UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

July 16, 2004

Gregg R. Overbeck, Senior Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 52034
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SUBJECT: PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3 - NRC AUGMENTED INSPECTION TEAM (AIT) REPORT 05000528/2004012; 05000529/200412; 05000530/2004012

Dear Mr. Overbeck:

On June 18, 2004, the Nuclear Regulatory Commission (NRC) completed an Augmented Inspection at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3. The enclosed report documents the inspection findings, which were preliminarily discussed on June 18, 2004, with Mr. Levine, Senior Vice President of Generation, and other members of your staff. A public exit was conducted with you and members of your staff on July 12, 2004.

The event that led to the conduct of the Augmented Inspection can be summarized as follows: On June 14, 2004, at 7:41 a.m. MST, a ground-fault occurred on Phase “C” of a 230 kV transmission line in northwest Phoenix, Arizona, between the “West Wing” and “Liberty” substations located approximately 47 miles from your Palo Verde Nuclear Generating Station. A failure in the protective relaying resulted in the ground-fault not isolating from the local grid for approximately 38 seconds. This uninterrupted fault cascaded into the protective tripping of a number of 230 kV and 500 kV transmission lines, a nearly concurrent trip of all three Palo Verde Nuclear Generating Station units and the loss of six additional generation units nearby within approximately 30 seconds of fault initiation. This represented a total loss of nearly 5,500 megawatts-electric of local electric generation. Because of the loss-of-offsite power, a Notice of Unusual Event was declared for all three units at approximately 7:50 a.m. MST. The Unit 2 Train “A” emergency diesel generator started but failed early in the load sequence process due to a diode that had less than 70 hours of run time in the exciter rectifier circuit that short-circuited. This resulted in the Train "A" engineered safeguards features busses de-energizing, which limited the availability of certain safety equipment for operators. Because of this failure, the emergency declaration for Unit 2 was elevated to an Alert at 7:54 a.m. MST. All three units were safely shutdown and stabilized under hot shutdown conditions.

Due to the significance of this operational event, an NRC Augmented Inspection Team was dispatched to the site later that same day and independently found that your staff’s response to the event was generally acceptable. The response was complicated by equipment failures, procedure issues, and human performance issues with diverse apparent causes and with varying degrees of significance. A number of these issues require additional followup and are tracked as unresolved items in the enclosed report.

The team reviewed your immediate corrective actions prior to restart of the units, including actions to improve the independence and reliability of offsite power sources and found those actions appropriate for continued operation of the units.

Some of the material enclosed herewith contains exempt information in accordance 10 CFR 2.390(d)(1). Therefore, the applicable material will not be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,

/RA/

Bruce S. Mallett
Regional Administrator

Dockets: 50-528; 50-529; 50-530
Licenses: NPF-41; NPF-51; NPF-74

Enclosure: NRC Inspection Report 05000528/2004012;
05000529/200412; 05000530/2004012

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528; 50-529; 50-530
Licenses:	NPF-41; NPF-51; NPF-74
Report No.:	05000528/2004012; 05000529/2004012; 05000530/2004012
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
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SUMMARY OF FINDINGS

IR 05000528/2004012; 05000529/2004012; 05000530/2004012; June 18, 2004; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Augmented Inspection

The report covered a period of inspection by five inspectors, an NRC risk analyst, and an NRC contractor. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000. An Augmented Inspection was established in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program." The Augmented Inspection Team charter did not require the team to address compliance or assess significance of findings and observations. A followup inspection will be scheduled to address the unresolved issues identified by the team.

NRC-Identified and Self-Revealing Findings

On June 14, 2004, at approximately 7:41 a.m. MST, a ground-fault occurred on Phase "C" of a 230 kV transmission line in northwest Phoenix, Arizona, between the "West Wing" and "Liberty" substations located approximately 47 miles from the Palo Verde Nuclear Generating Station. A failure in the protective relaying resulted in the ground-fault not isolating from the local grid for approximately 38 seconds. This uninterrupted fault cascaded into the protective tripping of a number of 230 kV and 500 kV transmission lines, a nearly concurrent trip of all three Palo Verde Nuclear Generating Station units and the loss of six additional generation units nearby within approximately 30 seconds of fault initiation. This represented a total loss of nearly 5,500 megawatts-electric of local electric generation. Because of the LOOP, the licensee declared a Notice of Unusual Event for all three units at approximately 7:50 a.m. MST. The Unit 2 Train "A" emergency diesel generator started but failed early in the load sequence process due to a diode that had less than 70 hours of run time in the exciter rectifier circuit that short-circuited. This resulted in the Train "A" engineered safeguards features busses de-energizing, which limited the availability of certain safety equipment for operators. Because of this failure, the licensee elevated the emergency declaration for Unit 2 to an Alert at 7:54 a.m. MST. All three units were safely shutdown and stabilized under hot shutdown conditions.

An NRC Augmented Inspection Team was dispatched to the site later that same day and found that the licensee's response to the event was generally acceptable, although complicated by a number of equipment failures, procedure issues, and human performance issues with diverse apparent causes and with varying degrees of significance. A number of these issues requiring additional followup were identified and are tracked as unresolved items in the report. The team reviewed the licensee's immediate corrective actions prior to restart of the units, including actions to improve the independence and reliability of offsite power sources and found those actions appropriate for continued operation of the units.

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1.0 Introduction

1.1 Event Description

On June 14, 2004, at approximately 7:41 a.m. MST, a ground-fault occurred on Phase “C” of a 230 kV transmission line in northwest Phoenix, Arizona, between the “West Wing” and “Liberty” substations located approximately 47 miles from the Palo Verde Nuclear Generating Station (PVNGS). A failure in the protective relaying resulted in the ground-fault not isolating from the local grid for approximately 38 seconds. This uninterrupted fault cascaded into the protective tripping of a number of 230 kV and 500 kV transmission lines, a nearly concurrent trip of all three PVNGS units and the loss of six additional generation units nearby within approximately 30 seconds of fault initiation. This represented a total loss of nearly 5,500 megawatts-electric of local electric generation (Section 2.1). Because of the loss-of-offsite power (LOOP), the licensee declared a Notice of Unusual Event for all three units at approximately 7:50 a.m. MST. The Unit 2 Train “A” emergency diesel generator (EDG) started, but failed early in the load sequence process due to a diode with less than 70 hours of run time in the exciter rectifier circuit failed, causing a short-circuit (Section 2.4). This resulted in the Train "A" engineered safeguards features busses de-energizing, which limited the availability of certain safety equipment for operators. Because of this failure, the licensee elevated the emergency declaration for Unit 2 to an Alert at 7:54 a.m. MST. All three units were safely shutdown and stabilized under hot shutdown conditions.

An NRC Augmented Inspection Team was dispatched to the site later that same day and found that the licensee’s response to the event was generally acceptable, although complicated by a number of equipment failures, procedure issues, and human performance issues with diverse apparent causes and with varying degrees of significance. A copy of the Augmented Inspection Team charter is contained in Attachment 2. Issues requiring additional followup by the NRC were identified and are tracked as unresolved items in the report (see Attachment 1). Details of the team’s findings are contained in each section referenced with some key ones summarized below:

- A number of issues related to offsite power line reliability and independence contributed to the failure of an electrical fault to isolate and electrical line problems, which caused the loss of offsite power lines as a source of electrical power for safety systems. (Section 2.1)

- The failure of one of the emergency diesels in Unit 2 to provide electrical power to the safety system bus. (Section 2.4)

- Some emergency response interface and equipment problems. For example:

    - The Technical Support Center (TSC) EDG failed because a test switch was not returned to its proper position following maintenance six days prior to the event. As a result, the emergency response organization assembled in the alternate TSC. This resulted in some confusion and posed some unique challenges to the emergency response organization. (Section 3.4)

- The ability of licensee personnel to conduct automatic dial-out for emergency responders and to develop protective action recommendations, had they been needed, appeared to have been affected by the loss of power. (Section 3.5)

- Human performance errors resulted in delays in notifying the emergency response organization on the emergency classification. (Section 3.5)

Despite the number of challenges to the plant operating staff and management, all three units were safely shutdown, placed in a stable condition immediately following the LOOP event, and power restoration efforts began immediately. With the exception of the local 500 kV transmission grid surrounding the PVNGS switchyard, the Arizona, California, and Nevada electrical grid remained relatively stable, only noting the fault through some minor frequency and voltage fluctuations. This was notable considering the amount of generation lost. The total local generation lost during the event included the three PVNGS units, three co-generation units at the Red Hawk Generating Station, and three co-generation units at the Arlington Generating Station for a total of approximately 5,500 Megawatts-electric.

In the following sections, each pertinent aspect of the event is discussed in detail. Section 2.0 contains the team's findings in the area of system performance and design. Section 3.0 contains the team's findings in the area of human performance and procedures. Section 4.0 contains the team's findings associated with the facilities interaction with offsite entities. Finally, Section 5.0 includes a summary of the NRC analysis associated with overall risk significance of the event.

1.2 System Descriptions

1.2.1 Offsite Power Transmission and Distribution Systems

a. General

The PVNGS is connected by its associated transmission system to the Arizona-New Mexico-California-Southern Nevada high voltage grid, which is interconnected to other high voltage systems within the Western System Coordinating Council (WSCC). Attachment 7 contains a drawing of the local PVNGS grid arrangement.

b. Palo Verde Nuclear Generating Station (PVNGS) Switchyard

The PVNGS switchyard consists of two 500 kV buses, which are connected to the three PVNGS 500/22.8 kV main step-up transformers, and seven transmission lines, using a breaker and a half scheme. A breaker and a half scheme uses two breakers to connect the source of power to the switchyard or transmission line. Both breakers are required to open to isolate a fault in the system. This scheme is used to increase reliability of power and allows flexibility for maintenance. The seven 500 kV transmission lines comprising the PVNGS transmission system are situated in four corridors from the PVNGS switchyard as follows:

- One line to the Devers substation (240 mi.)
- Three lines to the Hassayampa substation (3 mi.)
- One line to the Rudd substation (25 mi.)
- Two lines to the Westwing 500 kV substation (44 mi.)

c. West Wing Substation

The Westwing substation is comprised of a two-bus 230 kV section and a two-bus 500 kV section. The 500 kV section is connected to the adjacent 230 kV Westwing section through three 500/345/230 kV load tap-changing transformers. The Westwing 230 kV buses are connected to the transmission system using a breaker and a half scheme as follows:

- One line to the Surprise substation
- One line to the Pinnacle Peak substation
- One line to the Liberty substation
- One line to the Agua Fria substation
- One line to the Deer Valley substation
- One line to New Waldell substation
- Two 230/69 kV transformers feeding the Arizona Public Service Company (APS) distribution system

d. Hassayampa Switchyard

The Hassayampa substation is located three miles from the PVNGS switchyard. It consists of two 500 kV buses connected to the PVNGS switchyard and several other generating stations and substations through a breaker and a half scheme, as follows:

- Three lines to the PVNGS switchyard (3 mi.)
- Two lines to the Red Hawk switchyard (1 mi.)
- One line to the Jojoba substation (20 mi.)
- One line to the North Gila substation (110 mi.)
- One line to the Mesquite switchyard (0.5 mi.)
- One line to the Arlington Valley switchyard (1 mi.)
- One line to the Harquahala switchyard (30 mi.)

The three lines to the PVNGS switchyard were equipped with negative sequence relays and traditional time-distance relays, both of which were intended to serve as pole-mismatch protection, or open conductor, for the Hassayampa to PVNGS transmission lines. Personnel employed by APS indicated that the negative sequence relaying was set to trip on 20 percent negative sequence current after a finite time delay of 5 seconds.

1.2.2 On-site Power Distribution System

a. General

Power is supplied to the PVNGS auxiliary buses from the offsite power supply through three startup transformers. In addition, during normal plant operation, power for the onsite non-Class 1E alternating current (ac) system is supplied through the unit auxiliary transformer connected to the main generator isolated phase bus. The non-Class 1E ac buses normally are supplied through the unit auxiliary transformer, and the Class 1E buses normally are supplied through the startup transformers. Each unit's non-Class 1E power system is divided into two parts. Each of the two parts supplies a load group including approximately half of the unit auxiliaries. Three startup transformers connected to the 500 kV switchyard are shared between Units 1, 2, and 3 and are connected to 13.8 kV buses of the units. Each startup transformer is capable of supplying 100 percent of the startup or normally operating loads of one unit simultaneously with the engineered safety feature loads associated with two load groups of one other unit. The 4160 V Class 1E buses are each normally supplied by an associated 13.8/4.16 kV auxiliary transformer, and receive standby power from one of the six standby diesel generators. The Class 1E 4160 V system supplies power to 480 V and lower distribution voltages through 18 4160/480 V load center transformers.

b. Palo Verde Nuclear Generating Station Generator Protective Relaying

The main generator protection schemes include relaying designed to protect the generators against internal as well as external faults. Protection against external faults includes backup distance relaying and negative sequence time over-current relaying. The backup distance relaying provides backup protection for 24 kV and 500 kV system faults close to the switchyard. The distance relay operates through an external timer. If the fault persists and the time delay step is completed, a lockout relay trips the unit auxiliary transformer 13.8 kV breakers, generator excitation, 500 kV generator unit breakers, main turbine, and the main transformer cooling pumps. The lockout relay also initiates transfer of station auxiliary loads.

The generator negative sequence time over-current relay provides generator protection against possible damage from unbalanced currents resulting from prolonged faults or unbalanced load conditions. The relay operates through a lockout relay to trip the unit auxiliary transformer 13.8 kV breakers, generator excitation, 500 kV generator unit breakers, main transformer cooling pumps and the main turbine. The negative sequence relay also incorporates a sensitive alarm circuit that, in conjunction with a separately mounted ammeter, alerts operators on relatively low values of negative sequence current (just above normal system unbalance).

c. Emergency Diesel Generators

The Class 1E ac system distributes power at 4.16 kV, 480 V, and 120 V to all Class 1E loads to ensure safe shutdown of the facility during postulated events. Also, the Class 1E ac system supplies power to certain selected loads that are not directly safety-related, but are important to the plant. The Class 1E ac system contains standby power sources (i.e., EDGs) that automatically provide the power required for safe-shutdown in the event of loss of the Class 1E bus voltage.

In the event that preferred power is lost, the Class 1E system functions to shed Class 1E loads and to connect the standby power source to the Class 1E busses. The load sequencer then functions to start the required Class 1E loads in programmed time increments.

d. Station Blackout Gas Turbine Generator Sets

A non safety-related alternate ac power source consisting of two redundant gas turbine generators is available to provide power to cope with a 4-hour station blackout event in anyone nuclear unit.

Each gas turbine generator has a minimum continuous output rating of 3400 kW at 13.8 kV under worst-case anticipated site environmental conditions. This rating was sized to provide power to the loads identified as being important for coping with a postulated station blackout.

e. Technical Support Center Emergency Diesel Generator

The TSC diesel generator provides standby ac to the 480 V electrical distribution panel that supplies all electrical power to the TSC emergency planning facility. The diesel engine is cooled by a self-contained cooling water system with an air-cooled radiator. The radiator is in turn cooled by an electric motor-driven fan. The fan motor is powered by the TSC electrical power distribution panel. Normal electrical power for the TSC comes from the offsite electrical power supply to Unit 1. During a LOOP, when power is lost to the TSC electrical power distribution panel, the technical support diesel generator automatically starts and re-energizes the TSC electrical loads, including the diesel engine radiator cooling fan.

1.2.3 Chemical Volume and Control System

The chemical and volume control system controls the purity, volume, and boric acid content of the reactor coolant. Water removed from the reactor coolant system is cooled in the regenerative heat exchanger. From there, the coolant flows to the letdown heat exchanger and then through a filter and a demineralizer where corrosion and fission products are removed. It is then sprayed into the volume control tank and returned by the charging pumps to the regenerative heat exchanger where it is heated prior to returning to the reactor coolant system.

When the vital 4160 Vac buses are de-energized, the charging pump breakers must be manually reset, and the pumps restarted from the control room. Therefore, no charging flow is assumed for 30 minutes after the time of trip to allow for resetting the breaker and performing manual alignment of one of three gravity-fed boration pathways to the charging pump suction.

Following a LOOP, the letdown subsystem is designed to isolate automatically due to the loss of nuclear cooling water to the letdown heat exchanger or by operator action. When charging is restarted, the resulting mismatch between letdown and charging will cause volume control tank level to decrease. To reduce the chance of losing suction to the charging pumps, the volume control tank level is monitored by two non-safety grade instrument channels. Alarms are provided on low level and if the two channels differ significantly. The use of two channels of different types (one has a wet reference leg and the other is dry) decreases the probability of operator error misaligning the boration systems should one channel fail.

1.2.4 Auxiliary Feedwater System (AFW)

The AFW provides an independent means of supplying water to the steam generators during emergency operations when the AFW is inoperable. Auxiliary feedwater system maintains the water inventory necessary to allow a reactor coolant system cooldown at a maximum rate of 75°F/hr down to a temperature of 350°F. It also provides the necessary water inventory for startup, normal shutdown, and hot standby conditions.

1.3 Preliminary Risk Significance of Event

Management Directive 8.3, "Incident Investigation Program," specifies the formal process used for incident evaluation. This directive documents a risk-informed approach to determining when the NRC will commit additional resources for further investigation of an event. The risk metric used for this decision is the conditional core damage probability.

A complete LOOP is a significant event at any nuclear facility. Because the combustion engineering plant is designed without primary system power-operated relief valves, making a reactor coolant system feed and bleed evolution impossible, the risk significance is relatively higher for this design. To evaluate this event, the team used the Standardized Plant Analysis Risk (SPAR) Model for PVNGS, Revision 3, and modified appropriate basic events to include updated LOOP curves published in NUREG CR-5496, "Evaluation of Loss of offsite power Events at Nuclear Power Plants: 1980 - 1996." The team evaluated the risk associated with the Unit 2 reactor because it represented the dominant risk of the event.

For the preliminary analysis, the team established that a LOOP had occurred and that the event may have been recovered at a rate equivalent to the industry average. Both EDG "A" and Charging Pump "E" were determined to have failed and assumed to be unrecoverable. Additionally, the team ignored all sequences that included a failure of operators to trip reactor coolant pumps, because all pumps trip automatically on a LOOP. The conditional core damage probability was estimated to be 6.5×10^{-4} indicating that the event was of substantial risk significance and warranted an augmented inspection team.

2.0 System Performance and Design Issues

A number of unresolved items were identified by the team associated with system performance and potential design issues, which were revealed during and following the event. Each of these issues is discussed in sections below. Each of the unresolved items will be the subject of an NRC inspection to assess the licensee's effectiveness of determining the root and contributing causes, extent of condition, and corrective actions.

2.1 Offsite Power Reliability and Independence Issues

a. Inspection Scope

The team reviewed design drawings associated with the PVNGS, Hassayampa, West Wing, Devers, and Rudd switchyards and substations. In addition, the team conducted interviews with licensee personnel, APS personnel, and Salt River Project (SRP) personnel involved in the licensees investigation. Finally, the team reviewed the sequence of event and alarm printouts in detail to develop a comprehensive understanding of the event progression.

b. Observations and Findings

An Unresolved Item (URI) 05000528; -529; -530/2004012-001 was identified by the team that would facilitate the review of the root and contributing causes of the ground fault failing to isolate from the grid and protective tripping of the Hassayampa to PVNGS transmission lines, review the extent of condition associated with any other potential design issues that could affect the independence and reliability of offsite power to PVNGS, and assess the effectiveness of corrective actions implemented by the licensee.

The 500 kV system upset at the PVNGS switchyard originated with a fault across a degraded insulator on the 230 kV Liberty transmission line between the Westwing and Liberty substations approximately 47 miles from PVNGS. Protective relaying detected the fault and isolated the line from the Liberty substation. The protective relaying scheme at the Westwing substation received a transfer trip signal from the Liberty substation actuating the Type AR relay in the tripping scheme for Breakers WW1022 and WW1126. The Type AR relay had four output contacts, all of which were actuated by a single lever arm. The tripping schematic showed that Contacts 1-10 and 2-3 should have energized redundant trip coils in Breaker WW1022, while contacts 4-5 and 6-7 should have energized redundant trip coils in Breaker WW1126.

Breaker WW1126 tripped, demonstrating that the Type AR relay coil picked up, and at least one of the Type AR relay contacts, 1-10 or 2-3, closed. Breaker WW1022 did not trip. Bench testing by APS showed that, even with normal voltage applied to the coil, neither of the tripping contacts for Breaker WW1022 closed. The breaker failure scheme for Breaker WW1022 featured a design where the tripping contacts for the respective redundant trip coils also energized redundant breaker failure relays. Since the tripping contacts for Breaker WW1022 apparently did not close, the breaker failure scheme for Breaker WW1022 also was not activated, resulting in a persistent uncleared fault on the 230 kV Liberty line.

Various transmission system events recorders show that during approximately the first 12 seconds after fault inception, several transmission lines on the interconnected 69 kV, 230 kV, 345 kV, and 500 kV systems tripped on overcurrent, including lines connected to the Westwing and Hassayampa substations. Also during the first 12 seconds, two Red Hawk combustion turbines and one Red Hawk steam turbine power plants tripped, and the fault alternated between a single phase-to-ground fault to a two phase-to-ground fault, apparently as a result of a failed shield wire falling on the faulted line. After 12 seconds, the fault became a three phase-to-ground fault, and additional 500 kV lines tripped.

Approximately 17 seconds after fault inception, the three transmission lines between the PVNGS switchyard and the Hassayampa substation tripped simultaneously due to action of their negative sequence relaying, thereby isolating the fault from the several co-generation plants connected to the Hassayampa substation. Approximately 24 seconds after fault inception, the last two 500 kV lines connected to the PVNGS switchyard tripped, isolating the PVNGS switchyard from the transmission system. At approximately 28 seconds after fault inception, the three PVNGS generators were isolated from the switchyard and, by approximately 38 seconds, all remaining lines feeding the fault had tripped, and the fault was isolated.

Reliability Issues

The degraded insulator was caused by external contamination and did not, by itself, represent a concern relative to the reliability of the insulators on the 230 kV transmission system. Nevertheless, the failed Type AR relay and the lack of a robust tripping scheme raised concerns relative to the maintenance, testing, and design of 230 kV system protective relaying. Interviews with APS transmission and distribution personnel indicated that the Westwing substation, where the relay failure occurred, was subject to annual maintenance and testing.

Following the event, the failed Type AR relay was removed from service by APS personnel and visually inspected by the NRC team at PVNGS. The relay showed no apparent signs of contamination or deterioration.

As noted earlier, the tripping scheme lacked redundancy that may have prevented the failure of the protective scheme to clear the fault. Personnel employed by APS and SRP reviewed the design of the Westwing substation, as well as all other substations connected to the PVNGS switchyard and found that only the Liberty and Deer Valley transmission lines at the Westwing substation featured a tripping scheme with only one Type AR relay. All of the newer lines featured two Type AR relays.

However, APS personnel found that the bus sectioning breakers in the breaker and a half scheme at the Westwing substation only contained one trip coil, as opposed to two trip coils in the breakers. This feature was found by SRP personnel to be representative of the design at the Devers substation.

In order to improve reliability, APS modified the tripping schemes for the Liberty and Deer Valley lines to feature two AR relays energizing separate trip coils for each breaker. In addition, personnel from APS and SRP stated that they would evaluate the feasibility of installing two trip coils in all single trip-coil breakers. Finally, APS personnel indicated that the APS 500/230 kV transformers did not have the same overcurrent protection as the SRP transformers and would consider the installation of overcurrent protection.

The team found that APS improved the reliability of its Westwing substation by installing a redundant tripping scheme with two Type AR relays for the Liberty and Deer Valley transmission lines. In addition, the APS and SRP intention to include dual trip coils and ground fault protection on lines that have transformers connecting 500 kV and 200 kV stations would also serve to increase the reliability of power to the grid. The team also noted that the PVNGS licensee actively coordinated the offsite power investigation and facilitated discussions with APS and SRP.

Independence of Offsite Power Supplies

Licensees are required to ensure that the facility meets the general design criteria contained within 10 CFR Part 50, Appendix A. Specifically, General Design Criterion 17, "Electric Power Systems," requires that power from the offsite transmission network be supplied by “two physically independent circuits designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions." This event highlighted an issue associated with the three transmission lines between the Hassayampa and PVNGS switchyard. These three transmission lines featured negative sequence relaying intended to serve as pole mismatch protection. This design was implemented in 1999 as part of extensive modifications to the Hassayampa switchyard intended to accommodate new co-generation facilities local to the PVNGS. The negative sequence protection scheme was designed to actuate a complete isolation of all three of the subject transmission lines after a 5-second time delay to avoid spurious tripping due to faults. Although these individual lines were previously considered as separate sources of offsite power, this event demonstrated that the lines were subject to simultaneous failure (acting as one) because of the protective relaying scheme. Personnel employed by SRP and the licensee stated that the negative sequence relaying was disabled and pole mismatch protection was being implemented by alternate relaying.

The team found that the licensee effectively coordinated their investigation with APS and SRP. The design changes implemented on the Hassayampa switchyard to PVNGS switchyard transmission lines to remove the negative sequence protection improved the independence of those transmission lines and should prevent the three subject transmission lines acting as one in the future for the same type of fault.

2.2 Unit 1, Atmospheric Dump Valve (ADV) Failure

a. Inspection Scope

The team interviewed operators, reviewed control room logs, and reviewed Condition Report/Disposition Request (CRDR) 2716011 associated with the loss of manual control of the Valve ADV-185 during the performance of Procedure 40EP-9EO10, “Loss of Offsite Power/ Loss of Forced Circulation,” Revision 10.

b. Observations and Findings

The team identified URI 05000528/2004012-002 to review of the root and contributing causes of the Valve ADV-185 failure, review the licensee’s extent of condition, and assess the effectiveness of corrective actions implemented by the licensee.

Following the Unit 1 LOOP, Valve ADV-185 failed to operate properly while being remote-manually operated from the control room. Operators in the control room observed that the valve had drifted closed, despite a remote-manual controller setting demanding the valve to be open. The operators were able to adjust Valve ADV-185 from the control board by adjusting the demand higher than needed. However, the valve position would not remain in the desired position.

The team assessed how much Valve ADV-185 affected the operator's ability to control reactor coolant temperatures and concluded that the impact was minimal. The operator had been trained sufficiently to readily diagnose the problem and utilize an alternate ADV for decay heat removal. The other three Unit 1 ADVs responded properly to remote-manual control signals and presented no further challenges to the control room operators.

Licensee personnel identified the apparent cause of the malfunction as internal leakage equalizing around a pilot valve causing the valve to shut. The valve and its associated control circuit were quarantined, maintenance personnel began troubleshooting the components to determine the root cause of the malfunction.

2.3 Unit 1, Letdown System Isolation Failure

a. Inspection Scope

The team reviewed the circumstances surrounding the Unit 1 letdown heat exchanger's failure to isolate following the June 14, 2004, LOOP event. Since the Unit 1 letdown system was temporarily modified by the licensee, the team's review included a detailed inspection of Temporary Modification 2594804. In addition, the team reviewed CRDR 2715667 documenting the system response during the event to understand the licensee's investigation into the failure. The team also interviewed plant personnel and reviewed control room logs and temperature plots to determine the impact of the high temperature on the letdown system.

b. Observations and Findings

The team identified URI 05000528/2004012-003 to review of the root and contributing causes of the failure of the letdown system to isolate which appeared to involve inadequate design control aspects, review the licensee's extent of condition, and assess the effectiveness of corrective actions implemented by the licensee.

During the June 14, 2004, LOOP event, the Unit 1 letdown system did not operate as expected when fluid temperatures exceeded the alarm setpoint. The letdown system bypassed the ion exchanger and the filter at 140°F, as expected. However, a temporary modification to bypass a flow sensor resulted in the system failing to isolate when needed. The letdown system response had apparently not been anticipated by the engineers designing the temporary modification, and operators were unaware of the systems response to a LOOP. The team was concerned that inadequate design control had resulted in the overheating of a system designed for low temperature operation. The system was designed to isolate the letdown system if temperature at the outlet of the non-regenerative heat exchanger exceeded 148°F.

The licensee identified that the apparent cause of the system not isolating as expected was a failure of the temporary modification to fully address the functioning of the letdown control system during a loss of power to the controller. As a consequence of the LOOP, the nuclear cooling water flow is normally lost to the non-regenerative heat exchanger. Typically, when power is restored to the system, the valves would be in a manual mode of operation, and flow through the system would not be secured by the normal control system. The temporary modification effectively bypassed the backup initiating signal for isolating the system in the event cooling water flow to the heat exchanger was lost, which occurred as a result of the LOOP event.

The impact on the plant systems and personnel was minimized when the ion exchanger bypass valves actuated to remove high temperature water from the resin. However, the introduction of high temperature water created a distraction when, as a result of paint and insulation being heated, the fire brigade was activated for a report of smoke/fumes. The fire brigade responded to the report of a potential fire, and operators conducted a detailed walkdown of the system.

The licensee conducted an engineering calculation to determine the maximum stress associated with 350°F fluid temperature that was considered the worst-case temperature the letdown system could have been subjected. The worst-case thermally induced stress was calculated to be 27,475 pounds per square inch. The licensee's engineers determined that a socket-weld on the drain for purification Filter F36 was the only weld of concern that could have exceeded its maximum allowable stress if it had reached 350°F. Licensee personnel performed a visual inspection of the effected weld, and removed the filter element to determine if any damage occurred. Because the filter element was rated for 180°F for 1-hour, and there was no indication of any heat damage, the licensee personnel concluded that the weld was not subjected to the temperatures that could have caused excessive stress on the weld. In addition, the licensee conducted a soft parts analysis to ascertain if any parts susceptible to high temperatures were present and found none.

With respect to the extent of condition, the team found that Unit 1 was the only unit that had this modification installed to bypass the low flow isolation signal. Therefore, the team had no concerns with the other units.

2.4 Unit 2, Train "A" Emergency Diesel Generator Failure

a. Inspection Scope

The team interviewed licensee representatives and reviewed the sequence of events that led up to the failure of the Unit 2, Train "A" EDG to determine the apparent cause. The team also reviewed the effects the loss of the diesel generator had on the recovery of the event, the action plan for determining the root cause (CRDR 2715709), and the extent of condition of the apparent cause.

b. Observations and Findings

The team identified URI 05000529/2004012-004 to review of the root and contributing causes of the failure of the diode in Phase "B" of the Unit 2 Train "A" EDG voltage regulator exciter circuit, review the licensee’s extent of condition and assess the effectiveness of corrective actions implemented by the licensee.

The team found that the apparent failure of the Unit 2, Train "A" EDG was a failed diode in Phase "B" of the voltage regulator exciter circuit. The diode failure resulted in a reduced excitation current which was unable to maintain the voltage output with the applied loads.

At approximately 07:41:15 a.m., the Unit 2, Train "A" EDG received a start signal as a result of an undervoltage signal on the Train "A" 4.16 kV Class 1E bus. The emergency generator started, came up to speed and voltage, and energized the bus at approximately 07:41:23 a.m., within the 10 seconds allowed by design. Approximately 5 seconds later, the Train "A" battery chargers, control element drive mechanism cooling units, and the containment cooling units were sequenced onto the bus. The essential cooling water pump was sequenced onto the bus approximately 15 seconds after the first loads.

The team noted that, at approximately the same time the essential cooling water pump was energized, the output voltage from the EDG began to fail. The control room operators observed the voltage and current indications in the control room were zero, and had an auxiliary operator observe the indications locally, at the EDG control panel. The indications were also zero. The control room operators initiated a manual emergency trip of the diesel at approximately 07:56:21 a.m. The team found these actions to be appropriate for the circumstances.

The team found that the failed EDG did not have a large impact on plant stabilization and recovery but did result in having only one train of safety equipment available. The only apparent effect of the loss of Train "A" safety-related equipment was associated with the availability of Train "A" charging pumps that rely on emergency power from the EDGs.

The team noted that licensee engineers and maintenance personnel developed a comprehensive plan to troubleshoot the failure (CRDR 2715709). The plan was methodical and prioritized. The team found that the troubleshooting activities were thorough and well controlled, resulting in the identification of the failed diode in Phase "B" of the exciter circuit. The failure resulted in a half-wave output with significantly reduce current that led to the loss of adequate excitation to maintain the required voltage for the applied loads.

The team found that, while this diode was common to all the EDGs at the PVNGS, there was insufficient data to indicate there was a common mode problem. A review of the industry database on component failures revealed only one other failure that occurred in 1997 of this specific model diode. As such, the team found the extent of condition review by licensee personnel to have been appropriate for the circumstances.

The team noted that the failed diode had been replaced during the fall 2003 refueling and steam generator replacement outage. This diode had been subject to approximately 65 hours of operation before it failed. Licensee personnel had plans to perform additional testing to determine the root cause, if possible, of the diode failure.

2.5 Unit 3, Plant Response to Loss of Offsite Power Event

a. Inspection Scope

The team reviewed CRDR 2715659 documenting the Unit 3 reactor trip, plant response, and pre-startup review. In addition, control room logs associated with system temperature, pressure and flow plots, voltage and frequency plots, and nuclear instrumentation plots to assess whether the plant responded as designed. Finally, various personnel that were either involved in the event or in the analyses of the event were interviewed.

b. Observations and Findings

The team identified two unresolved items. The first URI (05000530/2004012-005) involved a review of the root and contributing causes of the automatic main steam-line isolation in Unit 3, which appeared contrary to the expected response described in the plant safety analysis applicable failure or issue; the extent of condition; and the effectiveness of corrective actions implemented by the licensee. The second URI (05000530/2004012-006) involved a review of the root and contributing causes of the Unit 3 main generator excitation controls, which appeared to respond differently during the event than the Unit 1 and 2 main generator excitation controls and may have contributed to the variable overpower reactor trip on Unit 3; the extent of condition; and the effectiveness of corrective actions implemented by the licensee.

b.1. Main Steam Isolation

The team noted that Unit 3 experienced an automatic main steam-line isolation. Licensee personnel attributed the automatic isolation to a steam bypass control system anomaly that caused all the bypass valves to open simultaneously, suddenly decreasing main steam line pressure, and causing a main steam isolation. The team found, through interviews with licensee engineers, the apparent cause of the "anomaly" was the result of a momentary loss of power to the control system being re-energized in the automatic mode, vice manual. According to the licensee engineers, this power loss initiated a 30-second timer that disconnected the valve control signals from the control cabinet. When the 30-second timer completed, all eight valves modulated open in about 14 seconds.

The PVNGS Final Safety Analysis Report, Revision 12, Section 1.8, "Conformance to NRC Regulatory Guides," documents that the licensee took exception to the separation criterion of NRC Regulatory Guide 1.75, "Physical Independence of Electric Systems," Revision 1, for the power supplies to Panel D11. As a result, Panel D11 was powered from both a non-vital power supply (normal) and a vital power supply (backup). Upon loss of normal power, the supply automatically transfers to the backup supply. After the normal supply returns, the panel must be manually transferred back to the normal supply. Upon a total loss of power to Panel D11, the steam bypass control system will be unable to automatically respond to any challenges (Final Safety Analysis Report, Section 7.2.2.4.1.2.1). The team also noted that the power supply configuration was identical on all three units. However, Units 1 and 2 did not respond the same as Unit 3.

The team noted that, in each subsection of the Final Safety Analysis Report listed below, the steam bypass control system is assumed to be unavailable because it is either deenergized or in manual. During the LOOP event, the team found that the system was reenergized and operated in automatic. The team noted that this system response may not be as described in the licensee's safety analysis with applicable sections listed below.

6.3.3.5D.	For all break sizes, the reactor trip will result in a turbine trip and the subsequent loss of offsite power will result in the loss of main feedwater flow. Since the steam bypass control system is not available due to loss of condenser vacuum on loss of offsite power. . . .
7.2.2.4.1.2.1A.	The [Steam Bypass Control System] SBCS and [Reactor Pressure Control System] RPCS will be unable to automatically respond to any challenges on a failure of distribution panel E-NNN-D11.
7.2.2.4.1.2B	. . . the LOFW [loss-of-feedwater] event presented in subsection 15.2.7 assumed that the [Pressurizer Pressure Control System] PPCS, SBCS, and [Reactor Regulating System] RRS are in the manual mode of operation, unable to automatically respond to challenges.
15.1.4.2	Case 1 Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed . . .
15.1.4.2	Case 2 Since the steam bypass control system is assumed to be in the manual mode with all bypass valves closed . . .
15.2.3.1	. . . in this analysis both the SBCS and RPCS are assumed to be in the manual mode and credit is not taken for their functioning.
15.3.1.1	The only credible failure which can result in a simultaneous loss of power is a complete loss of offsite power. In addition, since a loss of offsite power is assumed to result in a turbine trip and renders the steam dump and bypass system unavailable, the plant cooldown is performed utilizing the secondary valves and atmospheric dump valves (ADVs) . . . The loss of offsite power will make unavailable any systems whose failure could affect the calculated peak pressure. For example, a failure of the steam dump and bypass system to modulate or quick open

and a failure of the pressurizer spray control valve to open involve systems (steam dump and bypass system and pressurizer pressure control system (PPCS)) which are assumed to be in the manual mode as a result of the loss of offsite power and, hence, unavailable for at least 30 minutes.

15.3.1.2C.	The turbine is assumed to trip on loss of offsite power. The loss of offsite power produces a loss of load on the turbine which generates a turbine trip signal. The turbine stop valves are closed as a result of the trip. The steam bypass control system becomes unavailable due to the loss of offsite power and subsequent loss of condenser vacuum.
15.3.4.1	The assumed loss of ac renders the steam bypass control system inoperable as a result of the loss of circulating water pumps.
15.3.4.2C.	The loss of offsite power causes a loss of power to the plant loads and the plant experiences a simultaneous loss of feedwater flow, condenser inoperability, and a coastdown of all reactor coolant pumps.
15.3.4.3.1C.	The loss of offsite power also causes a loss of main feedwater and condenser inoperability. The turbine trip, with the steam bypass control system (SBCS) and the condenser unavailable, leads to a rapid buildup in secondary system pressure and temperature. . . .
15.4.2.2D.	Following the generation of a turbine trip on reactor trip, the main feedwater control system (FWCS) enters the reactor trip override mode and reduces feedwater flow to 5% of nominal, full power flow. Since the steam bypass control system (SBCS) is assumed to be in manual mode with all bypass valves closed, the main steam safety valves (MSSVs) open to limit secondary system pressure and remove heat stored in the core and the RCS.
15.4.2.3B.	All the control systems listed in Table 15.4.2-2, except the SBCS, were assumed to be in the automatic mode since these systems have no impact on the minimum [Departure from Nucleate Boiling Ratio] DNBR obtained during the transient. The steam bypass control system is assumed to be in manual mode because this minimizes DNBR during the transient.
15.4.8.3C.	The steam bypass control system is inoperable on loss of offsite power and, therefore, is unavailable.

15.5.2.1	The loss of normal ac power results in loss of power to the reactor coolant pumps, the condensate pumps, the circulating water pumps, the pressurizer pressure and level control system, the reactor regulating system, the feedwater control system, and the steam bypass control system.
15.5.2.3C.	Since the steam bypass control system is in the manual mode . . . The unavailability of the steam bypass valves. . . .
15.6.3.1.2D	Since the SBCS is assumed to be in manual mode with all bypass valves closed . . .
15.6.3.3.1A.	The ADVs are used due to the unavailability of the steam bypass control system due to loss of offsite power.
15.6.3.3.3.1C.	The loss of offsite power also causes the steam bypass system to the condenser to become unavailable.

b.2. Main Generator Excitation Control Response

During the team's review of the time-line, it was noted that the main turbine stop valves closed on each unit at approximately 07:41:21 a.m. The Units 1 and 2 reactor coolant pumps had tripped on undervoltage approximately 1 second prior to the turbine trips, and the reactors tripped on anticipatory low DNBR within 1 second of receipt of the turbine trips. However, on Unit 3, the reactor tripped on variable over-power approximately 1 second after the other units. Next, the team noted that the Unit 3 main generator tripped approximately 1 second after the reactor trip on a volts/hertz signal, while the other units' main generators did not trip on volts/hertz signals until approximately 3.5 seconds after the reactor trips. And, approximately 5 seconds after the Units 1 and 2 reactor coolant pumps tripped on undervoltage, the Unit 3 reactor coolant pumps tripped on undervoltage. All three units experienced post-event frequency increases to approximately 67 hertz.

During the LOOP event, the Unit 3 reactor coolant pumps remained connected to the substation bus while the turbine was in an overspeed condition. Licensee engineers concluded that the bus voltage was maintained because of an unexpected response of the Unit 3 generator's excitation circuit. As a result of the excitation circuit response, the excitation and, therefore, the output voltage remained high, delaying the load shed and tripping of the reactor coolant pumps. The licensee planned to conduct troubleshooting to evaluate the main generator excitation control system.

Since the Unit 3 reactor coolant pumps remained operating longer, they turned at the higher frequency, increasing flow through the critical reactor core. This increase in flow (approximately 108.2 percent of design flow), produced a power of approximately 109 percent, as read on excore nuclear instruments. This positive rate of change in reactor power generated a variable over-power-trip signal to shutdown the reactor.

The team reviewed the licensee's evaluation of the increased reactor coolant flow and noted that the estimated flow of 108.2 percent was less than the evaluated limit of 110.4 percent of design volumetric flow. According to the licensee's analyses, the most limiting component of each reactor coolant pump was the motor flywheel, which was designed for 125 percent of rated speed. The team noted that this value was not approached during the event. The team agreed with the licensee's conclusion that there was no impact to the continued power operation with respect to fuel grid-to-rod fretting, vessel hydraulic uplift forces, and fuel mechanical design.

While all three turbine generators were in an over-speed condition and connected to the plant busses, all connected loads experienced a higher frequency. The reactor coolant pumps for Units 1 and 2 were not exposed to the high frequency condition because their undervoltage relays actuated before the higher frequency was attained.

2.6 <u>Unit 3, Reactor Coolant Pump 2B Lift Oil Pump Breaker</u>

a. <u>Inspection Scope</u>

The team reviewed the thermal overload curves for the lift oil pumps and the operator response to the loss of the pump with regard to restoring forced circulation in the primary plant. The team also interviewed plant personnel, reviewed CRDR 2715659, and reviewed control room logs regarding the activities surrounding the failure of the lift oil pump to start.

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

The team identified URI 05000530/2004012-007 to review the design of the lift oil pump motor breaker thermal overloads and operation of the lift oil system that appeared to have contributed to the delay in restoring forced coolant flow through the reactor core, review the licensee's extent of condition, and assess the effectiveness of corrective actions implemented by the licensee.

During restoration efforts following the June 14, 2004, LOOP, the Unit 3 Reactor Coolant Pump 2B lift oil pump thermal overloads were actuated while operators were making preparations to start reactor coolant pumps.

The team noted that the procedure for starting reactor coolant pumps did not contain any note or precaution that warned operators of a potential thermal overload trip if the lift oil pump motor was run longer than 10 minutes. Licensee Procedure 40EP-9EO10, Appendix 1, "RCP [Reactor Coolant Pump] Restart," states, in part:

> "5. <u>Ensure</u> the appropriate lift oil pump has been running for 7 minutes or more."

The team noted that the thermal overload trip resulted in an unnecessary delay in the restoration of forced reactor coolant flow through the core.

In addition, the licensee's calculation for sizing the thermal overloads for the motor breaker resulted in the overloads being only 0.1 amp greater than the motor running current. At this level of running current, the licensee calculated that the overloads would actuate in approximately 600 seconds. Licensee personnel identified the apparent cause of the trip of the lift oil pump was operating the pump in excess of 10 minutes. The licensee initiated CRDR 2715659 to address this issue.

2.7 Unit 3, Low Pressure Safety Injection System In-Leakage

a. Inspection Scope

The team reviewed CRDR 2715659, which documented that a leaking Borg-Warner check valve had pressurized the low pressure safety injection system during the event. Plant personnel were interviewed and control room logs and plots were reviewed to determine the impact of the in-leakage to the control room operators during the LOOP event.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-008 to review the root and contributing causes, extent of condition, and corrective actions associated with the Borg-Warner safety injection check valve leakage; to review the effectiveness of prior corrective actions for previous check valve leakage issues; to evaluate the adequacy of the in-service testing program for demonstrating check valve operability; and to assess the licensees use of industry operating experience and generic communications.

While Unit 3 operators were implementing LOOP emergency procedures, they were required to implement Alarm Response Procedure 40AL-9RK2B, "Panel B020B Alarm Response," Revision 48, on three occasions to depressurize a section of safety injection piping to maintain the low pressure safety injection system operable. The team found that, while operators maintained an adequate level of control, they were moderately challenged by the unnecessary distraction from emergency procedures. Apparently, Valve RCEV-217, a 14-inch Borg-Warner check valve began to leak and pressurized the safety injection header to Reactor Coolant Loop 2A. The licensee's apparent cause involved a thermal hydraulic interaction that resulted in check valve leakage when system temperatures changed rapidly.

2.8 Units 1 and 3, General Electric Magna Blast Breaker Failures

a. Inspection Scope

The team reviewed the failure of two 13.8 kV circuit breakers to close on demand during the recovery from the loss-of-offsite power. The team also interviewed licensee personnel associated with the investigation into the breaker failures.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-009 to review the root and contributing causes, extent of condition, and corrective actions associated with the reliability of Magna-Blast circuit breakers; to review the effectiveness of prior corrective actions for previous Magna-Blast circuit breaker failures; to evaluate the adequacy of the testing program for demonstrating breaker operability; and to assess the licensees use of industry operating experience and generic communications.

The team noted that, while recovering from the LOOP event, 13.8 kV Breakers 1ENANS06K and 3ENANS05D failed to close on demand from the control room. This resulted in some delays in restoring offsite power to the safety busses. The licensee initially determined the apparent cause of the inability to close the breakers was that they had not been cycled frequently enough. Apparently, the licensee believed that improper operation of the latching mechanisms may have occurred due to grease hardening and contamination by dirt. The licensee initiated CRDR 2716019 to evaluate the failures, determine the root cause(s), and take any corrective actions identified.

The team noted that the initial response only involved a cycling of the breakers without any detailed troubleshooting. The team found that the licensee personnel considered this acceptable because of a known issue with grease hardening in Magna-Blast circuit breakers located in a relatively hot environment with little to no cycling during the 18-month operating cycle.

The team noted that each of the breakers had been refurbished in 2002. Breaker 1ENANS06K had been cleaned, inspected, and cycled during the last refueling outage earlier this year. The team found that the licensee personnel's initial determination of the apparent cause for the Unit 1 breaker was not well supported because of the recent cleaning and inspection.

Because of the large volume of industry operating experience with Magna-Blast circuit breaker reliability and the fact that both breakers had maintenance on them within the past 2 to 3 years, the team was concerned that the two breakers may have problems other than what was described in the licensees apparent cause.

2.9 Auxiliary Feedwater (AFW) System Performance

a. Inspection Scope

The team evaluated the adequacy of the AFW system performance during and after the LOOP event. The inspection was accomplished through a review of documents and interviews with operators and engineering staff.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-010 to review the root and contributing causes, extent of condition, and corrective actions associated with the design and operation of the AFW system. Specifically, a thermally induced vibration occurred when operators placed the non-essential AFW system into service, which also may have involved procedural issues.

As part of the reactor trip response, operators manually started the essential motor-driven AFW pumps in all 3 units. Six hours after the reactor trip, Unit 1 operators placed the non-essential motor-driven AFW pump into service and secured the essential pump. At this time, a plant operator reported high vibration for approximately 5 minutes in the main feedwater piping. The licensee generated CRDR 2715731 to document the high vibration. In Units 2 and 3, the nonessential pumps were placed in service, 17 and 29 hours after the reactor trips, respectively. No vibration was noted in Units 2 and 3.

There was no procedural requirement that compelled operators to secure the essential pump and place the nonessential pump in service. According to the Unit 1 operator, the basis for transferring from the essential pump to the nonessential pump was to allow operators to add chemicals to the feedwater, if needed.

The high vibration in the Unit 1 feedwater line occurred when the relatively cold auxiliary feedwater coming from the condensate storage tank mixed with the stagnant hot water in the insulated section of feedwater piping downstream of the injection point of the non-essential AFW pump. That section of feedwater became isolated as a result of a manual MSIS actuation required by the applicable emergency operating procedure. There were no subsequent procedural cautions or guidance for preventing the introduction of the cold water into the feedwater system prior to that section of piping being allowed to cool down sufficiently. The placement of the nonessential AFW pumps into service in Units 2 and 3 did not result in high vibration because those sections of feedwater piping had apparently cooled enough to preclude a thermally induced vibration transient.

3.0 Human Performance and Procedural Aspects of the Event

A number of unresolved items were identified by the team associated with human performance and procedures which were revealed during and following the event. Each of these issues is discussed in sections below. Each of the unresolved items will be the subject of an NRC inspection to assess the licensee's effectiveness of determining the root and contributing causes, extent of condition, and corrective actions

3.1 Auxiliary Feedwater System Operation

a. Inspection Scope

The team assessed emergency procedure implementation and control room operator response as it related to the AFW system. The inspection was accomplished through a review of documents and interviews with operators and engineering staff.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-011 to review the root and contributing causes, extent of condition, and corrective actions associated with emergency operating procedure implementation, the availability of equipment to accomplish manual drains on the turbine-driven auxiliary feedwater (TDAFW) system, and the decision-making process for implementing manual drain procedures.

Emergency Operating Procedure Implementation

As discussed previously, Unit 2 tripped at 7:41 a.m. on June 14, 2004, as a result of the LOOP event. The completion of reactor post trip actions resulted in entry into Emergency Operating Procedure (EOP) 40EP-9EO07, “Loss of Offsite Power/Loss of Forced Circulation,” Revision 10. Step 6 of this procedure requires control room operators to initiate an MSIS actuation. In addition to closing the main steam isolation valves, this step also causes closure of drains associated with two critical steam traps required to maintain operability of the TDAFW pump. With the steam traps unavailable, condensate can accumulate in the steam lines which can contribute to an overspeed trip of the turbine during startup.

The team noted that the EOP did not caution the operators that an MSIS would potentially make the TDAFW pumps inoperable. The EOP also did not direct the operators to implement the applicable sections of Normal Operating Procedure 40OP-9SG01, “Main Steam,” Revision 37, which provide the necessary instructions for manually draining those sections of piping necessary to maintain operability of the pump. This procedure requires that the piping associated with the critical steam traps be blown down every 2 hours until a dry steam condition is reached and then every 6 hours thereafter. On the day of the event, operators did not commence actions to drain the associated piping until 11 hours after the reactors tripped.

Turbine-Driven Auxiliary Feedwater (TDAFW) Steam Drain Line Equipment

As discussed above, without the steam traps available, condensate can accumulate in the steam lines and lead to a potential overspeed trip of the pump. A condensation induced overspeed trip of the Unit 1 TDAFW pump previously occurred on April 24, 1990. At that time, Engineering Evaluation Request 90-AF-011 was generated to evaluate the root cause. The necessary corrective actions identified included directions to revise the operating and surveillance procedures to address maintaining the steam traps dry and directions to implement manual methods to ensure that the steam lines were maintained drained while in Modes 1, 2, and 3 with the turbine not on line.

After operators realized that draining of the piping associated with the critical steam traps was necessary to ensure continued operability of the TDAFW pump, the applicable portions of the main steam normal operating procedure were referenced. The procedure required the installation of a vent rig tool constructed in accordance with Engineering Evaluation Request 92-SG-007 at each manual drain location. Consequently, each TDAFW pump required two vent rig tools. Operators were only able to find sufficient vent rig tools for one TDAFW pump.

Decision-Making with Limited Resources

The AFW system has a relatively high value of risk importance. As such, with only enough vent rig tools to drain one TDAFW pump at a time, operations management decided to begin draining the Unit 1 TDAFW pump steam traps first. The team noted that with Unit 2 having only one of two EDGs available, it was a more prudent decision to restore the Unit 2 TDAFW pump to service first.

3.2 Unit 2, Train “E” Positive Displacement Charging Pump Trip

a. Inspection Scope

The team reviewed the EOPs and the control room operator response to the LOOP event with respect to the charging pumps to determine the effect on the response to the event. The team also interviewed plant personnel and reviewed CRDRs 2716521 and 2716806 regarding the activities surrounding the charging pump operations.

b. Observations and Findings

The team identified URI 05000529/2004012-012 to review the root and contributing causes, extent of condition, and corrective actions associated with operator errors during Unit 2 charging pump operations.

As the volume control tank level dropped, as expected, to approximately 15 percent with Positive Displacement Charging Pump CHB-P01 operating, a control room operator recognized the need to transfer the charging pump suction from the volume control tank to the refueling water tank. Because of the LOOP, control room operators were implementing Procedure 40EP-9EO07.

Step 11 of Procedure 40EP-9EO07 states:

> **IF** VCT makeup is **NOT** available, **THEN** perform the following:
>
> a. **IF** RWT level is below or approaching 73%, **AND** the CRS desires to keep charging in service, **THEN** PERFORM **ONE** of the following:
>
> - Appendix 10, Charging Pump Alternate Suction to the RWT / Restoration
> - Appendix 11, Charging Pump Alternate Suction to the SFP / Restoration
>
> b. **IF** RWT level is above 73%, **THEN** perform the following:
>
> 1) **IF** three charging will be used, **THEN** stop the Boric Acid Makeup Pumps.
>
> 2) **IF** three charging pumps are will be (sic) used, **AND** a Fuel Pool Clean Pump is recirculating the RWT, **THEN**

<u>stop</u> RWT recirc by stopping the appropriate Fuel Pool Cleanup Pump.

3) <u>Open</u> CHN-HV-536, RWT Gravity Feed to Charging Pump Suction.

4) <u>Close</u> CHV-UV-501, Volume Control Tank Outlet.

The team noted that since refueling water tank level was greater than 73 percent at the time, the appropriate steps in the procedure for transferring the charging was Step 11.b.3) and 4). However, the control room supervisor decided that Step 11.a. was appropriate because Valves CHN-HV-536 and CHN-UV-501 did not have power and the supervisor knew that the valves in Step 11.a. could be manually operated. The supervisor failed to consider that the valves in Step 11.b. could also be manually operated. By making this decision, the control room supervisor's decision to implement Step 11.a. may not have been in accordance with the requirements of the EOP for the plant conditions at the time (i.e., the refueling water tank level was greater than 73 percent). The licensee initiated CRDR 2716521 to evaluate the human performance error.

After deciding to implement Step 11.a., the control room supervisor conducted a briefing with an auxiliary operator to discuss the manual transfer of the Charging Pump CHE-P01 suction from the volume control tank to the refueling water tank using Appendix 10 to Procedure 40EP-9EO10, "Standard Appendices," Revision 32. Appendix 10 states, in part:

1. <u>Request</u> that Radiation Protection accompany the operator performing the local operations to perform area surveys.

2. **IF** it is desired to align Charging Pump(s) suction to the RWT, **THEN** <u>perform</u> the following:

    a. <u>Place</u> the appropriate Charging Pump(s) in "PULL-TO-LOCK."

    b. <u>Direct</u> an operator to <u>PERFORM</u> Attachment 10-A, <u>Aligning Charging Pump Suction to the RWT</u>, for the appropriate Charging Pump(s).

    c. **WHEN** the appropriate Charging Pump(s) has been aligned, **THEN** <u>start</u> the appropriate Charging Pump(s) as necessary.

Attachment 10-A states, in part:

1. <u>Open</u> CHB-V327, "RWT TO CHARGING PUMPS SUCTION" (70 ft. East Mechanical Piping Penetration Room). . . .

4. **IF** aligning Charging Pump E, **THEN** <u>perform</u> the following (Charging Pump E VlvGallery)

   a. <u>Close</u> CHE-V322, ""E" CHARGING PUMP CHE-P01 SUCTION ISOLATION VALVE."

   b. <u>Open</u> CHE-V757, ""E" CHARGING PUMP ALTERNATE SUCTION ISOLATION VALVE."

5. <u>Inform</u> the responsible operator that the appropriate Charging Pump(s) are aligned to the RWT.

The team found that the auxiliary operator did not implement Appendix 10, Step 1, of EOP 40EP-9EO10. Instead of requesting a radiation protection person to accompany him, the operator went to the radiologically controlled area access to perform a routine entry. However, because of the LOOP, the access computers were not functioning and routine entry data was being entered manually. The auxiliary operator failed to inform the radiation protection person of the necessity of his entry nor of the procedural requirement for a radiation protection person to accompany him. This resulted in some delay in implementing the EOP. The licensee initiated CRDR 2716806 to evaluate the delay at the access point.

Once access was gained, the auxiliary operator proceeded to perform Attachment 10-A, Steps 4 and 5, that were not in the correct order. After positioning the valves listed in Step 4, the auxiliary operator informed the control room operator that the Charging Pump CHE-P01 suction had been transferred. The control room operator then started Charging Pump CHE-P01 at approximately 08:05 a.m. and secured Charging Pump CHB-P01 at approximately 08:05:52 a.m. At approximately 08:05:59 a.m., Charging Pump CHE-P01 tripped on low suction pressure, resulting in a loss of all charging flow.

At approximately 08:06:22 a.m., the control room operator restarted Charging Pump CHB-P01. The team found that the control room operator was unaware that this pump was operating with the suction from the volume control tank. After approximately 4.5 minutes, the control room operator noticed that the volume control tank level had dropped to approximately 10 percent. At that time, the operator secured Charging Pump CHB-P01 to prevent it from tripping on low suction pressure or becoming air-bound.

At approximately 08:11:31 a.m., the charging pump suction was properly transferred to the refueling water tank and Charging Pump CHB-P01 was restarted. At approximately 11:32:37 a.m., the time line indicated that Charging Pump CHA-P01 was started.

3.3 Entry Into Technical Specification Action Statements

a. Inspection Scope

The team evaluated control room log entries associated with the plant trip caused by the LOOP. The inspector also assessed the operator response as it related to the required entry into Technical Specification Action Statements. The inspection was accomplished through a review of documents and interviews with operators and engineering staff.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-013 to review how Technical Specifications are used during and following an event in which EOPs were used. Specifically, the team observed that Technical Specification Limiting Conditions for Operation were not started until the applicable step in the EOP was reached to assess Limiting Conditions for Operation (LCOs).

The team found that in each of the following examples, the time of entry into the LCO did not reflect the time of discovery of the inoperability of the affected components.

A review of the Unit 2 control room log entries disclosed that operators exited the EOP at 5:10 a.m. MST on June 15, 2004. Coincident with this log entry were the entries into Technical Specifications LCO 3.7.5 for an inoperable TDAFW pump and LCO 3.8.1 for an inoperable Train "A" EDG.

The EDG was not operable shortly after the reactor trip because a failed diode in the exciter prevented it from accepting loads from the load sequencer (Section 2.4). When the manual MSIS actuation occurred, the TDAFW system steam trap drains were isolated which could cause the TDAFW pump to become inoperable without manual action to drain the associated piping within 2 hours (Sections 2.9 and 3.1). The manual action did not occur until approximately 11 hours after the MSIS actuation. Consequently, the team considered both components to be inoperable prior to exiting the EOP.

During the plant transient, the battery chargers to the Unit 2 A and C Vital 125 V batteries were not operable for approximately 2 hours when the Train "A" electrical bus was not powered by either offsite power or the EDG. Technical Specification 3.8.4 requires that, within 1 hour, battery cell parameters be verified to meet Table 3.8.6-1 Category "A" limits when the required battery charger is inoperable. The batteries were discharged for 110 minutes until offsite power was restored to the electrical bus and the battery charger. The entry into the required Technical Specification action was not documented in the control room log and the action to verify battery cell parameters was not taken until approximately 5 hours after the battery charger became inoperable. Additionally, the batteries were declared operable solely on the restoration of offsite power to the bus and battery charger and without any surveillance to verify compliance with the Technical Specification.

The Unit 3 Loop 2A Safety Injection Check Valve SIE-V217, is a 14-inch swing check valve. At 10:12 a.m. on June 14, an alarm indicating back leakage through this check valve was received. Alarm Response Procedure 40AL-9RK2B, requires that, when indicated pressure is greater than 1850 psig, Low Pressure Safety Injection Train "B" be declared inoperable and Technical Specification 3.5.3 be entered. At 8:44 p.m. on June 14, 1850 psig was exceeded. Entry into Technical Specification 3.5.3 was logged as being the time that the LOOP EOP was exited, 12:40 a.m. on June 15, 2004, and not at the time that 1850 psig was exceeded.

The Normal Operating Procedure 40DP-9OP02, “Conduct of Shift Operations,” Revision 28, requires that when reliable plant indication identifies a condition that requires entry into a Technical Specification condition, the applicable condition shall be entered immediately. The logging of entry into the applicable LCO after the time of discovery created the potential for failing to meet Technical Specification requirements.

3.4 Technical Support Center (TSC) Emergency Diesel Generator Trip

a. Inspection Scope

The team interviewed members of the licensee’s emergency planning organization and electrical maintenance department. Security department logs were reviewed to determine the cause of the failure of the TSC diesel generator during the LOOP event. The team walked down the TSC electrical distribution system and the TSC diesel generator. The team reviewed the licensee’s preliminary findings attached to CRDR 2715749 written to investigate and determine the root causes for the emergency planning problems arising from the LOOP and plant trip on June 14, 2004.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-014 to review the root and contributing causes, extent of condition, and corrective actions associated with a failure of the TSC diesel generator.

The team found that the apparent cause for the failure of the TSC diesel generator to restore power to the TSC was a human performance error that had occurred during post maintenance testing of the diesel engine starting system on June 8, 2004.

On June 14, 2004, as a result of the LOOP event, electrical power was lost to the TSC. As designed, the TSC diesel generator started but it did not re-energize the TSC electrical loads. Electrical maintenance technicians were called to investigate the problem and shortly after they arrived at the TSC, the diesel engine tripped. The engine control panel alarms indicated that the trip was due to high engine temperature. Electrical power was restored to the TSC when offsite power was restored to Unit 1 at approximately 9:10 a.m. The TSC was without electrical power for approximately 1 hour 30 minutes.

During subsequent troubleshooting, electrical maintenance technicians determined that the engine operating switch was in “Idle.” With the switch in “Idle,” the diesel generator started on loss of electrical power to the TSC, but did not come up to proper voltage and frequency and did not re-energize the TSC electrical distribution panel. As a result, the engine radiator cooling fan did not start; therefore, the engine overheated and tripped on high temperature. The electrical maintenance technicians returned the engine operating switch to its normal “Run” position and wrote CRDR 2715726.

The licensee determined that the engine operating switch was apparently left in the “Idle” position after post-maintenance testing of the engine starting system performed on June 8, 2004, under Work Order 2623863. During this monthly engine starting battery inspection, electricians noted that one battery terminal and connector were corroded. The electricians contacted their team leader and received permission to cleanup the connection using the same work order. The team leader and the lead electrician determined that the starting system needed to be tested after the battery was returned to its normal configuration. The lead electrician suggested using a portion of preventative maintenance task, “Quarterly Restrike Test for TSC Diesel Generator.” Since this test is routinely performed by the electricians working on the starting battery, the team leader allowed the electricians to perform the test without a working copy of the test procedure in the field. After the diesel generator was successfully started, the engine operating switch was moved from “Run” to “Idle” to let the engine run at a slower speed and cooldown before being secured. The team determined that the failure to have a working copy of the test procedure at the engine during this post-maintenance testing and failure to use the restoration guidance contained in the test procedure contributed directly to the failure to restore the TSC diesel generator to its normal standby condition.

On June 16, 2004, the licensee performed the periodic 1-hour loaded test run of the TSC diesel generator using preventative maintenance task, “Quarterly Restrike Test for TSC Diesel Generator,” under Work Order 2715869. The diesel generator started as expected and automatically energized the TSC electrical power distribution panel. The diesel generator ran loaded for 1 hour with no problems noted. The diesel generator was shutdown using the task instructions and restoration directions.

The team determined that the diesel generator failure contributed to the delay in staffing the TSC. As a result of diesel generator failure, the responding members of the emergency response organization were moved to the satellite TSC adjacent to the Unit 2 control room. However, normal offsite power was restored to the TSC before the 2-hour staffing requirement of PVNGS Emergency Plan, Table 1, “Minimum Staffing Requirements for PVNGS for Nuclear Power Plant Emergencies,” Revision 28.

3.5 Emergency Response Organization Issues

a. Inspection Scope

The team interviewed members of the licensee’s emergency planning organization and security department and reviewed security department logs and emergency planning records to determine the cause of the multiple emergency response organization communication problems during the LOOP. The team also reviewed the licensee’s preliminary findings attached to significant CRDR 2715749 initiated to investigate and determine the root causes for the emergency planning problems arising from the LOOP and plant trip on June 14, 2004, and attended the significant event investigation team meetings. In addition, CRDR 2716281 associated with the availability of dose projection computers was reviewed.

b. Observations and Findings

The team identified URI 05000528; -529; -530/2004012-015 to review the root and contributing causes, extent of condition, and corrective actions associated with emergency response organization issues. Specifically, the NRC review will include an assessment of the effectiveness of licensee corrective actions associated with communication and coordination issues involving the notification of state and local officials of emergency classifications, the apparent unavailability of the radiological dose projection computers used to develop timely protective action recommendations to state and local authorities from the control room, and the apparent delays in notifying and staffing emergency response organization.

The team found that the apparent causes for the multiple emergency response organization communication problems were: (1) the unanticipated LOOP event to all three units that resulted in the loss of normal emergency planning communications equipment, and (2) human performance errors in implementing Emergency Plan Implementing Procedure (EPIP)-01, “Satellite Technical Support Center Actions,” Revision 14.

When the LOOP event and the subsequent three-unit trip occurred, two of the unit shift managers; the onsite manager; and the operations manager (who was the on-call TSC emergency coordinator), were in the plan of the day meeting in the operations support building adjacent to the Unit 2 control room. The Unit 1 shift manager returned to the Unit 1 control room and assumed the duties as emergency coordinator for all three units. When the onsite manager arrived at the Unit 1 control room to relieve the shift manager of his emergency coordinator responsibilities, Unit 2 entered an Alert emergency action level; therefore, the onsite manager returned to Unit 2 to set up the satellite TSC at the most effected unit. The Unit 1 shift manager had declared a Notification of Unusual Event for the LOOP for greater than 15 minutes. He gave this information to the onsite manager to coordinate the emergency notification to state and local authorities.

The Unit 2 shift manager declared an Alert emergency action level based on the LOOP event concurrent with a loss of one of the Unit 2 EDGs for greater than 15 minutes. He directed the on-shift emergency communicator to notify state and local authorities. The emergency communicator immediately determined that the normal notification alert network system was not working and used the backup radio notification system to notify the state and local authorities within 8 minutes of the Alert classification.

When the onsite manager arrived at the Unit 2 satellite TSC in the Unit 2 control room, he was told by the operations manager that Unit 2 had assumed all emergency communications, but did not question him as to whether or not the Unit 1 Notification of Unusual Event was sent to the state and local authorities. Apparently, there was no formal turnover on emergency communications responsibilities from the Unit 1 shift manager to the Unit 2 shift manager or the onsite manager, who was going to relieve the Unit 2 shift manager of emergency coordinator responsibilities. In addition, the onsite manager and operations manager did not effectively communicate the status of the offsite notification. These two human performance errors resulted in the Unit 1 Notification of Unusual Event not being sent to state and local authorities.

The Unit 3 shift manager declared a Notification of Unusual Event for the LOOP for greater than 15 minutes. There was a time delay before the Unit 3 on-shift emergency communicator attempted to send out the notification using the normal notification alert network system. When he determined that it was not working, he used the backup radio notification system but did not notify the state and local authorities until 20 minutes after the Notification of Unusual Event classification. The team determined that the delay in starting the notification process and the need to use the backup radio system were human performance errors that delayed the Unit 3 Notification of Unusual Event beyond the 15 minute requirement in EPIP-01, “Satellite Technical Support Center Actions,” Revision 14.

The loss of power to the normal notification alert network system complicated the emergency notification of state and local authorities. In addition, the licensee determined that the three satellite TSC dose projection computers had lost power and raised questions about their ability to make timely protective action recommendations. The apparent cause for both failures was that both systems were supplied electrical power from electrical circuits that have no backup power supplies. The licensee initiated CRDR 2715749 to address the loss of power to the normal notification alert network system and CRDR 2716281 to address the dose projection computers. The licensee implemented immediate corrective actions to install backup uninterruptible power supplies for both systems.

During the initial LOOP and the failure of the Unit 2 Train "A" EDG, the Unit 2 shift manager and on-shift emergency communicator were delayed in sending out the emergency pager notification to the on-call emergency response organization. The team determined that the delay of 16 minutes contributed to the greater than 2-hour response time of the on-call technical support electrical engineer to the TSC. The licensee did not activate the backup dialogic auto-dialer system for emergency response organization notification as required during an Alert emergency classification. During interviews, the Unit 2 shift manager had stated that he thought that June 14, 2004, a Monday, was a normal working day and the emergency response organization would respond to the plant-wide announcement of the Alert classification. In fact, Monday was a normal off day for plant personnel, and the dialogic auto-dialer system should have been used to activate the emergency response. The team determined that this human performance error contributed to the late staffing of the TSC and the less than minimum required number of radiation protection technicians reporting to the operations support center within the required 2 hours. This failure to use EPIP-01 properly was documented in CRDR 2715749, and the licensee revised EPIP-01 to always require the activation of the dialogic auto-dialer for backup emergency response organization notification.

4.0 Coordination with Offsite Electrical Organizations

a. Inspection Scope

The team reviewed the licensee’s coordination with offsite organizations before, during, and after the June 14, 2004, LOOP event.

b. Observations and Findings

The team found that SRP Procedure PVTS-01, "Palo Verde Transmission System Interchange Scheduling and Congestion Management Procedure," Revision 8, was thorough, clear, and effective. For example, the licensee had calculated the minimum onsite requirement for electrical voltage to be 512 kV and worked closely with SRP and APS to ensure that the proper voltage range of 500 to 535 kV for the PVNGS 500 kV switchyard was implemented. Arizona Public Service Company continued to provide voltage at the expected voltage band following the isolation of the fault.

The team noted that the APS energy control center and PVNGS control room operators coordinated their efforts to reduce PVNGS switchyard voltage so reactor coolant pumps could be started during plant recovery efforts. In addition, the team found that the licensee actively coordinated the investigation into why a single insulator failure could result in a LOOP and a three-unit trip and was closely involved in the development of corrective actions to improve both reliability and independence of transmission lines.

The team concluded that the coordination with offsite electrical organizations was very good and the remedial measures coordinated between PVNGS, SRP, and APS personnel improved reliability and independence and appropriately minimized the possibility of a similar LOOP event occurring in the PVNGS 500 kV switchyard.

5.0 Risk Significance of the Event

The initial risk assessment for Unit 2 resulted in a conditional core damage probability (CCDP) of 6.5×10^{-4}. Subsequently, the team, assisted by Office of Nuclear Regulatory Research personnel, completed a detailed risk assessment for the event. This analysis used the SPAR Model for Palo Verde 1, 2, & 3, Revision 3.03, to estimate the risk. The analyst assumed that 95 percent of LOOP events, similar to the June 14th event, would be recovered within 2.5 hours. The resulting CCDPs were 4×10^{-5}, 7×10^{-4}, and 4×10^{-5} for Units 1, 2, and 3, respectively.

The team gathered information concerning the failed EDG and charging pump in Unit 2. Other equipment problems including TDAFW system drains, steam generator power-operated relief valves problems, and 13.8 kV breaker issues were assessed. In addition, the team evaluated the ability of the licensee to recover offsite power, the probability that power could be provided to the vital buses from the gas turbine generators had it been needed, and the capability of vital and nonvital batteries to continue to provide control power, had a station blackout occurred.

The team made the following assumptions critical to the analysis:

- The Unit 2 EDG "A" failed and could not have been recovered prior to postulated core damage.

- A Unit 2 licensed operator misaligned the suction path to Charging Pump "E" causing the pump to trip on low suction pressure. The pump could not have been recovered prior to postulated core damage because the pump was air bound.

- The required mission times, during this specific event, for the EDGs and the TDAFW pump were 2.5 hours.

- Recovery of ac power to the first vital bus, via the gas turbine generators or offsite power, was possible within 1 hour following a postulated station blackout. This assumption was derived from the following facts and their associated time frames:

  - The east switchyard bus was energized from offsite power (32 minutes)

  - The gas turbine generators were started and loaded (29 minutes)

  - Licensed operators determined the grid to be stable (49 minutes)

  - Power can be aligned from east bus to a vital 4160 volt bus (≈30 minutes)

- The probability that operators failed to restore offsite power within 1 hour was 4×10^{-2} as determined using the SPAR-H method. The nominal action failure rate of 0.001 was modified because the available time was barely adequate to accomplish the breaker alignments necessary, the operator stress level would have been high, and the actions required were of moderate complexity.

- The probability that operators failed to restore offsite power prior to the core becoming uncovered during a reactor coolant pump seal loss of coolant accident (LOCA) was estimated as 4×10^{-3}. The same performance shaping factors were used as for the 1-hour recovery with the exception of the time available. The team determined that the time available was nominal, because there would be some extra time, above what is minimally required, to execute the recovery action.

- The failure probability for recovery of offsite power prior to battery depletion during a station blackout was estimated as 4×10^{-3}. The same performance shaping factors were used as for the seal LOCA recovery.

- The team concluded that the failures of 13.8 kV feeder breakers in Units 1 and 3 would have increased the complexity in recovering offsite power for these units. However, the potential contribution of common cause failure probabilities would not greatly impact the nonrecovery probabilities described previously for Unit 2.

- The PVNGS gas turbine generators used for station blackout could be started and loaded within 1 hour of blackout initiation.

To account for the offsite power circumstances on June 14, 2004, the team modified the SPAR to replace industry average LOOP nonrecovery probabilities with ones derived from actual grid conditions and estimated probabilities of human actions failing. Additionally, modeling of the PVNGS gas turbine generators was improved to better represent their contribution in providing power to vital buses if needed. The team determined that this modified SPAR was an appropriate tool to assess the risk of this event.

The team set the likelihood of a LOOP to 1.0, and the likelihood of all other initiating events was set to the house event FALSE, indicating the assumption that it is unlikely that two initiating events would occur at the same time. The failure to start and failure to run basic events for both EDG "A" and Pump CHE-P01 were set to the house event TRUE, permitting calculation of the probability that similar components would fail from common cause. The SPAR model was quantified following the modifications, and the mean of the best estimate CCDPs was obtained through Monte Carlo simulation of the event.

6.0 Exit Meeting Summary

On June 18, June 24, and July 7, 2004, the team presented the preliminary observations from the Augmented Inspection in progress. On July 12, 2004, the Region IV Regional Administrator and the Augmented Inspection Team Leader presented the results of the inspection in a public meeting held at the Estrella Community College in Goodyear, Arizona to Mr. G. Overbeck and Mr. J. Levine, and other members of his staff. Mr. Overbeck acknowledged the team’s findings. Proprietary information reviewed by the team was returned to the facility.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

Jim Levine, Senior Vice President, Generation, Arizona Public Service Company (APS)
Greg Overbeck, Senior Vice President, Nuclear, APS
David Mauldin, Vice President, Nuclear Engineering & Support, APS
Dennis W. Gerlach, Manager, Transmission & Generation Operations, SRP
Mike Gentry, Manager, Grid Operations-PDO, Transmission and Generation Dispatching, SRP
Giang Vuong, Protection Engineer, SRP
Edmundo, Marquez, Manager System Protection, Electronic Systems, SRP
Cary B. Deise, Director, Transmission Planning and Operations, APS
Tom Glock, Power Operations Manager, Power Ops Tech Services, APS
Steven Phegley, Section Leader, Protection Metering, & Automated Control, APS
Steven Kestler, Electrical Engineer, Palo Verde Nuclear Station
Bajranga Aggarwal, Systems Engineer, APS
John Hesser, Director of Emergency Services
Larry Leavitt, Significant CRDR Lead Investigator
David Crozier, Program Leader for Emergency Planing
Martin Rhodes, Security Team Leader
Danne Cole, Security Section Leader

NRC

Ellis Merschoff, Deputy Executive Director for Reactor Programs
Bruce Mallett, Regional Administrator, Region IV
Pat Gwynn, Deputy Regional Administrator, Region IV
Jose Calvo, Chief, Electrical Instrumentation and Controls Branch, Office of Nuclear Reactor Regulation
Dwight Chamberlain, Director, Division of Reactor Safety, Region IV

ITEMS OPENED

05000528/2004012-01; 05000529/2004012-01; 05000530/2004012-01	URI	Corrective actions to improve the reliability and independence of offsite power (Section 2.1).
05000528/2004012-02	URI	Unit 1 Atmospheric Dump Valve 185 Failure (Section 2.2).
05000528/2004012-03	URI	Unit 1 Letdown System Failure to Isolate (Section 2.3).
05000529/2004012-04	URI	Unit 2 Train "A" Emergency Diesel Generator Failure (Section 2.4).

05000530/2004012-05	URI	Unit 3 Main Turbine Bypass Valve Control System Operation (Section 2.5).
05000530/2004012-06	URI	Unit 3 Main Generator Excitation Controls and Variable Overpower Trip on June 14, 2004 (Section 2.5).
05000530/2004012-07	URI	Unit 3 Reactor Coolant Pump 2B Lift Oil Pump Motor Breaker Thermal Overload Sizing (Section 2.6).
05000528/2004012-08; 05000529/2004012-08; 05000530/2004012-08	URI	Borg-Warner Check Valve Leakage Problems (Section 2.7).
05000528/2004012-09; 05000529/2004012-09; 05000530/2004012-09	URI	Magna-Blast Circuit Breaker Reliability (Section 2.8).
05000528/2004012-10; 05000529/2004012-10; 05000530/2004012-10	URI	Auxiliary Feedwater System Operational Issues (Section 2.9).
05000528/2004012-11; 05000529/2004012-11; 05000530/2004012-11	URI	Turbine-driven Auxiliary Feedwater System Drains, Design Control, and Procedures (Section 3.1).
05000529/2004012-12	URI	Unit 2 Charging Pump Operations Errors (Section 3.2).
05000528/2004012-13; 05000529/2004012-13; 05000530/2004012-13	URI	Use of Plant Technical Specifications (Section 3.3).
05000528/2004012-14; 05000529/2004012-14; 05000530/2004012-14	URI	Technical Support Center Emergency Diesel Generator Failure (Section 3.4).
05000528/2004012-15; 05000529/2004012-15; 05000530/2004012-15	URI	Emergency Response Organization Challenges (Section 3.5).

DOCUMENTS REVIEWED

Drawings

NUMBER	TITLE	REVISION
01-J-SPL-003	Control Logic Diagram Essential Spray Pond Auxiliary Pumps, Day Tk Valve & Alarms	3
01-J-EWL-001	Control Logic Diagram Essential Cooling Water Pumps and Surge Tank Fill Valves	2
01-J-EWL-002	Control Logic Diagram Essential Cooling Water Loop A X-Tie Valves & System Alarms	0
01-J-SPL-001	Control Logic Diagram Essential Spray Pond Pumps	3
01-M-EWP-001	P&I Diagram Essential Cooling Water System	29
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 1 of 3	35
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 2 of 3	35
01-M-SPP-001	P&I Diagram Essential Spray Pond System Sheet 3 of 3	35
01-M-SPP-002	P&I Diagram Essential Spray Pond System	12
A-774-10.110 SRP	Palo Verde Station 500 kV Switchyard PL912 Closing and Tripping Schematic	0
A774-10.111/1 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL912 Schematic Diagram	0
A774-10.112 SRP	Palo Verde Station 500 kV Switchyard PL912 Fail/Fault and CT Fail/Fault Schematic Diagram	0
A774-10.113 SRP	Palo Verde Station 500 kV Switchyard PL915 Fail/Fault and CT Fault Schematic Diagram	0
A-774-10.13 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL932 Closing and Tripping Schematic Diagram	9

Drawings

NUMBER	TITLE	REVISION
A-774-10.14 SRP	Palo Verde Station 500 kV Switchyard 500 kV Switchyard 500 kV Breaker Failure & Fault Monitor PL992 & PL995 Schematic Diagram	9
A-774-10.15 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL915 Closing and Tripping Schematic Diagram	12
A-774-10.20 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL 942 Closing & Tripping Schematic Diagram	10
A-774-10.21 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL 945 Closing & Tripping Schematic Diagram	10
A-774-10.36 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL915 Schematic Diagram	6
A-774-10.42 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL 945 Schematic Diagram	10
A-774-10.49 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL935 Closing and Tripping Schematic Diagram	7
A-774-10.5 SRP	Palo Verde Station 500 kV Switchyard Devers Line Relaying Schematic Diagram	5
A-774-10.50 SRP	Palo Verde Station 500 kV Switchyard 500 kV Breaker PL938 Closing and Tripping Schematic Diagram	7
A-774-10.82 SRP	Palo Verde Station 500 kV Switchyard PL972 Closing and Tripping Schematic Diagram	1
A-774-10.86 SRP	Palo Verde Station 500 kV Switchyard PL975 Closing and Tripping Schematic Diagram	1
A-774-10.90 SRP	Palo Verde 500 kV Switchyard 500 kV Hassayampa #1 Line Rel 87La Schematic Diagram	3
A-774-10.91 SRP	Palo Verde 500 kV Switchyard 500 kV Hassayampa #1 Line Rel 87La Schematic Diagram	2

Drawings

NUMBER	TITLE	REVISION
A-774-20.3 SRP	Palo Verde Substation Westwing #1 500 kV Line Relaying21La Schematic Diagram Sheet 1	1
A-774-20.4 SRP	Palo Verde Substation Westwing #1 500 kV Line Relaying21La Schematic Diagram Sheet 2	1
A-774-20.6 SRP	Palo Verde Substation Westwing #1 500 kV Line Relaying21Lb Schematic Diagram Sheet 1	1
A-774-20.7 SRP	Palo Verde Substation Westwing #1 500 kV Line Relaying21Lb Schematic Diagram Sheet 2	1
A-774-20.9 SRP	Palo Verde Substation Westwing #1 500 kV Line Relaying 87Lc Schematic Diagram Sheet 2	1
A-774-8.2 SRP	Palo Verde 500 kV SWYD. One Line Diagram SH2 Bays 1 & 2 IN-6W	12
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G-33451 APS	Westwing 230 kV Switchyard WAPA 230 kV Liberty Line & West Bus Tie PCB WW1022 DC Schematic	14
G-33453 APS	Sheet 1 of 1, Westwing 230 kV Switchyard WAPA 230 kV Liberty & Pinn Pk Line PCB WW1126 Schematic	16
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01-E-MAB-001 PVNGS	Elementary Diagram Main Generation System Main Generator Three Line Metering and Relaying	13
01-E-MAB-0012 PVNGS	Elementary Diagram Main Generator System Main Generator Three Line Metering and Relaying	9
01-E-MAB-004 PVNGS	Elementary Diagram Main Generation System Main Transformer Three Line Diff, Metering and Relaying	8
01-E-MAB-006 PVNGS	Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping	3
01-E-MAB-007 PVNGS	Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping	5
01-E-MAB-008 PVNGS	Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping	5
01-E-MAB-009 PVNGS	Elementary Diagram Main Generation System Generator & Transformer Primary Protection Unit Tripping	4
01-E-MAB-010	Elementary Diagram Main Generation System Generator & Transformer Back-up Protection Unit Tripping	8
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01-E-NHA-001	Single Line Diagram 480V Non-Class 1E Power System Motor Control Center 1E-NHN-M13	21
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NUMBER	TITLE	REVISION
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Condition Report/Disposition Reports (CRDR)

2715726	2716011	2715941
2715667	2715659	2715768
2715709	2715727	2715731
2715749	2716281	2715669

Miscellaneous Documents:

NUMBER	TITLE	REVISION/DATE
	Security Computer Alarm logs for June 14, 2004	
	Security Access Transaction Records for June 14, 2004	
	Day Shift Security Department Logs for June 14, 2004	
	Sally Port Vehicle Barrier Operating Instructions, as posted on June 14, 2004	
	Sally Port Vehicle Barrier Operating Instructions, revised on June 17, 2004	
	PVNGS Emergency Plan, Table 1, “Minimum Staffing Requirements for PVNGS for Nuclear Power Plant Emergencies”	28

Miscellaneous Documents:

NUMBER	TITLE	REVISION/DATE
WO# 2623863	Monthly Inspection of TSC DG Battery and Battery Charger	June 9, 2004
WO# 2715869	Perform the Restrike Test for the TSC Diesel Generator	June 16, 2004
	APS Letter Robert Smith to N. Bruce et al., Final Report for the 2002 Palo Verde /Hassayampa Operating Study	June 5, 2002
	2003-04 Winter Palo Verde Unit 2 Uprating Net Generating Capacity of 1408MW for Updated Final Safety Analysis Report	November 2003
Procedure No. PVTS-01	Palo Verde Transmission System Interchange Scheduling and Congestion Management Procedure, Revision 8	November 30, 2003
	PVNGS Technical Specifications, Through Amendment No. 150,	November 21, 2003, Corrected December 12, 2003
	NRC Letter M Fields to G. Overbeck APS, Palo Verde Nuclear Generating Station Units 1, 2 and 3 – Issuance of Amendments Re: Changes Related to Double Sequencing and Degraded Voltage Instrumentation (TAC Nos. MA4406, MA4407, and MA4408)	
	APS Letter 102-04310-WEI/SAB/RKR, Response to NRC Request for Additional Information Regarding Proposed Amendment to Technical Specifications (TS) 3.8.1, AC Sources-Operating and 3.3.7, Diesel Generator (DG)-Loss of Voltage Start (LOVS),	July 16, 1999

Miscellaneous Documents:

NUMBER	TITLE	REVISION/DATE
	10CFR 50.59 Screening and Evaluation, Revise the Updated Final Safety Analysis Report, Technical Specifications, and Technical Specifications Bases to enhance the means of complying with the requirements of Regulatory Guide 1.93 for offsite power sources	0
	10CFR 50.59 Screening and Evaluation, S-04-0009, Updated Transmission Grid Stability Study: Salt River Project 20031126 (LDCR 2003F040)	0
	Visual Examination of Welds report number 04-250, component 1-CH-GCBA 1 WOOA	
	Visual Examination of Welds report number 04-250, component 1 CHN-F36 Purification Filter	
	Palo Verde Nuclear Generating Station Design Basis Manual, EW System	16
	Palo Verde Nuclear Generating Station Design Basis Manual, SP System	13
	PV Unit 2 Archived Operator Log 06/14/2004, 12:10:47 a.m., through 06/15/2004, 11:10:30 p.m.	
Bulletin 74-09	Deficiency in General Electric Model 4 kV Magne-Blast Breakers	August 6, 1974
Information Notice 84-29	General Electric Magne-Blast Circuit Breaker Problems	April 17, 1984
Information Notice 90-41	Potential Failure of General Electric Magne-Blast Circuit Breakers and AK Circuit Breakers	June 12, 1990
Information Notice 93-26	Grease Solidification Causes Molded Case Circuit Breaker Failure to Close	April 7, 1993

Miscellaneous Documents:

NUMBER	TITLE	REVISION/DATE
Information Notice 93-91	Misadjustment Between General Electric 4.16-kV Circuit Breakers and Their Associated Cubicles	December 3, 1993
Information Notice 94-02	Inoperability of General Electric Magne-Blast Breaker Because of Misalignment of Close-Latch Spring	January 7, 1994
Information Notice 94-54	Failures of General Electric Magne-Blast Circuit Breakers to Latch Closed	August 1, 1994
Information Notice 95-22	Hardened or Contaminated Lubricants Cause Metal-Clad Circuit Breaker Failure	April 21, 1995
Information Notice 96-43	Failures of General Electric Magne-Blast Circuit Breakers	August 12, 1996
	Unit 3 4 Pt Trend chart, “Core Differential Pressures for Loops 1A, 1B, 2A, 2B”, start time 07:41:15 through 07:41:45	
	Unit 1 4 Pt Trend chart, “Letdown System Temperature and Flow,” start time 6/14/04 07:40:00 through 6/14/04 09:40:00	
	PV Unit 1 and Unit 3 Archived Operator Logs 6/14/2004 1:30 a.m. through 6/15/2004 5:35 a.m.	
Calculation 13-MC-CH-508	CVCS Letdown Heat exchanger to Purification Filters, Unit 1 350 F Temperature Event During Plant Trip of 6-14-04	
90-AF-011	Engineering Evaluation Request	
92-SG-007	Engineering Evaluation Request	
	Control Room Log Books	

Procedures:

NUMBER	TITLE	REVISION/DATE
40EP-9EO07	Loss of Offsite Power/Loss of Forced Circulation	10
40EP-9EO10	Standard Appendices	33
40OP-9CH01	CVCS Normal Operations	35
40OP-9SG01	Main Steam	37
20SP-OSK08	Compensatory Measures for the Loss of Security Equipment Effectiveness	27
21SP-OSK11	Security Contingencies	13
20DP-OSK29	Security System Testing	27
EOP 40EP-9E O07	Loss of Offsite Power/Loss of Forced Circulation	10
EPIP-01	Satellite Technical Support Center Actions	14
EPIP-01	Satellite Technical Support Center Actions	15
EPIP-99	EPIP Standard Appendices, Appendix C, “Forms”	1
EPIP-99	EPIP Standard Appendices, Appendix D, “Notification”	1
EPIP-99	EPIP Standard Appendices, Appendix H, “Autodialer Activation”	1
20SP-OSK08	Compensatory Measures for the Loss of Security Equipment Effectiveness	27
21SP-OSK11	Security Contingencies	13
20DP-OSK29	Security System Testing	27
41AL-1RK6B	Panel B06B Alarm Responses, “Mn Gen Neg Seq Pre-Trip	32

01-P-CHF-201	Auxiliary Building Isometric Chem, Volume Control System Letdown Heat Exchanger	June 2, 1998

LIST OF ACRONYMS

ac	alternating current
ADAMS	Agency-Wide Documents Access and Management System
ADV	atmospheric dump valve
AFW	auxiliary feedwater system
AIT	Augmented Inspection Team
APS	Arizona Public Service Company
APS-ECC	APS Energy Control Center
CCDP	conditional core damage probability
CRDR	condition report/disposition request
DNBR	departure from nucleate boiling ratio
EDG	emergency diesel generator
EHV	extra high voltage
EOP	Emergency Operating Procedure
EPIP	Emergency Plan Implementing Procedure
ESF or Safety	Engineering Safeguards Features
°F	degrees Fahrenheit
FWCS	feedwater control system
GTG	gas turbine generators
kV	Kilovolt
kW	kilowatt
LOCA	loss of coolant accident
LOFW	loss-of-feedwater
LOOP	loss-of-offsite-power
MSIS	main steam isolation signal
MSSVs	main steam safety valves
NOUE	Notice of Unusual Event
PCB	power circuit breaker
PPCS	pressurizer pressure control system
PVNGS	Palo Verde Nuclear Generating Station
RCP	reactor coolant pump
RPCS	reactor pressure control system
RRS	reactor regulating system
SBCS	steam bypass control system
SPAR	Standardized Plant Analysis Risk
SRP	Salt River Project
TSC	Technical Support Center
TDAFW	turbine-driven auxiliary feedwater
URI	unresolved item
WSCC	Western System Coordinating Council
V	volt
Vac	volts alternating current

ATTACHMENT 2

AUGMENTED INSPECTION TEAM CHARTER

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

June 15, 2004

MEMORANDUM TO: Anthony T. Gody, Chief
Operations Branch
Division of Reactor Safety

FROM: Bruce Mallett, Regional Administrator /RA/

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER; PALO VERDE NUCLEAR GENERATING STATION, UNITS 1, 2, AND 3, COMPLETE LOSS OF OFFSITE POWER AND MULTIPLE MITIGATING SYSTEM FAILURES

In response to the complete loss of all offsite power sources, the trip of all three units, and the Unit 2 Emergency Diesel Generator "A," failing to function as required at Palo Verde Nuclear Generating Station on June 14, 2004, an Augmented Inspection Team is being chartered. There was no impact to public heath and safety associated with the event. You are hereby designated as the Augmented Inspection Team (AIT) leader.

A. Basis

On June 14, 2004, at 9:45 a.m. CDT, all offsite power supplies to the Palo Verde Nuclear Generating Station were disrupted, with a concurrent trip of all three units. Additionally, the Unit 2 Emergency Diesel Generator "A" failed to function as required. As a result, the licensee declared a Notice of Unusual Event (NOUE) for all three units at about 9:50 a.m. CDT and elevated to an Alert for Unit 2 at 9:54 CDT. The licensee and NRC resident inspectors also reported a number of other problems, including the failure of Unit 2 Charging Pump "E," the failure of a Unit 3 steam bypass control valve, multiple breakers failing to operate during recovery operations, and emergency response facility and security interface issues which may have impeded emergency responders. This event meets the criteria of Management Directive 8.3 for a detailed follow up inspection, in that, it involved multiple failures to systems used to mitigate an actual event. The initial risk assessment, though subject to some uncertainties, indicates that the conditional core damage probability was in the range of high E-4. Because the initial risk assessment was in the range for consideration of an AIT and because of multiple failures in systems used to mitigate an actual event, it was decided that an AIT is the appropriate NRC response for this event.

The AIT is being dispatched to obtain a better understanding of the event and to assess the responses of plant equipment and the licensee to the event. The team is also tasked with reviewing the licensee's root-cause analyses.

Attachment 2

B. Scope

Specifically, the team is expected to perform data gathering and fact-finding in order to address the following:

1. Develop a complete sequence of events related to the loss-of-offsite power, the multiple unit trips, and the Unit 2 emergency diesel generator failure.

2. Assess the performance of plant systems in response to the event, including any design considerations that may have contributed to the event.

3. Assess the adequacy of plant procedures used in response to the event.

4. Assess the licensee's response to the event, including operator actions and emergency declarations, and any emergency response facility or security interface issues that may have adversely affected response to the event.

5. Assess the licensee's determination of the root and/or apparent causes of offsite power loss, emergency diesel generator failure, and other mitigating system(s) failures.

6. Based upon the licensee's cause determinations, review any maintenance related actions which could have contributed to the event initiation or produced subsequent response problems.

7. Review the licensee's assessment of coordination activities with offsite electrical dispatch organizations prior to and during the event.

8. Provide input to the regional Senior Reactor Analyst for further assessment of risk significance of the event.

C. Guidance

The Team will report to the site, conduct an entrance meeting, and begin inspection no later than June 16, 2004. A report documenting the results of the inspection should be issued within 30 days of the completion of the inspection. While the team is on site, you will provide daily status briefings to Region IV management. The team is to emphasize fact-finding in its review of the circumstances surrounding the event, and it is not the responsibility of the team to examine the regulatory process. The team should notify Region IV management of any potential generic issues identified related to this event for discussion with the Program Office. Safety concerns that are not directly related to this event should be reported to the Region IV office for appropriate action.

For the period of the inspection, and until the completion of documentation, you will report to the Regional Administrator. For day to day interface you will contact Dwight Chamberlain, Director, Division of Reactor Safety. The guidance in Inspection Procedure 93800, “Augmented Inspection Team,” and Management Directive 8.3, “NRC Incident Investigation Procedures,” apply to your inspection. This Charter may be modified should the team develop significant new information that warrants review. If you have any questions regarding this Charter, contact Dwight Chamberlain at (817) 860-8180.

Distribution:
B. Mallett
T. Gwynn
J. Dixon-Herrity
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N. Salgado
G. Warnick
J. Melfi

ATTACHMENT 3

Sequence of Events

Electrical Sequence of Events

07:40:55.747	Fault #1 inception Fault #1 type = C-N Fault #1 cause/location = Phase down (broken bells) reported near 115th Ave. & Union Hills (WW-LBX Line) At Westwing, the Liberty line relays operated properly and issued a trip signal. Incorporated in this scheme is a Westinghouse high-speed "AR" auxiliary tripping relay that is used to "multiply" that trip signal toward both trip coils of two breakers (WW1022 & WW1126). The "AR" relay failed (partially) and issued the trip signal to breaker WW1126 only. Since the trip signal was never successfully issued to WW1022, breaker failure for WW1022 was also never initiated (this would have cleared the Westwing 230 kV West bus and isolated the fault). Therefore, the "remote" ends of all lines feeding into the 500 kV and 230 kV yards were required to trip to isolate the fault.
07:40:55.814	4.0 cycles after fault #1 inception WW1126 opened (LBX / PPX 230 kV crossover breaker)
07:40:55.822	4.5 cycles after fault #1 inception LBX1282 opened (Westwing 230 kV Line)
07:40:56.115	22.1 cycles after fault #1 inception AFX732 & AFX735 opened (Westwing 230 kV Line)
07:40:56.122	22.5 cycles after fault #1 inception YP452 & YP852 opened (Westwing 500 kV Line)
07:40:56.136	23.3 cycles after fault #1 inception WW1426 & WW1522 opened (Agua Fria 230 kV Line)
07:40:56.142	23.7 cycles after fault #1 inception WW856 & WW952 opened (Yavapai 500 kV Line)
07:40:56.165	25.1 cycles after fault #1 inception DV322 & DV722 & DV962 opened (Westwing 230 kV Line)
07:40:56.172	25.5 cycles after fault #1 inception WW1726 & WW1822 opened (Deer Valley 230 kV Line)
07:40:56.196	26.9 cycles after fault #1 inception RWYX482 & RWYX582 & RWYX782 opened (Westwing 230 kV Line) (Waddell 230 kV Line) (230/69 kV Transformer #8)

07:40:56.515	46.1 cycles after fault #1 inception WW1222 opened (Pinnacle Peak 230 kV Line)
t = unknown	Surprise Lockout "L" operated (230/69 kV Transformer #4 Differential & B/U Over-Current)
07:40:56.548	48.1 cycles after fault #1 inception SC622 & SC922 & SC262 opened (Surprise 230/69 kV Transformer #4)
07:40:57.549	108.1 cycles after fault #1 inception SC1322 opened (Westwing 230 kV Line)
07:40:57.800	123.2 cycles after fault #1 inception RWP-CT2A opened (Redhawk Combustion Turbine 2A)
07:40:57.807	123.6 cycles after fault #1 inception RWP-ST1 opened (Redhawk Steam Turbine 1)
07:40:57.814	124.0 cycles after fault #1 inception RWP-CT1A opened (Redhawk Combustion Turbine 1A)
07:40:58.339	155.5 cycles after fault #1 inception RIV762 opened (Westwing 69 kV Line)
07:40:58.372	157.5 cycles after fault #1 inception HH762 opened (Westwing 69 kV Line)
t = unknown	Westwing Lockout "AK" operated (230/69 kV Transformer #11 Differential & B/U Over-Current)
07:40:59 (EMS)	WW2026 & WW2122 opened (Westwing 230/69 kV Transformer #11 - High Side)
07:40:59.272	211.5 cycles after fault #1 inception WK362 opened (Westwing 69 kV Line)
07:40:59.489	224.5 cycles after fault #1 inception HAAX935 & HAAX938 opened (Hassayampa - Arlington 500 kV Line) (Time stamp provided by SRP)
07:41:00 (EMS)	WW862 & WW962 & WW1362 opened (Westwing 230/69 kV Transformer #11 - Low Side)
07:41:00.392	278.7 cycles after fault #1 inception WW752 opened (South 345 kV Line)
07:41:01.982	Fault #1 type changed = B-C-N

07:41:02.144	383.8 cycles after fault #1 inception PSX832 closed auto (Perkins Cap-Bank Bypass) (Time stamp provided by SRP)
07:41:02.154	Fault #1 type changed = C-N
07:41:02.799	Fault #1 type changed = B-C-N
07:41:03.966	493.1 cycles after fault #1 inception SC562 opened (McMicken 69 kV Line)
07:41:05.373	577.6 cycles after fault #1 inception MQ562 opened (McMicken 69 kV Line)
07:41:07.849	12.102 seconds after fault #1 inception HAAX922 & HAAX925 opened (Palo Verde 500 kV Line #2) (Time stamp provided by SRP)
07:41:07.851	12.104 seconds after fault #1 inception PLX972 & PLX975 opened (Hassayampa 500 kV Line #2) (Time stamp provided by SRP)
07:41:07.859	12.112 seconds after fault #1 inception HAAX932 opened (Palo Verde 500 kV Line #1) (Time stamp provided by SRP)
07:41:07.875	12.128 seconds after fault #1 inception PLX982 & PLX985 opened (Hassayampa 500 kV Line #3) (Time stamp provided by SRP)
07:41:07.878	12.131 seconds after fault #1 inception HAAX912 & HAAX915 opened (Palo Verde 500 kV Line #3) (Time stamp provided by SRP)
07:41:07.880	12.133 seconds after fault #1 inception PLX942 & PLX945 opened (Hassayampa 500 kV Line #1) (Time stamp provided by SRP)
07:41:08.104	Fault #1 type changed = A-B-C-N
07:41:10.445	14.698 seconds after fault #1 inception NV1052 & NV1156 opened (Westwing 500 kV Line)
07:41:10.456	14.709 seconds after fault #1 inception WW556 & WW652 opened (Navajo 500 kV Line)
07:41:12 (EMS)	WW424J opened (Westwing 230 kV West Bus Reactor)

07:41:20.005	24.258 seconds after fault #1 inception PLX992 opened (Devers 500 kV Line) (PLX995 out-of-service at this time) (Time stamp provided by SRP)
07:41:20.113	24.366 seconds after fault #1 inception PLX932 & PLX935 opened (Rudd 500 kV Line) (Time stamp provided by SRP)
07:41:20.145	24.398 seconds after fault #1 inception RUX912 & RUX915 opened (Palo Verde 500 kV Line) (Time stamp provided by SRP)
07:41:20.864	25.117 seconds after fault #1 inception PLX912 & PLX915 opened (Westwing 500 kV Line #1) (Time stamp provided by SRP)
07:41:20.873	25.126 seconds after fault #1 inception WW1456 & WW1552 opened (Palo Verde 500 kV Line #2)
07:41:20.874	25.127 seconds after fault #1 inception WW1156 & WW1252 opened (Palo Verde 500 kV Line #1)
07:41:20.895	25.148 seconds after fault #1 inception PLX922 & PLX925 opened (Westwing 500 kV Line #2) (Time stamp provided by SRP)
07:41:23.848	28.101 seconds after fault #1 inception PLX988 opened (Palo Verde Unit-3) (Time stamp provided by SRP)
07:41:24.280	System Frequency = 59.514 Hz (Measured at APS Reach Substation)
07:41:24.641	28.894 seconds after fault #1 inception PLX918 opened (Palo Verde Unit-1) (Time stamp provided by SRP)
07:41:24.652	28.905 seconds after fault #1 inception PLX938 opened (Palo Verde Unit-2) (Time stamp provided by SRP)
07:41:25 (DOE)	ED4-122 & ED4-322 opened (DOE ED4 Substation) Tripped on under-frequency (Note frequency low at 07:41:24.280)
07:41:25 (EMS)	ML142, ML542, ML1042 & ML1442 opened (Moon Valley 12 kV Feeders) Tripped on under-frequency (Note frequency low at 07:41:24.280)
07:41:28 (DOE)	MEX794 closed auto (Mead Cap Bank bypass)

07:41:34.615	38.868 seconds after fault #1 inception MEX1092 & MEX1692 opened (Perkins - Westwing 500 kV Line) Fault #1 cleared
07:42:22.773	System Frequency = 59.770 Hz (Measured at APS Reach Substation)

ATTACHMENT 4

Sequence of Events

Unit 1 Sequence of Events

0741	Startup Transformer# 2 Breaker 945 Open Excessive Main Generator and Field Currents Noted Engineered Safeguards Features Bus Undervoltage Loss of Offsite Power Load Shed Train "A" and "B" Emergency Diesel Generator Train "A" and "B" Start Signal Low Departure from Nucleate Boiling Ratio Reactor Trip Master Turbine Trip Main Turbine Mechanical Over Speed Trip Emergency Diesel Generator “A” Operating (10 Second Start Time) Emergency Diesel Generator “B” Operating (13 Second Start Time*)
0751	Manual Main Steam Isolation System Actuation
0758	Declared Notice of Unusual Event (loss of essential power for greater than 15 minutes)
0810	Both Gas Turbine Generator Sets Started, #1 GTG is supplying power to NAN S07
0813	Closed 500 k 552-942. The East bus is powered from Hass #1
0838	Restored power to Startup Transformer X01
0844	Restored power to Startup Transformer X03
0855	Fire reported in 120 ft Aux building. Fire brigade confirmed that no fire existed but paint was heated causing fumes. Later it was confirmed that fumes were caused by the elevated temperature of the letdown heat exchanger when it failed to isolate.
0900	HI Temp Abnormal Operation Procedure entered for Letdown heat exchanger outlet temperature off scale high.
1002	Reset Generator Protective Trips (volts/hertz; Backup under-frequency) Palo Verde Switchyard Ring Bus restored
1159	Paralleled DG B with bus and cooled down engine restoring the in house buses
1207	Emergency Coordinator terminated NUE for all three units
1248	Paralleled DG A with bus and cooled down
2209	Noted grid voltage greater than 535.5 volts Shift Manager Coordinated with ECC
6/15	
0005	Restored CVCS letdown per Std Appendix 12 started Chg Pump ‘A’

0155	Established RCP seal injection and controlled bleed off
0241	Started 2A RCP, had to secure due to low running amps other two units had RCP's running (what were the amps at the time) exiting of EOP delayed due to switchyard conditions
0305	Exited Loss of Letdown AOP after restoration of letdown per Standard App. 12 of EOP's
0345	Palo Verde Switchyard E-W voltage at approx. 530.7 kV
0818	Started RCP's 2A and 1A
0920	Started RCP's 2B and 1B
0930	Exited EOP 40EP- 9E007 Loss of Offsite Power/Loss of Forced Circulation

ATTACHMENT 5

Sequence of Events

Unit 2 Sequence of Events

0740	4.16 kV Switchgear 3 Bus Trouble Alarm Generator Negative Sequence Alarm 4.16 kV Switchgear 4 Bus Trouble Alarm
0741	Main Transformer B Status Trouble Alarm Main Transformer A Status Trouble Alarm ESF Bus Undervoltage Channel A-2 ESF Bus Undervoltage Channel B-2 LOP/Load Shed B ESF Bus Undervoltage Channel B-3 DG Start Signal B LOP/Load Shed A ESF Bus Undervoltage Channel A-4 DG Start Signal A LO DNBR Channels A, B, C, & D Trip RPS Channels A, B, C, & D Trip Main Generator 500 kV Breaker 935 Open Mechanical Overspeed Trip of Main Turbine
0751	Manually initiated Main Steam Isolation Signal
0755	Declared an Alert for Loss of All Offsite Power to Essential Busses for Greater than 15 minutes
0901	Energized 13.8 kV Busses 2E-NAN-S03 and 2E-NAN-S05
0927	Energized 4.16 kV Bus 2E-PBA-S03
0951	Exited Alert
1001	Energized 13.8 kV Bus 2E-NAN-S01
1024	Energized 13.8 kV Bus 2E-NAN-S02
1132	Started Charging Pump A
1618	Engineering and Maintenance review concluded that Charging Pump E was available for service after fill and vent
1714	Started Charging Pump E
1716	Started RCP 1A
1722	Started RCP 2A
1806	Stopped RCPs 1A and 2A on low motor amperage. ECC contacted to adjust grid voltage as-low-as-possible

2040 Started RCPs 1A and 2A

2051 Stopped RCPs 1A and 2A on low running amperage

6/15

0400 Started RCPs 1A and 2A

0610 Exited Emergency Operating Procedures

ATTACHMENT 6

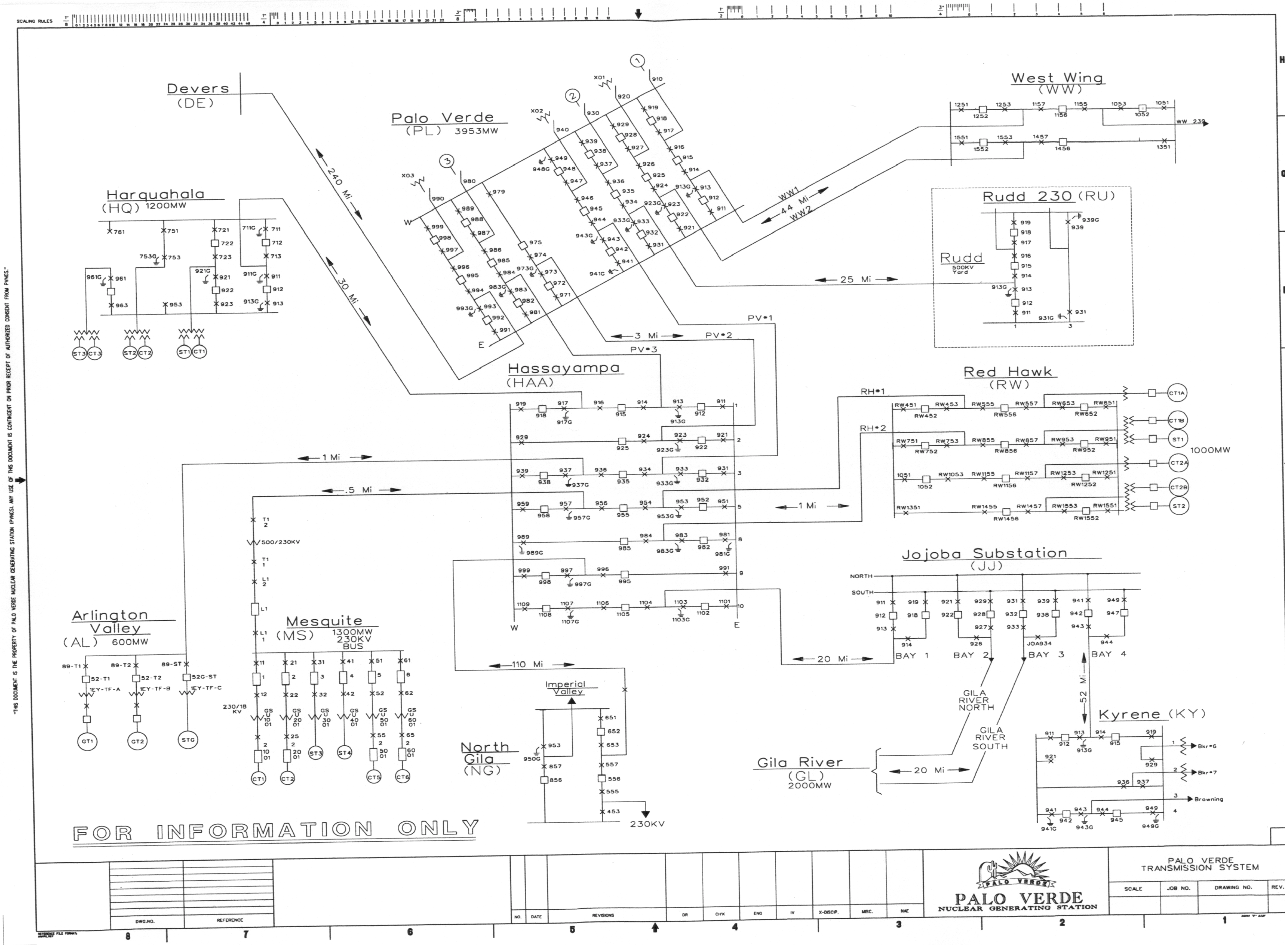
Sequence of Events

Unit 3 Sequence of Events

0740	Generator Under Voltage Negative Sequence Trip Master Turbine Trip 3ENANS01 Bus Under Voltage Reactor Trip Circuit Breakers Open
0741	Exciter Voltage Regulator Mode Change Unit 3 Main Generator 500 kV Breaker 985 Opens Engineered Safeguards Features Bus Undervoltage Loss of Offsite Power Load Shed A and B Emergency Diesel Generator A and B Start Signal Main Turbine Overspeed Mechanical Trip Turbine Bypass Valves Quick Open
0742	Low Steam Generator Pressure Alarm Unit 3 Main Generator 500 kV Breaker 988 Opens
0743	Automatic Main Steam Isolation on Low Steam Generator Pressure
2341	Started Reactor Coolant Pump 1A
2345	Started Reactor Coolant Pump 2A
6/15	
0040	Exited Emergency Operating Procedures
1637	Started Reactor Coolant Pump 1B
6/16	
0207	Started Reactor Coolant Pump 2B

ATTACHMENT 7

Offsite Power Electrical Diagram



Devers
(DE)
Palo Verde
(PL) 3953MW
West Wing
(WW)
WW 230
Rudd 230 (RU)
Rudd
500KV
Yard
Harquahala
(HQ) 1200MW
240 Mi
30 Mi
25 Mi
WW1
44 Mi
WW2
PV#1
PV#2
PV#3
3 Mi
Hassayampa
(HAA)
Red Hawk
(RW)
RH#1
RH#2
1000MW
1 Mi
.5 Mi
500/230KV
Jojoba Substation
(JJ)
NORTH
SOUTH
BAY 1
BAY 2
BAY 3
BAY 4
20 Mi
52 Mi
GILA
RIVER
NORTH
GILA
RIVER
SOUTH
Gila River
(GL)
2000MW
Kyrene (KY)
Bkr#6
Bkr#7
Browning
Arlington
Valley
(AL) 600MW
Mesquite
(MS) 1300MW
230KV
BUS
230/18
KV
110 Mi
Imperial
Valley
North
Gila
(NG)
230KV
FOR INFORMATION ONLY
PALO VERDE
NUCLEAR GENERATING STATION
PALO VERDE
TRANSMISSION SYSTEM
SCALE
JOB NO.
DRAWING NO.
REV.
NO.
DATE
REVISIONS
DR
CHK
ENG
IV
X-DISCIP.
MISC.
NAE
DWG.NO.
REFERENCE