instances of failures that require evaluation via an Open Item.

   DISCUSSION: On 1/31/93 during surveillance testing, 2-FCV-37 failed to close remotely. Inspections revealed no apparent problems except inadequate stem lubrication. The valve stem was lubricated, the valve was successfully stroked several times, and the valve was declared operable. The root cause of the failure was stated to be "sticking valve stem."

   Subsequent upper internal and limit switch compartment inspections on 2/4/93 revealed nothing that would have caused the failure to close. Generic Letter (GL) 89-10 MOV testing was performed satisfactorily, and a manual load cell test was also satisfactory. Since the load cell test was performed at the design basis thrust, the valve was declared operable following the above-mentioned work.

A detailed internal inspection of the valve operator in March revealed water, particulates, and visible corrosion of the upper bearing. Corrosion-inducing binding of the operator upper bearing was determined to be the actual cause for the January failure. Since the valve stem is exposed to the atmosphere and two bevel gear quad rings had not been installed during a 2R3 overhaul of the operator, rain and condensate entered the operator. The reason for the failure to install the quad rings could not be determined. The person who performed the overhaul could not remember any specifics of this work. The TRG root cause was "procedural deficiency" in that the maintenance procedure did not contain sufficient detail for installation of the quad rings.

Following extensive evaluation, the event was determined not to be reportable. Only manual closure of this valve is required to fulfill its safety function, and this was not affected. Additionally, the valve was always capable of reopening following partial or complete closure in accordance with the GL 89-10 valve mispositioning requirements. The valve operator's ability to deliver the required maximum thrust for opening was not affected. The upper bearing is not loaded in the opening direction. The required thrust capability was confirmed by load cell testing during 2R5.

3. NCR DC0-93-TN-N006: Failure to Perform DCM Category I Maintenance and Surveillances

   CONCERN: DCMs issued by NES contain "Category 1" maintenance and surveillance requirements. An NCR was issued in early 1993 to address these requirements not being performed by the plant in all cases. Thus, safety related equipment may not meet all design bases requirements. This may impact operability. This NCR should receive elevated management attention.

RESOLUTION: The OSRG believes that this NCR should receive high management attention and maximum resource allocation. This is needed to ensure prompt determinations of operability for affected equipment. This issue will be presented to NSOC.

DISCUSSION: During an audit performed during the last quarter of 1992, QP&A personnel determined that numerous maintenance and surveillance requirements specified in various DCMs are not being performed. The most important category of these requirements, designated as Category I, are required to ensure the design bases capabilities of safety related components and systems.

During the only ' RG meeting, 2/3/93, it was noted that NES believes the Category I surveillance and maintenance requirements to be equivalent to those specified by Tech Specs. Therefore, the Category I requirements are required to ensure that the affected equipment will perform its intended safety function. Based on this information, the OSRG representative identified the need for prompt operability assessments for equipment for which one or more Category I requirements have not been performed. It was determined in the TRG that operability assessments could not be performed until the Category I requirements were adequately identified. Evidently, some requirements are in DCMs, some are still being finalized based on NES and Plant Engineering discussions, and some are not yet identified.

The TRG determined that a substantial effort was required to identify and evaluate all Category I requirements. The TRG was to have reconvened in February with additional department (Maintenance and Operations) in attendance. Investigative actions include assignment of NES personnel for review of DCMs to determine status of Category I requirements, and development of a tracking system for the review. As of April, the TRG has not reconvened.

The NCR was discussed with the QA representative to the TRG. He concurred that this NCR had not received adequate priority/attention. QA had discussed this NCR with QC and requested that it be included in a Plant Manager's Meeting.

PACIFIC GAS & ELECTRIC COMPANY
DIABLO CANYON POWER PLANT

Onsite Safety Review Group (OSRG)
May 1993 Monthly Report

SUMMARY

The following items summarize the OSRG's observations and concerns from the meetings for this month. A more detailed description follows, and all items that were reviewed are listed in Attachment 1.

2. The Unit 2 containment equipment hatch was not closed fully during core off-load in refueling outage 2R5. There was a surprising lack of procedural compliance and lack of independent verification.

3. The design change that upgraded radiation monitors RM-44A/B made them non-fail-safe for MODE 6 operations. This could result in a single failure of a monitor's power supply preventing an automatic containment isolation from occurring during a fuel handling accident. The design change safety evaluation did not identify the reduction in margin of safety as defined in the basis for the applicable Technical Specification. Similarly, the license amendment request sent to the NRC did not identify this change.

DESCRIPTION

The following items were discussed by the OSRG. Generally, where concerns exist, they have been discussed with the appropriate TRG Chairman or responsible department head and an AR has been initiated, if applicable.

2. NCR DC2-93-MM-N013: Unit 2 Containment Equipment Hatch not Fully Closed During Core Off-Load

   CONCERN: The Unit 2 containment equipment hatch was not closed fully during core off-load during the fifth refueling outage. There was a surprising lack of procedural compliance and lack of independent verification

   RESOLUTION: The NCR corrective actions address the concerns regarding this incident.

   DISCUSSION: During refueling outage 2R5, preparations were being made to off-load the core. One of the prerequisites was to install the containment equipment hatch "with a minimum of 4 bolts." The mechanic, who was called upon to install the hatch, was not told why it was necessary.

   The tailboard held by the maintenance foreman did not describe the post installation verification in detail. After installation, the procedure required verification that the hatch was seated all the way around its circumference from outside containment.

   The mechanic went into containment without taking the procedure or work package in hand. He executed the task from memory. As a result, the bolts were not torqued to the exact specifications, the post-installation inspection was not performed in a complete manner, and the bolts were not spaced evenly enough to seal the entire circumference. Although the mechanic thought the bolts were spaced evenly, the ladder that he was using and the lack of installed rigging prevented him from reaching the bolts at the top of the hatch safely. As a result, there was a gap at the top of the hatch. The gap was visible from outside containment. This was not noticed until a refueling SRO noted the gap during a walkdown, some 36 hours after the start of core unloading.

The mechanic signed off the maintenance procedure after the job was completed without reading it carefully. Also, there was no mandatory requirement for QC or other independent verification of the hatch closure. Due to a lack of past problems, a QC planner elected not to conduct a surveillance of this activity. In addition, a verification block in a refueling operating procedure for a Shift Foreman (SFM) signature was merely a check that the applicable work order had been completed. No physical verification was required.

50-275/323-OLA-2
I-MFP-207
"NOT ADMITTED"

WLF P. Exhibit 20 (NRC / Notice of Violation
026.14

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/973-4684
TWX 910-372-6587

James D. Shiffer
Senior Vice President and
General Manager
Nuclear Power Generation

155170

RELATED CORRESPONDENCE

'93 OCT 28 P6:55

July 23, 1990

PG&E Letter No. DCL-90-190

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Reply to Notice of Violation in NRC Inspection Report
Nos. 50-275/90-16 and 50-323/90-16

Gentlemen:

NRC Inspection Report Nos. 50-275/90-16 and 50-323/90-16 (Inspection Report), dated May 24, 1990, contained a Notice of Violation citing two Severity Level IV violations regarding maintenance activities on Limitorque motor-operated valves (MOVs). PG&E's response to the Notice of Violation is provided in the Enclosure. The Inspection Report also requested that PG&E discuss corrective actions to provide an adequate technical evaluation for the testing and maintenance of MOVs to assure their design basis operability. This area is being addressed extensively in PG&E's actions for Generic Letter 89-10 and is also addressed in the enclosure.

Kindly acknowledge receipt of this material on the enclosed copy of this letter and return it in the enclosed addressed envelope.

Sincerely,

J. D. Shiffer

cc: A. P. Hodgdon
J. B. Martin
P. P. Narbut
S. A. Richards
H. Rood
CPUC
Diablo Distribution
INPO

Enclosure

DCO-90-EM-N014

3283S/0084K/ALN/2237

RECEIVED
JUL 26 1990
NRC
CORRESP. CONTROL CENTER

ENCLOSURE

REPLY TO NOTICE OF VIOLATION IN NRC
INSPECTION REPORT NOS. 50-275/90-16 AND 50-323/90-16

On June 22, 1990, as part of NRC Inspection Report Nos. 50-275/90-16 and 50-323/90-16 (Inspection Report), NRC Region V issued a Notice of Violation citing two Severity Level IV violations for Diablo Canyon Power Plant (DCPP) Units 1 and 2. The statements of violation and PG&E's responses follow.

A. STATEMENT OF VIOLATION

10 CFR Part 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, states, in part:

"Activities affecting quality shall be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures or drawings..."

Nuclear Plant Administrative Procedure NPAP-E-14/NPG-5.3, Supplier Documents and Recommendations, states as follows, in part:

Paragraph 1.2: "Information covered by this procedure includes vendor bulletins, vendor information..."

Paragraph 4.1: "Supplier recommendations/documents within the scope of this procedure, when received by NPG organizations...or individuals, shall be forwarded to the Supervisor, PSG."

Contrary to the above, Limitorque Maintenance Update 89-1, when received by individual licensee employees from Limitorque on or about December 2‚, 1989, was not forwarded to the Supervisor, PSG. In addition Limitorque Maintenance Update, dated August 1988 had been received from the vendor by an individual licensee employee but had not been forwarded to the Supervisor, PSG, as of May 25, 1990.

This is a Severity Level IV violation (Supplement 1).

REASON FOR THE VIOLATION IF ADMITTED

PG&E concurs that plant personnel failed to follow administrative requirements in NPAP E-14 regarding control and technical evaluation of information received from Limitorque. PG&E's review concluded that this failure to forward vendor information to the Supervisor, PSG, in accordance with NPAP E-14 was due to lack of familiarization with NPAP E-14 requirements.

CORRECTIVE STEPS TAKEN AND RESULTS ACHIEVED

PG&E has reviewed the subject vendor maintenance update information to determine if the information had been appropriately incorporated into the maintenance program. This review determined that all appropriate information had been incorporated into the DCPP maintenance program prior to the NRC inspection.

CORRECTIVE STEPS THAT WILL BE TAKEN TO AVOID FURTHER VIOLATIONS

The requirements of NPAP E-14 will be reemphasized to all appropriate personnel. Training on the requirements of NPAP E-14 will be incorporated into the ongoing maintenance training program to ensure that maintenance personnel receive periodic refresher training concerning the proper methods for receipt and incorporation of vendor information.

PG&E will also submit written requests to all of its suppliers listed on the Qualified Suppliers List that all future correspondence regarding vendor technical information shall be directed to the appropriate responsible organization. In addition, a standard clause will be added to all future purchase orders stating the this requirement.

The Limitorque vendor manual update is within the portion of Vendor Manual Review Program which will be completed by the end of 1990. This program consists of performing both a Nuclear Engineering and Construction Services (NECS) and DCPP technical review, contacting the vendor, and reissuing the manual in an updated format as a controlled document.

Further, PG&E as a result of its Vendor Manual Review Program has reviewed its vendor contact program and identified potential enhancements. These enhancements are being finalized and will be described as part of PG&E's response to Generic Letter 90-03.

DATE WHEN FULL COMPLIANCE WILL BE ACHIEVED

PG&E is in full compliance with administration procedures in that the Limitorque information is appropriately incorporated into PG&E's maintenance program. All actions to enhance handling of vendor material and prevent recurrence are targeted for completion of the end of 1990.

B. STATEMENT OF VIOLATION

10 CFR Part 50, Appendix B, Criterion V, Instructions, Procedures and Drawings, states, in part:

"Activities affecting quality shall be prescribed by documented instructions, procedures or drawings of a type appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures, or drawings..."

Nuclear Plant Administrative procedure NPAP C-12, Rev. 19, Identification and Resolution of Problems and Nonconformances, Paragraph 5.4.1.a, states, in part:

"A Quality Evaluation is required for any of the following situations in which the quality of an item or activity is determined to be unacceptable or indeterminate.

1. An item will not perform its intended safety function or no longer meets its design requirements such as seismic or environmental qualification requirements.

2. There is a question whether an item will perform its intended safety function or meet design requirements."

Contrary to the above, at the time of the inspection, a Quality Evaluation had not been performed on spring pack deficiencies in Limitorque actuators of four safety-related valves identified in Request Nos. A0126108, A0126109, A0126110, A0125750 dated October 1988. The deficient condition raised the question of whether the items would perform their intended safety function or meet design requirements.

This is a Severity Level IV violation (Supplement 1).

REASON FOR THE VIOLATION IF ADMITTED

PG&E does not believe that inappropriate action was taken or that a violation of procedures occurred regarding the assessment of spring pack deficiencies.

During the Unit 2 second refueling outage in the fall of 1988, PG&E identified a problem with four SMB-00 spring packs. In all four cases the craftsman identified the problem as a "collapsed" spring pack and documented this on Action Requests (ARs). In three cases the craftsman had noted that the spring pack thrust washer could be rotated by hand and had interpreted this as a sign of potential relaxation and replaced the spring pack. In the fourth case, the craftsman identified the spring pack as "collapsed" because different gap measurements were observed around the perimeter of the thrust washer. The gap difference between 0 degrees and 180 degrees was 0.004 inches. The craftsman also interpreted this as a sign of potential relaxation and replaced the spring pack. An investigation of these ARs was conducted by the PG&E maintenance engineer cognizant in Limitorque valve operators who determined that the actions taken were conservative. The ability to rotate a thrust washer by hand may be indicative of a spring pack relaxation problem. PG&E has found that, dependent upon the factory set preload of certain SMB-00 spring packs the thrust washer can be rotated by hand on a new, fully loaded spring pack. The gap difference is also normal for a new, fully loaded spring pack and does not necessarily indicate a degraded condition.

In all four cases the maintenance engineer made the decision that the spring packs had been operable and that the actuators would have performed satisfactorily before maintenance. This evaluation was supported by the successful performance of surveillance testing. In addition, for AR A0125730, the maintenance engineer's evaluation concluded that the valve operator was fully functional prior to maintenance as demonstrated by load cell testing approximately sixteen months earlier.

The evaluation of the four cases of spring pack relaxation occurred before the Limitorque "Notes from the Field" were issued addressing possible spring pack relaxation. No manufacturer's maintenance information existed prior to the identification of these cases and, therefore, there was no reason to consider these observed spring pack differences as more than a preventive maintenance task and normal wear and tear.

As a result of manufacturer information which was published subsequent to these four cases, if similar spring pack conditions should occur they would result in issuance of a Quality Evaluation. In retrospect, PG&E believes that initiation of a Quality Evaluation would have better documented evaluation of the problems noted in the subject ARs. However, considering the information available at the time of identification of these four cases, and the associated successful pre-maintenance and/or post-maintenance surveillance testing, it is PG&E's position that the maintenance engineer made the correct judgement in the determination that actuator operability was not compromised and that a Quality Evaluation was not required. Based on the information provided by the PG&E maintenance engineer cognizant in Limitorque valve operators, Quality Control concurred in the decision that no Quality Evaluation was required. Also, as noted in the Inspection Report, an observed significant strength involved PG&E's identification of a potential generic deficiency.

ACTIONS TAKEN TO IMPROVE PERFORMANCE

Even though PG&E believes that the maintenance engineering evaluation of the problem as a non-quality problem was appropriate, the following actions have been taken since the time when the subject ARs were initiated that should further enhance evaluation of maintenance problems:

1. Plant management recognized the need for increased management attention in the electrical maintenance area and created a new Electrical Maintenance Manager position in March 1990.

2. The new Electrical Maintenance Manager has emphasized problem identification, elevating problems to the appropriate management attention, preservation of equipment problem evidence, troubleshooting techniques, and root cause analysis in staff and department meetings.

3. In addition, the Assistant Plant Manager - Maintenance has also emphasized problem identification and initiation of the appropriate quality documentation, i.e., QE or NCR.

ADDITIONAL INFORMATION REQUESTED

The Inspection Report also requested that PG&E discuss corrective actions to provide an adequate technical evaluation for the testing and maintenance of MOVs to assure their design basis operability.

In addition to the above actions to address the specific violations, PG&E has recently developed a program plan in accordance with Generic Letter 89-10 to verify by design basis review and testing the capability of the installed safety-related valves to perform their intended design function. The program includes enhanced testing and maintenance activities for the Diablo Canyon MOVs. The enhanced maintenance will include "as found" MOV diagnostics on a sampling basis as a minimum. Equipment procurement is in progress and the first set of "as found" data will be taken during the next refueling outage for each unit. This program plan was jointly developed by engineering and plant personnel and is currently being implemented, with full implementation targeted by June 1994.

Major action for this program are summarized below.

* Identify all motor operated valves and which valves are to be excluded from further review.
* Establish the maximum differential pressure based on accident analysis and operating procedures.
* Compare the valve design differential to the identified design value to establish capability.
* Based on the maximum differential pressure recalculate required setting for the motor operator.
* Perform differential pressure testing for all of the motor operated valves.
* Develop a program to control the setpoints for each valve.
* Develop a predictive/preventive maintenance program for each valve.
* Develop an enhanced surveillance program for motor operated valves.

MFP EXHIBIT 213

U. S. NUCLEAR REGULATORY COMMISSION

RELATED CORRESPONDENCE REGION V

DOCKETED USNRC

'93 OCT 28 P6:55

Report Nos. 50-275/92-13 and 50-323/92-13

Docket Nos. 50-275 and 50-323

License Nos. DPR-80 and DPR-82

Licensee: Pacific Gas and Electric Company
77 Beale Street, Room 1451
San Francisco, California 94106

50-275/323-OLA-2
I-MFP-213
"NOT ADMITTED"

Facility Name: Diablo Canyon Units 1 and 2

Meeting at: San Luis Obispo, California

Meeting Conducted: April 2, 1992

Report Prepared by: [signature] FOR 4-15-92
M. H. Miller, Resident Inspector — Date Signed

Approved by: [signature] FOR 4-15-92
P. H. Johnson, Chief — Date Signed
Reactor Projects Section 1

Summary: An announced periodic management meeting was held to discuss recent Diablo Canyon events and issues, and to review progress of licensee programs.

DETAILS

1. Meeting Attendees

   a. Licensee Attendees

      R. Anderson, Manager, Nuclear Engineering and Construction Services (NECS)
      M. Angus, Manager, Technical Services
      J. Blakley, Sr. Licensing Engineer, Nuclear Safety Assessment and Regulatory Affairs (NSARA)
      J. Castner, Regulatory Compliance
      M. Davido, Senior Engineer, NECS
      R. Domer, Vice President, General Engineering and Construction
      W. Fujimoto, Vice President, Nuclear Technical Services
      J. Gisclon, Acting Manager, Nuclear Operations Support
      W. Goelzer, System Engineering
      T. Grebel, Supervisor, Regulatory Compliance
      B. Giffin, Manager, Maintenance Services
      K. Herman, Supervisor, Instrumentation and Controls Engineering
      J. Hoch, Manager NSARA
      P. Lang, Senior Engineer, Quality Control
      T. Leserman, Nuclear Operations Support
      N. Malenfant, Corporate Communications
      T. Nelson, Nuclear Operations Support
      H. Phillips, Director, Electrical Maintenance
      J. Phipps, Systems Engineering
      R. Powers, Director, Mechanical Maintenance
      G. Rueger, Sr. Vice President, Nuclear Power Generation
      J. Sexton, Manager, Quality Assurance
      J. Shiffer, Executive Vice President
      J. Shoulders, Onsite Project Engineering, NECS
      D. Sokolsky, Nuclear Regulatory Affairs
      H. Thailer, Supervisor, Piping Engineering, NECS
      J. Tompkins, Director, NSARA
      J. Townsend, Vice President, Diablo Canyon Operations
      M. Tresler, DCPP Project Engineer
      R. Webb, NCES Engineering

   b. NRC Region V Attendees

      J. Martin, Regional Administrator
      L. Miller, Chief, Reactor Safety Branch
      M. Miller, Resident Inspector
      P. Morrill, Chief, Reactor Projects Section 1
      K. Perkins, Deputy Director, Division of Reactor Safety and Projects
      R. Scarano, Director, Division of Radiation Safety and Safeguards
      H. Wong, Senior Resident Inspector

c. NRC Headquarters Attendees

C. Regan, Assistant Project Manager, Project Directorate - V
H. Rood, Project Manager, Project Directorate - V

d. Other Attendees

Jeff Neal
June Von Ruden, Mothers for Peace

2. Details

Mr. Martin opened the meeting, stating that this was a periodic meeting to review topics of general interest and concern. He observed that several management meetings had been conducted at or near the Diablo Canyon site, and future meetings would be conducted at locations open for public attendance.

a. Containment Fan Cooler Unit Backdraft Dampers

PG&E presented their evaluation of recent containment fan cooler unit (CFCU) problems. Several of the CFCUs were found to have backdraft dampers that did not fully close when the fan was secured. This event is described in Licensee Event Report 50-275/91-19. PG&E also demonstrated a mechanical model of a backdraft damper to illustrate the various technical concerns.

Mr. Giffin noted that a contributing cause of inadequate maintenance of the CFCUs, which led in part to the problems, was underestimating the safety significance of the backdraft dampers. He added that during the troubleshooting process, although there was a concern that the dampers were open, no one initially thought to verify that the dampers would fully close when the associated fan was shut down. Mr. Morrill commented that in meetings with PG&E in February 1992, the NRC had urged visual verification to determine if CFCU counter rotation was occurring.

Mr. Rueger stated that the NECS organization was involved early in the CFCU concerns. This was due to processes put in place after issues concerning Regulatory Guide 1.97 occurred in late 1991. Mr. Fujimoto added that a methodology to establish an integrated problem response team had been established. A team had been formed and had met to resolve the CFCU issues.

The NRC questioned the licensee regarding why indications of broken bolts on backdraft dampers in March of 1991 were not adequately followed up. Mr. Perkins considered that the system engineer should have been involved in determining the cause of broken bolts since system problems may have been the root cause. In addition, management should better communicate expectations to system engineers to identify system initiated problems and the need to evaluate system history. Mr. Townsend agreed that system

engineering has the responsibility for tracking the history of these kinds of problems, however he felt that the component engineers should have resolved the cause of the broken bolts.

Mr. Fujimoto noted that, after evaluation of industry and historical experience, the integrated problem response team identified that adequate safety margin remained in the dampers, in that the CFCUs contained around 800 bolts, and that only about 20 had been found broken.

Mr. Martin observed that the March 1991 failure to evaluate the broken bolt issue illustrated a lack of basic engineering instincts. Mr. Martin closed the discussion of this issue by stating that the attitude should be that if any bolts are broken, there is a problem. He restated the NRC concern that licensee management needed to communicate the right expectations for resolving problems to all engineering groups and to organizations performing the quality assurance functions.

b. Feedwater Pump Trip

The licensee has experienced several feedwater pump problems due to the failure of an associated control system power supply. The licensee presented a discussion of technical and historical information concerning this issue. Mr. Rueger stated that PG&E may have been too narrowly focused on the issue, causing PG&E to fix the existing equipment, rather than to question the adequacy of the design after repeated failures. Mr. Fujimoto noted that since the equipment had been redesigned in February, 1989, there was a tendency to continue to try to make the new design work, rather than reassess the design.

Mr. Martin observed that it was not typical of a strong engineering organization to wait for several failures to fix a deficient design, particularly in the case of these failures, which resulted in challenges to operators and the plant. He noted that the December 3, 1991, failure should have raised serious concerns, and should have been dealt with more forcefully. Each action PG&E took may have appeared reasonable when considered individually, but not in perspective with the whole issue. Although these particular components were not safety-related, there is a need to come to terms with timely corrective action for these situations before problems arise with higher safety significance.

Mr. Rueger agreed, noting that he had used this issue as an example of an area requiring improvement.

c. Equipment Unavailability

The licensee presented summaries of availability data for key safety systems. Data indicated that system availability at Diablo Canyon was in the highest quarter of the industry.

not successfully resolved because of lack of overall perspective. Mr. Martin concluded that management expectations should direct technical organizations to seek out these types of problems. Mr. Shiffer agreed.

Mr. Martin stated that items on the agenda which were not covered in this meeting should be covered in the next management meeting. The meeting was adjourned.