U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report: 50-528/92-14, 50-529/92-14, and 50-530/92-14

Dockets: 50-528, 50-529, and 50-530

Licenses: NPF-41, NPF-51, NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999, Station 9012
Phoenix, Arizona 85072-3999

Facility: Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Inspection Duration: April 27 - May 1, 1992 (Preparation week)
June 1 - 5, 1992 (Inspection week)

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* Week of April 27 - May 1, 1992 only.

Approved By: Anthony O. Gody Jr. 7/2/92
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Background and General Conclusions:

The inspection was conducted during the week of June 1 - 5, 1992, with an information gathering week from April 27 to May 1, 1992.

The objective of this inspection was to verify the functionality of safety systems by inspecting performance related attributes of the system with a focus on its associated instrumentation and controls systems, and the ability of the system to perform its intended design function.

In order to perform this assessment, the team reviewed the adequacy of selected instrumentation and control systems, the Palo Verde Nuclear Generating Station setpoint control program, I&C maintenance and calibration operations and procedures, Quality Assurance's intrusion into the I&C programs and process, and the Palo Verde management commitment to the support and development of the I&C and setpoint programs.

The team concluded that APS management had recognized the importance of I&C and setpoint programs, and had taken positive steps to improve the programs by initiating a Quality Engineering technical assessment, and by taking appropriate corrective action for items identified during the assessment. The team also noted that the Palo Verde business plan included the support required to continue efforts in these areas. The licensee's self-assessment, its commitments to resolving identified problems, and its program improvement plans were considered proactive.

However, based on the findings of inadequate corrective actions in two different areas, and the apparent acceptance of I&C technicians that "skill-of-the-craft" judgment superseded procedural compliance in use of M&TE, the team expressed concern (1) that similar cases of inadequate engineering evaluations and corrective actions for instruments found out of tolerance could be prevalent throughout the units, and (2) that the I&C technicians' failure to follow procedural requirements for M&TE usage could result in non-conservative calibration of safety-related instrumentation.

The team concluded that the licensee's failure to evaluate and take corrective action, for transmitters found out of tolerance, appeared to have a root cause in two areas. First, an instrument trending program, designed to ensure engineering attention for out-of-tolerance as-found data, had not been clearly defined or implemented. Second, procedures did not provide a clear definition, to the technician or the reviewing supervisor, for what degree of instrument out-of-tolerance should be considered significant or deserving of engineering attention.

Additionally, the team noted a weakness in NSSS vendor calculation review, and a continued weaknesses in the Palo Verde vendor manual control and review.

The licensee had not formally reviewed or accepted NSSS vendor setpoint calculations. The team found that installed instrumentation differed, in some cases, from the instrumentation data used in vendor-performed setpoint and other calculations.

Revised vendor information for feedwater flow transmitters, issued by the vendor in 1989, was not obtained and approved by the licensee until October 1991. The revised data had not been incorporated into calculations until this inspection, when the licensee had to use the updated specifications to mitigate non-conservative calculational assumptions identified by the NRC.

Inspection Report 50-528/92-15, dated June 15, 1992, had identified two similar vendor manual control and review problems involving reactor trip breakers.

Based on these findings, the team concluded that the Palo Verde vendor manual control and review program was in need of additional management oversight.

Areas Inspected:

Based on review of probabilistic risk assessment (PRA) data and Palo Verde's updated Final Safety Analysis Report (UFSAR), the following systems, accidents, and instrument loops were selected for inspection:

SYSTEM	ACCIDENT	INSTRUMENT LOOP
AFW	Loss of Feedwater Loss of Power	Steam Generator Level Pressurizer Pressure
EDG	Loss of Power	Control & Timing Relay Setpoints
MFW	Main Steam Line Break	Main Feedwater Flow, Temperature (inputs into secondary Calorimetric)

During this inspection the following inspection procedures were used as guidance: Draft NRC Inspection Procedure Systems Based Instrumentation and Control Inspection, and NRC Inspection Modules 56700, 61700, 61705, 61725, 62704, 37701, and 37702.

Significant Safety Matters:

No significant safety matters were identified during this inspection.

Summary of Violations and Deviations:

In the areas inspected, two violations and one deviation were identified:

Violations:

A. A violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action. Corrective actions or engineering assessments had not been performed for pressurizer narrow range pressure transmitters or the emergency diesel generator low lube oil pressure trip transmitters, which were routinely found to be outside of their as-found acceptance tolerances. (Violation 50-528, 529, 530/92-14-02).

B. A violation of Technical Specification 6.8.1. The licensee failed to follow procedural requirements for M&TE while performing instrument calibrations for safety-related instrumentation. (Violation 50-528/92-14-03).

Deviation:

The EDG air start system was routinely operated at lower pressures than that used to demonstrate the five-start design capability of the starting air cylinders. (Deviation 50-528, 529, 530/92-14-01).

Inspection Follow-up Items:

During this inspection three items were opened, and no items were closed.

Strengths:

The team concluded that the licensee had realized the importance of instrumentation and control and setpoint programs, and had formalized their efforts through increased management oversight and support of programs and work.

Weaknesses:

Based on the inspectinn findings, the team concluded that weaknesses existed in the following areas:

- Identification of items requiring corrective actions and/or assessments by engineering,

- Procedural compliance in the documentation and use of M&TE,

- Vendor manual update and information distribution, and

- NSSS vendor setpoint calculation review and documentation.

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INSPECTION REPORT 50-528, 50-529, 50-530/92-14
ARIZONA PUBLIC SERVICE COMPANY
PALO VERDE NUCLEAR GENERATING STATION UNITS 1, 2, AND 3

1 EXECUTIVE SUMMARY

During the period of June 1 - 5, 1992, the NRC conducted an announced system-based instrumentation and control (I&C) team inspection at the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (PVNGS 1,2,3). In preparation for the inspection, the NRC team conducted an information gathering week at PVNGS from April 27 through May 1, 1992.

The inspection was conducted to verify the functionality of safety systems by inspecting performance-related attributes of the safety system with a focus on its associated I&C systems. The inspection evaluated process parameters used to control safety system operations, to ensure that each safety system examined would perform as described in the Updated Final Safety Analysis Report (UFSAR) and as assumed in accident analyses. The inspection reviewed, in depth, both the design and field oriented aspects of the associated I&C systems, including setpoint calculations, mechanical/electrical system interfaces, calibration procedures, isolation, and equipment specifics.

The inspection team selected analyzed accidents and/or transients requiring automatic or timely protective action for accident mitigation. Palo Verde's UFSAR, licensing documents, licensee draft individual plant examination/probabilistic risk assessment (IPE/PRA), and the NRC plant-specific PRA were used to select the dominant accident sequence and instrument loops.

The team identified specific mechanical systems and associated I&C systems for each accident mitigation sequence, and identified controlling process variables for protective action initiation. The inspection included those instruments relied upon for safety system actuation, control, and indication. The adequacy of the I&C system for controlling process variables was then evaluated relative to accident analyses, assumptions, calibration uncertainties, drift, environmental uncertainties, and other factors. Additionally, design assumptions related to instrument type, location, maintenance, and drift were evaluated.

The inspection identified several deficiencies in the Palo Verde I&C and setpoint programs. The deficiencies were in the areas of corrective actions, procedural compliance, vendor manual control, and deviation from UFSAR commitments:

Corrective actions:

Due to a lack of clear procedural guidance, data indicating that safety-related transmitters (and switches important to safety) were routinely found to be out of tolerance had not received complete engineering evaluations or corrective actions. This condition was specifically observed for the pressurizer high pressure transmitters and the emergency diesel generator (EDG) low lube oil pressure trip switches.

Procedural compliance:

Technicians routinely used measurement and test equipment (M&TE) other than that required and/or recommended by procedure and failed to document the M&TE actually used.

Vendor manual control:

A 1989 vendor product update had not been reviewed or approved until October 1991, and had not been identified as being available or applicable until this inspection.

Deviation from UFSAR commitments:

The EDG air start system was routinely operated at lower pressures than had been used to demonstrate the five-start design capability of the starting air cylinders.

Based on the findings of inadequate corrective actions in two different areas, and the apparent acceptance of I&C technicians that "skill-of-the-craft" judgment superseded procedural compliance in use of M&TE, the team expressed concern (1) that similar cases of inadequate engineering evaluations and corrective actions for instruments found out of tolerance could be prevalent throughout the units, and (2) that the I&C technicians' failure to follow procedural requirements for M&TE usage could result in non-conservative calibration of safety-related instrumentation.

The team concluded that the licensee's failure to evaluate and take corrective action, for transmitters found out of tolerance, appeared to have a root cause in two areas. First, an instrument trending program, designed to ensure engineering attention for out-of-tolerance as-found data, had not been clearly defined or implemented. Second, procedures did not provide a clear definition, to the technician or the reviewing supervisor, for what degree of instrument out-of-tolerance should be considered significant or deserving of engineering attention.

Regarding the procedural compliance deficiencies, the team noted that the licensee had established a program to ensure that operations and maintenance personnel were aware of management expectations on the importance of following procedures. This program and other programs, such as the Quality Monitoring Program, Management Observation Program, and Safety Training Observation Program, were all efforts which the licensee had taken to ensure procedural compliance.

As a result of the inspection, the licensee committed to: (1) review its interim vendor manual control program to ensure timely distribution and availability of updated information to appropriate personnel, (2) review its setpoint program for documenting instrument drift, and calculate Periodic Test Error Bands, (3) revise NSSS vendor calculations or perform new licensee calculations to correct identified errors, (4) provide guidance to technicians for determining the need for engineering review of out-of-tolerance test data, and (5) continue efforts to ensure procedural compliance throughout operations and maintenance.

2 REVIEW OF SYSTEM INSTRUMENTS

2.1 Steam Generator Wide Range Level

2.1.1 Setpoint Calculation and Bases

Chapter 15 of the UFSAR contained the bases for the steam generator low level (SG LO) reactor trip setpoint. This trip provided protection for a loss of condenser vacuum, and was a backup (diverse) trip for feedwater and steam line break events. An SG LO signal also started auxiliary feedwater pumps during small break loss of coolant and feedwater line break ESFAS events. Setpoints for the SG LO trip were based on a percent of span between the steam generator wide range level transmitter taps.

The team reviewed the steam generator wide range level transmitter scaling calculation, CE Analysis 14273-ICE-3645, Revision 1, "Calibration Data for Steam Generator Wide Range Level Transmitters," and the SG LO reactor trip and ESFAS actuation setpoint calculation, CE Calculation 14273-ICE-3631, Revision 4, "ANPP, PVNGS-1,2,3 PPS Setpoint Calculation."

Calculation 14273-ICE-3631 determined the allowable value for the SG LO reactor trip to be 43.7% of span, based on the worst case analysis setpoint of 35% of span. Calculation 14273-ICE-3631 determined the allowable value for ESFAS SG LO actuation to be 25.3% of span, based on the worst case analysis setpoint of 10% of span. The team determined that PVNGS Technical Specifications accurately included these setpoints.

The team found the methodology, assumptions, and results of these calculations for SG LO reactor trip to be acceptable, with two exceptions. These exceptions were (1) failure to account for thermal expansion of the steam generator and (2) failure to include construction tolerances in uncertainty calculations.

The licensee reviewed these two calculations with the team, and agreed that thermal expansion and construction tolerances should have been included in the setpoint calculation.

The licensee performed a preliminary setpoint and scaling calculation to demonstrate the effects of steam generator thermal expansion. This calculation also included the uncertainty resulting from construction tolerances. Based on the results of the calculation, the licensee concluded that thermal expansion would cause a conservative error in the SG LO reactor trip and ESFAS actuation setpoints. The licensee also concluded that this conservative error more than offset the effect of adding the construction tolerance uncertainty.

The team reviewed the preliminary calculation and agreed that the omissions discussed above would not have had a non-conservative effect on the SG LO trip setpoints.

In response to the teams findings the licensee committed to revise the existing calculations or complete new ones as part of its setpoint program.

2.1.2 Logic, Testability, Isolation, and Independence

For each steam generator, the SG LO trip circuit contained four independent transmitters and associated channels. A reactor trip required a two-out-of-four logic for any one steam generator. The ESFAS auxiliary feedwater actuation also required a two-out-of-four actuation logic. The team confirmed that each of the four SG LO trip channels could be independently tested.

The team reviewed drawings associated with each of the four SG LO reactor trip channels and determined that each trip channel was isolated from control channels and non-1E circuits and that each channel was independent. In addition, the team determined that each channel included wiring to its own Class 1E indication circuit.

No deficiencies were noted in this area.

2.1.3 Installation Verification

The team verified transmitter location and orientation for consistency with plant drawings, Technical Specifications, and the UFSAR. Transmitters were examined for proper make, model number, setpoint, range, and material of construction. Licensee drawings indicated that the steam generator level transmitters were ITT Barton Model 764. Sensing lines were traced to verify proper slope, venting, draining, equalizing, process isolation, channel separation, and supports, and to ensure that any extreme elevation differences or other unusual configurations were accounted for in the setpoint calculations. Instrument loop environments were also evaluated for temperature and humidity effects, and for vulnerability from high-energy line breaks, impingement, seismic shock, and vibration.

During the field verification of the wide range transmitters, the team also inspected the steam generator narrow range high level reactor trip transmitters. The transmitters inspected are identified in Table 1.

The team found that the ranges identified on the transmitter label plates were different than the calibration ranges for a number of steam generator narrow and wide range transmitters in Unit 1 (see Table 1). The team found one wide range transmitter, Serial Number 1595, with one label plate identifying it as a ITT Barton Model 764 and a separate label plate identifying it as a Model 765.

The licensee stated that they had purchased the transmitters with the specific ranges shown on the label plates. The licensee noted that ITT Barton technical literature for the transmitters specified a 5% tolerance for setting the zero and span. Within this 5%, all the ITT Barton specified performance characteristics remained unchanged. The team noted that all the differences between the calibrated ranges and the design ranges were less than 5%. At the request of the team, the licensee obtained written ITT Barton confirmation that the transmitter uncertainties were unchanged for zero and span changes up to 5%.

The licensee contacted the vendor concerning Transmitter 1595 and obtained vendor verification that the transmitter was a Model 764. The licensee agreed to correct the inaccurate label plate.

The team reviewed the information concerning range differences and concluded that the transmitters were technically acceptable for the ranges being used. The team also concluded that transmitter tolerances had been correctly used in Calculation 14273-ICE-3631.

2.1.4 Calibration Procedures and Data

The team verified that the transmitters were being calibrated to the values required by the scaling calculation by ensuring that the range specified in the calculation was actually used to calibrate the transmitters. The team verified that the transmitters were being calibrated to the accuracy limits assumed by the setpoint calculation by comparing the procedure requirements to the assumptions made in the calculation. Due to the reduced scope of the inspection, the team did not review transmitter calibration data.

2.2 Emergency Diesel Generator Setpoints

In order to determine what bases were used for setpoints outside the reactor trip system, the team selected two EDG systems for setpoint review. The team chose the EDG lube oil and air start systems.

2.2.1 Setpoint Calculation and Bases

2.2.1.1 EDG Lube Oil Low Pressure Trip

The team limited the EDG lube oil system setpoint review to the EDG lube oil low pressure trip. The licensee had six EDGs, two per unit. Each EDG had four switches that would cause an emergency EDG trip when low pressure was sensed in the EDG lube oil system. Low lube oil pressure was one of three conditions that would cause an EDG to trip during emergency operation.

The trip setpoint was 30 psi. Normally the lube oil system pressure at the trip switch location was 50 to 55 psi. The licensee indicated that the setpoint for the EDG lube oil low pressure trip had been provided by the manufacturer based on the manufacturer's experience. No tolerances had been provided. The licensee indicated that this trip had been designed to protect the EDG from complete loss of lube oil pressure and that the actual setpoint was not critical. The licensee had established an as-found acceptance tolerance of ± 0.38 psi, based on ± 0.5% of the switch range.

The team reviewed the design of the lube oil system and did not identify any immediate safety concerns with the lack of a setpoint analysis fc· the present setting of the EDG low lube oil pressure switch.

2.2.1.2 EDG Air Start System

2.2.1.2.1 Cranking Timer

The team reviewed the setpoint for the EDG cranking limit timer, relay 62CL. The licensee indicated that the setpoint for this Agastat time delay relay was 15 seconds as recommended by the diesel manufacturer. The 15-second time was to shut off the air to the diesel during normal starting, if the diesel did not start. The team confirmed that on an emergency start signal the EDG air start system would supply uninterrupted starting air until the EDG either started or the air ran out. On an emergency start of the EDG, the time delay relay 62CL would be bypassed. Therefore, the licensee concluded (and the team concurred) that the 15-second time setpoint was not a critical value.

The team review of the design of the cranking limit timer circuit did not identify any immediate safety concerns with the lack of a setpoint analysis for the present setting of the timer.

2.2.1.2.2 Air System Capability

The team also reviewed the setpoints associated with maintaining the design bases for the emergency diesel generator starting system (DGSS).

The UFSAR stated, in part A of Section 9.5.6.1, that, "The DGSS shall provide a stored compressed air supply sufficient for accomplishing diesel generator cranking cycle five times without starting the diesel generator air compressors."

The UFSAR also stated, in part A of Section 9.5.6.4, that, "Sufficient storage capacity is provided in each compressed air tank to provide for five starting cycles of a diesel generator without starting an air compressor."

The team requested the calculation which demonstrated the above criteria. The licensee stated that no calculation had been accomplished to demonstrate the five-start criteria. However, the licensee indicated that the ability to start the diesel five consecutive times had been demonstrated in tests, and provided the test results to the team.

Data from Test Procedures 91PE-1DG01, 91PE-2DG01, and 91PE-3DG01, "Starting Air Receiver Capacity Test," dated between July 7, 1983 and November 11, 1986, showed that each independent air start system had started its associated diesel five times without resupply. The tests had been started at 250 psig air receiver pressure.

The team noted that the air receivers normally operated between 240 psig and 250 psig, within the accuracy of the instrumentation. As a result, the air receivers were regularly operated at lower pressures than the 250 psig at which the design air start capability had been demonstrated.

Because the test had been started at the maximum normal operating pressure and did not consider any instrumentation uncertainties, the team concluded that the pressures at which the DGSS was routinely operated did not support the UFSAR design criteria. This is an apparent deviation (Deviation 50-528/92-14-01).

The team reviewed this issue with the licensee. The licensee observed that the EDGs were operated with single emergency air start capability, and concluded that the team's concern did not affect the immediate operability of the EDG. The team concurred that the apparent failure to properly demonstrate this design capability was not an immediate operability concern.

2.2.1.3 Conclusion - Emergency Diesel Generator Setpoints

Based on the above observations, the team concluded that the setpoint bases for non-reactor trip equipment was not always well established. The licensee concurred with this conclusion. The licensee indicated that their setpoint program would check setpoints outside of the reactor trip system, and for setpoints determined to be safety significant, a setpoint basis would be established as defined in APS Internal Letter 283-00923-JHH/MSB, dated February 14, 1992. The licensee's I&C Setpoint Supervisor indicated that balance-of-plant (BOP) setpoints would also be reviewed for safety significance and the need for a setpoint basis. However, the licensee had not yet formulated the review criteria for accomplishing the BOP setpoint reviews.

2.2.2 Logic, Testability, Isolation, and Independence

The team found that the EDG lube oil low pressure trip circuit used a one-out-of-two-taken-twice logic, using four independent pressure switches. Licensee documentation listed this trip as a two-out-of-three trip. The licensee indicated that the actual installation could be considered a two-out-of-three trip, even if one pressure switch failed. The team concurred with the licensee's conclusion.

The team verified that the low lube oil pressure switches could be independently tested. Circuit isolation and independence were not reviewed during this inspection.

The team did not review the logic, isolation and independence of the EDG air start components.

2.2.3 Installation Verification

The team verified transmitter location and orientation for consistency with plant drawings, Technical Specifications, and the UFSAR. Transmitters were examined for proper make, model number, setpoint, range, and material of construction. No deficiencies were noted in this area.

2.2.4 Calibration Procedures and Data

The team evaluated the calibration history of the EDG low lube oil pressure switches. This evaluation included examination of records and procedures, interviews with cognizant personnel, and review of the licensee's failure data trending (FDT) system.

2.2.4.1 Results of Record Review

The team reviewed 67 records of individual calibrations performed on EDG low lube oil pressure switches between January 1987 and January 1992. These calibrations had been performed as PM tasks.

The licensee had assigned a tolerance band of 29.62 - 30.38 psi for the 30 psi switch setpoint. Out of the 67 records provided, the switch being calibrated had been found out of tolerance on 52 occasions, or for approximately 78% of the calibrations. The team noted 10 instances in which a switch setpoint had been found to be less than 27 psi or greater than 33 psi. The lowest as-found setpoint recorded had been 22.4 psi, and the highest had been 36.4 psi.

2.2.4.2 Failure Data Trending System

The licensee used an FDT system to alert cognizant maintenance, engineering, operations, and managerial personnel when specific plant component failures were identified as indicating potential adverse trends. The FDT system identified trends based on 3-month, 18-month, and 36-month analyses.

The team reviewed several quarterly FDT reports. Failures of the EDG low lube oil pressure switches had been identified in several 3-month analyses. The 18-month analysis ending with December 1991 had identified failure of the EDG switches as indicating a potential adverse trend.

2.2.4.3 Licensee Corrective Action Prior to the Inspection

Interviews with engineering and FDT staff revealed that, due to temporary shifts in the EDG system engineer assignments, none of the EDG system engineers had received two consecutive FDT reports in 1991. In each case, the system engineer reviewing the FDT report had decided that the EDG switch failures exhibited over a 3-month period were not significant. No corrective actions had been considered necessary.

The 18-month analysis that identified EDG switch failure as a potential adverse trend had prompted a discussion between the FDT staff and the system engineer. Based on a review of the data, the licensee had concluded that the magnitude and frequency of switch failures did not appear particularly significant, and that no corrective action or formal engineering analysis was warranted.

In discussions with the team, the engineering and FDT staff stated that, prior to the inspection, they had been unaware of the magnitude and frequency of the out-of-tolerances found during EDG low lube oil pressure switch calibrations, and that they had not realized the extent of the adverse trend.

2.2.4.4 <u>Licensee Evaluation Prompted by the Inspection</u>

The team questioned the licensee concerning the safety significance of the repeated out-of-tolerance condition of the EDG low lube oil pressure switches. Specifically, the team requested vendor data regarding design accuracy of the switches, indication of switch failure, and the potential impact of the out-of-tolerance switches on an EDG during emergency operation.

The licensee was unable to obtain vendor data regarding design accuracy of the switches. In addition, at the completion of the inspection, the licensee had not reached a conclusion regarding what degree of switch out-of-tolerance should be considered an indication of switch failure.

After discussions with the EDG manufacturer, the licensee performed an evaluation of the potential impact of the out-of-tolerance switches on EDG emergency operating capability. The evaluation stated that the low lube oil pressure switch was designed to protect the EDG against a sudden loss of pressure, as would occur during a lube oil pipe rupture. Slowly decreasing lube oil pressure, according to the evaluation, would be detected by routine operator monitoring. Two scenarios were considered in which lube oil pressure suddenly decreased and subsequently stabilized slightly above or slightly below the 30 psi switch setpoint. These scenarios were discounted, however, because the evaluation did not consider such a failure credible.

In determining the significance of the out-of-tolerance switches, the evaluation noted that the four switches for each EDG are configured in a one-out-of-two-taken-twice logic. Failure of one switch, therefore, would not prevent an EDG trip on low lube oil pressure during an emergency run condition. The evaluation concluded that the switch out-of-tolerances would not impact EDG operability, and did not constitute a significant challenge to safety.

2.2.4.5 Conclusions - Calibration Procedures and Data

The team concurred with the licensee's conclusions regarding the impact of the switch out-of-tolerances on EDG operability. The team determined, however, that the licensee had possessed sufficient data to indicate the need for a formal engineering evaluation prior to the inspection, and that such an evaluation should not have required NRC prompting.

In addition, the team observed that the licensee had no criteria to indicate switch failure based on performance outside the switch design accuracy.

As one possible conclusion, the licensee's evaluation had stated that the tolerance band for the switch setpoint had been "extremely narrow." The team concluded that such a tolerance band may have had a negative impact, by desensitizing technicians and engineers to significant out-of-tolerance conditions.

The team concluded, finally, that the licensee's failure to identify and correct conditions adverse to quality regarding performance of the EDG low lube oil pressure switches constituted one example of an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (Violation 50-528/92-14-02).

2.3 High Pressurizer Pressure

2.3.1 Setpoint Calculation and Bases

Chapter 15 of the UFSAR contained the bases for the high pressurizer pressure (HI PZR PRESS) reactor trip setpoint. This trip provided protection for loss of condenser vacuum and main steam line isolation valve closure events. This trip was also a backup (diverse) trip for feedwater and steam line break events.

The team reviewed the HI PZR PRESS reactor trip setpoint calculation, CE Calculation 14273-ICE-3631, Revision 4, "ANPP, PVNGS-1,2,3 PPS Setpoint Calculation." The calculation determined that the allowable value for the HI PZR PRESS reactor trip was 2388 psi, based on the worst case analysis setpoints of 2450 psi and 2475 psi for two separate analyzed events.

The team concluded that the methodology, assumptions and results of this calculation were acceptable for the HI PZR PRESS loop.

2.3.2 Logic, Testability, Isolation, and Independence

The HI PZR PRESS trip circuit contained four separate and independent transmitters and associated channels. A two-out-of-four logic was required for a reactor trip on high pressurizer pressure. The team confirmed that each of the four HI PZR PRESS trip channels could be independently tested.

The team reviewed drawings associated with each of the four HI PZR PRESS reactor trip channels and determined that each trip channel was isolated from control channels and non-1E circuits. The team determined that each of the four HI PZR PRESS trip channels also contained wiring to Class 1E indication circuits for that channel. Each channel, however, was independent.

2.3.3 Installation Verification

The team verified transmitter location and orientation for consistency with plant drawings, Technical Specifications, and the UFSAR. Transmitters were examined for proper make, model number, setpoint, range, and material of construction. Sensing lines were traced to ensure proper slope, venting, draining, equalizing, process isolation, channel separation, and supports, and to ensure that any extreme elevation differences or other unusual configurations were accounted for in the setpoint calculations. Instrument loop environments were also evaluated for temperature and humidity effects, and for vulnerability from high-energy line breaks, impingement, seismic shock, and vibration. No deficiencies were noted in this area.

2.3.4 Calibration Procedures and Data

The team evaluated the calibration history of the HI PZR PRESS loop. This evaluation included examination of records and procedures, interviews with cognizant personnel, and review of the licensee's FDT system.

The licensee performed surveillance checks on the HI PZR PRESS loops once every refueling and after corrective maintenance. The team found numerous surveillances which contained out-of-tolerance as-found data for HI PZR PRESS transmitters. Procedure 36ST-9SB20, Revision 3, "PPS Input Loop Calibration for Parameter 5, Hi Pzr Press," specified an as-found acceptance tolerance of ± 0.5%. Approximately 2/3 of the surveillances reviewed contained out-of-tolerance as-found transmitter data.

The team found that the licensee did not have a data trending program for HI PZR PRESS and other reactor protection transmitters. In addition, the team could find no indication that the licensee had recognized and evaluated the cause of the high number of out-of-tolerance transmitter surveillances. Therefore, the team questioned the long term operability of the transmitters.

The licensee reviewed all HI PZR PRESS transmitter data since start-up and provided charts to the team which showed that 37 out of 60 surveillances contained as-found data outside the tolerance listed in Procedure 36ST-9SB20.

The licensee indicated that the major cause of the high number of out-of-tolerance surveillances was that the as-found tolerance was too narrow. The licensee stated that the as-found tolerance did not contain any uncertainty for drift. The licensee stated, and the inspectors confirmed, that the "as-found" tolerances listed in Procedure 36ST-9SB20 were the same as the "as-left" tolerances, which only accounted for transmitter inaccuracy and did not include drift uncertainty.

To determine the acceptability of the as-found surveillance data and demonstrate satisfactory long-term transmitter performance, the licensee calculated a broader acceptance tolerance of +2.2% and -5.2% for as-found data. The team noted that the recalculated as-found tolerance was defined as the "Periodic Test Error Band," and included accuracy requirements for the transmitter, accuracy of M&TE, rated transmitter drift, and a larger negative error. The larger negative error was intended to account for a known manufacturing defect that could have affected individual transmitters. The licensee confirmed that the negative margin added for the known manufacturing defect would be appropriately adjusted in the calculations and procedures when the transmitters were replaced.

The licensee compared the Periodic Test Error Band to previous HI PZR PRESS surveillance data, and concluded that only 5 of 64 surveillances contained as-found transmitter data outside the new Periodic Test Error Band. A detailed engineering review had been accomplished for two of these five surveillance failures. For both of these failures, engineering had directed transmitter replacement. Detailed engineering reviews had not been done for the remaining three surveillance failures, which were also outside of the new Periodic Test Error Band.

The licensee reviewed the HI PZR PRESS surveillance data packages for Units 1, 2, and 3, and concluded that a transmitter operability concern did not exist. The team reviewed the data and concurred with the licensee that an operability concern did not exist. However, the team noted that the -5.2% Periodic Test Error Band could mask potential transmitter problems not associated with the manufacturing defect. The licensee concurred with this observation.

The team noted that a detailed engineering review had been accomplished on only 2 of 37 failed as-found transmitter surveillances. For the remaining failures, including transmitter data which varied more than 5% from the desired value (and transmitter data which varied more than 2% different from the desired value on four consecutive surveillances), no detailed engineering review or trending had been accomplished.

The team concluded that the failure to recognize and evaluate the long-term trend of out-of-tolerance as-found HI PZR PRESS transmitter data was a second example of an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action" (Violation 50-528/92-14-02).

In response to these concerns, the licensee committed to calculate Periodic Test Error Bands for all safety-related transmitters, and to add this information to the associated surveillance procedures.

2.4 Main Feedwater Temperature and Flow

2.4.1 Setpoint Calculation and Basis

Main feedwater temperature and flow were two of the principal parameters influencing the secondary calorimetric calculations performed by COLSS on the PVNGS plant process computers. Calorimetric results were significant, because they were used to calibrate the safety channel excore nuclear instrumentation. Instrumentation associated with the secondary calorimetric, however, was not quality-related.

The team reviewed CE Calculations 14373-TS-005, "PVNGS - 1, 2, and 3 COLSS Measurement Channel Uncertainties," and 14273-TS-017, "PVNGS-1 COLSS Secondary Calorimetric Power Error." Both calculations applied acceptable methodology for determining loop uncertainty. However, several errors were observed.

Both calculations reflected the specifications of Rosemount Manual 4235 (January 1988), "Model 1152 Alphaline Pressure Transmitters for Nuclear Service," for the feedwater flow transmitter accuracy (±0.25%). However, PM Task 040189, which is used to calibrate the total feedwater flow instrumentation loop, only requires calibration of the transmitters to ±0.50%.

The licensee had previously identified this condition, as it affected PPS calibrations and calculations, during the Quality Engineering "Technical Assessment of the Set-Point Control Program," and had initiated CAR 91-31. After determining that the PPS calculations contained adequate conservatism despite the inaccurate transmitter accuracy assumption, the licensee had established a schedule for addressing potential consequences in the instrumentation loops and calculations associated with COLSS. However, the licensee had not initiated a review of the COLSS instrumentation calculations prior to the team's determination that these calculations were affected.

Both calculations also incorrectly assumed that M&TE used for calibration was at least five times as accurate as the equipment being calibrated (5:1 ratio). The licensee's program and practice, however, required using M&TE at least as accurate as the equipment being calibrated (1:1 ratio). In response to this observation, the licensee reviewed Calculation 14273-TS-017 (see below), and initiated CRDR 9-2-0284. This CRDR identified 12 instrumentation loops which input to COLSS, and provided a schedule for calculating revised uncertainties for the instrument loops, the COLSS secondary calorimetric, and the COLSS overall uncertainty analysis. Using updated vendor data and assumptions consistent with industry practice, the licensee calculated revised uncertainties. The team concluded that the revised uncertainties indicated that the assumptions of the COLSS secondary calorimetric were still valid.

Calculation 14373-TS-005 included minor discrepancies in sketches of the feedwater flow loop and feedwater temperature loop configurations:

The feedwater flow loop sketch indicated the wrong model number for feedwater low transmitters SGN-FT-1112 and SGN-FT-1122. Rosemount Model 1152DP6E92PB was depicted, but Rosemount Models 1152DP6E22PB and 1152DP6N22PB were actually installed.

- The -6E- and -6N- models had different electronics but identical specifications. When the licensee first had replaced a -6E- model with a -6N- model, they had determined the equivalency of the different models, and had concluded that there was no impact on the associated calculations. The equivalence had been documented on the licensee's design drawings.

- The difference between the -92PB and -22PB models related to different housing materials, either of which was acceptable for the application. Following the identification of this model number error in the calculation, the licensee determined that the calculation results were unaffected.

The feedwater flow loop sketch also indicated an incorrect label for the current-to-voltage converter. [SGN-]FY-1112 was shown, but the correct label was SGN-FY-0201F1. The calculation used the appropriate data, and was otherwise unaffected by the error.

The feedwater temperature loop sketch indicated an incorrect temperature-to-voltage (T/E) converter. The sketch indicated that the thermocouple was a Type K grounded thermocouple and that the temperature converter (transmitter) was of a Foxboro Model 2AI-T2V+F+E. The model number implied that the termination module was for a Type E thermocouple. Actual installed equipment, however, was verified to be a 2AI-T2V+K+K converter (transmitter). This incorrect converter designation in the sketch did not affect the calculation, since the calculation used the correct specification for the Type K thermocouple.

Calculation 14373-TS-005 referenced Foxboro Technical Information Manual TI-2AI-170 for the converter. The licensee was unable to retrieve this manual; however, the licensee contacted Foxboro, and the equivalent specification was provided to the team.

The team concluded that the vendor calculations used to support the plant design for COLSS contained several errors, but that the acceptability of the design was supported by the new licensee calculations.

The licensee stated that the vendor calculations would not be immediately revised, but committed to either revise the calculations or perform new calculations as part of its setpoint upgrade program.

2.4.2 Logic, Testability, Isolation, and Independence

These instruments were not safety-related, and were not subject to independence and isolation requirements. The team did not review logic, testability, isolation, or independence of these instruments.

2.4.3 Installation Verification

The team confirmed that the installed instrumentation conformed to design.

2.4.4 Calibration Procedures and Data

The team reviewed the calibration PM task and found it to be adequate, with the exceptions noted above

3 CONTROL OF VENDOR TECHNICAL INFORMATION

During the resolution of non-conservative assumptions in the COLSS calculations discussed in Section 2.4.1, the team observed that licensee personnel did not always have ready access to current licensee-approved vendor documentation.

CE Calculations 14373-TS-005, "PVNGS - 1, 2, and 3 COLSS Measurement Channel Uncertainties," and 14273-TS-017, "PVNGS-1 COLSS Secondary Calorimetric Power Error," both used specifications given in the January 1988 edition of Instruction Manual 4235, "Model 1152 Alphaline Pressure Transmitters for Nuclear Service." During the inspection, the licensee contacted the vendor to determine if any updated information might be available to offset the non-conservative assumptions identified in the calculations. The vendor provided an October 1989 revision of Product Data Sheet 2235, "Model 1152 Alphaline Nuclear Pressure Transmitters," which contained revised specifications less conservative than those in the January 1988 vendor manual. The licensee needed these revised specifications to demonstrate the adequacy of the COLSS assumptions.

The team questioned the licensee as to why the October 1989 information had not been received, reviewed, and incorporated into appropriate design basis documentation. The licensee determined that its vendor manual group had consolidated all Rosemount transmitter information into a new vendor manual (VTM-R369-0001) in October 1991. In preparing the consolidated manual, the licensee had contacted the vendor to ensure that all applicable vendor information was being incorporated in the consolidated manual. The October 1989 product data sheet had then been identified, obtained, and reviewed by the licensee.

Even though the current vendor manual contained the correct vendor information, the outdated January 1988 manual was the revision provided to users requesting current information from the licensee's drawing and document control center (DDC). The January 1988 manual was also listed as the current manual in the SIMS database. The licensee responded to this observation by indicating that the SIMS database would be updated in July 1992, when a model verification project was scheduled to complete verification of applicable components associated with the new vendor manual. The licensee also indicated that until this model verification was completed and the vendor manual information in SIMS was updated, the SIMS data was color-coded to indicate that it was not verified information.

The licensee's vendor manual project was a multi-year project which addressed concerns raised by the NRC's Diagnostic Evaluation Team (see Inspection Report 528/89-56). With this project incomplete, and the model verification project also incomplete, the licensee appeared at risk of using incorrect or outdated vendor information.

The team noted that Inspection Report 92-15, dated June 15, 1992, had identified two similar vendor manual control and review problems. First, a revised General Electric reactor trip breaker manual had been received by the licensee in 1990 with applicability to non-1E circuit breakers. The licensee had not taken action to verify applicability to the Class 1E reactor trip breakers and incorporated the manual instructions until the NRC had questioned maintenance problems with these breakers in April 1992. Second, a revised Westinghouse information bulletin had been received in November 1991 and not properly evaluated for necessary action until a Westinghouse reactor trip breaker failed to open when required.

The team concluded that the licensee continued to be vulnerable to errors resulting from poor control of vendor information. The licensee committed to reconsider its interim actions to ensure adequate control of vendor information during the implementation phase of the vendor manual and model verification projects.

4 MAINTENANCE AND TEST EQUIPMENT

The team reviewed M&TE data provided on a sample of safety-related WOs. M&TE usage was evaluated for completeness of documentation, appropriate instrument range and accuracy, system applicability, and current National Institute of Standards and Testing (NIST)-traceable calibration.

4.1 Completeness of Documentation

The team observed that M&TE usage forms included in WO packages frequently did not record the ranges selected, the actual readings taken, the functional units, or other information. The licensee stated that these forms were not required to be filled out in detail, because all required M&TE information for each WO was available in the SIMS data base.

At the team's request, the licensee attempted to retrieve M&TE information for several work orders from the SIMS data base. The team observed that this data retrieval process was convoluted, and that information necessary to verify NIST traceability for M&TE used in past work performances was not included in SIMS as part of the work order package. As a result, verification of the objective basis for a given calibration could only be accomplished by piecing together information from various parts of the SIMS data base and matching this information with metrology laboratory data concerning the M&TE calibration history.

The team observed that the lack of information accompanying the hard-copy WO package would make it more difficult for the package reviewer to verify appropriate M&TE usage. In addition, SIMS did not include information on the actual readings taken with a given piece of M&TE.

Procedure 34AC-OME01, "Measuring and Test Equipment Users Administrative Requirements," Step 3.8.2.2, states:

> At least one (1) work document M&TE usage entry and one (1) SIMS M&TE usage entry shall be made for each unique piece of M&TE used during the performance of that work document.

The team noted that no M&TE usage form had been included for the use of a 0 - 4000 psi Heise gauge in a 1989 work order (WO 00374180), although the procedure required using such a gauge, and the procedural step indicating gauge usage had been signed off through appropriate review levels. The licensee was unable to verify what gauge had, in fact, been used.

4.2 <u>Appropriate Instrument Range and Accuracy - Torque Wrenches</u>

The team observed that the licensee routinely used adjustable torque wrenches for torque applications from 20% to full scale of the instrument range. To substantiate these applications, the licensee provided vendor data for Snap-On TQ-type torque wrenches. The vendor data stated that ±4% accuracy was guaranteed for 20% to full scale of instrument range. In subsequent conversations with the team, the manufacturer recommended using only 25% to 75% of instrument range, in order to prevent instrument wear and extend instrument life. However, full range usage from 20% to 100% was acceptable.

The team concluded that use of the wrench within the vendor's data range was acceptable.

4.3 <u>Appropriate Instrument Range and Accuracy - Pressure Gauges</u>

In the licensee's performance of WO 00517901 (an ST for routine calibration of a low pressurizer pressure transmitter), the team noticed that Procedure 36ST-9SB21 required using a pressure gauge capable of measurements from 0 to 3020 psig. As the suggested M&TE, the procedure listed a 0 - 4000 psi Heise gauge. Step 8.2.3 included a sign-off step that stated, "Install the 0 - 4000 psi Heise gauge ..."

The team noted that a 0 - 4000 psi gauge had been used for calibrating the first three instrument channels. Channel D, however, had been calibrated using a 0 - 3000 psi gauge. In response to the team's questions, the licensee stated that the 0 - 3000 psi gauge was appropriate for the readings actually used, and that deciding to deviate from the procedure in this manner was considered a judgment within the skill of the craft.

The team observed, in addition, that the procedure required pressure inputs of 0 - 3005 psig for Channels A and B and inputs of 25 - 2995 psig for Channels C and D. On the M&TE usage forms, however, readings of 0 - 2995 psig had been recorded for the 0 - 4000 psi gauge and 25 - 2995 psig for the 0 - 3000 psi gauge. Since the M&TE usage forms gave no indication that the 3005 psig inputs required for Channels A and B had actually been performed, the team asked the licensee whether this indicated a lack of procedural compliance. The licensee responded that this discrepancy was not significant, since technicians were not required to record the actual readings taken.

4.4 System Applicability

In the licensee's performance of WO 00465432 (for calibration of an emergency diesel generator low lube oil pressure switch) the team noted that the procedure suggested using a pressure gauge suitable for oil use, capable of measuring 0.5 - 76.6 psig. The M&TE usage form included in the WO package indicated that a 0 - 60 psi Heise gauge had been used.

The team examined the actual gauge used, and observed that it was marked for air and nitrogen use only. The team noted that use of this gauge on an oil system could adversely affect system or gauge cleanliness, and could impact the readings of the high-accuracy gauge due to the variance in compressibility of gas and liquid.

In response to the team's questions, the licensee stated that the gauge used was considered appropriate, and that the decision to use a gauge different than suggested by the procedure was within the skill of the craft. The Unit 3 I&C maintenance supervisor stated that all craft technicians were aware of methods to keep such a gauge from getting contaminated with oil when using it on an oil system, and were also aware of how to counteract the inaccuracies introduced in using such a gauge by ensuring no oil got into the gauge. The team did not verify the technicians' ability to prevent oil contamination of air systems.

4.5 Current NIST-Traceable Calibrations

The team verified NIST traceability for selected M&TE, including the licensee's control of traceable standards, methods of ensuring proper accuracy ratio between M&TE and plant equipment, and the M&TE calibration schedule. No discrepancies were identified.

The team evaluated calibrations of M&TE used in performing several safety-related STs. In one instance, calibration of a steam generator low-level transmitter (WO 00465702) had been completed on January 30, 1991. All M&TE used in the ST had been recorded as being in current calibration; however, examination of the M&TE histories revealed that the torque screwdriver used in the ST had been scrapped for parts on February 1, 1992.

The team asked the licensee whether the torque screwdriver had performed erratically during the ST, and whether reverification of the pressure transmitter screw torques had been necessary. The licensee stated that the torque screwdriver had performed well during the ST. However, during subsequent testing in the metrology lab, the torque screwdriver readings, although within tolerance, were not able to be consistently repeated. As a conservative measure, the metrology lab had scrapped the torque screwdriver for parts. Based on this explanation, the licensee stated that calibration of the steam generator low-level transmitter had not been called into question.

The team concluded that the torque screwdriver was acceptable when used on January 30, 1991.

4.6 Conclusions Regarding Use of M&TE

The team concluded, first, that the incomplete M&TE information retained in hard-copy records, together with the difficulty of obtaining complete M&TE information for a given work order through various licensee data bases, made ready verification of the objective basis for a given calibration a difficult process.

In addition, the team concluded that the lack of compliance with procedures, as described in Section 4.3, above, constituted an apparent violation of NRC requirements (Violation 50-528/92-14-03). The team further concluded that the licensee's apparent tolerance of procedural non-compliance, as described in Section 4.3 above, was inconsistent with previous licensee statements regarding management expectations.

5 Current Setpoint Calculation Adequacy

As part of the evaluation of engineering adequacy, the team reviewed parts of a recent licensee-prepared setpoint calculation, performed under the licensee's new setpoint program. The calculation reviewed was Calculation 13-JC-SI-205, Revision 0, dated November 14, 1991, "Pressurizer Pressure (Restricted Range) Loops P-103 and P-104 Total Loop Uncertainty and Setpoints." The team found the methodology, assumptions, and results of the reviewed parts of this calculation to be acceptable.

Calculation 13-JC-SI-205 concluded that a TS change was required. The team found that the TS change had been submitted and approved. The licensee was in the process of preparing instructions to accomplish the required field work. The team concluded that the licensee was taking appropriate action to implement the results of new setpoint calculations.

As part of the evaluation of engineering adequacy, the team reviewed parts of recent licensee prepared setpoint calculation technical guidance. The team reviewed DSG-IC-0205, Revision 2, dated April 2, 1992, "Design Guide for Instrument Uncertainty and Setpoint Determination." The team found the methodology, assumptions and directions of the reviewed parts of this instruction to be acceptable.

6 EXIT MEETING

The team met with licensee management at the conclusion of the inspection on June 5, 1992. The scope and findings of the inspection were summarized. The licensee acknowledged the findings, and concurred with the commitments as presented by the licensee staff during the inspection.

Table 1

Unit 1 Steam Generator Level Detector Data

Channel	Serial Number	Label Plate Range (inches of water)	Calibration Range (inches of water)
SG No. 1 Wide Range			
A	3573	96.26 to 358.86	96.26 to 358.86
B	1592	91.43 to 358.93	96.26 to 358.86
C	1593	91.43 to 358.93	96.26 to 358.86
D	1912	91.43 to 358.93	96.26 to 358.86
SG No. 1 Narrow Range			
A	1919	36.57 to 143.57	37.59 to 139.75
B	1918	36.57 to 143.57	37.59 to 139.75
C	1601	36.57 to 143.57	37.59 to 139.75
D	1917	36.57 to 143.57	37.59 to 139.75
SG No. 2 Wide Range			
A	1595	91.43 to 358.93	96.26 to 358.86
B	1596	91.43 to 358.93	96.26 to 358.86
C	1597	91.43 to 358.93	96.26 to 358.86
D	1598	91.43 to 358.93	96.26 to 358.86
SG No. 2 Narrow Range			
A	1603	36.57 to 143.57	37.59 to 139.75
B	1924	36.57 to 143.57	37.59 to 139.75
C	3589	37.59 to 139.59	37.59 to 139.75
D	1606	36.57 to 143.57	37.59 to 139.75

APPENDIX A

PERSONNEL CONTACTED DURING INSPECTION

1 List of Personnel Attending Entrance Meeting - April 28, 1992

Nuclear Regulatory Commission (NRC)

M. Royack,	Team Leader
J. Sloan,	Assistant Team Leader
D. Acker,	Reactor Inspector
L. Coblentz,	Radiation Specialist
F. Gee	Reactor Inspector
L. King,	Reactor Inspector, Region II
T. Sundsmo,	Project Inspector
L. Tran,	Reactor Engineer, (NRR Intern)

Arizona Public Service (APS)

R. Adney,	Plant Manager, Unit 3
K. Albers,	Operations Monitor, QA/QM
J. Bailey,	Director, Nuclear Engineering
B. Ballard,	Special Assistant to Executive Vice-President Nuclear
J. Baxter,	Engineer, Compliance
B. Berthlett,	Manager, Operations Computer Systems
K. Bjornn,	Senior Engineer, Nuclear Engineering I&C
T. Bradish,	Manager, Compliance
W. Brown,	Supervisor, Maintenance Standards I&C
M. Burns,	Supervisor, Nuclear Engineering I&C Setpoints
D. Chin,	Senior Engineer, Technical Issues
L. Clyde,	Manager, Operations Unit 3
P. Coffin,	Engineer, Compliance
W. Corcoran,	Principal Discipline Engineer, ISI/IST
B. Cross,	Training Coordinator, Unit 2 I&C
J. Dennis,	Manager, Operations Standards
E. Dotson,	Director, Engineering
D. Douglass,	Auditor, Quality Audits
D. Elkinton,	Tech. Specialist Quality Assurance/RP Chem. Monitoring
L. Esau,	Senior Engineer, Operations Computer Systems
R. Flood,	Plant Manager, Unit 2
T. Foster,	General Manager, Outage Planning & Management
R. Fullmer,	Manager, Quality Audits and Monitoring
D. Garchow,	Manager, Fire Protection Support
D. Gouge,	Gen. Mgr., Plant Support and Chairman, Plant Review Bd.
L. Grabowski,	Senior Engineer, Procurement Engineering
S. Grier,	Manager, Procurement Engineering
S. Guthrie,	Site Director, Quality Assurance (QA)
R. Harton,	Auditor, QA & M
D. Hansen,	Supervisor, ISI/IST
J. Hesser,	Manager, Nuclear Engineering I&C
M. Hodge,	Manager, Nuclear Engineer Mechanical

P. Hughes,	General Manager, Radiation Protection
W. Ide,	Plant Manager, Unit 1
D. Kanitz,	Engineer, Compliance
S. Kanter,	Senior Coordinator, Management Services
M. Karbassian,	Supervisor, Fire Protection Engineering
M. Kerwin,	Manager, Maintenance Standards
S. Kesler,	Supervisor, Nuclear Engineering Electrical
P. Kish,	Engineer, Nuclear Engineer Mechanical
D. Kissinger,	Supervisor, Quality Engineering
W. Leaverton,	Senior Engineer, Site Nuclear Engineering I&C
J. Levine,	Vice President, Nuclear Power Production
M. Lockhart,	Analyst, Design & Document Control
D. Mauldin,	Director, Site Maintenance & Modifications
R. Mayes,	Senior Advisor, Operations Standards
C. McClain,	Manager, Technical Training
H. Miyahara,	Supervisor, Civil/Engineering Mechanics
M. Oren,	Manager, Operations Engineering
G. Overbeck,	Site Director, Technical Support (STS)
S. Penick,	Supervisor, Independent Safety Engineering
L. Perez,	Technical Assistant, STS
R. Prabhakar,	Manager, Quality Engineering
M. Raddocia,	Manager, Site Nuclear Engineering Mechanical and Manager, Unit 2 Maintenance
J. Reynolds,	Supervisor, Unit 3 Maintenance I&C
C. Russo,	Manager, Quality Control
R. Rouse,	Supervisor, Compliance
M. Sanetra,	Design & Document Control
J. Schmadeke,	Manager, Work Control Unit 3
C. Schmidt,	Principal Discipline Engineer, Systems Engineering I&C
M. Shea,	Manager, Radiation Protection
T. Shriver,	Assistant Plant Manager, Unit 2
E. Simpson,	Vice President, Nuclear Engineering
D. Smith,	Manager, Outage Planning & Management, Unit 3
R. Sorensen,	Manager, Site Chemistry
C. Stevens,	Manager, Nuclear Engineering Analysis
R. Stevens,	Director, Nuclear Licensing & Compliance
C. Stock,	Analyst, Administrative Support
F. Swirbul,	Supervisor, Nuclear Engineering I&C Balance-of-Plant
J. Terry,	General Manager, Nuclear Information & Records
B. Thiele,	Reactor Engineering Supervisor, Operations Engineering
B. Trenholme,	Engineer, Nuclear Engineering I&C
P. Trimble,	Engineer, Nuclear Fuel Management - Safety Analysis
N. Turley,	Engineer, Nuclear Licensing
J. Valerio,	Supervisor, Operations Computer Systems
D. Visio,	Senior Engineer, Quality Engineering
F. Warriner,	Supervisor, Unit 1 Maintenance I&C
B. Whitney,	Technical Specialist II, Quality Audits
D. Wittas,	Supervisor, Quality Engineering
B. Weinhold,	Supervisor, Nuclear Engineering Mechanical
R. Younger,	Manager, Maintenance Standards

SITE REPRESENTATIVES

A. Cordova,	Site Representative, Public Service of New Mexico
T. Donat,	Setpoint Coordinator, PG&E
J. Draper,	Site Representative, Southern California Edison
K. Hall,	Site Representative, El Paso Electric (EPE)
R. Henry,	Site Representative, Salt River Project
E. Quinn,	Lead Setpoint Engineer, Southern California Edison

The inspectors also talked with other licensee and contractor personnel during the course of the inspection.

2 <u>List of Personnel Attending Exit Meeting - June 5, 1992</u>

<u>Nuclear Regulatory Commission (NRC)</u>

M. Royack,	Team Leader
J. Sloan,	Assistant Team Leader
L. Miller,	Chief, Reactor Safety Branch, Region V
D. Acker,	Reactor Inspector
L. Coblentz,	Radiation Specialist
L. Tran,	Reactor Engineer (NRR Intern)

<u>Arizona Public Service Company</u>

B. Ballard,	Director, Nuclear Administration
J. Bailey,	Director, Nuclear Engineering
W. Brown,	Supervisor, Maintenance Standards I&C
M. Burns,	Supervisor, Nuclear Engineering I&C Setpoints
C. Churchman,	Acting Director, Nuclear Engineering
K. Cutler,	Acting Manager, Maintenance
K. Hamlin,	Director, Nuclear Safety
J. Hesser,	Manager, Nuclear Engineering I&C
P. Hom,	Senior Coordinator, Owner Services
D. Kanitz,	Engineer, Compliance
S. Kesler,	Supervisor, Nuclear Engineering Electrical
W. Leaverton,	Senior Engineer, Site Nuclear Engineering I&C
W. Powell,	Setpoint Program, Nuclear Engineering I&C Engineering
B. Trenholme,	Engineer, Nuclear Engineering I&C
C. Schmidt,	Principle Discipline Engineer, Systems Engineering
E. Simpson,	Vice President, Nuclear Engineering and Construction
C. Stock,	Analyst, Administrative Support
F. Swirbul,	Supervisor, Nuclear Engineering I&C Balance-of-Plant
D. Visco,	Senior Engineer, Independent Safety Engineering
D. Wittas,	Supervisor, Quality Engineering

<u>Other Utilities</u>

M. Benac,	Manager, El Paso Electric
R. Bockhorst,	Supervisor, Control Discipline, Southern California Edison
J. Draper,	Site Representative, Southern California Edison
R. Henry,	Site Representative, Salt River Project
K. Herman,	I&C Group Supervisor, Pacific Gas and Electric
A. Thiel,	Manager, Control Discipline, Southern California Edison

APPENDIX B

LIST OF ABBREVIATIONS

AFW	Auxiliary Feedwater
ANPP	Arizona Nuclear Power Project
APS	Arizona Public Service Company
BOP	Balance-of-Plant
CAR	Corrective Action Request
CE	Combustion Engineering
COLSS	Core Operating Limits Supervisory System
CRDR	Condition Report/Disposition Request
DDC	Drawing and Document Control
DGSS	Diesel Generator Starting System
EDG	Emergency Diesel Generator
ESFAS	Engineered Safety Feature Actuation System
FDT	Failure Data Trending
HI PZR PRESS	High Pressurizer Pressure
I&C	Instrumentation and Control
ISI	In-Service Inspection
IST	In-Service Testing
M&TE	Maintenance and Test Equipment
MFW	Main Feedwater
NIST	National Institute of Standards and Testing
NRR	NRC Office of Nuclear Reactor Regulation
NSSS	Nuclear Steam Supply System
PG&E	Pacific Gas and Electric
PM	Preventive Maintenance
PPS	Plant Protection System
PRA	Probabilistic Risk Assessment
psi	pounds per square inch
psig	pounds per square inch gauge
PVNGS	Palo Verde Nuclear Generating Station
QA	Quality Assurance
QE	Quality Engineering
RP	Radiation Protection
SG LO	Steam Generator Wide Range Low Level
SIMS	Station Information Management System
ST	Surveillance Test
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	Work Order