PALO VERDE NUCLEAR GENERATING STATION

UNIT 1

STARTUP

EXPERIENCE

REPORT

A Management Overview

February 24, 1986

0441K/0020K

TABLE OF CONTENTS

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

I. INTRODUCTION

This report summarizes the overall experience gained by the Arizona Nuclear Power Project (ANPP) management and staff during the Palo Verde Nuclear Generating Station (PVNGS) Unit 1 Power Ascension Test Program. The experience has been derived from assessment of the plant and staff performance during normal and abnormal events from January 7, 1985 (fuel load) through January 27, 1986 (completion of NRC required testing).

The primary objective of ANPP management was to determine through the testing program whether the plant would perform its intended function in a safe, reliable and well planned manner and would respond to abnormalities according to its design and performance criteria. Performance objectives and goals for management and staff were established not to just meet the minimum requirements, but to achieve the best possible results. ANPP management at all levels actively participated in all facets of plant operation to ensure that these goals would be met.

II. TESTING SCHEDULE

In January 1985, ANPP had planned for the completion of NRC required testing in PVNGS Unit 1 by December 16, 1985. The actual completion date was January 27, 1986. The difference between planned and actual was 42 days, even though all the unexpected outages combined lasted more than two and a half months. This reflects positively on ANPP's ability to overcome unexpected delays and aggressively pursue the critical path of testing on a first-of-a-kind plant.

The testing program for Palo Verde Unit 1 consisted of the following five phases:

A) Fuel load

B) Post core hot functional tests

C) Initial criticality

D) Low power physics testing

E) Power ascension testing

The following is a discussion of the planned versus actual schedules of these five phases.

A) Fuel load was completed in 8 days versus the scheduled 10 days (January 7 - 15, 1985). Reactor vessel head and Control Element Drive Motor assembly was completed on February 7, 1985, one day ahead of the scheduled 24 day duration. An unplanned electrical train A and B outage of 74 days followed. This outage was taken to implement obligatory design changes necessary to support initial Mode 4 entry.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Major work activities accomplished during the outage were: field completion of 48 fire protection design changes required to satisfy condition 2.C.7.a of License NPF-34 (PVNGS 1 Low Power License); corrective maintenance required to ensure operability of various monitors in the Radiation Monitoring System; implementation of a design change to the Containment Purge System required by the operating license; and various diesel generator enhancements.

B) Post core hot functional testing commenced on April 20, 1985 and was successfully concluded on May 18, 1985. This testing was completed 3 days ahead of the planned 31 day duration.

The testing demonstrated proper integrated operation of the plant primary, secondary and auxiliary systems with fuel in the reactor vessel. Additionally, pre-core carryover testing was completed. Test acceptance criteria were satisfied and PVNGS 1 proved capable of functionally supporting power operation.

C) Initial criticality was achieved on May 25, 1985. This evolution required the scheduled two days.

Measured reactor coolant system boron concentration at criticality was 1054 ppm, only 9 ppm different from the predicted value of 1063 ppm. This was well within the acceptance criteria of 963 ppm to 1163 ppm.

D) Low power physics testing was completed in 8 days versus a scheduled 12 days. The testing verified that the control element assemblies (CEA) and the fuel were properly fabricated and the core correctly loaded. The results of additional tests for CEA and boron reactivity worth were within the predicted values.

E) Power ascension testing commenced on June 5, 1985 and it was completed on January 27, 1986. The scheduled duration was 182 days, but the actual time taken was 233 days. This slippage in completion was attributable to the following factors:

(1) Modifications to complete the Post Accident Sampling System deficiencies. Corrective actions included implementation of design changes, procedural revisions and retraining of chemistry and radiation protection personnel. These activities required 44 days.

(2) Repair work required on Calvert buses and the resolution of requirements for Reactor Coolant System (RCS) pipe whip restraints. Both tasks were successfully completed concurrently. Four Calvert Buses associated with the reactor coolant pumps were reinspected and corrective maintenance performed as necessary. Loose whip restraint bolts noted during performance of surveillance testing were retorqued and concurrently an exemption was granted to ANPP from the requirements of General Design Criteria 4. A similar exemption is included in the PVNGS 2 license, NPF-46. These activities required 26 days.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

(3) Troubleshooting and modifications to switchyard breaker controls. Repeated failures of the Plant Multiplexer System (PMUX) required hard wiring of selected switchyard breaker controls to regain reliable remote operational capability. This activity required 8 days.

(4) Repair work required to stop main condenser tube leakage. This work was performed between December 10 and 15, 1985 and again between January 10 and 17. Permanent long term fixes (tube staking and rerouting of sparger and main feed lines to the condenser) will be implemented in the March 1986 outage in Unit 1. The design changes have already been implemented in Unit 2.

(5) Others as discussed in Section III.

The ANPP management firmly believes that although the planning and implementation of the Power Ascension Testing Schedule had to overcome several unexpected delays, the overall program was successful in demonstrating expected plant response.

III. SUMMARY OF UNEXPECTED EVENTS

A detailed summary of significant unexpected events occurring during Power Ascension Testing is provided as follows:

A. Unexpected Event: Inoperability of the Post Accident Sampling System (PASS)
Date: 07/24/85

Description

The NRC branch of Emergency Preparedness and Radiological Protection conducted a routine unannounced inspection between June 24 and July 24, 1985. The inspection reviewed over 12 areas in the radiation protection and chemistry departments. During the inspection, the team identified several concerns with the PASS and with the ability of personnel to operate the system after an accident.

Staff Performance

ANPP management recognized the significance of the issue and involved the organizations within ANPP and to solve the concerns. ANPP's approach was first to review the basic design criteria required to meet PASS operability and ensure that every requirement was identified. Management direction of the various departments throughout the entire process resulted in the development of numerous corrective actions. The responsibilities to complete the corrective actions were carried out effectively by individual departments.

Root Cause

The use of equipment for other than its original design intent without appropriate design review.

Lessons Learned

1) A more stringent review process was needed to ensure systems in the plant met the commitments ANPP has made.

2) Informal task forces do not ensure a well controlled design change process.

Corrective Actions

1) Procedures controlling the design change process were revised.

2) A QA audit was conducted to ensure the commitments made by ANPP to NRC were satisfactorily dispositioned.

3) A senior manager (Assistant Vice President of Nuclear Production) was assigned full time to the site to improve Palo Verde's efforts in compliance for the Power Ascension Testing Phase.

4) The Post Accident Sampling System (PASS) was modified to meet the defined design basis.

5) PASS operating procedures were revised to reflect the above changes.

6) Personnel were trained on the modified PASS and the related implementing procedures.

7) A more formal review process of correspondence to the NRC was incorporated into the Licensing Department's program.

8) Procedures to control and better define the responsibility of task forces are being developed.

9) Compliance group organizational changes are being implemented.

Effect on Unit 2

1) Design changes identified in Unit 1 necessary to make PASS operable are being incorporated into Unit 2.

2) Procedures related to PASS have been revised to reflect the design changes.

3) The review process developed for Unit 1's PASS is being used to ensure Unit 2's PASS is complete and operable.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

4) The reorganization of the Compliance Group will enhance overall site compliance.

5) The QA audit was performed in all three units.

6) Formalized reviews for NRC correspondence are being applied to all letters transmitted to the NRC.

B. Unexpected Event: Loss of Suction to the Charging Pumps and Operability of Auxiliary Pressurizer Spray

Date: 09/12/86

Description

The plant was at 53% power in preparation for the Load Rejection Test. The test was initiated by opening the main generator output breaker. Because of problems in the turbine control system in maintaining the house loads, the Reactor Coolant Pump (RCP) breakers opened and the Core Protection Calculators (CPCS) tripped the plant on low projected DNBR. The operators established natural circulation and brought the plant to a stabilized condition. During this time the charging pumps lost suction and became gas bound due to the draining of the Volume Control Tank. Auxiliary Pressurizer Spray capability was lost.

Staff Performance

The operators observed the erroneous indication of Volume Control Tank (VCT) Level and loss of charging pump suction. Prompt action was taken to align the charging pumps to the Refueling Water Tank and restore charging pump suction thereby regaining the capability of Auxiliary Pressurizer Spray. The operators identified the problem correctly, determined proper corrective actions and implemented them effectively.

Root Cause

The VCT level instrument reference leg was not entirely full which caused an erroneous level indication of 20% when the tank was actually empty.

Lessons Learned

1) The post-trip review process required additional evaluation to ensure that the safety significance of off-normal events are thoroughly addressed.

2) The charging pumps were out of service for a short period of time due to a loss of offsite power and a single level instrument failure.

Corrective Actions

1) A post-trip review group consisting of personnel from the Technical Support Group and Operations was formed to ensure that all aspects of an event are reviewed.

2) The post-trip report procedure was reformatted to address a more detailed review.

3) A design change was initiated to allow the bleed off of H_2 to a holding tank if a charging pump became gas bound.

4) Provide automatic realignment of charging pump suction line valves, to the refueling water tank, on LO-LO VCT level and loss of offsite power.

5) Provide 1E class power to the charging pump suction side line valves.

6) Enhance the reliability of the VCT level indication.

7) Isolation valves from the refueling water tank and to the auxiliary spray valves are locked open.

8) A long term solution to eliminate the need for charging pump venting is being evaluated.

Effect on Unit 2

1) The post-trip review group, composed of the same organizations, will perform the review for the three units.

2) The post-trip report is controlled by a procedure that is common to the three units.

3) All design changes made to the CVCS are being implemented in Unit 2. (See SSER 9, Sec. 5.4.3 for Schedule).

C. Unexpected Event: Failure of Plant Multiplexing System (PMUX)

Date: 10/03/85 and 10/07/85

Description

On October 3, 1985, Unit 1 was at 52% power preparing for a Power Ascension test which required plant electrical loads be aligned to the offsite power supply. The plant multiplexer (PMUX) failure caused a loss of offsite power which tripped the reactor coolant pumps and caused the reactor to trip. The operators established natural circulation and then restored normal power to the electrical buses. They then restarted the reactor coolant pumps to maintain Mode 3.

On October 7, 1985, the Unit was in Mode 3 preparing to go to Mode 2 when the reactor tripped because of loss of offsite power. Troubleshooting was being conducted on the PMUX and it had failed again.

Staff Performance

Operator action in maintaining natural circulation was adequate and appropriate to remove the decay heat from the core. The operators successfully restored forced circulation after encountering difficulties with resetting reactor coolant pump lockouts.

Root Cause

Failure of the Plant Multiplexing System.

Lessons Learned

1) Elements of the Plant Multiplexer system were unreliable.

2) The operators needed more information about resetting reactor coolant pump lockouts for pump restarts.

Corrective Actions

1) Procedures were modified to inform operators of RCP lockouts and how to clear them for pump restarts.

2) The PMUX controls to switchyard mainfeeder breakers were disabled and breaker controls were hardwired from the switchyard to the control room.

3) The operators were informed of the plant's response to the modification made in item 2.

4) Operations procedure were revised to reflect the modification.

Effect on Unit 2

1) All procedures that were modified due to the problems observed during the event in Unit 1 were also modified in Unit 2.

2) Unit 2 switchyard breaker controls were modified as in Unit 1.

3) Unit 2's operating staff was informed of the affects of the modification to the Unit.

[illegible]

D. Unexpected Event: Spurious Engineered Safety Feature (ESF) Actuations caused by an Overheated ESF Sequencer Module

Date: 12/16/85

Description

Following normal performance of the daily Balance of Plant/Engineered Safety Feature Actuation System (BOP/ESFAS) auto test, a popping noise was heard and the smell of burnt electronics was noted by the operator to be coming from the "A" BOP/ESFAS cabinet. Upon reaching the front of the cabinet, the operator noted all lights on the Sequencer Module "ON" and the Sequencer Module cooling fan not operating. I&C was called to investigate the problem.

During the investigation the Sequencer caused a spurious start of the Diesel Generator (DG) in a test mode and an invalid load shed to occur on Train "A", Class 1E, 4160 bus. The bus normal and alternate supply breakers were opened and all bus loads stripped. The DG output breaker did not close on the bus, thus no power was being supplied to the train "A" side of EFAS.

Staff Performance

The operators handed the unexpected event by attempting to restore power to the bus per procedure. Failure to obtain satisfactory results did not prevent the operators from further investigating alternate methods to restore power. Down powering the BOP-ESFAS cabinet and reenergizing the BOP-ESFAS Panel to restore the bus was the successful solution to an unanticipated problem.

Root Cause

Failure of the Sequencer Module cooling fan. This resulted in the Sequencer overheating and malfunctioning.

Lessons Learned

1) More aggressive reporting of similar events to various NRC groups by ANPP allows for better understanding of PVNGS activities.

Corrective Actions

1) The fan and Sequencer board were replaced. Annunciation was installed in the control room to warn operators of high outlet air temperature in the BOP/ESFAS cabinets.

Effect on Unit 2

1) The DCP for the final disposition of the root cause has been implemented in Unit 2.

E. Unexpected Event: Reactor trip resulting from initiation of Turbine Trip Test

Date: 01/09/86

Description

The plant was at 100% power in preparation for the Turbine Trip Test. The test was initiated by manual actuation of the Unit Differential Generator protection relay. As expected, the 525KV Generator output breakers opened but the house loads (including Reactor Coolant and Circulating Water Pumps) did not "fast-transfer" to the offsite power source. A reactor trip resulted due to the Core Protection Calculator (CPC) projecting a low Departure from Nucleate Boiling Ratio (DNBR) caused by the decreasing of Reactor Coolant Pump (RCP) speed. Following RCP coastdown, core cooling flow was established via natural circulation.

After the 525KV generator output breakers opened, the Steam Bypass Control (SBC) valves received a Quick Open signal, but reclosed almost immediately due to loss of power. This caused the Steam Generator (SG) pressure to increase enough to lift a Main Steam Supply valve and stay open until SG pressure was reduced. Power was reestablished to the SBC valves and they began to modulate and oscillate because the SBC system was now in manual and was using the last auto demand signal to maintain SG levels. At this time, the operator was taking manual control of the SBC valves in order to mitigate the cooldown, however, steam generator pressure had dropped sufficiently to actuate the Main Steam Isolation Signal. Subsequently, Reactor Coolant System temperature and pressure increased to 2357 psia prior to the operator reestablishing a cooldown via use of Steam Generators and an auxiliary feedwater pump.

Staff Performance

The operator's sense of priority in reestablishing power to SBC valves for gaining manual control was accurate. They successfully maintained SG levels, which eventually allowed for an orderly reactor cooldown. The operators exhibited a proper understanding of the sequence of events and procedural compliance.

Root Cause

Automatic transfer of 13.8 KV bus from the Unit Auxiliary Transformer to the Startup Transformers did not occur because of a suspected frequency mismatch. The mismatch may have caused the synchronization check relay to block the transfer from occurring.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Lessons Learned

1) The setpoint of the synchronization check relay is unnecessarily conservative. This causes the synchronization check reset to occur very slowly and prevents the fast transfer from occurring prior to the CPCs tripping the plant on low DNBR.

2) A need to increase the reliability of the SBCS following a loss of power.

3) Data shows that RCP coastdown can occur more rapidly than assumed in the safety analysis.

4) The Core Protection Calculators (CPC) algorithm in the flow projected LO DNBR code is sensitive to minor RCP speed deviation (less than 10 rpm).

Corrective Actions

1) A Design Change Package (DCP) will be issued to modify the synchronization check feature for Fast Bus Transfer. House loads are being maintained on the Startup Transformers until troubleshooting is completed, to determine if additional design changes are necessary to improve the Fast Bus Transfer reliability.

2) Power supplies to the SBCS instrument panels will be shifted to Class 1E sources.

3) All shiftcrews have been informed of the consequences of the loss of complete power to the SBCS instrument panels and the operation of Unit 1 on the Startup transformers.

4) The Flow Penalty Factor (EPOL1) in Core Operating Limit COLSS has been increased by approximately 2.0% to insure a more conservative DNBR calculation. The Penalty Factor (BERR1) term in the CPCs has been multiplied by approximately 1.02 when COLSS is out of service. This reduces the operating margin to accommodate the observed coastdown effects and to ensure that the conclusions of the safety analysis remain valid.

5) The Nuclear Steam Supply System (NSSS) vendor (CE) will examine the sensitivity of the CPC algorithm as part of their proposed Margin Improvement Program.

Effect on Unit 2

1) All DCPs and other design changes identified in the testing of the Fast Bus Transfer system will be incorporated into Unit 2.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

2) Design changes to the SBCS will be incorporated into Unit 2.

3) Shift crews on Unit 2 were informed of the consequences of the loss of complete power to the SBCS instruments.

4) The changes made to COLSS and the CPCs will be reflected in Unit 2.

Management Overview of Unexpected Events Experience

The events discussed in this section were unexpected as specific events but were anticipated as a result of the magnitude of the test program and first-of-a-kind design. It is realized that these events are of a serious nature and should be avoided. ANPP management believes that the actions taken by management and staff were effective in controlling each event and that modifications will mitigate any serious consequences that could have occurred if the problems had gone uncorrected. The events were the results of equipment failures or design errors, not from plant staff deficiencies. Plant and off-site support personnel responded properly, correcting the problems expeditiously. Management believes that through the experience obtained from the events, a better insight of conducting the operation of all PVNGS units was achieved.

IV. SUMMARY OF UNPLANNED REACTOR TRIPS

The following is a discussion of unplanned reactor trips. Section A provides a summary and history, Section B provides details of each unplanned trip.

A. ANPP acknowledges that unplanned reactor trips of any kind are undesirable. Industry data however shows that they do occur and should be expected to occur at a first-of-a-kind plant like PVNGS Unit 1. Management's 1985 performance objective was to limit planned and unplanned reactor trips to 20 (well within industry experience). Unit 1 has experienced 10 unplanned trips between January 1, 1985 and January 27, 1986. Five trips were caused by design deficiencies, four by component or equipment failure and one by human error (see Table 2). None of the trips caused any challenges to fission product barriers or resulted in the release of radioactive materials.

SUMMARY TABLE

Reactor Trip	Date	Root Cause
#1	06/14/85	Equipment Failure
#2	07/01/85	Equipment Failure
#3	07/17/85	Equipment Failure
#4	09/12/85	Design Deficiency
#5	10/03/85	Design Deficiency
#6	10/07/85	Design Deficiency
#7	10/24/85	Design Deficiency
#8	12/09/85	Equipment Failure
#9	12/16/85	Design Deficiency
#10	12/20/85	Personnel Error/ Equipment Failure

B. Detailed Description

1) Title: Reactor Trip on High Pressurizer Pressure

Date Occurred: 6-14-85

LER Number: 85-019-00

DESCRIPTION

On 6/14/85, Unit 1 was in Mode 1 at 19% power with the main generator on-line. The "B" main feedwater pump was running in manual, supplying feedwater to the steam generators and a reactor operator was in the process of starting the "A" Main Feedwater Pump per Procedure. The "A" Main Feedwater Pump Mini-Flow Control Valve did not properly control the flow, allowing excessive condensate flow back to the condenser. This, in conjunction with improper operation of Condensate Pump Mini-Flow Control Valves, caused a low suction pressure trip of the "B" Main Feedwater Pump at 1155. The reactor operators manually tripped the turbine-generator, started auxiliary feedwater, and began manually reducing reactor power by insertion of CEA's. At 1156 the reactor tripped on high pressurizer pressure. Following the reactor trip, the "C" Condensate Pump tripped on low recirculation flow because its Mini-Flow Control Valve did not open sufficiently.

ROOT CAUSE

The cause of this trip was a failure of the "A" Main Feedwater Pump Mini-Flow Control Valve to properly control flow thereby causing loss of suction pressure available to the operating "B" Main Feedwater Pump which then tripped on low suction pressure. Loss of feedwater to the S/Gs caused the reactor to trip on High Pressurizer Pressure due to inadequate heat removal from the Reactor Coolant System.

CORRECTIVE ACTION

Main Feedwater Pump and Condensate Pump Mini-Flow Control valves were repaired.

STAFF PERFORMANCE

Operator action before and after the trip was correct and effective and no procedural deficiencies were identified.

LESSONS LEARNED

1) The operators were able to bring the plant to a stable condition after the plant tripped.

2) The procedures used during the event were found to be adequate.

SPECIFIC EFFECT ON UNIT 2

None.

2) Title: Inadvertent Reactor Protection System (RPS) Actuation

Date Occurred: 7-17-85

LER Number: 85-049-00

DESCRIPTION

An unplanned automatic Reactor trip occurred on July 17, 1985 due to a malfunction of a "memory" card in a Control Element Assembly Calculator (CEAC). The operator attempted to reset the failed CEAC prior to the trip but was unsuccessful. Failure to reset the CEAC caused a false radial peaking factor penalty to be sent to the Core Protection Calculators (CPC), which in turn tripped the plant. Following the trip, an excess cooldown rate, which was well within Tech. Spec. allowances, occurred due to the combined effects of: steam generator blowdown initially at the "abnormal" rate, main steam line drain valves automatically opening, Boric Acid Concentrator in service, Main Feed Pump turbine operation, and a low level of core decay heat generation at this point in the fuel cycle. Appropriate operator action limited the overcooling to within 5-10°F below the normally expected post trip temperature of 565°F.

ROOT CAUSE

Failure of a Memory Circuit Board in CEAC 2 causing faulty output signals to be sent to the CPC's.

CORRECTIVE ACTION

1. Replaced the memory circuit board in CEAC2.

2. Replaced modems between CEACs and CPCs to reduce recurrence of trip indication.

3. Evaluate logic changes for main steam line drain valves opening on turbine trips.

STAFF PERFORMANCE

The operators exhibited a proper understanding of system interactions and performed the correct procedural steps to mitigate the consequences of the CEAC failure.

LESSONS LEARNED

1) The interface between the CPCs and the CEACs required redesign.

SPECIFIC EFFECT ON UNIT 2

Replaced the modems connecting the CPC's to the CEAC's.

3) Title: Reactor Trip on High Pressurizer Pressure

Date Occurred: 7-01-85

LER Number: 85-043-00

DESCRIPTION

On July 1, 1985, at 1812 hours, Palo Verde Unit 1 was in Mode 1 at 45% power when the reactor tripped automatically on High Pressurizer Pressure. Reactor power was in the process of being increased from 40% to 50% for testing at the 50% plateau of the Power Ascension Test Program.

"A" Main Feedwater Pump was in manual control supplying water to the Steam Generators. The feedwater regulating valves were in automatic and an oscillation developed between Number 1 Steam Generator level and feedwater flow. The operator increased feedwater pump speed to maintain Steam Generator level and the pump tripped on low suction pressure. A manual turbine trip later resulted in the High Pressurizer Pressure reactor trip.

ROOT CAUSE

Investigation revealed that the small mesh suction strainers in the Feedwater system, used for startup, were blocked causing a high pressure drop across the strainers. This resulted in the low suction pressure trip setpoint to be reached earlier than if the pressure drop was normal for the system.

[illegible]

CORRECTIVE ACTION

The suction strainers were replaced with strainers of a coarser mesh (originally scheduled to be installed during the March 1986 outage upon completion of testing). Differential pressure was restored to normal and monitored more frequently. Strainer configuration was verified for other pumps which had fine mesh strainers.

STAFF PERFORMANCE

Operator action was appropriate and in accordance with approved plant procedures.

LESSONS LEARNED

1) Care must be exercised in the use of the small mesh suction strainers at higher feedwater flowrates due to the increase in differential pressure.

2) More thorough analysis of problems in controlling Steam Generator levels would have helped mitigate the chances of a reactor trip.

SPECIFIC EFFECT ON UNIT 2

Replaced fine mesh strainers on main feed pumps with coarse mesh strainers.

4) Title: Reactor Trip During Load Rejection Test

Date Occurred: 9-12-85

LER Number: 85-063-01

DESCRIPTION

On September 12, 1985, Palo Verde Unit 1 was in Mode 1 at 53 percent reactor power when the Main Generator breaker was opened at 2208 to initiate a planned load rejection test. As an unexpected result, the reactor tripped due to the Core Protection Calculators (CPC) sensing an imminent loss of forced coolant circulation resulting from the slowing down of the Reactor Coolant Pumps (RCP). The reactor trip caused a subsequent turbine trip. Natural Circulation was then established. Due to the combined effects of auxiliary feed, open steam line drain valves, an open atmospheric dump valve, and low decay heat, the Reactor Coolant System (RCS) was cooled down and depressurized to the Safety Injection and Containment Isolation Actuation setpoint. An unrelated failure in the Volume Control Tank (VCT) level instrumentation resulted in the charging pumps losing suction due to the VCT being emptied.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

ROOT CAUSE

Failure of the Turbine Control System to control the main turbine on house loads.

CORRECTIVE ACTIONS

1) Monitor the reference leg of the Volume Control Tank level indicator on a daily basis. If the data obtained justify a less frequent monitoring interval, ANPP may propose a different interval to the NRC staff.

2) Revise the appropriate procedures to require alignment of the refueling water tank to charging pump suction promptly on loss of offsite power.

3) Institute procedural cautions on restart of the charging pumps.

4) Examine the post-trip review process in light of the September 12, 1985 event to ensure that off-normal events are adequately evaluated, particularly with respect to their potential safety significance.

5) Examine the process for vendor reviews of the remaining Power Ascension tests to assure that, for equipment particularly sensitive to the test being conducted, appropriate vendor input has been provided in the test development.

6) A review of the shift complement for the remaining Power Ascension tests will be performed prior to performance of the tests, to determine if additional staffing may be appropriate.

7) Provide power to CH-501 and 536 from a IE Motor Control Center following a Loss-of-Offsite Power and/or a Safety Injection Actuation Signal.

8) Enhance the reliability of the Volume Control Tank (VCT) level indication.

9) Provide automatic realignment of CH-501 and 536 on Lo-Lo VCT level and loss-of-offsite power, to align charging pump suction from the Refueling Water Tank.

10) Automatic opening of main steam line drain valves on turbine trip was removed.

STAFF PERFORMANCE

The operators conducted a normal shutdown and the plant was stabilized using natural circulation. Control Room Operator

action was appropriate during this evolution, in particular in restoring charging pump capability.

LESSONS LEARNED

1) General experience gained by the operating staff in responding to unexpected failures and an unexpected cooldown rate of the RCS.

2) The post-trip review process required additional evaluation to ensure that off-normal events are adequately addressed.

3) The Chemical Volume and Control System (CVCS) could not perform its intended function due to a single instrument failure.

SPECIFIC EFFECT ON UNIT 2

Corrective actions 7, 8 and 9 were implemented in Unit 2.

5) Title: Reactor Trip Due to Loss of Offsite Power

Date Occurred: 10-3-85

LER Number: 85-058-00

DESCRIPTION

At 1644 on October 3, 1985, Unit 1 was at 52 percent reactor power when a reactor trip occurred due to flow projected, low Departure from Nucleate Boiling Ratio on all four Core Protection Calculators (CPC's). This was due to a loss of offsite power (LOP) which caused the speed of the reactor coolant pumps to decrease. The CPC's sensed an imminent loss of forced coolant circulation and tripped the reactor. The loss of offsite power was caused by switchyard breakers opening due to an apparent malfunction in the Plant Multiplexer (PMUX). Due to the LOP, both emergency diesel generators started and loaded, and the Engineered Safety Features system actuated.

ROOT CAUSE

The Plant Multiplexer was rendered inoperable due to multiple failures/misalignments resulting in the opening of the off-site power normal supply breakers.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

CORRECTIVE ACTION

1) The offsite normal supply breakers were placed in manual.

2) Hard wiring of control/indication circuits to all major offsite power breakers was implemented.

3) Testing of the PMUX using the 18-month surveillance test will be performed to determine why the equipment failed.

STAFF PERFORMANCE

Control room operator actions were appropriate with the exception of control of the "B" diesel generator. The diesel generator was secured incorrectly following a restoration of off-site power. This resulted in the DG being declared inoperable unnecessarily. The problem was found to be an error by a non-licensed operator. Operators were not well versed in the operation of the generator coastdown trip lockout mechanism, resulting in a delay in restarting reactor coolant pumps.

LESSONS LEARNED

1) The procedures governing the restart of the RCP's were changed to specify that the relay must be reset after events which result in their actuation.

2) The lack of training of a non-licensed operator regarding the proper shutdown of a diesel generator.

3) Loss of cooling sources to the reactor coolant pump seals should not be any longer than a minute before the controlled bleedoff valves are closed.

SPECIFIC EFFECT ON UNIT 2

1) Design changes to the multiplexer were initiated in Unit 2.

2) Procedure changes due to the RCP restart problems were incorporated in Unit 2's procedures and training of Unit 2 operators was conducted.

3) Procedural changes to insure RCP seal integrity after a LOP were made in Unit 2 procedures.

6) Title: Reactor Trip Due to Loss of Offsite Power

Date Occurred: 10-7-85

LER Number: 85-076-00

DESCRIPTION

At 1958 on October 7, 1985, Unit 1 was in Mode 3, with the Reactor Coolant System pressure of approximately 2250 psia and temperature of approximately 565F, when a loss of power (LOP) from offsite sources caused a reactor trip.

The Reactor Coolant Pumps speed decreased as a result of the LOP. The Plant Protection System sensed low reactor coolant system flow, measured by steam generator differential pressure, and initiated a reactor trip. Due to the LOP, both emergency diesel generators started and loaded, and the Engineered Safety Features system actuated.

ROOT CAUSE

Off-site power normal supply breakers were opened as a result of a spurious failure in the plant multiplexer (PMUX). The multiplexer was undergoing troubleshooting at the time, though the trip was unassociated with these activities. Plant start-up was awaiting completion of the investigation and rework.

CORRECTIVE ACTION

Corrective actions from the trip on 10-3-85 are applicable to this trip.

STAFF PERFORMANCE

No additional operator action occurred during this trip. Once offsite power was restored, one RCP was restarted without incident and forced circulation restored. All operator actions were per approved procedures.

LESSONS LEARNED

No additional lessons to the 10-3-85 trip were learned.

SPECIFIC EFFECT ON UNIT 2

Same as the 10-3-85 trip.

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

7) Title: Reactor Trip Initiated by Load Rejection Test From 80% Power

Date Occurred: 10-24-85

LER Number: 85-071-00

DESCRIPTION

At 1010 MST on October 24, 1985, Palo Verde Nuclear Generating Station-Unit 1 was operating in Mode 1, with a generator output of 1019 MWe (81% power). As a part of scheduled activities supporting the 80% Load Rejection startup test, a turbine trip was manually initiated.

An unanticipated reactor trip immediately followed the turbine trip due to a sensed, but errant, low steam generator level. The reactor trip was accompanied by a cooldown and subsequent depressurization, which resulted in the receipt of actuation signals for Safety Injection, Containment Isolation, and Main Steam Isolation.

ROOT CAUSE

A high pressure pulse, which occurred when the Turbine Throttle Valves were closed, caused an undesirable Plant Protection System (PPS) response to the sensed low steam generator level indications. Investigations have determined that the duration of the Turbine Throttle valve closure induced high pressure pulse was approximately 300 msec.

CORRECTIVE ACTION

1) A modification was completed which increased the present delay time of 100 msec. for the steam generator low level trip bistable, to a value which should prevent pressure spikes from initiating errant reactor trips.

STAFF PERFORMANCE

The operators stabilized the plant after the actuation of Safety Injection, Containment Isolation and Main Steam Isolation Signals and brought the plant through to a normal shutdown using the appropriate procedures.

LESSONS LEARNED

Experience was gained due to additional exposure to bringing the plant under control and commencing an orderly shutdown.

SPECIFIC EFFECTS ON UNIT 2

The PPS was modified to reflect the increased time delay required for the steam generator low level trip bistable.

8) Title: Reactor Trip Due to Defective Phase Synchronizing Card

Date Occurred: 12-4-85

LER Number: 85-088-00

DESCRIPTION

On December 4, 1985, at 1907, with Unit 1 in Mode 1 at 54% power (700 MWE) while attempting to control Axial Shape Index (ASI) with a part length Control Element Assembly (CEA), the reactor tripped due to a high penalty factor generated by the Control Element Assembly Computer (CEAC).

A defective phase synchronizing card, which controls the voltage to the CEA subgroups, caused an increase in the voltage supplied to subgroup #12. This voltage increase in turn caused the subgroup breaker to open, dropping the subgroup and initiating a reactor trip. The reactor trip caused a voltage transient which was reflected into the plant and sensed by the 13.8 kV electrical bus (NANS04). All Engineered Safety Features (ESF) equipment operated in accordance with plant design.

ROOT CAUSE

The root cause of the event was that a defective phase synchronizing card caused the loss of the power supply to the part length CEA drive mechanism, which caused the rods to drop.

CORRECTIVE ACTION

The phase synchronizing card was replaced and calibrated, and the associated CEA breaker was replaced as a precautionary measure. A coil trace test was successfully performed on the effected control element drive mechanisms to ensure they were operating correctly.

STAFF PERFORMANCE

The operators took prompt corrective actions to perform an orderly plant shutdown per procedure.

LESSONS LEARNED

Experience gained by operating under abnormal conditions were the only lessons learned.

SPECIFIC EFFECTS ON UNIT 2

None.

9) Title: Reactor Trip Initiated by Feedwater Anomaly at Low Power

Date Occurred: 12-16-85

LER Number: 85-090-00

DESCRIPTION

At 2331 on December 16, 1985, Unit 1 was operating at 2% reactor power in Mode 2, when an automatic actuation of the plant protection system resulted in a reactor trip due to low level in steam generator 1.

At the time of the trip, the reactor was in the process of being taken to Mode 4, HOT SHUTDOWN, as a result of equipment inoperability which occurred during an unrelated event prior to the trip. This previous event is described in LER 85-083-00.

This event resulted from a feedwater anomaly which prevented sufficient feedwater flow from entering the steam generators via the main feedwater pumps. An attempt to utilize the non-essential auxiliary feedwater pump was initiated, but the pump was immediately tripped by the operators based on erroneous Control Room indications of pump failure.

ROOT CAUSE

The cause of the reactor trip has been attributed to a feedwater anomaly which prevented the "B" main feedwater pump from providing sufficient feedwater flow to the steam generators at a low power level.

CORRECTIVE ACTION

As a corrective action, the installed pressure gauge for the non-essential auxiliary feedwater pump will no longer be isolated for installation of a temporary gage during surveillance testing of the pump, and operating procedures will be revised to advise licensed operators on how to respond to the low power feedwater anomaly.

[illegible]

STAFF PERFORMANCE

Operator actions were adequate, with the exception of a delay in restoring feedwater flow. The non-essential auxiliary feedwater pump was initially selected to provide feedwater flow, even though it was being prepared for required surveillance testing. The delay occurred in securing that pump and shifting to the essential auxiliary feedwater pump. This resulted in an actuation of the plant protection system on low steam generator level and the subsequent reactor trip. Normal shutdown was commenced per procedure.

LESSONS LEARNED

1) Installing a more accurate pressure instrumentation on the non-essential auxiliary feedwater pump during surveillance testing was not required. Procedures were revised to reflect this.

2) Additional attention to main feedwater operation during low power operation is needed. Procedures were revised to provide precautionary and/or procedural guidance on the operations of the main feedwater system under these conditions.

SPECIFIC EFFECT ON UNIT 2

The procedures as identified in Lessons Learned were also revised for Unit 2.

10) Title: Reactor Trip Due Out of Tolerance Setpoints of Runback Demand Module

Date Occurred: 12-20-85

LER Number: 85-080-00

DESCRIPTION

On December 20, 1985, at 0241, Palo Verde Unit 1 was at 40 percent reactor power when the reactor tripped on high pressurizer pressure after Reactor Power Cutback System (RPCS) signals simultaneously initiated a turbine runback and a Steam Bypass Control System (SBCS) quick open block.

The RPCS signals were generated when a Licensed Senior Reactor Operator put the RPCS into service to reset an RPCS trouble alarm. The system was put in service due to an incorrect sequence of pushbutton operation. The RPCS sensed a loss of one main feedwater pump, since only one of two pumps was running with the reactor at 40 percent power, and

correctly generated a SBCS quick open block. In addition, the RPCS was receiving a turbine runback demand input signal, due to an out of tolerance setpoint, and generated a turbine runback command output signal.

With the combination of a turbine runback and SBCS quick open block, a mismatch between reactor power and secondary steam demand occurred which resulted in a reactor trip.

ROOT CAUSE

An incorrect sequence of pushbutton operation placed the RPCS in service. This in conjunction with an erroneous turbine runback caused the reactor trip. Troubleshooting of the RPCS revealed that a turbine runback demand signal was sent to the RPCS from the runback demand module in the SBCS due to an out of tolerance setpoint in the runback demand module. Downcomer Control Valve refill demand position voltage was found set at a value greater than that which is required for 100% open valve position. This caused excessive modulation time between demand for the valve to close and actual valve movement.

CORRECTIVE ACTION

1) Revised all applicable procedures to include necessary cautions for resetting RPCS alarms and placing the system in service.

2) Recalibration of setpoint in the runback demand module.

3) The initial refill demand position voltage for the Downcomer Valves was reset.

4) The Main Feedwater pump running speed for a Reactor Tripped Override (RTO) condition was reset.

STAFF PERFORMANCE

After the trip had occurred the operators had to take manual control of the steam generator feedwater flow because of the RTO problem to stabilize the primary system temperature, pressurizer level and pressurizer pressure. Once this was accomplished a normal shutdown was commenced and no additional non-routine actions were required by the operators.

LESSONS LEARNED

1) Caution must be observed before placing the RPCS in service and procedures are changed to reflect this.

SPECIFIC EFFECT ON UNIT 2

Unit 2 procedures will reflect the same cautions.

C. Management's Overview of Unplanned Reactor Trip Experience

The number of trips experienced by the Unit is quite low for a first-of-a-kind plant compared to similar units (Refer to Table 1). Management anticipated that unplanned trips would occur as a result of the vigorous exercise of plant systems and personnel. Active and continued management involvement in the post trip review process has resulted in design changes to increase the number of computer data points collected and analyzed; a re-emphasis to the operations staff to review all possible causes and effects of a trip and specific changes in plant operating procedures. Additionally, ANPP has pursued long-term changes in plant design to avoid the causes of the trips in the future. The improvements in the post trip review process are ongoing and will enhance ANPP's ability to learn from these trips.

V. THE EFFECT OF UNIT 1 EXPERIENCE ON UNIT 2

Management has established mechanisms to ensure that the lessons learned on Unit 1 are incorporated site wide through procedural changes, plant design changes or organizational structuring. In order to maintain procedural commonality, each department has a group of procedure writers that are responsible for all procedures within that group's area of responsibility. The vast majority of procedures are identical for all three units, with the exception of unit unique equipment designators. Procedural changes are identified through the LER Tracking System, Corrective Action Reports, the Test Results Review Group,and the Post-Trip report followups and are incorporated by these writers. Therefore, any changes necessitated by the past year's operation of Unit 1 are reflected also in the Unit 2 procedures concurrently. The obverse is true of changes as a result of Unit 2 operations and ultimately Unit 3.

Plant design changes are issued as three unit changes, though they may be implemented at different times based on an individual unit's particular schedule. All design changes are prioritized by safety significance, regulatory need (to meet a commitment or Technical Specification requirement), personnel or equipment safety, or plant improvement.

ANPP management has made organizational changes as necessary based on our experienced with Unit 1. As an example, management has formed the Radiation Protection Surveillance Test Group to perform and track Radiation Monitor period testing at all three units. This was a direct result of problems ANPP encountered with meeting Tech. Spec. requirements for surveillance testing at Unit 1. This Group will be better able to apply its expertise to Unit 2 than would three separate organizations. ANPP management recently created the new position of

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Manager of Compliance, to alleviate the valid concerns in the Compliance area. The position has been filled by an experienced individual from our QA organization. This is in addition to having assigned the Assistant Vice President of Nuclear Production to the Site from September 1985 till the end of December 1985. The Assistant Vice President position is currently unfilled, with the duties temporarily being assumed by the Vice President of Nuclear Production. This position will be filled by an individual with significant operating experience.

Unit 1 operating experience has been directly transferred to Unit 2 by involving Unit 2 personnel in the Unit 1 Power Ascension Program. For example, Unit 2 Radiation Protection and Chemistry Technicians were assigned to Unit 1 for training and to augment the Unit 1 staff. In addition, several Unit 1 control room supervisors have been reassigned to Unit 2.

Several key groups involved in the Unit 1 testing program will perform the same functions at Unit 2. The experience gained at Unit 1 will enable the Power Ascension Support Group, which coordinates major work activities, and the Operations Engineering Department, which performs the power ascension tests, to apply their increased knowledge to the program of Unit 2. Additionally, many members of both organizations were involved in the pre-fuel load activities at both units.

VI. OVERALL STAFF PERFORMANCE

Management has observed a consistent improvement in our staff's ability to perform under normal and unplanned plant conditions. This is attributable to a number of management decisions in regards to testing and staffing. Every effort was made to obtain experienced senior operators to form the core of our control room staff, particularly previously qualified shift supervisors. This group, plus other more junior operators, were involved in an extensive training program, including many months of plant specific simulator training and power operations at similar operating plants. ANPP was one of the first utilities to purchase its own plant-specific simulator. While this provided an initial high level of readiness for actual Unit 1 operations, additional time was allowed in the power ascension testing program for obtaining real-time experience in all facets of complex plant operations. In particular, testing of various Reactor Control systems and Main Feedwater Controls at several power plateaus enabled the staff to learn from actual plant responses and to build on this knowledge. Low operating staff turnover (6.8%), January 1, 1985 to December 31, 1985, has assured the retention of this knowledge.

A conscious effort has been made to avoid problems in the complex interactions of systems and subsystems through the use of experienced contractors with specific skills to augment our staff. They are providing in-depth knowledge and training to our personnel in their

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

areas of expertise. An example is the Engineering Power Ascension Test Group composed of senior test engineers from Combustion Engineer's Test Support Department working with our test engineers. In addition, we retained the services of two experienced operators from SONGS as Control Room Advisors.

Senior management operating experience was enhanced by appointing Mr. P. McGuire, formerly Plant Manager at Boston Edison's Pilgram Plant, as an advisor to the Executive Vice President; plus the addition of Mr. J. Haynes, formerly Plant Manager at SONGS, and Mr. R. Butler, formerly Manager of Nuclear Engineering at Boston Edison, to our staff as Vice President of Nuclear Production and Director of Technical Services, respectively. Mr. Haynes also was an advisor to ANPP management in early 1985. Additionally, the duties of the Assistant Vice President have recently been expanded to include direct responsibility for the Water Reclamation Facility, Nuclear Training, Administative Services and Emergency Planning, thus freeing the Plant Manager of ancillary duties, allowing him to concentrate on the operations of the Power Block.

Management believes that staff performance has been superior. This is supported by operator response to unexpected events and reactor trips as well as by management and support personnel in implementing corrective actions.

VII. OVERALL PLANT PERFORMANCE

An evaluation of plant performance not only measures the effectiveness of plant design, construction and operations personnel performance but also represents the continued commitment and degree of involvement by ANPP management. At the inception of the project, management recognized this relationship between plant performance and management participation. Management proposed and implemented the following actions/criteria which resulted in improved plant performance and its adequate monitoring during testing:

(1) Stringent specifications to enhance procurement of quality equipment and plant design were set up.

(2) An experienced startup team was assembled to perform the testing program.

(3) Problems were identified early on along with root causes.

(4) The project's Quality Assurance Group was appointed to follow the progress of construction and testing to ensure systems were built and tested according to the specifications and regulatory requirements.

(5) It was decided that all systems would be successfully tested at each power plateau prior to proceeding to the next power level.

Difficulties encountered prior to the Power Ascension Test Program (i.e., reactor coolant pump/core shroud failures, low pressure safety injection rotor problems and deficiencies noted during the 1983 construction assessment team audit) were successfully resolved, resulting in a significantly improved plant.

These management actions/criteria resulted in successful demonstration of the operability of control systems, such as, the Reactor Power Cutback System, which enhance the overall reliability of the unit. They also eliminated and/or mitigated problems that have occurred at other plants. As an example, PVNGS did not experience the extensive dropped control rod problem observed at other units.

In summary, PVNGS has functioned well because of the conscientious efforts of the ANPP management to ensure that it was designed, constructed, tested and operated in accordance with stringent criteria.

VIII. CONCLUSIONS

ANPP management believes that the performance of the staff and the plant has been highly satisfactory. Management also recognizes the need for continued improvement. Efforts have been made to ensure that proper management controls are in place to identify and correct any design problems, that procedures reflect correct operating methods, and that the staff has the level of experience and training to safely operate and maintain the plant. Because of these efforts, ANPP is confident that operation of PVNGS Units 2 and 3 will proceed smoothly and safety.

Table 1

REACTOR TRIP SUMMARY OF RECENT PLANT STARTUPS - FUEL LOAD TO COMMERCIAL OPERATION

PLANT	PLANNED TRIPS	UNPLANNED TRIPS	TOTAL
PVNGS 1	3	10	13
GRAND GULF	5	17	22
WPPSS 2	5	21	26
LA SALLE 1	5	25	30
WATERFORD 3	4	19	23
SONGS 2	12	27	39
BYRON 1	4	23	27

[illegible]

[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]		
[illegible]			
[illegible]			

Table 2

SUMMARY OF REACTOR TRIPS BY ROOT CAUSE - FUEL LOAD TO COMPLETION OF POWER ASCENSION TESTING

PLANT	DUE TO DESIGN DEFICIENCIES	DUE TO PERSONNEL ERROR	DUE TO COMPONENT FAILURE/ PROCEDURAL ERROR	TOTAL
PVNGS 1	5	1	4*	10
WPPSS 2	8	8	5	21
WATERFORD 3	7	4	8	19
BYRON 1	5	8	10	23

*No PVNGS 1 trips due to procedural error.