ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	May 19 through June 19, 1997
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ATTACHMENT: Supplemental Information

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EXECUTIVE SUMMARY

Palo Verde Nuclear Generating Station, Units 1, 2, and 3
NRC Inspection Report 50-528/97-19; 50-529/97-19; 50-530/97-19

An inspection team consisting of NRC Region IV inspectors and the Office of Nuclear Reactor Regulation Project Manager, performed an inspection at the Palo Verde Nuclear Generating Station on May 19 through June 19, 1997. The team reviewed the licensee's engineering activities to evaluate the effectiveness of the engineering organization in performing routine and reactive site activities, including the identification and resolution of technical issues and problems. The team also ascertained that the licensee was implementing a safety evaluation program that conformed to 10 CFR 50.59.

The team found that the licensee's engineering organization performed good routine and reactive engineering in support of operations and maintenance.

Engineering

- All seven of the design modifications reviewed by the inspection team had proper 10 CFR 50.59 screenings/evaluations and post-modification testing requirements. Applicable drawings and procedures were updated accordingly (Section E1.1.1).

- All five of the deficiency work orders reviewed by the team were adequately prepared (Section E1.1.3).

- All five design calculations reviewed by the team were accurate and complete (Section E1.1.4).

- All eight operability determinations reviewed by the team were performed appropriately. In each case, engineering provided a detailed discussion of the degraded condition and provided an adequate evaluation of the operability implications. Where necessary, calculations were included to support the determination of operability (Section E1.2).

- Each of the 23 condition reports/disposition requests reviewed by the inspection team represented a quality effort, in which the problem was clearly stated, the investigation determined a cause, and the corrective actions were appropriate to the discrepancy. Licensee engineering was providing good support to plant operations and maintenance through the condition report/disposition request process (Section E1.3).

- Documentation for three of the seven design modifications reviewed by the team had minor inconsistencies that were clarified by the licensee (Section E1.1.1).

- Only one safety-related temporary modification was outstanding during the inspection. The inspectors concluded that the licensee controlled temporary modifications in an excellent manner (Section E1.1.2).

- The independent safety engineering group met the function, composition, and responsibilities required by the technical specifications. In addition, the assessments and recommendations of this group appeared to be of high quality (Section E1.5).

- Procedure 93AC-0NS01, "10 CFR 50.59 Screenings and Evaluations," was conservative with respect to the scope of activities to be addressed by 10 CFR 50.59. However, the inspection team identified that other plant administrative procedures contained inconsistent guidance that could result in not performing safety evaluations for all changes to the facility as described in the licensing basis. Nevertheless, the licensee's overall program for implementation of 10 CFR 50.59 was generally conservative and well understood by the licensee's staff (Section E1.6).

- The licensee was performing good self assessments of the implementation of the requirements of 10 CFR 50.59, but was still in the process of correcting identified problems (Section E1.6).

- System engineers were proactive and effective in providing quality engineering resolution of technical issues of site activities. System engineers provided excellent engineering support in the troubleshooting and root-cause determinations of the May 31, 1997, reactor trip (Section E2.1).

- The design basis in the Updated Final Safety Analysis Report sections for the essential cooling water system and the essential chilled water system was accurately maintained (Section E2.2).

- The inspection team identified that the licensee had incorrectly deleted a Updated Final Safety Analysis Report required procedure for assuring continued spray pond system cooling capability beyond 26 days after a loss-of-coolant accident without performing a 10 CFR 50.59 safety evaluation. However, the licensee's engineering self assessment had previously identified this condition on May 7, 1997. This was identified as a noncited violation (Section E2.2).

- The extent and scope of a procedural deficiency that led to a water hammer event in the Unit 3 containment spray system was not adequately evaluated and corrected to preclude the root cause of the event from recurring. Specifically, plant operational procedures were not reviewed for confusing "if/then" procedural steps that could be misinterpreted by plant operators. This failure was identified as a corrective action violation (Section E2.3.1).

- Six of 20 main steam safety valves that were found to have lift setpoints outside the +/- 3 percent technical specification tolerances prior to the recent Unit 3 refueling outage were not reported to the NRC as required. Although a licensee analysis of the as-found conditions determined that the design basis had not been exceeded, the failure of multiple trains of a safety system is required to be reported in accordance with 10 CFR 50.73 (Section E2.3.2).

- The plant material condition and housekeeping were very good (Section E2.4).

- The licensee performed a good engineering self assessment. Although the self-assessment report was not issued until the last onsite day of the NRC team inspection, discussions with licensee personnel and review of condition reports confirmed that the self assessment identified strengths and weaknesses of the engineering organization similar to those identified by the NRC team (Section E7.2).

Plant Support

- The licensee's engineering self assessment identified that approximately 80 commitments to the emergency plan had been deleted without a 10 CFR 50.59 safety evaluation being performed prior to the emergency plan procedures being revised. This item will be followed as a followup item pending further evaluation (Section E2.2).

Report Details

III. Engineering

E1 Conduct of Engineering

E1.1 System Reviews

The team reviewed plant modifications (permanent and temporary), deficiency work orders, and engineering calculations associated with three safety-related systems to evaluate the effectiveness of the engineering organization in performing routine and reactive site activities. The three systems reviewed were the essential chilled water system, essential cooling water system, and the essential spray pond system. In addition, the team also reviewed engineering activities associated with recent containment spray system water hammer events.

E1.1.1 Permanent Plant Modification Review

a. Inspection Scope (37550)

The team reviewed the seven permanent plant modification requests listed in the Attachment to verify their conformance with applicable installation and testing requirements. Specific attributes included: 10 CFR 50.59 safety evaluations, post-modification testing requirements, applicable drawing changes, updates to the final safety analysis report, inclusion of necessary training, and field installation. In addition, the team reviewed Procedure 81DP-OEE10, "Plant Modifications," Revision 0, to determine the scope of the licensee's modification process.

b. Observations and Findings

The team determined that the plant modification procedure provided adequate control for equivalency replacements, maintenance modifications, paper change modifications, and design modifications. The team noted that the procedure required a review of the 10 CFR 50.59 safety evaluation as part of "use-as-is" and "repair" dispositions for material-related problems. The team found that all seven modifications had proper 10 CFR 50.59 screenings and evaluations. In addition, the team found that post-modification testing requirements were adequate to assure component operability. The team verified that affected drawings and procedures were updated in accordance with the modification packages. The team verified that the physical installations of the modifications associated with Work Orders 696842 and 785094 were consistent with the description in the modification package.

During the review of the seven design modification packages, the team discussed the following observations regarding the documentation for three of the modifications.

- Design modification Work Orders 00721193 and 889006 for Unit 2, Train A, changed the setpoint of a flow transmitter in the essential spray pond system. The instrumentation provided continuous flow indication and a differential flow alarm to detect a pipe break by comparing the supply and return flows in the closed-loop system. The licensee stated that historically the indication of Unit 2 return flow had been higher than the supply flow. The modification revised the span of the supply transmitter so that the indication of the return flow would agree with the indication of the supply flow.

  In the work order, the licensee had concluded that the material used for internally coating the carbon steel pipe had potentially failed due to lack of adhesion and poor selection for spray pond piping application. The licensee was concerned that the flapping and possible separation of the lining close to the process measurement of the flow element was providing an erroneous flow profile. Upon further evaluation, the licensee concluded that this flow condition had existed since original startup and appeared to be stable and not degrading. However, the team noted that the licensee had not determined the root cause of the large difference between the supply and return flow. Rather, they had only determined that the difference was not caused by calibration or instrument malfunction. In further discussions, the licensee stated that the original root cause stated in the modification was incorrect because the coating was not becoming loose and flapping. The team noted that the modification to the supply transmitter allowed the supply and return flow to agree.

- The team reviewed Condition Report/Disposition Request 2-6-0163, dated September 3, 1996, which reported that during the performance of the quarterly ASME Section XI surveillance test, the Unit 2, Train A, spray pond pump produced a flow of 16,300 gpm. While at 16,300 gpm, the pump met the minimum design basis flow requirement, the pump was declared inoperable because the minimum surveillance test flow rate acceptance criteria was 16,700 gpm. The team noted that the condition report/disposition request recommended that the system flow be increased by increasing the orifice size. Although the report stated that the licensee could not determine the root cause for the reduced flow condition, the report concluded that the single most likely contributing component resulting in low flow was pump degradation and the second largest contributor was the increase in system resistance caused by corrosion of the carbon steel piping.

  In accordance with the recommendation of Condition Report/Disposition Request 2-6-0163, design modification Work Order 785094, dated January 14, 1997, replaced the orifice plate in Train A of the spray pond system with a larger orifice plate in order to increase the flow in Train A.

The modification was applicable to Train A in all three units. The modification stated that Train A flow was historically lower than Train B and the cause of the reduced flow was due partially to the design of Train A, which had a longer run of pipe than Train B. Nevertheless, the licensee indicated that they did not know the actual root cause of the degradation of Train A flow.

The team reviewed Condition Report/Disposition Request 3-7-0003, dated January 6, 1997, which documented that the system flow was low for the Unit 3 spray pond Train A pump. In this condition report/disposition request, the licensee concluded that the cause of the low flow condition was a combination of changing the method of recording flow data and the instrument re-span of the supply flow transmitters. The team noted that the reason for this low flow differed from the root causes documented in Condition Report/Disposition Request 2-6-0163. However, the team concluded that the low flow conditions were different than that identified previously and that the licensee's corrective actions were appropriate for the identified condition. The team also noted that by increasing the orifice plate size, the Train A flow was increased such that the surveillance test flow requirements could be met. In addition, the team noted that the licensee was addressing the spray pond piping corrosion problem since 1995 by using zinc phosphate as a corrosion inhibitor and planed to perform a system flush with zinc oxide at high concentrations. This was being performed to reduce carbon steel piping corrosion by providing a protective coating on the piping and to improve flow conditions.

- Work Order 736534, dated December 10, 1995, raised the setpoint of the spray pond pump discharge temperature alarm from 87 degrees F to 105 degrees F for the three units. The setpoint was increased because the licensee determined by analysis that the previous setpoint would be reached shortly after a loss-of-coolant-accident and, therefore, would not be available to provide an alarm if the spray pond system did not perform as designed. The design basis limit for the pump discharge temperature was 110 degrees F, which was based on the temperature limit of the emergency diesel generator coolers. In the modification, the licensee stated that the new alarm setpoint of 105 degrees F had enough margin for operator response prior to reaching the design basis limit of 110 degrees F.

  The team was concerned that increasing the alarm setpoint was a nonconservative action because it allowed the operators less time to perform the required actions to prevent the spray pond temperature from reaching the design basis limit. The team also noted that the licensee had not determined how long it would take for the pump discharge temperature to increase from

105 degrees F to the design temperature and if there would be adequate time for the operators to perform the required actions. In response to this concern, the licensee determined that there would be a minimum of 3 hours before the design temperature was reached. The team acknowledged that this amount of time provided adequate time for the operators to perform the required actions.

c. Conclusions

The team found that all seven modifications reviewed had proper 10 CFR 50.59 screenings and safety evaluations, post-modification testing requirements were adequate, and drawings and procedures had been updated accordingly. The team also noted several documentation inconsistencies in three of the seven modification packages that the licensee subsequently resolved.

E1.1.2 Temporary Plant Modification Review

a. Inspection Scope (37550)

The team noted that the licensee did not have any temporary modifications installed on the three systems selected for review during this inspection. Therefore, the team reviewed one temporary modification that was installed on another safety-related system. Specific attributes reviewed by the team included the 10 CFR 50.59 safety evaluations and the license impact reviews.

b. Observations and Findings

The team found that there were only six open temporary plant modifications open during this inspection. There were none for Unit 1, three for Unit 2 and three for Unit 3. Five of these temporary modifications were on nonsafety-related systems. The one safety-related temporary modification was installed in Unit 2 and was closed and converted to permanent design status by initiation of a design master work order during the inspection. This conversion was accomplished in accordance with applicable plant procedures addressing temporary modifications.

The team reviewed the safety-related, Temporary Modification TMOD 2-96-SE-003, which reduced excessive noise in the low power range of Channel D of the Unit 2 excore nuclear instrument. The noise reduction was accomplished by the installation of two ferrite beads to the logic input cabling. The team found that the modification had the proper safety evaluations, license impact review, operability evaluations, and that the post-modification testing requirements were properly specified. The licensee evaluations of Temporary Modification TMOD 2-96-SE-003 concluded that there was no operability concern and no change was required to the technical specifications.

c. Conclusions

Based on the review of this one temporary safety-related modification and the low number of open temporary modifications, the team concluded that the temporary plant modification program was in conformance with plant procedures and being properly managed.

E1.1.3 Deficiency Work Order Review

a. Inspection Scope (37550)

The team reviewed the five deficiency work orders listed in the Attachment and reviewed Administrative Procedure 81DP-OCD13, "Deficiency Work Order," Revision 10. The team discussed some of the deficiency work orders with appropriate licensee personnel.

b. Observations and Findings

The team determined that the licensee used deficiency work orders to authorize "repair," "use-as-is," "rework," or "scrap" of plant systems, structures or components, which were in a condition not supported by any engineering, design basis, or design output document. The team found that the five deficiency work orders reviewed had comprehensive 10 CFR 50.59 screenings and/or safety evaluations. In four of the five deficiency work orders, the team concluded that the dispositions were appropriate, as well as, inspection and testing requirements. The team had questions regarding only one work order.

The licensee used Deficiency Work Order 00661874 to disposition an industry concern regarding potential gearbox disengagement of Limitorque HBC motor-operated butterfly valves similar to those used at Palo Verde. The licensee had been informed by a Technical News Report (Operating Event Report 0052593) that a spine adapter had disengaged from the drive sleeve in a Limitorque HBC gearbox at the Beaver Valley Nuclear Power Plant. Limitorque had informed the licensee that the possibility existed for the HBC spline adapter to become disengaged from the drive sleeve at Palo Verde. The licensee initiated Condition Report/Disposition Request 9-4-0033, which affected 23 motor-operated butterfly valves in each unit for a total of 69 valves.

In a Limitorque HBC valve, the spline adapter is keyed to the drive sleeve spline and can separate in situations where the valve stem is oriented below horizontal or under seismic conditions where excessive vibrations are present. If the spline adapter, key, and drive sleeve spline form a tight interference fit, this problem will not occur. However, if the fit is loose, the key can become disengaged and the valve will fail in its existing position. The existence of the interference fit can be verified only by disassembly and a visual check is not sufficient to determine the degree of tightness.

The licensee informed the team that they were aware of the problem and had inspected all 69 motor-operated valves as part of the licensee's NRC Generic Letter 89-10 program and had verified the interference fit for those valves. However, the licensee also considered that a secondary mechanism was desirable to preclude spline adapter disengagement. The licensee attempted to modify the valves by inserting a spacer between the spline adapter and the pointer cap, but abandoned this plan after determining that the dimensional tolerances of the gearbox were too unpredictable. After considering many options, the licensee developed a modification to install setscrews in the spline adapter to prevent the key and spline adapter from sliding on the valve stem, thus, preventing disengagement. The licensee intended to install this modification only on those HBC gearboxes that did not have or could not be reworked to have an acceptable interference fit.

The licensee had scheduled installation of the proposed modification (or verification of an interference fit) on the HBC gearboxes in all three units over the next 2-3 years as a secondary measure for precluding spline adapter disengagement. In the interim, stopgap measure, the licensee applied Loctite Compound 290 to the spline adapter keys to lessen the chance of disengagement of the key. This activity was covered under the deficiency work order disposition to Work Order 00661874. The licensee appeared to take adequate precautions to preclude migration of the Loctite into the process fluid and only a few drops were applied on each keyway. Loctite 290 has a quick cure time of about 3 minutes and excess compound was quickly removed.

The team noted that the spline adapter, key, and drive sleeve spline had to be at least snug tight for the Loctite compound to form a bond that would provide resistance to the movement of these parts under load. The team acknowledged that the Loctite application was probably better than doing nothing, but was concerned that the licensee may be using it as a justification for lowering the priority (and, thus, pushing back the installation timetable) of the tightness verification or setscrew modification. Subsequent discussions with licensee personnel indicated that the licensee did not intend to lower the priority for tightness verification or setscrew modification. As a result, the team concluded that, given the low occurrence rate of this failure mechanism, no further followup of this issue was necessary.

c. Conclusions

The team concluded that the five deficiency work orders that the team reviewed were adequately prepared.

E1.1.4 Review of Engineering Calculations

a. Inspection Scope (37550)

The team reviewed the five engineering calculations listed in the Attachment associated with the three selected systems, to determine that:

- Required technical, design verification, and independent design reviews were performed;

- Design information was correctly used for setpoint calculations;

- Calculational and analytical methodology complied with regulatory requirements, licensee design guides, license commitments, and industry practices.

- Calculational assumptions were technically reasonable;

- Open or verification-pending items in the calculations were satisfactorily resolved or properly identified and tracked for future resolution.

b. <u>Observations and Findings</u>

The team found that the five calculations reviewed were accurate and complete. The calculation assumptions were technically reasonable and the required reviews were performed.

c. <u>Conclusions</u>

The reviewed calculations were accurate, the assumptions were technically reasonable, and the required reviews were performed.

E1.2 <u>Operability Determinations</u>

a. <u>Inspection Scope (37550)</u>

The team reviewed the eight operability determinations listed in the Attachment that were performed by engineering in support of operations.

b. <u>Observations and Findings</u>

The team found that the eight operability determinations were appropriately performed by engineering. In each case, the engineer provided a detailed discussion of the degraded condition and provided an adequate evaluation of the operability implications. Where necessary, calculations were included to support the determination of operability.

c. <u>Conclusions</u>

Licensee engineering adequately performed the eight operability determinations that were reviewed by the team. Licensee engineers provided good support for operations by means of the operability evaluations.

E1.3 Condition Reports/Disposition Requests

a. Inspection Scope (37550)

The team reviewed 23 condition reports/disposition requests that involved the spray pond system, essential water, and the chilled water system. The condition report/ disposition requests reviewed by the team are listed in the Attachment.

b. Observations and Findings

The team found that each of the reviewed condition reports/disposition requests represented a quality effort, in which the problem was clearly stated, the investigation determined a cause, and the corrective actions were appropriate to the discrepancy. In some cases, the level of documentation was not sufficient for an independent reviewer to discern all ramifications of the problem or the thought processes used within the disposition. However, in each of these cases, licensee engineers were able to resolve all concerns.

c. Conclusions

Licensee engineering provided good support to plant operations and maintenance through the condition report/disposition request process.

E1.4 Surveillance of non-Technical Specification Equipment

a. Inspection Scope (37550)

The team reviewed surveillance test procedures to verify that equipment for systems that were not covered by technical specifications were being maintained reliable and operable. This included equipment for station blackout, Regulatory Guide 1.97 instrumentation, anticipated transient without a scram equipment, and the safety parameter display system.

b. Observations and Findings

The team found that there were no design changes or modifications made during the last 2 years to the three systems selected that involved nontechnical specification equipment. The team verified that the licensee had proper controls for ensuring operability of these systems or portions of the systems when not controlled directly by the requirements of the technical specifications. The team found that these controls included Administrative Procedure 80DP-0CC01 for configuration management of process computer software, which included equipment for station blackout, anticipated transient without a scram equipment, and the safety parameter display system. The Regulatory Guide 1.97 instrumentation requirements were addressed in the Post-Accident Monitoring Instrumentation Topical Report.

c. Conclusions

The team concluded that the licensee had adequate procedures to maintain equipment and systems, that were not covered by technical specifications, to ensure system reliability and operability.

E1.5 Independent Safety Engineers

a. Inspection Scope (37550)

The team interviewed independent safety engineers within the licensee's Nuclear Assurance Operations Department to determine whether they were accomplishing the functions described in the technical specifications. The team attended a meeting of the independent safety engineers and reviewed completed Nuclear Assurance Evaluation Reports to confirm that required independent safety engineering verifications were being performed.

b. Observations and Findings

The team determined that the independent safety engineers examined plant operating events, NRC issuances, industry advisories, and other sources of operating experience information. Based upon those examinations, the independent safety engineers made and satisfactorily tracked to completion detailed recommendations for improving plant safety.

The team determined that seven full-time engineers were dedicated as independent safety engineers. Each member had at least a bachelor's degree in engineering or a related science and at least 2 years of professional level experience in his field as required by the technical specifications.

The team noted that the licensee reorganized the independent safety engineering organization in 1994. What previously had been a separate Independent Safety Engineering Group had been dissolved, with the independent safety engineers being absorbed into the Nuclear Assurance Operations Department (i.e., quality assurance group). Independent safety engineers were assigned to one of four sections within the department (engineering, maintenance, operations, plant support). Each independent safety engineer reported through a section leader and department leader to the Director of Nuclear Assurance.

The team attended a meeting of independent safety engineers on June 4, 1997 and noted that the meeting served a large administrative function with little collective discussion of technical issues. Nevertheless, the team interviewed two independent safety engineers, both of whom appeared knowledgeable of the functions and responsibilities of the position.

c. Conclusions

The licensee's independent safety engineers met the function, composition, and responsibilities as required in the technical specifications. The assessments and recommendations of this group appeared to be of high quality.

E1.6 10 CFR 50.59 Safety Evaluations and Screenings

a. Inspection Scope (37001)

The team reviewed the licensee's 10 CFR 50.59 program guidance, 7 screenings that concluded that a safety evaluation was not required, and 31 safety evaluations. The screening and safety evaluations were associated with permanent and temporary modifications to the plant and procedures, and licensing document change requests. In addition, the team reviewed the licensee's self assessments of their 10 CFR 50.59 program and of the quality of completed screening and safety evaluations.

b. Observations and Findings

b.1 Administrative Requirements

The licensee's screening and safety evaluation process for changes to the facility was controlled by Administrative Procedure 93AC-0NS01, "10 CFR 50.59 Screening and Evaluations." The procedure specified the responsibilities and the methods for determining if facility changes, procedure changes, and development and performance of special tests and experiments could be made without prior Commission approval. The procedure also specified qualification requirements for personnel who were authorized to perform screening, evaluations, and reviews in the 10 CFR 50.59 process.

The procedure required a comprehensive description of the change, such that an independent reviewer could understand what, why, where, and how the change would be done. Screenings are performed to determine whether or not a 10 CFR 50.59 evaluation was required. The procedure defined the scope of documents that were considered for screening and potentially for evaluation as licensing basis documents. These documents included the Updated Final Safety Analysis Report (including the Combustion Engineering Standard Safety Analysis Report), the Operating License, the Safety Evaluation Report, and correspondence in separate letters to/from the NRC and Arizona Public Service Company that were referenced in the Safety Evaluation Report. The inspectors noted that this scope exceeded the minimum requirements of 10 CFR 50.59; therefore, the team considered this a strength in the licensee's program.

Administrative Procedure 93AC-0NS01 provided screening criteria for facility changes by using four questions that were amplified in the procedure. If the results of the screening concluded that a safety evaluation was not required, the procedure required that a detailed justification be provided for all "no" answers. If the results

of the screening concluded that one or more of the screening criteria were met, the process required a safety evaluation to determine if the change constituted an unreviewed safety question. The team had the following observations relating to Procedure 93AC-0NS01 and discussed them with the licensee:

(1) The procedure required that the safety evaluation explain the application of criteria to determine why the change may or may not be implemented with no effect on nuclear safety. This implied that the 10 CFR 50.59 evaluation was a safety standard, as opposed to a determination whether or not prior Commission approval is required for a proposed change;

(2) The procedure called for determining if the proposed change "required" a technical specification change, as opposed to addressing whether or not the proposed change "involves" a technical specification change. While the team did not find any situations for which this wording affected the outcome of a safety evaluation, this difference in wording provided the potential for missing the intent of the rule, which was to have the technical specifications reflect the actual plant design and limiting conditions;

(3) The licensee used several different terms in the specific safety evaluation questions for defining the scope of the safety evaluation. For example, the safety evaluation questions used the terms "licensing basis," "quality-related equipment," and "equipment that has a discernible impact on nuclear safety or hazard of radioactive release" to define the scope of the evaluation. Although the team did not identify any safety evaluations that were limited due to these inconsistencies, the potential exists for misinterpretation of the scope of the safety evaluation.

(4) The procedure only considered dose to the public (10 CFR Part 100) in its consequences evaluations, as opposed to also considering the dose consequences to those onsite (10 CFR Part 20). Although the team did not identify any instance where this would have changed the outcome of a screening or safety evaluation, the potential exists for not meeting the full intent of 10 CFR 50.59.

During the inspection, the licensee provided a draft change to Procedure 93AC-0NS01 that, when implemented, would resolve these concerns.

The team identified that safety evaluations were not required for certain changes that were identified as "paper only" changes. Administrative Procedure 81DP-0EE10 defined these changes as those that change design documents to reflect the current plant physical configuration. For example, Work Order 00696862 updated a technical manual that was referenced in work procedures to allow plugging a percentage of essential chilled water heat exchanger tubes to a specified value that was within the bounds of a revised calculation. The work order stated that because the change was a paper change only, a 10 CFR 50.59 screening/evaluation was not required. Although the team determined that this specific change did not require a safety evaluation, the team

was concerned that this process constituted a 'pre-screening' of changes, and could potentially inhibit performing a formal screening as specified in Administrative Procedure 93AC-0NS01. In evaluating this "paper only" change process, the team identified several administrative procedures that permitted such 'pre-screenings' without evaluating the change against the screening criteria specified in Administrative Procedure 93AC-0NS01.

In further evaluating this concern, the team determined that Administrative Procedure 81DP-0EE10, "Plant Modifications," discussed criteria to be used in determining whether or not a screening was required for "paper only" changes. The criteria was, ". . . [c]ould the change affect the conclusions reached in the Updated Final Safety Analysis Report/Design Basis about the design, function or method of performing the function of a structure, system or component described in the Updated Final Safety Analysis Report/Design Basis, or does the change affect technical specifications?" The screening criteria contained in Administrative Procedure 93AC-0NS01 included:

(1) Any change to the description of a structure, system or component which may alter its design, function, or method of performing its function as described in the Updated Final Safety Analysis Report, including Combustion Engineering Standard Safety Analysis Report, or other Licensing Basis document either by text, drawing, or any other information which could have been relied upon by the NRC in granting Palo Verde's licenses to operate.

(2) Any change to any structure, system or component not explicitly described in the Updated Final Safety Analysis Report which may affect or alter the function of any structure, system or component that is explicitly described in a licensing basis document. This includes consideration of changes to systems not classified as safety related if they have a potential for impacting nuclear safety.

(3) Any change to any structure, system or component for which credit is taken in Chapter 6 or Chapter 15 safety analyses and for which all allowed outage times, permissible mode conditions, or permitted reductions in redundancy are not specified in the technical specifications.

(4) Any change in plant configuration while work is in progress.

(5) Changes to structure, systems or components, which could affect topical issues.

(6) Any change which could potentially impact plant safety. This includes consideration of the plant design requirements, intended or unintended operation of equipment, potential failure modes of component, human errors, and plant conditions.

(7) Specific review of Generic Letter 95-02 when considering analog-to-digital instruments and control system replacements.

(8) A change in the design basis or licensing basis of the plant to make it agree with the as-built plant may constitute a change in the facility and, thus, require a "Yes" response and an Evaluation even though no physical change is to take place.

(9) And, if the as-built condition of the plant is to be changed to agree with the licensing basis, an evaluation may not be required.

Therefore, the team concluded that the criteria used in Administrative Procedure 81DP-0EE10 did not fully consider the criteria required for a screening as required in Administrative Procedure 93AC-0NS01 such that the potential existed for an inadequate screening of "paper only" changes. However, the team did not identify any procedure changes that would have required a safety evaluation to be performed as a result of this 'pre-screening' process.

The team identified a second example of the potential for prescreening of changes. Administrative Procedure 01DP-0AP01, "Procedure Process," used a flow chart with questions for determining if a procedure change constituted an "intent change." The identification of an "intent change" required a screen of the procedure change against the criteria in Administrative Procedure 93AC-0NS01. The questions in Administrative Procedure 01DP-0AP01 require determinations regarding whether the proposed change involved:

- Changing the objective or purpose of the procedure
- Causing a system or component to be used in a manner outside the design basis
- Change the sequence of activities or methods described in the Updated Final Safety Analysis Report
- Limit the ability of the structure, system or component to perform its safety function
- Alter current licensing/design basis acceptance criteria

Procedure 93AC-0NS01 required the performance of a safety evaluation for a change to a procedure that is outlined, summarized, or completely described in the licensing basis; therefore, the team concluded that the criteria used in the two procedures were inconsistent. As mentioned previously, the team did not identify any procedure changes that were not appropriately screened as a result of the inappropriate use of "intent only" changes.

The licensee acknowledged the team's concerns and stated that they had a program underway to reevaluate their use of criteria in multiple procedures that affected the 10 CFR 50.59 screenings and safety evaluations.

b.2 Screenings and Evaluations

The team reviewed 7 sreenings to determine if safety evaluations were required. The team determined that the licensee had appropriately screened the proposed changes. The team also reviewed 31 safety evaluations with the following comments or observations:

- The team considered that 24 of the 31 evaluations reviewed contained the appropriate information to conclude that no unreviewed safety question existed.

- For 5 of the 7 remaining evaluations, the team needed additional information beyond that provided in the safety evaluations to understand how the licensee concluded that no unreviewed safety question existed. The team noted that this level of documentation was not consistent with the guidance of Administrative Procedure 93AC-0NS01. The procedure stated that the safety evaluation would provide sufficient explanation so that a qualified reviewer could draw the same conclusion based on the information provided. This concern had been previously identified in the licensee's internal audits over the past 3 years (see Section b.3 of this report). Despite this weakness, the team did not identify any safety evaluations that would have resulted in a determination that an unreviewed safety question existed. In addition, the licensee had taken corrective action for this concern by conducting training in November 1996 on the weaknesses they had identified through their own audits.

- Evaluation Log 96-00017 - This change involved an interpretation of the operability requirements for the post-accident sampling system. The change provided an interpretation that only the primary instrumentation could be used to determine system operability, and that alternate instrumentation was not appropriate. The team considered this interpretation to be noteworthy in that it was conservative, and that the safety evaluation appropriately concluded that the change did not involve an unreviewed safety question or a change to the technical specifications.

- Evaluation Log 96-00014 - This safety evaluation involved an extension of the peak fuel rod burnup associated with fuel handling accidents. The team was concerned that the licensee had not performed a 10 CFR 50.59 safety evaluation for a change in the method of calculating the source term for the fuel handling accident analysis. The evaluation stated that Updated Final Safety Analysis Report, Section 15.7.4.1.3, used a different method (i.e., Regulatory Guide 1.25) to calculate the amount of radioactive gasses released during a fuel handling accident than was currently used by the fuel vendor (Asea Brown Boveri Combustion Engineering). Specifically, the

vendor used a computer code called FATES, which was the method specified in ANSI/ANS-5.4 - 1982, "American National Standard for Calculating the Fractional Release of Volatile Fission Products from Oxide Fuel Elements." The evaluation justified this use of the FATES computer code based on the NRC's approval of this method at another licensee and the vendor's letter, which stated that the use of the FATES code was acceptable for use at Palo Verde.

The team concluded that a 10 CFR 50.59 safety evaluation was required for the change in analysis methodology described in the Updated Final Safety Analysis Report and did not agree that the approval of the use of this computer code for another licensee applied to the Palo Verde licensing basis. The team noted that the vendor's letter, dated January 15, 1996, stated that the vendor's evaluation was suitable for reference in a 10 CFR 50.59 safety evaluation performed by Palo Verde. This appeared to support the team's concern that a 10 CFR 50.59 safety evaluation should have been performed before the FATES computer code was used. The vendor's letter also stated that:

> Asea Brown Boveri Combustion Engineering Nuclear Operations (ABB CENO) used the FATES code with the ANS 5.4 model in 1991 . . . in conjunction with the implementation of a 52 MWD/kgU peak rod average burnup at Palo Verde Nuclear Generating Station. Asea Brown Boveri Combustion Engineering Nuclear Operations concluded that the dose consequences were bounded by the initial analysis of record (Updated Final Safety Analysis Report initial analysis using Regulatory Guide 1.25) and, therefore, the Palo Verde Nuclear Generating Station Updated Final Safety Analysis Report statements concerning the dose calculation were not changed.

The licensee indicated that, although the FATES computer code was used to generate the source term for the fuel handling accident analysis, the Updated Final Safety Analysis Report use of Regulatory Guide 1.25 remains bounding. Therefore, the licensee concluded that there was no need to update the Updated Final Safety Analysis Report to reflect the actual analysis methods of record. Although the current Updated Final Safety Analysis Report may be bounding, the team pointed out that 10 CFR 50.71(e) requires that the information included in the Updated Final Safety Analysis Report contains the latest material developed. The licensee also provided Condition Report/ Disposition Request 9-6-0010, which stated:

> ". . . the current analyses of record for Palo Verde Nuclear Generating Station fuel handling accidents have not used the methods described in Reg. Guide 1.25. Additionally, the assumptions of Reg Guide 1.25 no

longer apply to Palo Verde Nuclear Generating Station as fuel burnup now exceeds the limits in Reg. Guide 1.25. Methods currently in use have been approved by the NRC for use by [another licensee]."

The licensee identified that the original staff licensing safety evaluation report for the Combustion Engineering Standard Safety Analysis Report Design, NUREG-0852, Section 4.2, "Fuel System Design," as referenced in the Palo Verde licensing safety evaluation report, NUREG-0857, specifically referenced use of the FATES code. However, the team concluded that this section of the safety evaluation report applied to the material properties and analysis of fuel centerline melt limit, and not for use in generating the source term for fuel handling accidents in the Chapter 15 fuel handling accident analyses. At the conclusion of the inspection, the licensee was still researching documents for applicable evaluations. This issue will be followed as an unresolved item pending completion of the licensee's review of additional evaluations (50-528;-529;-530/9719-01).

b.3 Licensee Self-Assessments

Administrative Procedure 93AC-0NS01 required that the Department Leader, Nuclear Regulatory Affairs, annually evaluate the overall performance of 10 CFR 50.59 screenings and evaluations. The team verified that this evaluation was performed, and reviewed the Significant Root Cause Investigation, Condition Report/Disposition Request 9-6-Q417, that documented these findings. The team also reviewed 6 months of reports (October 1996 to April 1997) of a special nuclear assurance evaluation program, which assessed the adequacy of the 10 CFR 50.59 program by reviewing the completeness of approved screenings and safety evaluations. Although these licensee evaluations concluded that the licensee's performance in implementing their 10 CFR 50.59 program improved from 1995 to 1996, these assessments also concluded that the program was not improving further. Deficiencies identified in subsequent assessments further indicated that the licensee's Level 1 program goals were not being met. Based on the licensee's criteria of requiring 95 percent of all screenings and safety evaluations to contain no technical errors (defined by a set of 14 different criteria), the licensee concluded that the quality of their 10 CFR 50.59 screenings and safety evaluations were inadequate.

The NRC team's questions and concerns regarding the licensee's implementation of the requirements of 10 CFR 50.59 reflected some of the same concerns identified by the licensee's line and independent assessments.

c. Conclusions

The team found that the 10 CFR 50.59 screenings and safety evaluations provided substantive information that supported the licensee's conclusions. Although the guidance contained in the licensee's administrative procedures contained inconsistencies with respect to the requirements of 10 CFR 50.59, the licensee had

corrective actions in place to address these weaknesses. The licensee's administrative procedure for 10 CFR 50.59 screenings and safety evaluations had a broad scope and provided adequate guidance for performing safety evaluations. The team identified several minor procedural weaknesses that could result in not appropriately screening changes to the facility as described in the licensing basis; however, the team did not identify any examples where a safety evaluation had not been performed as required. The licensee's overall program for implementation of 10 CFR 50.59 was generally conservative and well understood by most of the licensee's staff. The licensee had performed strong, self-critical assessments of their 10 CFR 50.59 program and identified significant issues with specific issues and programmatic concerns that affected the ability of the licensee to improve their performance.

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support

a. Inspection Scope (37550)

The team evaluated the extent and quality of engineering involvement in site activities by reviewing condition reports and interviewing eight system engineers. Interview topics included management expectations for system engineers, use of probabilistic risk assessment in decision making, and training regarding system interrelations. In addition, the extent and effectiveness of the site engineering communications with other departments, such as maintenance, operations, and corporate engineering were discussed and evaluated. The team performed walkdowns of the spray pond system and the chilled water system with the systems engineers.

The team evaluated engineering involvement with the resolution of technical issues selected from recent plant events or routine work documents. Also, the team evaluated the extent of backlogged engineering work.

b. Observations and findings

The team observed good engineering involvement in site activities based on reviews of events and personnel interviews. The team noted that the system engineers were involved in identifying and resolving technical issues affecting the plant. The system engineers discussed with the team how they interfaced with operations, maintenance, and design engineers to resolve problems. Approximately 50 percent of the system engineers interviewed stated that they routinely held monthly system meetings with maintenance, design engineering, and operations to update system status and planned modifications. The rest of the system engineers individually contacted their system counterparts to update system status.

During the interviews, the team determined that the system engineers were knowledgeable of their systems and modifications to their systems. For example, during the system walkdown of the essential chilled water system, the system

engineer was able to answer all the inspector's questions concerning system operability and maintenance requirements, post-maintenance testing requirements, and acceptance criteria. All system engineers interviewed were able to discuss past modifications, recent plans or changes for their system, and future expectations for their system. System engineers typically requested the probabilistic risk assessment group to perform a risk assessment prior to performance of scheduled maintenance on their systems.

The team also noted good system engineering performance subsequent to the Unit 3 reactor trip that occurred on May 31, 1997. The trip was caused by the incorrect crimping of two terminal board leads and a missing jumper on the reactor protection system. The team noted that a similar event had occurred on May 19, 1997. Although the licensee's troubleshooting and investigation efforts could not precisely determine the root cause of the initial event, during troubleshooting for the May 31, 1997, event, the licensee's system engineer and instrumentation and control technicians were able to determine the cause of the problem.

c. <u>Conclusions</u>

The team concluded that the system engineers were effective in providing quality engineering resolution of technical issues. System engineers were knowledgeable of their assigned systems. The team concluded that the system engineers provided excellent support in the troubleshooting and root-cause determination of the May 31, 1997, reactor trip.

E2.2 Facility Conformance to License Conditions and Design Basis Documents

a. <u>Inspection Scope</u>

While performing the inspections discussed in this report, the team reviewed applicable sections of the Final Safety Analysis Report that related to the selected plant systems. The team specifically reviewed Section 9.2.2.1, "Essential Cooling Water Systems," Section 9.2.5, "Ultimate Heat Sink," and Section 9.2.9.2, "Essential Chilled Water Systems," of the Final Safety Analysis Report. The team also interviewed licensee personnel and reviewed plant procedures and calculations to determine if the in-plant systems were consistent with the description in the Final Safety Analysis Report.

b. <u>Observations and Findings</u>

The team found that maintenance of the design basis in the Final Safety Analysis Report sections for the essential cooling water system and the essential chilled water system was very good, in that the team did not find any discrepancies in the two sections.

The team also reviewed Section 9.2.5.1.1.C of the Final Safety Analysis Report for the spray pond system, which stated that procedures for assuring continued cooling capability beyond 26 days were available. The licensee indicated that the

requirement to have procedures in place to ensure continued capability of the ultimate heat sink was required for compliance with Regulatory Guide 1.27. The regulatory guide required 30 days of ultimate heat sink inventory without makeup. Since the licensee's ultimate heat sink was designed for 26 days of water inventory, the licensee was committed to have an analyzed alternate means of complying with the 30-day requirement by identifying other sources of water and having procedures in place to ensure the alternate water source could be delivered to the spray ponds. The team noted that Emergency Procedure EPIP-56, "Ultimate Heat Sink Emergency Water Supply," Revision 5, contained the information supporting the licensee's commitment to Regulatory Guide 1.27.

When the team requested a copy of the procedure, the licensee indicated that it had been deleted approximately 1 year ago. In addition, the licensee indicated that their self assessment had previously identified this discrepancy in Condition Report/Disposition Request 9-7-Q257, dated May 7, 1997. The engineering self assessment (Audit 97-005) had identified that procedures were not in place to replenish the ultimate heat sink. Upon investigation, the licensee had determined that the emergency planning department had performed a total conversion of the emergency plan procedures and revised several emergency plan manuals during the first half of 1996. In April 1996, nine commitments, which were applicable to the ultimate heat sink backup water sources, were inactivated without performing a 10 CFR 50.59 safety evaluation when the commitments were inactivated. In addition, some of the instructions for obtaining a backup water supply were not transferred into the new procedures during the procedure conversion process, due to the inactivation of the commitments.

The team reviewed the licensee's corrective actions for the condition report, which included revisions to Procedures 16DPOEP14 and 16DP-OEP15 and reinstatement of the commitments concerning backup water sources for the emergency spray ponds. The failure to perform a 10 CFR 50.59 safety evaluation when these commitments concerning the backup water source for the emergency spray pond were deleted was a violation of 10 CFR 50.59. However, the licensee identified this violation and took appropriate corrective action by revising the applicable procedures to include the deleted commitments. The violation was not a repeat of a previous violation and did not appear to be willful. This non-repetitive, licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (50-528;-529;-530/9719-02).
The team noted that Condition Report/Disposition Request 9-7-Q257 also identified that approximately 80 commitments to the emergency plan had been deleted without a 10 CFR 50.59 safety evaluation being performed prior to the emergency plan procedures being revised. At the time of this inspection, the licensee had not completed the corrective actions for this aspect of the condition report.

The team noted that the licensee's planned corrective actions included reviewing all the emergency planning commitments that were inactivated during the procedure reduction process to determine whether commitments were still contained in the emergency plan, the procedures, and the Final Safety Analysis Report. The due date for completion of these corrective actions was August 25, 1997. The licensee's deletion of emergency plan commitments and corrective actions will be reviewed during future NRC inspections. This was identified as a followup item for further inspection by NRC emergency preparedness inspectors (50-528; -529; -530/9719-03).

c. Conclusions

The team concluded that the licensee had adequately maintained the design basis of the essential cooling water system and the essential chilled water system in the Final Safety Analysis Report. The team identified a noncited violation for a licensee-identified deletion of a procedure specified in the Updated Final Safety Analysis Report without performing a 10 CFR 50.59 evaluation. The licensee also identified that approximately 80 commitments had been deleted from the emergency plan without performing a 10 CFR 50.59 safety evaluation.

E2.3 Resolution of Recent Plant Events

E2.3.1 Containment Spray System Water Hammer Events

a. Inspection Scope (37550)

The team reviewed the licensee's response to two water hammer events that had occurred in the past 2 years. The events involved a series of water hammers that occurred in the Unit 2 containment spray system during the period July 21-26, 1995, and a water hammer in the Unit 3 containment spray system on April 25, 1997. In selecting these events for review, the team sought to determine the effectiveness of the licensee's engineering staff in response to an unscheduled occurrence and support of plant operations. Within this framework, the team evaluated the licensee's damage assessment of the events and actions taken to prevent recurrence.

b. Observations and Findings

1995 Water Hammer Event

Train A of the Unit 2 containment spray system experienced several water hammer events during the period of July 21-26, 1995. These events occurred during evolutions associated with startup of Unit 2 from a refueling outage. A total of approximately six water hammer events occurred during this period, several of which were the result of the troubleshooting efforts. During the events, licensed operators heard loud banging sounds and observed pipe vibrations. The sounds and vibrations quickly subsided and the pump and system ran smoothly after each event. The licensee determined that an excessive amount of air was present in the

system on the discharge side of the pump. The licensee postulated that on pump starts an air bubble collapsed and sent a pressure wave from the discharge side of the pump through the pump and back to the refueling water tank on the suction side.

The licensee initiated Condition Report/Disposition Request 2-5-0256 to investigate these events. The licensee did not observe any damage during a piping system and pipe support walkdown of the suction and discharge sides of the pump. The inspectors noted that this examination was performed by a design engineer on July 28, 1995. The examinations were visual and were performed from deck level without using scaffolding or the removal of piping insulation (which covers most of the piping in this system).

Based on visual observations of piping displacement that occurred during the events, the licensee performed a piping system computer stress analysis. This analysis predicted potential damage to two snubber supports that provided axial support to the system piping. Snubbers CH-142 and CH-424 were manually stroked and determined to have not been damaged during the events. The licensee concluded that the piping displacements had been overestimated by the operators and that the actual pipe stresses had been less than those calculated in the stress analysis.

The licensee determined that the root cause of the water hammer event was the lack of a procedure detailing how the containment spray system should be vented following an outage or system maintenance. In response, Operational Procedure 40OP-9SI02, "Recovery from Shutdown Cooling to Normal Operating Lineup," Revision 9, was revised to add guidance for venting the system. At the conclusion of these efforts, the licensee had determined the root cause of the events, had taken efforts to preclude recurrence by providing procedural guidance for venting the containment spray system during return to service, and had determined that the system had not been damaged and remained operable.

<u>1997 Water Hammer Event</u>

Train A of the Unit 3 containment spray system experienced a water hammer event on April 27, 1997, when the pump was started for a surveillance test following a system outage. During the event, operators heard a slamming noise that quickly subsided. The pump and system ran smoothly after initial plant startup.

The licensee initiated Condition Report/Disposition Request 3-7-0216 to investigate the event. As in 1995, the licensee postulated that the root cause of the water hammer was excessive air in the discharge sections of the piping. The piping had not been adequately vented following the Unit 3 refueling outage. Step 4.3.9 of Operational Procedure 40OP-9SI02, which provided the venting steps added in response to the 1995 water hammer event, had not been performed by the licensed operators. This procedural step was prefaced with a conditional clause stating that the venting needed to be performed ". . . if Safety Injection Train A is being restored from an outage/maintenance condition." The operators had incorrectly

concluded that the venting steps were not needed because the system had been surveillance tested and run in certain modes. However, the previous operating modes had not involved the entire system piping, some portions of which contained a sizable volume of air. As corrective action, the licensee revised Operational Procedure 40OP-9SI02 to remove the conditional statements preceding the venting actions in Step 4.3.9 and to require venting during any system recovery effort.

As in 1995, a design engineer performed a deck level inspection of the system and supports and found no signs of damage. Because no visual observations of piping deflection were available, the licensee did not attempt to perform a stress analysis. The licensee concluded that the Unit 3 event of 1997 was bounded by the 1995 event. No snubbers were exercised following this event.

The team conducted a walkdown of the affected containment spray piping in Unit 3 and did not note any evidence of damage other than several places where the piping insulation was slightly crushed. The team reviewed the licensee's operability evaluations for both the Unit 2 and Unit 3 events and determined that the evaluations were reasonable.

The team reviewed the licensee's corrective actions for the events. As previously mentioned, the licensee determined that the second event was caused by the failure to vent the system following restoration due to a confusing conditional statement in the procedure. The team was concerned that the licensee had not considered the applicability of this procedural deficiency to other plant operational procedures. In response to this concern, the licensee reviewed several other similar procedures and identified many instances of similar conditional clauses and one example where following the procedure would not have resulted in a satisfactory system vent. This latter example occurred in the same operational procedure involved in the water hammer events (Operational Procedure 40OP-9SI02, Steps 4.3.4.13 and 5.3.4.13). As an additional corrective action, the licensee initiated a condition report/disposition request to determine whether conditional statements in plant procedures could be similarly misinterpreted and result in the nonperformance of necessary plant evolutions.

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The failure to identify and evaluate the adequacy of the conditional statements in other operational procedures is a violation (50-528;-529;-530/9719-04).

During review of the water hammer events, the team noted a potential inconsistency in the licensee's technical specifications. Technical Specification 4.6.2.1.c, requires the licensee to check that the level in the containment spray piping is at least 115 feet every 31 days. This check is performed in the control room using a remote indicator of a differential pressure sensing unit on the containment spray piping downstream of the containment spray

containment isolation valve, which is normally closed. This check is performed to ensure that the containment spray piping is filled sufficiently to provide timely delivery of spray water to the containment and to preclude system disturbances, such as a water hammer, that could result from the presence of excessive air in the system. Because the containment isolation valve is closed during the surveillance, the level in the containment spray piping does not provide assurance that the piping upstream (pump side) of the containment isolation valve is filled with water.

The inspectors noted that the Technical Specification 4.5.2.b.2 surveillance requirements for the emergency core cooling subsystems, require a monthly venting of a system high point vent to demonstrate a solid system with no air bubbles. Since similar venting of the containment spray system is not required, the fill status of the system remains untested during the operating cycle. The licensee stated that the reason for the difference in the surveillance requirements between the containment spray and the emergency core cooling systems is that the containment spray system does not have an interface with a high pressure source and, therefore, is not considered to have as great a potential to have intrusion of dissolved gases. However, the team was concerned that incomplete system venting upon startup of the containment spray system could result in air in the system that could remain undetected and contribute to abnormal system stresses and performance over time. The lack of a surveillance requirement to periodically assure that the containment spray system is adequately filled and vented was identified as an inspection followup item (50-528;-529;-530/9719-05) and will be further discussed by the inspectors with the Office of Nuclear Reactor Regulation.

c. Conclusions

The team concluded that the licensee had reasonably determined that Unit 2 and 3 containment spray systems remained operable subsequent to the water hammer events in 1995 and 1997. However, the licensee failed to consider the applicability of the root cause of these events to other operational procedures. As a result, other potentially confusing procedure steps were not identified and corrected. This inadequate corrective action is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action."

E2.3.2 Unit 3 Main Steam Safety Valves Lift Setpoints

a. Inspection Scope (37550)

The team reviewed the licensee's engineering evaluations and corrective actions for 6 of the 20 main steam safety valves and one of four pressurizer safety valves that were found to have lift setpoints outside their technical specification tolerances during the recent Unit 3 refueling outage.

b. Observations and Findings

Licensee Event Report 94-02, dated April 13, 1994, reported that 7 of the 20 main steam safety valves tested on Unit 3 had setpoints outside their technical specifications lift tolerances (+/- 1 percent at that time) during the March 1994 refueling outage. Twelve other licensee event reports dating back to 1988 reported similar conditions in all three Palo Verde units. On May 16, 1994, the licensee obtained NRC approval for an amendment to Technical Specification 3.7.1.1 for all three Palo Verde units to increase the main steam safety valve lift setpoint tolerance to +/- 3 percent. Similarly, the same amendment increased the Technical Specification 3.4.2.2 pressurizer code safety valve lift setpoint tolerance to +3 percent and -1 percent.

The team noted that Condition Report/Disposition Request 3-7-0056 reported that 6 of the 20 main steam safety valves and one of the four pressurizer safety valves were found to have lift setpoints outside the +/- 3 percent technical specification tolerances on February 11, 13, 14, and 15, 1997, prior to the recent Unit 3 refueling outage. A Trevitest of the six valves determined the lift setpoints to be +3.2 percent, +3.2 percent, +3.7 percent, +4.4 percent, + 5.0 percent, and greater than 6 percent (valve did not lift) of their required lift setpoints. At the time of the discovery, the control room was notified of the conditions, five valves were reset to their required setpoint, and the valve that did not lift was gagged and declared inoperable.

The team also noted that Condition Report/Disposition Request 3-7-0148 reported on March 17, 1997, that one of the four pressurizer code safety valves that were shipped offsite for as-found testing and refurbishment, had a lift setpoint that was -1.2 percent lower than the technical specification required setpoint.

As part of the corrective actions for Condition Report/Disposition Requests 3-7-0056 and 3-7-0148, the licensee performed an analysis of the as-found conditions of the main steam safety valves and pressurizer code safety valves to determine if their design basis had been exceeded. The licensee analyzed a loss of condenser vacuum event using worst case operating conditions during the past Unit 3 operating cycle and the as-found setpoints of the valves. The licensee determined that the design basis had not been exceeded during the past unit operating cycle. The team reviewed the results of the analysis, which demonstrated that the highest secondary peak pressure was 1395.86 psia, which was only 1.14 psia less than the allowed 110 percent of the secondary design pressure (1397 psia).

The team discussed the licensee corrective actions for the as-found lift setpoint discrepancies with the system engineer, who indicated that the main steam safety valves that were found out-of-tolerance were replaced with valves that had been set to their technical specification required setpoints. The system engineer also indicated that the out-of-tolerance valves that were removed had been shipped to an offsite test facility to attempt to determine the root cause of the out-of-tolerance

condition. The team noted that Condition Report/Disposition Requests 3-7-0056 and 3-7-0148 had been closed based on replacement of the valves and the design basis analysis that had been performed. However, when questioned about the results of the root-cause evaluation, the licensee indicated that the evaluation had not been completed and that Condition Report/Disposition Request 3-7-0056 had been erroneously closed.

The team noted that the licensee's reportability evaluation for Condition Report/Disposition Request 3-7-0056 determined the condition to be not reportable due to fact that the design basis was not exceeded. In response to the team's questions, the licensee performed an additional reportability evaluation and subsequently determined that the out-of-tolerance conditions of the main steam safety valve's lift setpoints was reportable under 10 CFR 50.73 (a)(2)(vii). The licensee indicated that a licensee event report, including the results of the root cause evaluation and the corrective actions would be submitted. The failure to report the six Unit 3 main steam safety valves as-found lift setpoints being outside their technical specification tolerances was a violation of 10 CFR 50.73 (a)(2)(vii) (50-530/9719-06).

. <u>Conclusions</u>

The licensee had performed appropriate design basis evaluations and immediate corrective actions after finding 6 of the 20 main steam safety valves and one of the pressurizer safety valves outside their technical specification tolerances in Unit 3. The failure to report this condition to the NRC within 30 days as required by 10 CFR 50.73(a)(2)(vii) is a violation.

E2.4 System Walkdowns

a. <u>Inspection Scope (37550)</u>

The team performed walkdowns of the following systems with associated system engineers and maintenance engineers:

- Unit 3 spray pond
- Unit 3 containment spray
- Unit 3 essential chilled water

b. <u>Observations and Findings</u>

The team found the systems to be installed and maintained in accordance with applicable system drawings and procedures during the visual walkthrough inspection of the systems. The material condition of the plant in all areas was very good. For example, very few deficiency tags were evident and no signs of damaged equipment were noted. Ladders, chains, and other temporarily-staged equipment were properly secured. No leaks, debris, material storage problems, transient combustible materials were seen and lighting was adequate. Overall, plant housekeeping was very good.

c. Conclusions

In the areas reviewed by the team, plant material condition and housekeeping were very good.

E6 Engineering Organization

E6.1 Engineering Indicators

The following information is tracking information for the engineering organization. The inspectors have summarized the information obtained from the licensee over the last three years and provided an indication of the trend. This information is collated here for future use and information. Any adverse trends or questions have been discussed in separate sections of this inspection report.

E6.1.1 Engineering Organization

- Size and Stability of Engineering Organization - The licensee's engineering organization has been relatively stable in the last 3 years. The number of engineers in the engineering organization is as follows:

  5/97 327
  9/95 362
  9/94 356

- Number of System Engineers:

  Over the past 3 years, the number of system engineers has held steady at 19.

- Number of Design Engineers:

  5/97 155
  9/95 191
  9/94 148

- Number and Function of Maintenance Engineers - The number of maintenance engineers has decreased in the following manner:

  5/94 66
  5/95 64
  5/96 63
  4/97 56

  The function of maintenance engineers is to support the maintenance needs of the site to ensure safe, reliable, efficient operation is achieved. The licensee's management expectations are as follows:

- Maintenance engineers are active members of the maintenance teams

- Maintenance engineers resolve basic issues rapidly, as close to the point of initiation as possible. The maintenance engineer should involve expertise in other organizations to resolve complex, programmatic, or specialized technical issues.

- Average Experience Level of Engineering Staff:

1994 13.6 years
1995 14.6 years
1996 16.1 years

- Average Engineering Overtime (percent)

	94	95	96
Design	4.0	4.6	1.4
System	3.2	2.2	1.3
Maintenance	7.0	9.2	0.2

- Percent of Engineering Work Accomplished by Contractors (percent of total engineering payroll):

1994 49.4
1995 45.4
1996 17.4

E6.1.2 Engineering Support

- Operability Determinations Performed by Engineering:

1995 42 total, engineering involved in the majority of these
1996 66 total, engineering involved in 28 (42 percent)
1997 16 to date, engineering involved in 16 (100 percent)

- Percent of System Engineer's Time in the Field - Through licensee survey, the team determined that the average time spent in the field by system engineers was estimated to be 20 percent with 10 percent of that time performing walkdowns. The licensee stated that this estimate varied with system requirements, for example, mechanical systems required more time in the field, whereas electrical and instrumentation and controls systems required less time in the field. The licensee stated that no trend data for time spent in the field was available, but presumed it to be steady.

- Condition Reports/Disposition Requests Generated by Engineering:

1994 2623 total, engineering initiated 607 (23 percent)
1995 2852 total, engineering initiated 410 (14 percent)

1996 3096 total, engineering initiated 355 (11 percent)
1997 1506 to date, engineering initiated 168 (11 percent)

- Size and Scope of Engineering Backlog - The main components of the engineering backlog tracked by the licensee are as follows:

  Condition Reports/Disposition Requests still open at the end of the year:

  1994 - 968 of 2623
  1995 - 523 of 2810
  1996 - 620 of 3096

  Deficiency Work Orders carried over from previous year:

  1995 - 65
  1996 - 112
  1997 - 189

  Design Modification Work Orders available to be worked on during year:

  1994 176
  1995 752
  1996 786
  1997 542

E6.1.3 Engineering Work Processes

- Description of Modification process:

  The team reviewed the licensees modification process and determined that the majority of the modifications were performed in accordance with Procedure 81DP-0EE10, "Plant Modifications," Revision 0. This was a new modification procedure with an effective date of January 15, 1997. This procedure applied to equivalency changes, maintenance or minor modifications, design modifications and paper change only changes. In addition, the procedure applied to setpoint or instrument range changes and software changes that required approved design output documents to be changed. Items outside of the scope of this procedure included material changes related to equivalency modifications, nuclear fuels issues related to the modification process, item procurement specification change notices, and temporary modifications. In addition, the team reviewed Procedure 81DP-0DC13, "Deficiency Work Order," Revision 10, which was applicable for authorizing repair, use-as-is, rework or scrap of plant systems, structures or components, which were in a condition that was not supported by any engineering, design basis, or design output documents.

- Number of Permanent Modifications Implemented:

The licensee completed 78 permanent modifications in 1994, 188 in 1995, 156 in 1996, and at the time of this inspection had completed 80 in 1997. The licensee stated that maintenance modifications started being tracked during 1996.

- Permanent Modifications Planned for Next Outage:

  The licensee compiled a list of permanent modifications planned for the next outage for each of the three Units. For Unit 2's seventh refueling outage scheduled to start September 6, 1997, the licensee has planned 33 design modifications and 58 maintenance modifications. The preliminary plans for Unit 1's seventh refueling outage are 65 design modifications and 17 maintenance modifications. The preliminary plans for Unit 3's seventh refueling outage are 42 design modifications and 15 maintenance modifications.

- Number of Safety Evaluations Performed:

  The number of 10 CFR 50.59 safety evaluations performed during the past three years has remained quite constant. The licensee performed 332 evaluations in 1994, 373 in 1995, 300 in 1996, and 95 through April 1997.

- Number of Operating Experience Information Issues Evaluated:

1995	133
1996	125
1997	34

E7 Quality Assurance in Engineering Activities

E7.1 Engineering Self Assessments

a. Inspection Scope (37550)

The team discussed engineering self assessments with the licensee to determine the number and scope of engineering self assessments performed over the past 3 years, and the organization performing these self assessments.

b. Observations and Findings

The licensee provided the following engineering self assessment information to the team.

Year	Nuclear Assurance	Engineering
1997	3 completed, 4 planned	5 completed, 6 planned
1996	9	13

1995	8	6
1994	4	-

The licensee stated that some self assessments were joint engineering and nuclear assurance audits. The subject areas for the engineering self-assessments in 1997 were as follows:

Engineering Team Inspection/Safety System Functional Inspection - Completed - Audit 97-005.

Engineering portion of INPO assessment - Completed.

Steam Generator program evaluation - Completed.

Unit 3 Cycle 7 Fuel Design - Completed.

Effective Implementation of the Maintenance Rule - Completed.

Licensing/Design Bases Maintenance Process Validation.

Design Change Process Benchmarking - Fuel - Planned.

Design Engineering support of in field work - Planned.

Accredited Engineering Support Personnel Training Program - Planned.

Instrument Out of Tolerance - Planned.

Vendor Technical Manual - Planned.

The licensee performed an engineering self-assessment (Audit 97-005) in April and May 1997 that evaluated engineering's ability to perform routine and reactive site activities. The audit report was issued on the last onsite day of the team inspection. As such, the team was able to discuss with the licensee the results of the audit, and read the report; however, the team did not have time to validate and perform a detailed review of the self assessment. The NRC team noted that the findings were generally consistent with those identified by the team. The self-assessment report noted that engineering was effective in performing routine and reactive site activities, but individual performance regarding technical rigor, follow-through, and attention-to-detail needed improvement. The self assessment noted that the process to maintain design basis manuals and calculations up-to-date was partially effective.

The Self Assessment Audit Report 97-005 determined several strengths in the engineering area. These strengths were as follows:

- The systems reviewed by the self assessment team were satisfactorily operated and maintained.

- Engineering communicated and interfaced well with its customers.

- Modifications were performed well, particularly those with involvement by the projects group.

- Individual knowledge in the engineering, operations, and maintenance areas was very good.

The Self Assessment Audit Report 97-005 determined several areas for improvement in the engineering area. These areas of improvement were as follows:

- Design and Licensing Basis Maintenance - The design basis manual contained errors, inconsistencies, and items needing clarification when compared to the Updated Final Safety Analysis Report and Safety Analysis Basis Document. The licensee identified ten examples of design and licensing basis errors, and inconsistencies.

- Although the audit did not identify any safety significant issues, the total number of issues identified indicated that management attention was needed to improve personnel performance. The licensee classified the personnel issues in the following categories with condition report totals provided in parenthesis: technical rigor (7), follow-through (11), and attention-to-detail (3).

In general, the team agreed with the engineering self-assessment findings. Corrective actions and root-cause evaluations in the two areas of improvement, and the condition reports generated by the licensee for specific self-assessment findings, were still being developed during the time of the NRC inspection.

c. Conclusions

The team concluded that the licensee performed good engineering self assessments with meaningful findings.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Violation 50-529/96010-01: This violation involved the failure to provide adequate grounding for a 480/120 volt regulating transformer located in the Train B dc equipment room.

The licensee failed to meet the electrical separation requirements of Section III.G.2 for the control room, in that both Trains A and B of the safe shutdown capability were located inside of the control room. For a postulated control room fire, the licensee used an alternative safe shutdown method, which required actions and equipment installed in the Train B dc equipment room. A fire in the Train B dc

equipment room resulted in a control room fire. Therefore, both trains of equipment relied upon to shut down the reactor during a postulated fire were exposed to the potential of receiving fire damage. Fire damage to both shutdown trains would have resulted in the inability of the operators to safely shutdown the plant. The failure to provide adequate grounding for the transformer, and the resulting related fires as described in NRC Inspection Report 50-528;-529;-530/96-10, demonstrated that both trains of safe shutdown equipment were exposed to the potential of receiving fire damage.

A predecisional enforcement conference was conducted on August 1, 1996, in the NRC's Region IV office, Arlington, Texas. At the conference, the license representatives agreed that a failure to comply with electrical grounding design requirements of IEEE 142, as committed to in the Palo Verde Final Safety Analysis Report, had occurred during plant construction, and that this constituted a violation of 10 CFR Part 50, Appendix B, Criterion III, but disagreed with the NRC's contention that the licensee had violated NRC's fire protection requirements. Based upon review of information developed during the inspection and the information that was provided during the conference, the NRC decided not to issue a citation against the requirements of Appendix R. The NRC concluded that information regarding the reason for the violation, the corrective actions taken and planned to correct the violation and prevent recurrence was already adequately addressed on the docket in Licensee Event Report 96-01, and Revision 1 to this licensee event report.

The team reviewed Licensee Event Report 96-01, discussed in Section E8.2 of this report, and the licensee's corrective actions for the reported condition. The team determined that the licensee took appropriate corrective actions to address the violation associated with the electrical grounding problem. This violation is closed.

E8.2 <u>(Closed) Licensee Event Report 50-528/96-175 and 96-200</u>: This item involved Licensee Event Report 96-01 that documented a condition were inappropriate grounding of equipment resulted in a condition outside the design basis of the plant.

On April 6, 1996, the licensee determined that the fire in Unit 2 on April 4, 1996, was associated with a condition outside the design basis of the plant. The condition existed in all three units where a fault in either regulating transformer in the Train A or B dc equipment room could cause a fire in the equipment room and the control room. The apparent cause of the fire was a short/failure of the hot lead to ground at the 100 foot control building transformer winding between terminals one and two of Transformer 2E-QBB-V02. The existing design for this power circuit did not utilize a ground at this point or any point within the transformer; therefore, the fault propagated through the building grounding system.

As an interim corrective action, the licensee established fire watches and issued a night order for heightened awareness of the situation. The licensee's investigation for inappropriate grounding of low voltage power distribution systems was initiated and identified 12 components (per unit) requiring modifications. On April 6, 1996, the license investigation team concluded that the Unit 2 fire on April 4, 1996, was associated with a condition outside the design basis of the plant and a

1-hour 10 CFR 50.72 notification was made. On April 5, 1996, the licensee performed a walkdown of the fire damage and adjacent equipment and determined that damage was confined to the Emergency Lighting Uninterruptible Power Supply 2E-QDN-D84, Junction Box 2EZ3ANKKJ15, Essential Lighting Isolation Transformer 2E-QBB-V02, and adjoining cables.

The licensee was committed to IEEE Standard 142, Section 1.6.1, "Grounding of Industrial and Commercial Power Systems," which required that a grounded system have a conductor grounded at the neutral point of a transformer. Contrary to this requirement the essential lighting isolation transformers were not grounded at neutral points of the transformers.

The licensee determined that the root cause of failure for the essential lighting isolation transformer was the loss of mechanical bonding of the varnish insulation material within the third harmonic choke, thereby, allowing normal transformer vibration to result in delamination of the transformer core. The root cause for the secondary fire (control room) was determined by the licensee to have been an incorrect grounding scheme used in the transformer secondary circuits.

Licensee Event Report 96-001-01 identified the following licensee corrective actions that were taken to address this event:

- A broadness review for appropriate grounding in 120V dc circuits was conducted. Twelve components (limited to regulating transformers, battery supplies and inverters) per unit were identified that required modifications for electrical circuit protection and/or grounding. Actions completed on May 2, 1996.

- A "vertical slice" review of 125V dc and 480V ac and above power distribution systems was expected to be completed by the end of June 1996. Actions completed on July 25, 1996.

- A temporary modification was developed to restore power to Essential Lighting Distribution Panel 2E-QBN-D84. Action completed on April 5, 1996. Restoration completed on April 30, 1996.

- Repaired the fire damaged equipment in Unit 2. Actions completed on April 25, 1996.

- Modifications, in all three units, to ensure circuitry protection and proper grounding have been completed on the two emergency lighting uninterruptible supply and essential lighting isolation transformer in each unit. Actions completed on June 5, 1996.

- Two instrument power supply regulating transformers in each of Units 1 and 2 were modified to provide proper circuit protection and would be modified during the next refueling outage in Unit 3. Actions completed for Unit 1 on October 10, 1996, and for Unit 3 on March 12, 1997. Actions scheduled for Unit 2 completion during next outage in September 1997.

- Testing on the shunts currently installed in the 125V dc power circuit from the Emergency Lighting Batteries E-QDN-F01 and F02 to the control room emergency lighting uninterruptible power supply. Actions completed on August 6, 1996.

- An evaluation was being performed to determine what the safety significance of the design inadequacy was prior to 1992. Since the raceway configuration was not changed since 1992, the safety significance was not readily apparent. Actions completed on September 25, 1996.

- Design modifications to permanently install fuses near the batteries to provide proper protection for these cables. Actions completed on September 25, 1996.

The team reviewed the licensee's corrective actions and determined that they were reasonable. This licensee event report is closed.

V. Management Meetings

X1 Exit Meeting Summary

The team leader and the engineering branch chief presented the inspection results to members of licensee management at the conclusion of the inspection on June 19, 1997. The licensee discussed the team findings and acknowledged the findings presented. The team leader asked the licensee whether any materials examined during the inspection were proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

C. Langstrom, Mechanical System Engineer
E. Sterling, Nuclear Assurance Operations Department Leader
J. Harnden, Senior Engineer, Nuclear Assurance
B. Blackmore, System Engineer
M. Radspinner, Design NSSS Section Leader
S. Daftuar, Senior Engineer
D. Oakes, Inservice Testing Section Leader
C. Corcoran, Senior Engineer
H. Miyahara, Senior Engineer
D. Visco, Senior Engineer, Nuclear Assurance
L. Elliott, Instrumentation and Control System Engineer
M. Hodge, Mechanical Design Section Leader
C. Lewis, Reactor Protection System Engineer
R. Smith, Nuclear Assurance Audit Team Leader
D. Wheeler, Nuclear Assurance Auditor
R. Younger, Nuclear Assurance Engineering Department-Leader
M. Afzai, Mechanical Maintenance Engineer
T. Szumski, Maintenance Engineer
K. Parrish, Group Leader, Transient Analysis, Nuclear Fuels Management
J. Webb, Senior Engineer, Transient Analysis, Nuclear Fuels Management
R. Stroud, Consultant, Nuclear Regulatory Affairs
D. Marks, Section Leader, Nuclear Regulatory Affairs
T. Barsuk, Emergency preparedness Coordinator, Emergency Planning
B. Thiele, Section Leader, Reactor Engineering, Nuclear Fuels Management
M. Winsor, Department Leader, Maintenance Engineering
M. Powell, Department Leader, Design Engineering
T. Cannon, Department Leader, Specialty Engineering
B. Rash, Department Leader, Systems Engineering
W. Ide, Vice President, Nuclear Engineering
G. Overbeck, Vice President, Nuclear Production
R. Fullmer, Director, Nuclear Assurance
R. Buzzard, Consultant, Nuclear Regulatory Affairs
S. Bauer, Section Leader, Nuclear Regulatory Affairs
A. Krainik, Department Leader, Nuclear Regulatory Affairs

NRC

K. Johnston, Senior Resident Inspector

INSPECTION PROCEDURES USED

37001	10 CFR 50.59 Safety Evaluation Program
37550	Engineering
92903	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-528; 529; 530/9719-01	URI	Lack of a 10 CFR 50.59 Safety Evaluation for Use of Fates Computer Code, Section E1.6
50-528; 529; 530/9719-02	NCV	Lack of 10 CFR 50.59 Safety Evaluation for the Deletion of Spray Pond Replenishment Procedure Required by the UFSAR, Section E2.2
50-528; 529; 530/9719-03	IFI	Lack of a 10 CFR 50.59 Safety Evaluation for the Deletion of Approximately 80 Emergency Plan Commitments, Section E2.2
50-528; 529; 530/9719-04	VIO	Inadequate Corrective Action for an Inadequate Operational Procedure that Caused Two Containment Spray Water Hammer Events, Section E2.3.1
50-528; 529; 530/9719-05	IFI	Potentially Inadequate Containment Spray System Technical Specification Surveillance Requirements, Section E2.3.1
50-528; 529; 530/9719-06	VIO	Failure to Report Six Main Steam Safety Valves Found Out of Technical Specification Tolerances, E2.3.2

Closed

50-529/9610-01	VIO	Control Room Fire Caused by Inadequate Grounding, Section E8.1
50-528/96-175	LER	LER 96-01 - Control Room Fire Caused by Inadequate Grounding, Section E8.2
50-528/96-200	LER	LER 96-01, Revision 1 - Control Room Fire Caused by Inadequate Grounding, Section E8.2

DOCUMENTS REVIEWED

Plant Procedures

Number	Revision	Title
81DP-0EE10	0	Plant Modifications
81DP-0DP13	10	Deficiency Work Orders
81DP-0DC17	1	Temporary Modification Control
74DP-9CY03	0	Chemistry Control Instruction
74DP-9CY04	0	System Chemistry Specifications
16DP-0EP15	5	Technical Support Center Actions
16DP-0EP14	2	Satellite Technical Support Center Actions
73ST-9EW01	4	Essential Cooling Water Pumps-Inservice Test
EPIP-56	5	Ultimate Heat Sink Emergency Water Supply
PD-0AP01	4	Administrative Control Program
90DP-0IP10	0	Condition Reporting
70DP-0EE01	6	Equipment Root Cause of Failure Analysis
73DP-0ZZ03	6	System Engineering
60DP-0QQ19	2	Internal Audits

Modifications

Number	Title
WO 721193	Spray pond flow transmitter problem
WO 785094	Spray pond orifice plate change
WO 765029	Revise specification to revise control valve
WO 736534	Raise setpoint of spray pond pump temperature alarm

WO 708024	Decrease setpoint of the ECW pump discharge temperature
WO 741111	Spray pond setpoint change from 1000 gpm to 600 gpm
WO 696842	Excess flow check valve bypass

Temporary Plant Modification No. 2-96-SE-003 "Unit 2 ex-core channel D exhibiting excessive noise."

Modification Deficiency Work Orders

Number	Title
WO 756706	Use-as-is non Q Unistrut
WO 772634	Pitting found on ECSW HX
WO 773994	Evaluate module found in the chiller
WO 760338	Studs found with less than full engagement
WO 661874	Use of Locktite on HBC Gearboxes

Calculations

Number	Title
13-MC-EC-254	Max Allowable Chilled Inlet Temp for EC Chillers
13-MC-EW-305	Essential water system hydraulic calculation
13-MC-NC-003	Nuclear cooling water system heat loads and water requirements
EDC 97-00111	MINET Hydraulic Analysis of the SP System
13-JC-SP-206	Essential spray pond pump discharge temperature instrument uncertainty and setpoint calculation
13-JP-SP-201	Essential spray pond flow instrument setpoint and uncertainty calculation
13-JC-EW-204	Essential cooling water pump discharge temperature instruments setpoint and uncertainty calculation

Operability Determinations

#043 Removal of missile shield for Spray Pond components

#068 Operability of essential chillers when hot gas bypass valve fails open or fails closed with EW temperature above 65F

#081 Diesel generator/spray pond operability with diesel genreator aftercooler and lube oil thermal reliefs failed open

#110 Operability of EC system with auto makeup function to surge tank disabled

#144 Essential Spray Pond operability with spray pond cross connect valve inoperable in closed position

#153 Operability of B Essential Chiller with refrigerant head pressure control valve in overridden position

#157 Operability of the Essential Water system with flow indicator spiking up to 2000 gpm

Condition Report/Disposition Requests

Number	Title
9-7-0257	Commitments concerning the ultimate heat sink were deleted
9-4-0302	Essential spray pond susceptibility to pitting
9-4-0080	Reduction of flow in emergency diesel generator jacket water and lube oil heat exchangers
9-5-0125	Corrosion found in emergency diesel generator jacket water and lube oil heat exchangers
2-6-0163	Spray pond pump train A failed flow test
1-5-0062	During inspection of the emergency diesel generator heat exchangers corrosion nodules were found lodged in the spray pond system inlet tubesheets
3-7-0003	Spray pond pump train A failed flow test
3-6-0185	Interruption of Spent Fuel Pool cooling during post-modification testing
9-6-1371	Piping clearance problems

1-6-0337	Spray pond cooling to B Diesel Generator air intercoolers isolated during maintenance
9-6-1449	Final Safety Analysis Report discrepancies
3-7-0003	Unit 3 Spray Pond pump "A" low flow
2-7-0008	Unit 2 Spray Pond filter pump flowrate degraded
3-7-0007	Unit 3 ESP "A" Pump inoperable because of low flow
2-7-0021	"A" Essential Chiller Pumpout Unit Conduit Broken
9-7-0127	Max operating temperatures used in stress analysis not consistent with system calculations
2-7-0145	EW "B" pump d/p exceeded acceptance criteria
9-7-Q271	Superseded calculation used to support design change
3-6-0178	Unable to open Unit 3 spray pond cross-connect valve
9-6-Q019	Chillers not operable in spray pond temperature drops below 49F
9-6-0046	Packing leakoff gland on essential chilled water pump 3-01 out of spec
9-6-0226	M&TE calibration data not recorded
9-6-0380	Foreign material on EC motor cooling refrigerant filters
9-6-0452	Unit 2 EC "B" low refrigerant level
9-6-0778	Unit 1 EC System Reliability Low
9-6-0791	Removal of both trains of shutdown cooling
2-6-0162	Spray Pond Pump "A" low flow
2-6-0163	White paper discussing low spray pond flows
2-6-0028	EC compressor oil temperatures high
3-7-0263	At 23:12 on 5/31/97, a reactor trip occurred in Unit 3 from 100 percent power steady state conditions.
9-7-Q283	Updated Final Safety Analysis Report errors and inconsistencies are present.

9-7-Q338 The Combustion Engineering Standard Safety Analysis Report is not being maintained per the requirements of ANSI N45.2.9-1974.

9-7-Q275 Sixty-six safety injection design basis manual errors and inconsistencies were identified.

9-7-Q277 Thirteen Pool Cooling design basis manual errors and inconsistencies were identified.

9-7-Q274 Two Spray Pond design basis manual errors and inconsistencies were identified.

9-7-Q266 Two Safety Analysis Basis Documents errors (related to the low pressure safety injection system) were identified.

9-7-Q297 Contrary to ANSI N45.2.11, the method to transmit information for reconstituted calculations is not always successful.

9-7-Q281 Independent Safety Engineering Group weekly meetings are not being conducted and additional management involvement is needed.

9-7-Q280 Procedure-specified heatup and cooldown rates for the shutdown cooling heat exchangers did not include instrument readability uncertainty.

9-7-Q258 Emergency operating procedures parameters for safety injection contain instrument uncertainty per NFM analysis SA-13-C000-95-004, but these parameters do not match those contained in normal operating procedures (which match values contained in the DBMs and Updated Final Safety Analysis Report).

9-7-Q259 The shutdown cooling initiating/securing temperature and pressure values contained in 40OP-9SI0-2 were different than those contained in the DBM and calculation 13-JC-SI-205.

9-7-Q233 Spray pond level calculation did not consider uncertainties associated with chemistry concentration or the pond maximum/minimum operating temperature.

9-7-Q257 EPIP-56 was canceled with no 10 CFR 50.59 evaluation and the associated regulatory commitments were not incorporated into the superseding procedures. A similar condition exists for other emergency planning procedures.

9-6-0183 Inadequate work control program for nontechnical specification Regulatory Guide 1.97 instruments.

9-6-0197 UFSAR wording regarding Shift Technical Advisors needs corrected.

9-6-0243	Trend process does not play an active role in identifying those conditions not
3-7-0148	3JRCEPSV0200 found set outside technical specification tolerance.
3-7-0056	Six main steam safety valves found set outside technical specification tolerance.
3-7-0050	3JSGEPSV0691 failed to lift during trevitesting.

Audit Reports and Self-Assessments

Audit Report 97-005	Engineering Team Inspection/Safety System Functional Inspection Audit Report.
Audit Report 96-002	Engineering and Corrective Action Effectiveness Self Assessment.