ELECTRICAL DISTRIBUTION SYSTEM

DESIGN ASSESSMENT

May 22, 1989

Prepared by: F.R. Denslow FOR S.L.K 5/22/89

Reviewed by: John T. Barrow, Jr.

Approved by: Edward C. Stark

Concurred by: J. Allen

ELECTRICAL DISTRIBUTION SYSTEM DESIGN ASSESSMENT

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In response to NRC concerns regarding PVNGS electrical distribution system design adequacy and reliability, particularly as it relates to involvement in complicated reactor trips and/or natural circulation cooldown, Arizona Public Service Company (APS) has completed an evaluation of the historical performance of this system, as documented herein, with recommendations for enhancement modifications.

A review of PVNGS reactor trip history reveals that the Fast Bus Transfer (FBT) scheme has functioned as designed during plant trips initiated at power levels up to 100% reactor power. On four occasions natural circulation entry has occurred when FBT did not take place; however, three of these events involved circumstances under which FBT operation would not be reasonably expected. The fourth resulted in a design modification to enhance FBT performance. Coastdown of the turbine-generator and Reactor Coolant Pumps (RCPs), with subsequent blocking of FBT, has resulted in natural circulation cooldowns and complicated recovery actions.

An examination of electrical distribution system alignment and/or design alternatives was performed to identify potential enhancements, and has resulted in the following three-part action plan:

1) Operate with one RCP bus powered from the Unit Auxiliary Transformer and with the other RCP bus powered from the Startup Transformer.

2) Revise the FBT scheme to initiate bus transfer upon the receipt of signals from the Subsynchronous Oscillation (SSO) relays and the generator back-up distance relays.

3) Provide direct tripping of the reactor in the event of any turbine-generator trip, as well as evaluate the feasibility of disabling Steam Bypass Control System (SBCS) and Reactor Power Cutback System (RPCS) operation above some reactor power level to be established.

APS is still evaluating the SSO relay operation experienced at PVNGS Unit 3 on March 3, 1989; however, interim actions pending completion of this evaluation have been established. They include adding these relays to the FBT scheme, and using digital fault recorders to assist in future diagnostic activities.

APS has determined that other electrical distribution system relays have not unreasonably contributed to historical reactor trips or their complexity.

APS has evaluated the vendor-recommended maintenance for electrical distribution system equipment and has identified six items which are considered mandatory precursors to unit restart. These items are in addition to other required maintenance, such as Equipment Qualification-related activities.

Furthermore, APS has initiated a long-term electrical distribution system evaluation project. This multi-phase project incorporates a historical, industry-wide nuclear plant and electrical system reliability evaluation; studies on specific current issues such as 'Station Blackout', 'Relay Coordination', and 'Lightning Protection'; and a detailed design bases review of the current electrical distribution system. All of the above are being conducted to enhance PVNGS design, reliability, availability, and safety.

ANALYSIS AND EVALUATION

PVNGS REACTOR TRIP HISTORY

Introduction

APS reviewed unanticipated, automatic PVNGS reactor trips to determine "lessons learned" from complicated trips; special emphasis was placed on natural circulation cooldowns and events that involved operation of the Fast Bus Transfer (FBT) scheme. Reactor trips occurring as a result of power ascension tests were included if the reactor trip occurred upon receipt of an unanticipated protective signal. APS excluded planned and manual reactor trips from consideration (including planned natural circulation tests) to ensure that the "lessons learned" depend upon PVNGS equipment and personnel response to unforeseen events.

Summary Analysis

Fifty-three (53) PVNGS reactor trips met the criteria for the "lessons learned" evaluation. Table 1 (Attachment 1) identifies these reactor trips in chronological order, the Unit involved, associated Licensee Event Report (LER) number and title, operating mode, reactor power at the time of the event, and whether the reactor trip involved natural circulation cooldown or FBT operation. The following bullets summarize the data contained in Table 1:

- Of the 53 reactor trips evaluated, 35 involved Unit 1 (66 percent); 16 involved Unit 2 (30 percent); and 2 involved Unit 3 (4 Percent).

- Of the 53 reactor trips evaluated, 47 (89 percent) occurred from operating Mode 1 (Power Operation); 1 (2 percent) occurred from Mode 2 (Startup); 3 (6 percent) occurred from Mode 3 (Hot Standby); and 2 (4 percent) occurred from Mode 5 (Cold Shutdown). The Mode 3 and Mode 5 events are reactor trip events because the Reactor Trip Switchgear (RTSG) opened; reactor power was at zero percent in each case. These events were included not only for completeness, but because one of the trips from Mode 3 also involved natural circulation cooldown.

- Of the trips evaluated, 7 (13 percent) involved entry into a natural circulation cooldown. As stated above, one of these occurred in Mode 3; the remaining six occurred in Mode 1. APS has estimated

the time spent in natural circulation based on post-trip documentation.. The natural circulation duration during these events has varied from approximately 43 minutes to approximately 12 hours 25 minutes. The mean natural circulation duration predicted from these PVNGS trips is 2 hours 4 minutes, if the longest duration event is excluded from the calculation, or 3 hours 33 minutes if it is included. An analysis of these natural circulation events is provided below.

- Of the 53 reactor trips, 30 (57 percent) occurred while the house loads for the affected unit were being fed from the Startup Transformers; therefore, no attempt was made to initiate an FBT. For 11 (21 percent) of the events, APS has not determined the electrical distribution system alignment at the time of the reactor trip. The unavailability of this data is not considered crucial to this evaluation because of the following:

    a) Had failure of the FBT scheme occurred during these events, the failure would have been reported in the documentation or the failure would have manifested itself as a natural circulation event.

    b) If each of these 11 events is assumed to have occurred while house loads were powered from the Startup Transformers, the number of FBT attempts would be underestimated, and the reliability of FBT as estimated from these events would be conservative.

- Of the 53 reactor trips, FBT was attempted but did not occur on 4 (8 percent) occasions; however, FBT was attempted and did occur during another 7 (13 percent) of the events. In an additional event, FBT occurred for one bus, but the feeder breaker for the other bus from the Unit Auxiliary Transformer (UAT) failed to trip. (The LER for this event does not provide a definitive root cause for the breaker failing to trip.) Of the 7 completely successful FBTs, 6 occurred during reactor trips from 99-100 percent reactor power and the seventh occurred during a trip from 50 percent reactor power. This data does not indicate low FBT reliability. Rather, it indicates that any concerns with FBT design should be limited in nature.

Natural Circulation Events

The following provides a brief summary of each of the seven PVNGS natural circulation events that occurred during unanticipated, automatic reactor trips. The role of the FBT scheme during these events is also described.

September 12, 1985

PVNGS Unit 1 was in Mode 1 at 53 percent reactor power when a main generator output breaker was opened to initiate a planned load rejection test. APS anticipated that the turbine would reduce speed and maintain house loads; however, the Electro Hydraulic Control (EHC) system did not maintain turbine control and main generator frequency decreased. The RCPs were being powered from the main generator along with other house loads, via the UAT. A reactor trip occurred when protective devices sensed the coastdown of the RCPs and projected an unacceptable RCS condition (i.e., a low Departure from Nucleate Boiling Ratio (DNBR)). The reactor trip generated a turbine trip and, as generator speed continued to decrease, the RCP breakers opened as designed. Fast transfer of the RCPs to the offsite power source did not occur because of the low frequency on the RCP buses. The duration of natural circulation for this event was 2 hours 19 minutes. Restoration of forced RCS flow was delayed because the charging pumps which supply RCP seal injection had become gas-bound due to inaccurate Volume Control Tank (VCT) level indication and control. As a result of the lessons learned from this event, design changes were implemented in all 3 PVNGS Units to preclude a similar loss of VCT level and gas binding of the charging pumps.

October 3, 1985

PVNGS Unit 1 was in Mode 1 at 52 percent reactor power when a reactor trip occurred due to a low DNBR condition projected by all 4 Core Protection Calculators (CPCs). At the time of this event the RCP buses were being powered from offsite via the NAN-S05 and NAN-S06 buses, as required in preparation for a subsynchronous resonance test. An apparent malfunction of the Plant Multiplexer (PMUX) caused 13.8 kv startup switchyard breakers to open and the resultant loss of power led to RCP coastdown and reactor trip. The duration of natural circulation for this event was 3 hours 34 minutes. To prevent recurrence, the switchyard breakers affected by the apparent PMUX malfunction were hardwired, bypassing the PMUX breaker control.

October 7, 1985

PVNGS Unit 1 was in Mode 3, at zero percent reactor power, with the RCS at approximately 2250 psia and 565 degrees Fahrenheit, and with the part-length and shutdown Control Element Assemblies (CEAs) withdrawn in preparation for startup. Troubleshooting was being conducted on the PMUX to determine the cause of the problem which led to the reactor trip on October 3, 1985. Another apparent PMUX malfunction occurred, resulting in a loss of offsite power to the RCP buses and a reactor trip on the loss of forced RCS flow as sensed by steam generator differential pressure instrumentation. The duration of natural circulation for this event was 44 minutes. To prevent recurrence, the switchyard breakers affected by the apparent PMUX malfunction were hardwired, bypassing the PMUX breaker control.

January 9, 1986

PVNGS Unit 1 was in Mode 1 at 100 percent reactor power, with the Reactor Power Cutback System in "Auto-Actuate-Out-of-Service," when a turbine trip and subsequent reactor trip

were initiated as part of a scheduled power ascension program test. The turbine trip was initiated by manual actuation of the unit differential generator protection relay. The 525-kV generator output breakers opened as designed but, due to a sensed frequency mismatch between the UAT and the offsite power source, a synchronization check relay blocked the anticipated FBT. Reactor trip occurred due to a CPC-projected low DNBR condition, rather than on an anticipated high pressurizer pressure condition. The duration of natural circulation for this event is 43 minutes. Following this event and on an interim basis, the Unit was operated with house loads aligned to the Startup Transformers. The design and operation of the synchronization check relay was reviewed by APS and an enhanced design was incorporated into the PVNGS FBT scheme.

July 12, 1986

PVNGS Unit 1 was in Mode 1 at 100 percent reactor power, when a reactor trip occurred upon the Plant Protection System (PPS) sensing low RCS flow through steam generator #2. Although this reactor trip was generated by 2-out-of-4 coincidence logic circuitry, subsequent investigation revealed that an actual low RCS flow condition did not exist. Rather, the PPS setpoints were close to the safety analysis limits and did not provide sufficient operating margin to preclude this type of event. At that time the undervoltage relays on the 13.8-kV NAN-S03 and NAN-S04 buses were set at 95.65 percent of rated signal voltage and, immediately following the reactor trip, the undervoltage relays sensed a grid perturbation. (The Transmission Control Center indicated that grid voltage can vary as much as 5 percent, placing nominal grid voltage within the range of the trip setpoint.) RCP buses NAN-S01 and NAN-S02 were load shed from NAN-S03 and NAN-S04, placing Unit 1 in a natural circulation cooldown. The duration of natural circulation for this event was 1 hour 23 minutes. Corrective actions have included the establishment of new PPS and undervoltage relay setpoints.

July 6, 1988

PVNGS Unit 1 was in Mode 1 at 100 percent reactor power when phase "B" of the 13.8-kV NAN-S02 bus faulted to ground, immediately followed by ground faults on the other 2 phases. The feeder breaker to the bus did not immediately trip because protection is afforded by a time-overcurrent scheme. The time-overcurrent protection was set to trip in 0.7 second (42 cycles) on a 3-phase fault; however, the UAT also experienced a fault and began to fail at 12 cycles. The UAT ruptured and caught fire. The RCPs were being powered from the UAT, and FBT could not be achieved because of frequency and voltage mismatches due to the ground faults. The duration of natural circulation for this event was 12 hours 25 minutes. Recovery of forced circulation cooling for the RCS was dependent upon the actions necessary to restore power to the RCPs safely, given the nature and extent of damage to the electrical distribution system.

March 3, 1989

PVNGS Unit 3 was in Mode 1 at approximately 98 percent reactor power, when the main generator output breakers opened. A Reactor Power Cutback occurred as designed; howev-

er, the control system for 4 of the 8 Steam Bypass Control System valves did not operate properly and the reactor tripped on steam generator #2 low pressure. Certain Engineered Safety Features (ESF) actuations occurred (e.g., Safety Injection) so 2 RCPs were tripped in accordance with plant operating procedures. The RCPs were being powered from the Unit Auxiliary Transformer at the time, and their power did not automatically fast transfer to the offsite power source because of the degrading frequency and voltage as main generator speed decreased. The two operating RCPs tripped on electrical protection. The duration of natural circulation for this event was 3 hours 42 minutes. Operation of subsynchronous protective relaying resulted in the opening of the main generator breakers. The APS investigation of the root cause for relay operation is ongoing (see Subsynchronous Oscillation (SSO) Relay Scheme section for details).

Discussion

Of the 7 natural circulation events, 3 (43 percent) were initiated while the RCPs were powered from the Startup Transformers; therefore, FBT was not attempted. The remaining 4, (57 percent) natural circulation events involved an attempted FBT which did not succeed because of mismatched frequency or voltage on the affected buses.

The three events that occurred while power was supplied to house loads from the Startup Transformers include the October 3 and October 7, 1985, and July 12, 1986, Unit 1 reactor trips. As indicated in the event summaries above, the Unit was aligned to offsite power on October 3, 1985, in preparation for a subsynchronous resonance test; on October 7, 1985, because the Unit was in Mode 3 with the UAT out-of-service; and on July 12, 1986, pending review of the FBT scheme following the January 9, 1986, event. Since the Unit was powered from offsite during these three events, it was vulnerable to natural circulation upon loss of offsite power.

The four natural circulation events which occurred while the RCPs were powered from the UAT include the September 12, 1985, January 9, 1986, July 6, 1988, and March 3, 1989, reactor trips. The July 6, 1988, event involved more than one electrical ground fault and resulted in the UAT rupturing and catching fire. Clearly FBT would not be expected to occur during this event because of the extent of electrical distribution system problems. Additionally, the January 9, 1986, event involved an attempted FBT which was blocked by a synchronization check relay. The design and operation of the synchronization check relay was reviewed by APS and an enhanced design was incorporated into the PVNGS FBT scheme.

The remaining two events (i.e., the September 12, 1985, and March 3, 1989, events) are the most significant in terms of identifying potential electrical distribution system enhancements. In both cases the main generator output breakers opened, disconnecting the main generator from the switchyard. Under such circumstances, the plant's control systems (e.g., Reactor Power Cutback System, Steam Bypass Control System, Turbine Electro Hydraulic Control System, etc.) should reduce reactor and turbine power such that house loads are continuously supplied from the main generator via the UAT. The plant should arrive at a stable operating plateau with all systems in balance and with the RCPs maintaining forced RCS cir-

culation.

Although the plant control systems have operated properly on other occasions, even preventing reactor trips, they did not achieve and maintain a stable condition during the September 12, 1985, and March 3, 1989, events. On September 12, 1985, the turbine EHC system did not maintain turbine speed, causing main generator frequency to decay. The RCPs were still connected to the main generator at the time and the reactor tripped when the protection system sensed the RCPs slowing down. On March 3, 1989, the control systems (principally the Steam Bypass Control System) could not maintain an adequate balance between primary and secondary systems, and the reactor tripped on low steam generator pressure. In both cases the main generator had coasted down as designed and had slowed sufficiently such that FBT would have been blocked.

The goal of this evaluation is to *enhance* the PVNGS ac electrical distribution system, over and above the current license basis, to prevent complicated trips. The identification of alternatives and the selection of options is described in the Electrical Distribution Alignment & Design Alternatives section of this report.

ELECTRICAL DISTRIBUTION ALIGNMENT & DESIGN ALTERNATIVES

Introduction

APS examined the PVNGS electrical distribution system to identify conceivable, alternative distribution alignments and design changes (particularly protective relaying modifications). The purpose of this review was to minimize natural circulation cooldowns, by maintaining a reliable source of power to the RCP buses. The following ten alternatives were identified as a result of this activity:

- Alternative 1 - Operate with both NAN-S01 and NAN-S02 aligned to the Unit Auxiliary Transformer.
- Alternative 2 - Operate with both NAN-S01 and NAN-S02 aligned to redundant Startup Transformers.
- Alternative 3 - Operate with both NAN-S01 and NAN-S02 aligned to a single Startup Transformer.
- Alternative 4 - Operate with one RCP bus powered from a Startup Transformer and the other RCP bus powered from the Unit Auxiliary Transformer.
- Alternative 5 - Modify the SSO relay to initiate FBT, and power the RCPs from the Unit Auxiliary Transformer.
- Alternative 6 - Disable the RPCS and SBCS functions, while powering the RCPs from the Unit Auxiliary Transformer or Startup Transformer(s).
- Alternative 7 - Combine Alternative 2 with the SSO relay modification of Alternative 5.
- Alternative 8 - Combine Alternative 3 with the SSO relay modification of Alternative 5.
- Alternative 9 - Combine Alternative 4 with the SSO relay modification of Alternative 5.
- Alternative 10 - Disable all non-direct turbine-generator trips.

Evaluation of Alternatives

Of the ten alternatives listed above, APS determined that only three were viable options: the others either violated regulations, contained internal contradictions, or did not provide reliability improvement. The three viable Alternatives are Alternatives 1, 4, and 5. Alternative 5 was expanded to include two phases, "a" and "b".

Phase "a" will be comprised of a change to the initiation requirements of the turbine and reactor trip sequences. The tripping of the generator breakers will initiate a turbine trip which in-turn will initiate a reactor trip, when the plant is operating above an as-yet-to-be-determined reactor power level. Phase "b" will be comprised of modifying the FBT circuitry to initiate FBT upon receipt of SSO relay signals.

Avoidance of complicated trips was determined to be at least as important as avoidance of reactor trips and/or natural circulation events. On this basis, Alternative 5 was determined to be the preferred Alternative.

Alternative 1 exposes the plant to complicated trips due to its reliance on FBT, RPCS, and SBCS, on generator trip events. Alternative 4 requires additional operator monitoring of electrical distribution system interactions, as well as its reliance on FBT for the RCP bus aligned to the Unit Auxiliary Transformer. This also leads to undue complexity, which is preferably avoided for a permanent solution.

Implementation

Alternative 5 is to be implemented in two phases. Although it also relies on FBT, it minimizes natural circulation by initiating FBT at the first indication of a potential disturbance affecting the power supply to the RCPs. Figure 1 is provided to clarify the implementation schedule of Alternative 5 in its entirety.

FIGURE 1
Implementation of Alternative 5

COMPENSATORY	PHASE 1	PHASE 2
Restart	Interim	Final

Until Alternative 5 can be implemented Alternative 4, to power two RCPs from the Unit Auxiliary Transformer and two from a Start-up Transformer, will be employed. This alignment practically excludes natural circulation entry for initiating events that do not involve the Start-up Transformer. It also prevents tripping two PVNGS Units upon an initiating event involving one Start-up Transformer, as would happen if RCPs for all three Units RCPs were powered from the preferred (offsite) power source. The current design and license bases for PVNGS are not affected for restart.

The first phase to be implemented is Alternative 5(b), that is, initiate FBT upon receipt of signals from the SSO relays and generator back-up distance relays. This interim modification is currently being designed as a Design Change Package(DCP) with a target issue date of June 1, 1989. It will then be implemented either at the next refueling outage of each unit or sooner, if possible. Operation of the Units without this DCP does not present a challenge to any design bases, since Alternative 4 virtually precludes natural circulation as well as other complicated trips.

The second phase to be implemented is Alternative 5(a), the use of RPCS and SBCS up to some predetermined, but as yet undetermined (e.g.,50-60 percent reactor power) power level. The exact level will be determined upon completion of a detailed engineering study of the RPCS, SBCS, Feedwater Control System(FWCS) and the Plant Protective Systems PPS. Among the factors to be considered in the study are system interactions and human responses to plant transients (e.g., a main feedwater pump trip).[1] Once the exact level is determined, the RPCS and SBCS would be kept out of service whenever the reactor is at or above this level. In order to achieve this the turbine tripping scheme would be modified to operate on the tripping of the generator breakers and the PPS would be modified to initiate a direct reactor trip upon a turbine trip. Operation of the Units without this portion of Alternative 5 does not present a challenge to any design bases, since Alternatives 4 and 5(b) virtually preclude natural circulation and other complicated trips.

SUBSYNCHRONOUS OSCILLATION (SSO) RELAY SCHEME

Design Basis Review

APS included the SSO relays in the original plant design to protect the turbine generators from the adverse affects of subsynchronous resonance (SSR). SSR has caused catastrophic failures of turbine-generators. The original design for the SSO relay tripping scheme was to sense a SSR event. isolate the turbine-generator, and permit continued operation of the reactor, turbine, and generator to supply the house loads. March 3, 1989. in Unit 3, SSO relay operation initiated a chain of events that led to coastdown of the RCPs, resulting in a reactor trip and natural circulation cooldown. This event is discussed below with alternatives to enhance the SSO relay scheme.

All three PVNGS Units are equipped with two SSO relays. Operation of either or both of the relays will initiate the opening of the 525-kV breakers. Opening these breakers isolates the main generator from the 525-kV transmission system. The application and setting of SSO relays at PVNGS was a result of extensive modeling, testing, and analysis.

The SSO relay settings for each PVNGS Unit is different to prevent simultaneous tripping of all three Units. During the occurrence of one SSR event, the isolation of one Unit will detune the electrical system; therefore, the other two Units would not be expected to trip. At PVNGS, the Unit 3 SSO relays are set to be the most sensitive, then Unit 2 and Unit 1, respectively. Unit 1 trips last, since its control room contains the switchyard mimic bus, the use of which may be necessary following an SSR trip event to prevent a joint Unit/switchyard transient control room response requirement.

PVNGS has experienced two Unit trips involving operation of the SSO relays. The first trip occurred on January 10, 1987, in Unit 1. The "1A" SSO relay had an internal design problem in its phase-lock-loop circuitry, that generated a false trip action which isolated the Unit 1 turbine-generator from the 525-kV transmission system. APS worked with the SSO relay manufacturer, Westinghouse, to resolve the phase-lock-loop circuitry problem..

The second trip occurred on March 3, 1989, in Unit 3. Printouts from the Plant Monitoring System indicate that an SSO relay-initiated trip signal opened the main generator 525-kV breakers. Initial investigation and analysis of a simulation of the condition on the 525-kV transmission system, at the time of the event, indicated that the SSO relay should not have operated. Functional tests performed on the SSO relays at PVNGS showed no apparent failure of either relay. Based on these findings, "bench" tests were performed on the SSO relay circuit boards. The results of these tests did not indicate component malfunction or failure.

Since test results of the Unit 3 SSO relays themselves have not identified the cause of the SSO relay/relays operation, APS investigated possible sources of erroneous signals to the SSO relays. The turbine-generator Power System Stabilizer (PSS) was reviewed as a possible source of erroneous input signals to the SSO relay. A malfunction of the PSS could generate a signal which could cause SSO relay operation; however, test results indicate that the PSS is not a likely source for the problem. Additionally, APS is testing the noisy generator

current transformer circuits as a potential source of an erroneous signal. APS is also monitoring the Unit 3 SSO relay performance in its plant environment with a synthetic stimulus (i.e., a stimulus that simulates the input to the relays at the time the Unit 3 SSO relay operation occurred) being applied during the refueling outage. Upon discovery of the cause of improper SSO relay operation, APS will take action to reduce or eliminate recurrence

Based on experience and analysis, an SSO relay operation will occur in the future. The possibility of going into complicated trip situations (such as natural circulation) for these events must be minimized. This possibility can be minimized by realigning the power supplies to the reactor coolant pumps as discussed in the Electrical Distribution Alignment Alternative sections. In addition, 5 alternative actions have been identified as long term means to minimize the negative impacts of a SSO relay operation, to enhance the capability to identify the cause of a SSO relay operation, and to improve SSO relay security. These alternatives are described in the following sections. A summary of these alternatives is contained on Figure 2.

FIGURE 2
Evaluation of SSO Relay Design Alternatives

ALTERNATIVE NUMBER	DESCRIPTION	ACTION	COMPLETION DATE Unit 1	Unit2	Unit3
1	Initiate and implement design change to include initiation of fast bus transfer for SSO relays operations	Issue design change pkg	6/15/89	6/15/89	6/15/89
		Implement desighn change	Next Scheduled Refueling		
2	Initiate and implement design change to provide for SSO relay quantities to be recorded on digital fault recorders	Issue Temporary Mod	cmplt	cmplt	cmplt
		Implement Temporary Mod	------------restart--------------		
		Issue design change pkg	1/1/90	1/1/90	1/1/90
		Implement design change pkg	Next Scheduled Refueling		
3	Initiate and implement design change to provided a voltage reference circuit which will allow only that target initiated by the relay operation to be displayed	Issue Temporary Mod	cmplt	cmplt	cmplt
		Implement Temporary Mod	------------restart-------------		
		Issue design change package	1/1/90	1/1/90	1/1/90
		Implement design change pkg	Next Scheduled Refueling		
4	Initiate and implement design change to revise SSO relay tripping logic	NONE-See Analysis/ SSO Relays			
5	Initiate and implement design change to disable the SSO relay tripping scheme	NONE-See Analysis /SSO Relays			

Note: RF is Refueling Outage

Analysis

The following subsections describe potential SSO relay enhancement alternative. APS determined that the following alternatives are viable. These subsections describe the logic behind the decision to inplement or not.

Alternative 1

Initiate and implement design changes to include initiation of fast bus transfer for SSO relay action. This is not a restart item since the alternate alignment of the reactor coolant pumps (described in Identification of Electrical Distribution Alignment Alternatives section of this report) addresses the complicated reactor trip/natural circulation concerns. This enhancement will be completed during the next refueling outages for the three units.

Alternative 2

Initiate and implement design changes to provide for SSO relay quantities to be recorded on digital fault recorders. This change will be implemented in Unit 2 prior to restart and in Units 1 and 3 during the current refueling outages via a temporary modification. The temporary modification will provide identical information on the SSO relay as will the design change package. The scope of the design change package includes many other areas; therefore, requiring additional evaluation prior to completion.

Alternative 3

Initiate and implement design change to modify the existing voltage reference circuit so it will allow only that target initiated by the relay operation to be displayed. This change will be implemented in Unit 2 prior to restart, and in Units 1 and 3 during the current refueling outage on a temporary mod. This modification provides immediate indication of the section of the SSO relay that operated. The modification providing for digital fault recording capability for the SSO relays, alternative #2, will provide the same information; however, this information is not immediately available. The design change package completion will be given appropriate priority, scheduled and worked as indicated in Figure 2.

Alternative 4

Initiate and implement a design change to revise the SSO relay tripping logic. This alternative is not considered as a desirable option at this time. This proposed modification will not necessarily reduce significantly the probability an event similar to the Unit 3 trip in March 3,1989.. The actual cause of the Unit 3 relay operation is, and may continue to be, unknown. APS believes the cause could either be a result of an intermittent component failure in the relay or a noise problem in the system. For a noise problem in the system a logic modification would have no positive effect . In addition, a logic modification could reduce the probability of tripping for an actual SSR event since the scheme would have to be more complex (i.e. more than one relay would have to operate to protect the units from the hazards of a SSR event).

Alternative 5

Initiate and implement a design change to disable the SSO relay tripping scheme. This would make all three units vulnerable to an SSR event, which could result in catastrophic failures of the turbine-generators. Detailed studies, simulations, and tests have justified, based on the probability of a SSR event occurring, that SSO relay tripping schemes are required on each unit, as second contingency protection. First contingency protection is not required.

EVALUATION OF THE RELIABILITY OF OTHER RELAYS AT PVNGS

Introduction

APS reviewed the list of PVNGS unanticipated reactor trips, especially those that resulted in an entry into Natural Circulation,. to identify trips in which *relay problems* were determined to be the root cause of, or a contributor to, the event. The purpose of this evaluation was to confirm that the logic configuration of the *other power system relays* did not unreasonably contribute to those trips or trip complexity.

Summary Analysis of Relay Contribution to Reactor Trip

A total of 53 PVNGS reactor trips met the criteria for this evaluation; of these, 10 reactor trips or 9 events (one event involved the tripping of two units) were considered to be relay failure/misoperation related. Two of the Unit trips resulted from SSO relay problems and are addressed in the Subsynchronous Oscillation (SSO) Relay Scheme section of this report. This leaves a total of seven events due, in part,. to other relay problems. The following sections summarize those seven events:

December 4, 1985

Unit 1 was in mode 1 at 54 percent power when a reactor trip occurred due to Low Departure from Nucleate Boiling Ratio (DNBR). All four channels of Core Protection Calculators actuated; the trip was attributed to a high penalty factor being inserted by the Control Element Assembly Controller due to the dropping of sub-group 12 (part length control element assemblies). All equipment functioned as designed and no safety system actuated. No Technical Specification [Tech.Spec.] limits were exceeded.

During the resultant turbine-generator trip, bus 1ENAN-S02 experienced a momentary loss of voltage. This was subsequently attributed to a dip of the supply voltage, caused by the loss of Main Generator output from the system in combination with a less than optimal tap setting of the Startup Transformer (SUT) supplying 1ENAN-S06, S04 and S02. No disturbance was encountered on buses 1ENAN-S05, S03 and S01. APS reset the (SUT) tap settings to the same value as the other (SUT) feeding the unaffected buses.

This problem was setting related and did not involve relay failure. All equipment and protective devices functioned as designed. Natural Circulation entry was avoided.

January 9, 1986

Unit 1 was in mode 1 at 100 percent power when a turbine trip and subsequent reactor trip were initiated as part of a scheduled power ascension test program test. The turbine trip was initiated by manual actuation of the unit generator differential protection relay. Fast bus transfer (FTB) from the Unit Auxiliary Transformer (UAT) to offsite power was blocked by a frequency mismatch between onsite and offsite power. Upon the loss of RCP power, Natural Circulation was initiated.

The device which inhibited the transfer block was the Sync Check relay which performed as designed during a subsequent investigation; APS found no indication of malfunction of FBT devices: Sync Check reset time (1.5 sec) may have been the primary contributor to this anomaly..

An engineering investigation determined that the original Sync Check relay, an electro-mechanical induction type, was not suitable for high-speed, bus transfer applications because of slow performance characteristics. Consequently, APS replaced the Sync Check relay with a high-speed, solid-state device.

May 31, 1986

Unit 2 was increasing in power when the Turbine Generator (TG) set tripped at approximately 35 percent power. Approximately 12 seconds after the TG trip, the reactor tripped on high pressurizer pressure (all 4 PPS channels tripped). RPS response times were within required values. Safety functions were maintained and the event was classified as an uncomplicated reactor trip. The SBCS did not prevent the reactor trip, due to master controller not being in REMOTE AUTO, but it did support the subsequent cool-down. Natural circulation was not entered.

The event initiator was the TG trip on negative sequence current. The actual cause has not been determined, but it is believed to be false operation of the phase current imbalance protection relay. The relays performed as designed during post trip diagnostics; however, pre-trip alarms had been received during the week prior to the event and PR&C had been involved in troubleshooting.

July 12, 1986

PVNGS unit 1 was in Mode 1 at 100 percent power, when a reactor trip occurred on low RCS flow as indicated by Steam Generator #2 differential pressure. APS determined that an actual RCS low flow condition did not exist: rather the PPS setpoints did not provide sufficient operating margin to preclude this event. The undervoltage relays on the 13.8KV NAN-S03 and NAN-S04 buses were set at 95.65 percent of rated system voltage and immediately following the reactor trip, the undervoltage relays sensed a dip in the grid voltage. RCP buses

NAN-S01 and NAN-S02 were shed on undervoltage placing unit 1 in a Natural Circulation cooldown.

The Systems Operations Department indicated that the grid voltage can normally vary as much as five percent, which places the nominal grid voltage within the range of the UV trip setpoint. As a result, APS lowered the relay settings temporarily 2.5 percent to 93.2 percent of rated voltage and initiated an investigation of the system grid and plant distribution models to determine a permanent relay setting.

August 6, 1986

Unit 2 was operating at seven percent reactor power when water from a leaky valve resulted in a fault/failure of load center NAN-S02. Subsequently, the SUT, NAN-X03, feeding both units 2 & 1 tripped on differential current resulting in the loss of two RCPs and consequent trip of each unit.. A current transformer (CT) was later found to have failed, (the project's failure history for CT is consistent with nuclear industry history, as given in IEEE std. 500-1984). All other devices operated acceptably. Natural Circulation entry was avoided during the course of the event in both units.

September 2, 1986

Unit 1 experienced a reactor trip on Steam Generator (SG) low flow (RPS channels B and D). Following the reactor trip, the TG tripped and a generator coastdown trip occurred shedding 13.8KV bus NAN-S02. A fast bus transfer occurred maintaining power to the RCPs. The loss of NAN-S02 was attributed to an undervoltage relay (type 227-1) trip under voltage transient conditions. Natural Circulation cooldown entry was avoided.

The problem has been corrected; relay setting of the undervoltage (UV) relay was changed to 90 percent of rated voltage from the previous 95.6 / 93.2 percent values to inhibit undervoltage trips during grid disturbances. As a result of the actions taken here, reactor trips from this cause have not recurred.

April 16, 1987

Unit 2 was operating at 100 percent power when a reactor trip and turbine trip occurred due to interaction between the RPS system, CPCs and troubleshooting of a suspected ground fault in the B train 120V AC (class IE) system. Natural Circulation entry was avoided.

A relay problem was encountered during the recovery actions. This problem involved an overcurrent trip of loadcenter breaker 2ENGNL08B2, when no faults (i.e.: overcurrent) were present. APS found that the shunt trip (SST) device in the breaker protection circuit was defective due to silicon controlled rectifier (SCR) leakage. Replacement of the breaker/SST device completed action on this item.

Conclusion and Action Plan

Two of the eight events (25 percent of relay-related trips or 4 percent of all trips) considered to have been affected by other relay problems resulted in unanticipated entry into Natural Circulation. These two events involved Fast Bus Transfer and Undervoltage (UV) Trip problems. Both of these trips occurred in Unit 1. APS has taken corrective actions which provide a reasonable assurance that these problems have been resolved.

Of the other Reactor trips, where Natural Circulation was *not* entered one trip was complicated by Undervoltage relay actuation under transient conditions (corrective activities conducted as a result of this event also resolved the problems identified in the UV trip-Natural Circulation event addressed above). Another trip involved a possible maintenance induced scram during troubleshooting. Another trip occurred during postcore power ascension testing, and involved SUT tap settings. Three events, involving four reactor trips, were the result of *random* component failures/spurious actuations. A Phase Current Imbalance relay in the Main Generator Protection System, a CT in SUT X03 and a SST overcurrent device in a non IE Load Center

Based on the historical data presented above, APS has determined that modifications to Power System relaying design are not warranted. The corrective actions taken to date have minimized the potential for a recurrence of those problems deemed preventable. The relay-related problems that resulted in entry into Natural Circulation have been essentially eliminated.

Random failures cannot be absolutely prevented; the use of a multiple (redundant) relay logic schemes would add significantly to the cost and complexity of the relay systems with little (if any) gain in reliability. Given the minimal consequences of the random relay failures to date, changes to the existing Generator, SUT, or Load Center Protection systems are not justified.

As discussed in the preceding section, the investigation regarding upgrades/betterments to the SSO relay system is continuing.

LONG TERM EVALUATION

History

APS initiated this evaluation February 1989 to coordinate a number of PVNGS projects and ensure compatibility of recommended enhancements. The evaluations and results documented in this Electrical Distribution Design Assessments report are one part of phase 1 of the long term evaluation.

Overview

Currently, APS is coordinating a number PVNGS studies and evaluations to enhance power system reliability. This effort is comprised of the following four Phases:

Phase 1 - Evaluation of PVNGS performance on its own base and against the industry, including a thorough review of possible distribution alignment and protection configurations

Phase 2 - Incorporation of the results of the Electrical Reliability Studies

Phase 3 - Incorporation of the results of the Engineering Excellence Program 1E System Reviews

Phase 4 - Incorporation of the results of the Engineering Excellence Program non-1E System Reviews

Summary

PHASE 1 - PVNGS Unit Trip Study

APS, under Phase 1, is reviewing all PVNGS plant trips and evaluating Electrical Distribution System involvement. This data will be compared with statistics from other US nuclear plants. The PVNGS unit trips will be evaluated to determine severity of electrical system contributing factors. The contribution of the Electrical Distribution system will be grouped into one of the following four categories:

1) Electrical Root Cause - Root cause determined to be entirely electrical
2) Other Root Cause - Non-electrical root cause resulting in a unit trip as a result of an electrical contributing cause
3) Electrical Problem-not a cause - Electrical problems related to plant trips
4) No Electrical Involvement

The PVNGS trip data will be compared with industry trip data to determine if PVNGS is experiencing a higher number of trip incidences involving the Electrical Distribution system than the industry. The following four comparisons will be made:

1) PVNGS Electrical Trips vs. PVNGS Total Unit Trips
2) PVNGS Trips vs. other Bechtel-GE Plants (licensed since 1980)
3) PVNGS Trips vs. all Region 5 Plants
4) PVNGS Trips vs. US Plants(licensed since 1980)

The PVNGS Electrical Distribution system will be evaluated to determine any unique system design characteristics. If unique characteristics are identified they will be reviewed for any impacts they may have had on reactor trips. The PVNGS design will be compared with other Bechtel plants using similar designs.

As noted above, the results of this Electrical Distribution System Design Assessment report is also included in the long term evaluation phase 1.

PHASE 2 - PVNGS Electrical Reliability Studies

As a result of recent events at PVNGS, the following additional studies have been initiated:

- Electrical Power Systems Reliability Study As a result of failures experienced in the non-class 1E power systems in the Power Block and the 525 kV Switchyard, APS initiated a reliability analysis. APS is coordinating this effort between APS and SRP to perform this reliability analysis and recommend any enhancements to improve the reliability of the power systems.

- Station Blackout Study In accordance with the requirements delineated in 10CFR 50.63 Station Blackout, APS evaluated PVNGS using guidance from NUMARC 87-00 document, "Guidelines and Technical bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors", except where Regulatory Guide 1.155 takes precedence.

- Relay Setting/Coordination Evaluation In response to IE Notice 88-45, "Problems in Protective Relay and Breaker Coordination", APS is reviewing the relay setting and coordination efforts at PVNGS.

- Lightning Evaluation Due to the January 1989 Unit 2 ESF transformer failures, APS performed an evaluation to determine if lightning was the root cause or a contributing factor. APS completed a lightning protection design evaluation July 28,1986. This evaluation was initiated in response to INPO Significant Event Report (SER) No.84-76.

- Fast Bus Transfer Design Review Following the March 3, 1989, Unit 3 trip during which a Fast Bus Transfer did not occur, APS initiated an evaluation of the Fast Bus Transfer design.

PHASE 3 - Q Electrical Systems

The Engineering Excellence Program (EEP) system review working groups for the Q class electrical systems will factor the findings of the Phase 2 report into the evaluation of the design basis review and their overall review findings into the Phase 3 report. The Q class electrical systems are as follows:

- PB - Class 1E 4.16-kV Power System
- PE - Class 1E Standby Generation System
- PG - Class 1E 480-V Power Switchgear System
- PH - Class 1E 480-V Power MCC System
- PK - Class 1E 125-v DC Power System
- PN - Class 1E Instrument AC Power System

PHASE 4 - Non-Q Electrical Systems

The Engineering Excellence Program system review working groups for the Non-Q electrical systems will factor the findings of the Phase 2 report into the evaluation of the design basis review and their overall review findings into the Phase 4 report. The Non-Q class electrical systems are as follows:

- MA - Main Generation System
- MB - Excitation and Voltage Regulation System
- NA - Non-Class 1E 13.8-kV Power System
- NB - Non-Class 1E 4.16-kV Power System
- NG - Non-Class 1E 480-V Power Switchgear
- NH - Non-Class 1E 480-V Power MCC System
- NK - Non-Class 1E 125-V DC Power System
- NN - Non-Class 1E 120-V Instrument AC Power System
- NQ - Non-Class 1E 120-V Uninterruptible AC Power System

Completion

APS will issue a report at the completion of each Phase. The schedule completion dates for these reports are subject to change based on completion of the individual activities included in that Phase . The current scheduled completion dates and Report outputs are listed below.

06/01/89 Phase 1 - Lessons Learned
- Preliminary Recommendations for Consideration

07/14/89 Phase 2 - Lessons Learned
- Recommendations for Implementation

03/12/91 Phase 3 - Refinement of Phase 2 Recommendations

08/05/93 Phase 4 - Refinement of Phase 2 Recommendations

Phases 3 and 4 are considered to be confirmatory and additional lessons-learned information. The results of phases 3 and 4 will provide in-depth review of the plant changes required or recommended during Phases 1 and 2.

ELECTRICAL DISTRIBUTION SYSTEM MAINTENANCE

Introduction

Arizona Public Service Company (APS) conducted a thorough investigation of the PVNGS Electrical Distribution System maintenance requirements. This investigation consisted of review of the vendor instruction and maintenance manuals to identify pertinent functional criteria and maintenance recommendations for system components. Functional criteria are the tasks required to be performed (whether performed recently or not) prior to the restart of a unit. APS determined the functional criteria based on the operational history of specific critical electrical system components or engineering recommendations (IEEE and other established standards). These functional criteria may exceed the normal preventive maintenance requirements and scope.

APS compared the maintenance recommendations and functional criteria with the current electrical preventive maintenance program. The implementation schedules of these tasks were reviewed to determine the overall technical adequacy of the current PVNGS Electrical Distribution System Maintenance Program.

APS reviewed the PVNGS restart activities related to Electrical Distribution System maintenance recommendations and functional criteria, including immediate and future enhancements. This review included safety analyses as applicable to the maintenance program.

The following report describes the scope, methods used, and results of the investigations described above.

Discussion

APS reviewed PVNGS Electrical Distribution System vendor instruction and maintenance manuals to identify vendor-recommended preventive maintenance. This review included the following Electrical Distribution Systems:

- 525-kV system (in-plant switchyard area only)
- 24-kV system (system designator MA)
- 13.8 kV system (system designator NA)
- 4.16-kV system (system designators NB and PB)
- 480-V load centers (system designators NG and PG)
- 480-V motor control centers (system designators NH and PH)
- 120-V power and instrumentation (system designators NN and PN)
- 125-VDC power and instrumentation (system designators NK & PK)
- Miscellaneous electrical components associated with the Fast Bus Transfer (FBT) and the Reactor Power Cutback System (RPCS).

APS reviewed the vendor-recommended maintenance and PVNGS operational history for critical electrical system equipment and components to determine the functional criteria. APS identified the six restart requirements described in the following subsections (a through f):

(a) Cleaning of all exposed high (525-kV ac) and medium (24 and 13.8 kV) voltage insulators, bushings and lightning arrestors.

APS identified cleaning of all high and medium voltage insulators, bushings, and lightning arrestors as a restart requirement based on the electrical flashover incidents experienced on the Unit 2 Engineered Safety Features (ESF) transformer, and on the Unit 3 main transformer. Based on investigation and analysis results, APS determined that the above flashovers resulted from the accumulation of salt drift contaminants (from the cooling towers and evaporative ponds) and the presence of a misting rain; lightning at the time of the incidents may also have contributed to the flashovers. Exposed Plant insulators, bushings, and lightning arrestors will be cleaned prior to restart of any PVNGS unit.

(b) Lubrication and cycling of FBT associated breakers

APS identified lubrication and cycling of Fast Bus Transfer breakers as a restart requirement, since the failure of one of the Unit 1 Auxiliary Transformer Y-winding, feeder breakers (13.8 kV breaker 1ENANS01) to trip after a reactor/turbine trip caused an incomplete fast bus transfer sequence. The failure of the breaker to trip was caused by coil failure, or failure of the mechanical linkages in the breaker. APS reviewed the maintenance history for the above breaker and found no previous failures had been experienced; however, scheduled maintenance had been waived twice consecutively just prior to the failure due to operational considerations. APS has not yet determined if waiving the scheduled maintenance contributed to the failure of the breaker to trip; however, performance of the scheduled maintenance may have identified potential or existing problems. The FBT breakers E-NAN-S01A, E-NAN-S02A, E-NAN-S03B & E-NAN-S04B will be inspected, lubricated, and cycled prior to restart of any PVNGS unit.

(c) Oil sample evaluation from large oil-filled transformers

APS identified sampling and evaluating oil from large, oil-filled transformers as a restart requirement based on manufacturers recommendations. Oil samples will be evaluated to determine the current oil characteristics and possible degradation which could inhibit per-

formance and lead to transformer failure. Oil samples will be taken from the large, oil-filled transformers (Main, Start-up, Auxiliary, Normal Service & ESF) and tested prior to restart of any PVNGS unit.

(d) <u>Inspect Large Oil-Filled Transformers and the Salt River Project (SRP) Cascade Potential Transformer for Oil Leaks</u>

APS identified inspecting large, oil-filled transformers (including the SRP cascade potential transformer) for oil leaks as a restart requirement since oil leaks from large, oil-filled transformers may reflect or lead to transformer operational problems. Transformer oil leaks can lead to low transformer oil level and failure, including fire and explosion. Large, oil-filled transformers, including the SRP cascade potential transformer will be inspected for oil leaks prior to restart of any PVNGS unit.

(e) <u>Verify Proper Operation of the Dehydrating Breather filter on the Main Transformer</u>

APS identified verification of proper operation of the dehydrating breather filter on the main transformer as a restart requirement, since filter saturation can cause degraded transformer performance or failure. The dehydrating breather filter of the main transformer removes moisture from transformer intake air. When saturated with moisture, the dehydrating material in the breather should be replaced. Over-saturation may eventually lead to transformer failures or inadequate performance. Proper operation of the dehydrating breather filter on the main transformer will be verified prior to restart of any PVNGS unit.

(f) <u>Performance of a Service Test on the Non-1E Battery System</u>

APS identified performance of a service test on the Non-1E Battery System as a restart requirement to verify the ability of the system to satisfy design requirements (battery duty cycle). The non-1E batteries provide control power to a multitude of breakers and protective relays. Improper operation of these breakers or relays could affect plant performance and reliability. The service test is one of the recommendations of IEEE standard 450 (IEEE Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Substations). A service test of the Non-1E Battery System will be conducted prior to restart of any PVNGS unit.

Review of PVNGS PM Tasks and Scheduled Implementation

APS compared the maintenance recommendations described above with the existing Electrical System Preventive Maintenance Program. This comparison indicated that the existing Preventive Maintenance Program for the Electrical System equipment reviewed technically meets or exceeds vendor recommendations.

APS has developed a Preventive Maintenance schedule to ensure that the restart requirements listed in the preceding paragraphs are completed prior to restart of any PVNGS unit.

The identified PM tasks and functional criteria do not provide relief from the Equipment Qualification (EQ) related special maintenance requirements. These Special Maintenance Requirements are provided in the PVNGS Equipment Qualification List (EQL), a controlled document which provides required maintenance directions for electric equipment within the scope of 10 CFR 50.49.

Review of PVNGS Design Changes Impacting PM Tasks

APS reviewed current PVNGS design changes that affect the PM tasks. This review indicated that due to the flashover occurrences (subsection (a)) a design change package (DCP # 1,2 & 3FE-NA-041) has been initiated to install creepage extenders on the ESF transformers. This change will help minimizing the flashover incidents and will extend the maintenance intervals for the clean-up of the bushings. The ESF transformer bushing creepage extenders installation is scheduled prior to a unit restart.

A design clarification currently being implemented at PVNGS is the installation of a drip loop on conductors connected to the ESF transformer bushings. This drip loop will prevent water carrying salt drift contaminants from running down the conductors onto the bushings; thereby, helping to minimize flashover incidents. Installation of the drip loops on the ESF Transformer is scheduled prior to unit restart.

In addition to the immediate enhancements described above, a long-term study is being initiated to investigate the possibility of adding special insulator coatings which could also have a measurable effect on minimizing the flashover incidents and prolong the maintenance intervals.

CONCLUSION

The review of vendor-recommended preventive maintenance combined with the review of the existing Electrical Distribution System Preventive Maintenance Program indicates that the existing program technically meets or exceeds the vendor-recommended requirements. The maintenance requirements and functional criteria identified in the preceding sections will be performed prior to unit start-up to assure reliable operation of the Electrical Distribution system. In the future, the existing Preventive Maintenance Program in combination with the pro-

posed design and procedural changes will be sufficient to assure enhanced operational reliablity of the Electrical Distribution system.

CONCLUSIONS AND ACTION PLAN

Conclusions

APS review and evaluation of the reactor trip history on PVNGS (specifically complicated trips and natural circulation events) with electrical systems scheme involvement, has resulted in a recommended enhancement action plan which, when implemented, will help in the minimizing of complicated reactor trips and the preclusion of natural circulation events. This review and evaluation focused primarily on electrical control and protection schemes in particular, with direct or indirect reactor trip involvement, and on the electrical distribution system alignment and reliability in general. The specific areas of the above study included: identification of electrical distribution alignment alternatives, subsynchronous oscillation (SSO) relays, evaluation of the reliability of other relays at PVNGS and the electrical distribution system maintenance. The followings summary includes the review and evaluation conclusions for each of the above specific areas:

Identification of Electrical Distribution Alignment Alternatives

Of the ten identified electrical distribution alignment alternatives, APS determined that one alternative is most feasible for minimizing natural circulation and complex trips. This alternative entails a change to the initiation requirements of a turbine trip and a reactor trip when the plant is operating above a predetermined reactor power level. The turbine trip will be initiated by the tripping of the generator breakers and the turbine trip will intiate a reactor trip. It will also include the initiation of a FBT upon the receipt of SSO relays signals. As a compensatory measure, in all three unit, one of the unit's reactor coolant pump buses will be supplied by the UAT and the other reactor coolant pump bus will be supplied from the SUT.

Subsynchronous Oscillation (SSO) relays

Of the five identified SSO relays operation enhancement alternatives, APS has determined that only three of the alternatives are presently desirable means to minimize the negative impact of an SSO relay operation and to improve SSO relay security, thus minimizing complicated reactor trip situations. The three proposed recommendations are:

- Initiate and implement design change to include initiation of FBT for SSO re lay operation; also add diverse reactor trip in a second phase.
- Initiate and implement design change to provide for SSO relay quantities to be be recorded on digital fault recorders
- Initiate and implement design change to provide a voltage reference circuit which will only allow the target initiated by the relay operation

to be displayed

Evaluation of The Reliability of Other Relays at PVNGS

Based on this evaluation, APS has determined that further modifications to PVNGS power system relaying design are not warranted. The corrective actions taken to-date have minimized the potential for a recurrence of those problems deemed preventable. The relay-related problems that have resulted in entry into natural circulation have been essentially eliminated.

Electrical Distribution System Maintenance

APS review of vendor-recommended preventive maintenance combined with the review of the existing Electrical Distribution System Preventive Maintenance Program indicates that the existing program technically meets or exceeds the vendor-recommended requirements. The maintenance requirements and functional criteria identified in the maintenance section will be performed prior to unit start-up to assure reliable operation of the Electrical Distribution system. In the future, the existing Preventive Maintenance Program in combination with the proposed design and procedural changes will be sufficient to assure continued reliable operation of the Electrical Distribution System.

Based on the above conclusions, APS believes that this review and evaluation, with respect to PVNGS Electrical Distribution System contribution to the units complicated reactor trips and natural circulation events, has been adequately addressed. The implementation of the proposed recommendations (alternatives) should enhance PVNGS Electrical distribution system reliability and provide a major contribution to the minimization of complicated reactor trips and natural circulation events.

Action Plan

The APS proposed action plan is to implement the recommended alternatives as detailed in their respective sections of this report and outlined in the above conclusion . The Action Plan implementation schedule is summarized in figure 3 (ACTION PLAN SCHEDULE).

FIGURE 3
ACTION PLAN SCHEDULE

TASK / ACTIONS REQUIRED	
Electrical Distribution System Alignment Alternatives	
Revise operating proceedures to specify operation of two RCPs on UAT with the other two on SUT power	restart
SSO and Gen. back-up distance relay initiated FBT modification	next scheduled refueling
Integrated system (inc. RPCS & SBCS) study and design enhancement	subsequent refeuling
SSO Relay System modifications	
Mod to initiate FBT on SSO actuation	next scheduled refueling
Digital fault recorder addition to SSO relays	restart
Reference circuit modification to SSO system	restart
Electrical Distribution System Preventative Maintenance	restart

FIGURE 3
ACTION PLAN SCHEDULE

TASK / ACTIONS REQUIRED :

Functional Criteria
specific tasks

a) Cleaning of high voltage bushings, insulators and arrestors	restart
b) Lubrication and cycling of FBT breakers	restart
c) XFMR oil sample evaluation	restart
d) Oil filled XFMR leakage checks	restart
e) Main XFMR dehydrating breather filter check	restart
f) Service testing of non-IE Battery System	restart

TABLE 1
PVNGS REACTOR TRIP EVENTS

Event Date	Unit	LER Number	LER Title	Mode	Reactor Power (%)	Natural Circulation	FBT Occurred
03/12/85	1	528-85-012-00	Erroneous Actuation of Low Steam Generator Pressure Reactor Trip	5	0		Note 1
03/21/85	1	528-85-009-00	Inadvertent Reactor Trip	5	0		Note 1
06/14/85	1	528-85-019-01	Reactor Trip	1	19		Note 2
07/01/85	1	528-85-043-00	Reactor Trip on High Pressurizer Pressure	1	43		Note 2
07/17/85	1	528-85-049-01	Inadvertent Reactor Protection System Actuation	1	50		Note 2
09/12/85	1	528-85-063-01	Reactor Trip During Load Rejection Test	1	53	2 hr 19 min	Note 3
10/03/85	1	528-85-058-00	Reactor Trip Due to Loss of Offsite Power	1	52	3 hr 34 min	Note 1
10/07/85	1	528-85-076-00	Reactor Trip Due to Loss of Offsite Power	3	0	0 hr 44 min	Note 1
10/24/85	1	528-85-071-00	Reactor Trip Initiated by Load Rejection Test From 80% Power	1	81		Note 1
12/04/85	1	528-85-088-01	Reactor Trip Due to Defective Phase Synchronizing Card	1	54		Note 2
12/16/85	1	528-85-090-00	Unit 1 Reactor Trip Initiated by Feedwater Anomaly at Low Power	2	2		Note 1
12/20/85	1	528-85-080-00	Reactor Trip Due to Out-of-Tolerance Setpoint in Turbine Demand Runback Module	1	40		Note 2
01/09/86	1	528-86-006-00	Reactor Trip Caused When a Synchronization Check Blocked the Transfer of Non-Essential Loads During Testing	1	100	0 hr 43 min	Note 3

TABLE 1 (Continued)
PVNGS REACTOR TRIP EVENTS

Event Date	Unit	LER Number	LER Title	Mode	Reactor Power (%)	Natural Circulation	FBT Occurred
02/03/86	1	528-86-020-01	Reactor Trip Initiated by Feedwater Anomaly	1	60		Note 2
02/07/86	1	528-86-024-00	Reactor Trip Due to Low Steam Generator Level	1	18		Note 1
03/07/86	1	528-86-018-00	Reactor Trip on Low Steam Generator Level Due to Feedwater Pump	1	18		Note 1
04/04/86	2	529-86-015-00	Reactor Protection System Actuation In Response to Loss of Seal Injection Flow	3	0		Note 2
05/25/86	2	529-86-025-00	Reactor Trip Due to Low Steam Generator Level, with Main Steam Isolation Signal, Safety Injection Actuation Signal, and Containment Isolation Actuation Signal Actuations	1	15		Note 1
05/31/86	2	529-86-027-00	Reactor Trip Caused by Improper Positioning of Steam Bypass Control System	1	35		Note 1
06/10/86	2	529-86-034-00	Reactor Trip Initiated by an Unanticipated Turbine Trip	1	41		Note 1
06/17/86	1	528-86-042-00	Low Departure From Nucleate Boiling Ratio Reactor Trip Due to CEA Misalignment	1	100		Note 1
07/12/86	1	528-86-047-00	Too Conservative Low Reactor Coolant Flow Trip Setpoints Cause Reactor Trip	1	100	1 hr 23 min	Note 1
07/25/86	2	529-86-047-00	Invalid Floating Point Fault in Core Protection Calculator Causes Reactor Trip	1	50		Note 1

TABLE 1 (Continued)
PVNGS REACTOR TRIP EVENTS

Event Date	Unit	LER Number	LER Title	Mode	Reactor Power (%)	Natural Circulation	FBT Occurred
08/06/86	1	528-86-003-00	Reactor Trips and Engineered Safety Feature Actuation System Actuations Due to Loss of Power	1	100		Note 1
08/06/86	2	528-86-003-00	Reactor Trips and Engineered Safety Feature Actuation System Actuations Due to Loss of Power	1	7		Note 1
08/15/86	1	528-86-045-00	Reactor Trip Initiated by Manual Generator Trip	1	50		Yes
08/25/86	2	529-86-026-00	Reactor Trip Initiated by Main Turbine Generator Trip	1	80		Note 1
08/28/86	2	529-86-033-00	Incorrect Wiring in Generator Results in Reactor Trip	1	80		Note 1
08/30/86	1	528-86-033-00	Reactor Trip Due to Spurious Low Reactor Coolant Flow Trip	1	100		Yes
09/02/86	1	528-86-044-00	Reactor Trip Due to Spurious Low Reactor Coolant Flow Signals	1	100		Yes
09/11/86	1	528-86-053-00	Maintenance Activity on Circuit Card Results in Reactor Trip	1	100		Yes
09/11/86	2	529-86-017-00	Reactor Trip Initiation by Reactor Protection System	1	99		Yes
09/23/86	2	529-86-049-00	Reactor Trip Due to Low Steam Generator Level Accompanied by Auxiliary Feedwater Actuation Signal	1	40		Note 1

TABLE 1 (Continued)
PVNGS REACTOR TRIP EVENTS

Event Date	Unit	LER Number	LER Title	Mode	Reactor Power (%)	Natural Circulation	FBT Occurred
10/06/86	1	528-86-056-00	Reactor Trip Due to Excessive Reactor Coolant System Cooldown	1	24		Note 1
11/19/86	1	528-86-061-00	Reactor Trip Followed by Entry Into Technical Specification Limiting Condition of Operation 3.0.3 Due to an Inoperable Main Steam Isolation Valve	1	100		Note 1
12/24/86	2	529-86-023-01	Reactor Trip Initiated by Loss of Power to the Plant Protection System	1	100		Note 1
01/10/87	1	528-87-003-00	Operator Error During Feedwater Transient Results in a Reactor Trip	1	40		Note 1
04/16/87	2	529-87-004-00	Reactor Trip While Performing Ground Isolation Due to Inadequate Information	1	100		Note 2
05/30/87	1	528-87-014-00	Reactor Trip During Main Feed Pump Turbine Testing Due to a Failed Limit Switch	1	100		Yes
06/04/87	2	529-87-010-00	A Reactor Trip Occurred Due to a Malfunction in the Feedwater Control System	1	100		Note 1
08/27/87	1	528-87-018-01	Reactor Trip Occurs During Shutdown Due to Pressure Boundary Leakage	1	8		Note 1
11/22/87	2	529-87-019-00	Reactor Trip Occurs During Startup Due to Axial Shape Index Out-of-Bounds	1	7		Note 1
12/17/87	3	530-87-004-00	Reactor Trip Occurs Due to Control Element Assembly Subgroup Deviation	1	50		Note 1

TABLE 1 (Continued)
PVNGS REACTOR TRIP EVENTS

NOTES:

Note 1 -- House loads powered from Startup Transformer(s); no fast bus transfer attempt made.

Note 2 -- Specific electrical distribution system alignment has not been determined through review of Licensee Event Report and post-trip review documentation. Had house loads been powered from the Unit Auxiliary Transformer, however, fast bus transfer must have worked. (If fast bus transfer did not work when called upon to do so, the event would be reported as a natural circulation cooldown event.)

Note 3 -- Fast bus transfer could not be achieved because of frequency and/or voltage mismatches.

Note 4 -- Fast bus transfer of bus NAN-S01 was successful; NAN-S02 did not fast transfer because its feeder breaker from the UAT did not trip. LER 50-528/89-004-00 does not provide a definitive root cause for the breaker failing to trip.

Note 5 -- PVNGS Operational Modes are defined as follows:

Mode	Reactivity (k_{eff})	% Rated Thermal Power*	RCS Cold Leg Temperature
1. Power Operation	≥ 0.99	> 5%	$\geq 350\ ^\circ F$
2. Startup	≥ 0.99	$\leq 5\%$	$\geq 350\ ^\circ F$
3. Hot Standby	< 0.99	0%	$\geq 350\ ^\circ F$
4 Hot Shutdown	< 0.99	0%	$350\ ^\circ F > T_{cold} > 210\ ^\circ F$
5. Cold Shutdown	< 0.99	0%	$\leq 210\ ^\circ F$
6. Refueling**	≤ 0.99	0%	$\leq 135\ ^\circ F$

* Excluding decay heat

** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

TABLE 1 (Continued)
PVNGS REACTOR TRIP EVENTS

NOTES:

Note 1 -- House loads powered from Startup Transformer(s); no fast bus transfer attempt made.

Note 2 -- Specific electrical distribution system alignment has not been determined through review of Licensee Event Report and post-trip review documentation. Had house loads been powered from the Unit Auxiliary Transformer, however, fast bus transfer must have worked. (If fast bus transfer did not work when called upon to do so, the event would be reported as a natural circulation cooldown event.)

Note 3 -- Fast bus transfer could not be achieved because of frequency and/or voltage mismatches.

Note 4 -- Fast bus transfer of bus NAN-S01 was successful; NAN-S02 did not fast transfer because its feeder breaker from the UAT did not trip. LER 50-528/89-004-00 does not provide a definitive root cause for the breaker failing to trip.

Note 5 -- PVNGS Operational Modes are defined as follows:

Mode	Reactivity (k_{eff})	% Rated Thermal Power*	RCS Cold Leg Temperature
1. Power Operation	$\geq$ 0.99	> 5%	$\geq$ 350 °F
2. Startup	$\geq$ 0.99	$\leq$ 5%	$\geq$ 350 °F
3. Hot Standby	< 0.99	0%	$\geq$ 350 °F
4. Hot Shutdown	< 0.99	0%	350 °F > T_{cold} > 210 °F
5 Cold Shutdown	< 0.99	0%	$\leq$ 210 °F
6. Refueling**	$\leq$ 0.99	0%	$\leq$ 135 °F

* Excluding decay heat

** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.