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COMMISSIONERS

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WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826 **NOTICE OF FILING REPORT**

Arizona Corporation Commission Staff ("Staff") hereby files its report regarding its investigation of the 2005 outages of the Palo Verde Nuclear Generating Station. The attached report is a public version with confidential information redacted. A confidential version of this report will be provided under seal to the commissioners, their assistants, the assigned administrative law judge, APS, and the parties who have signed protective agreements in this case.

RESPECTFULLY SUBMITTED this 17th day of August, 2006.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
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REPORT OF

GDS ASSOCIATES, INC.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

PUBLIC VERSION
REDACTED

August 17, 2006

Table of Contents

EXECUTIVE SUMMARY 1
I. INTRODUCTION 6
II. DESCRIPTION OF WORK 7
III. PALO VERDE PERFORMANCE 8
IV. PRUDENCE STANDARD 19
V. REVIEW OF 2005 PALO VERDE OUTAGES 20
A. Unit 1 13.8 kV Bus Failure and Reactor Coolant Pump ("RCP")-1B Upper Oil Seal Failure 20
B. Unit 1 Emergency Diesel Generator 'A' Governor Failure 22
C. Unit 1 Emergency Diesel Generator 'B' Voltage Regulator Failure and Reactor Trip due to Operator Error 24
D. Unit 1 Refueling outage and Steam Generator Replacement 27
E. Unit 1 Shutdown Cooling Line Vibration 28
F. Unit 2 Refueling Outage 28
G. Unit 2 Core Protection Calculators ("CPC") Inoperable 29
H. Unit 2 Refueling Water Tank Inoperable 31
I. Unit 3 Pressurizer Heater Replacement and RCP Seal Oil Leak 36
J. Unit 3 Reactor Coolant Pump Seal Oil Leak 37
K. Unit 3 Refueling Water Tank Inoperable 39
VI. TREATMENT OF COSTS ASSOCIATED WITH PALO VERDE OUTAGES 42
A. APS' Replacement Power Cost Analysis 42
B. Results of Analysis of Cost Impacts of Imprudent Palo Verde Outages 44
C. Summary 48
VII. CONCLUSIONS 51
VIII. RECOMMENDATIONS 52

TABLES

Table 1. Palo Verde Performance Metrics 2001 to 2005 8

Table 2. INPO Performance Index 2003 – 2005 17

Table 3. Summary Of Imprudent Palo Verde Outages 2005 41

Table 4: Summary Of APS' Claimed Replacement Power Costs For Palo Verde Forced Outages 44

Table 5: Recommended PSA Disallowances 49

ATTACHMENTS

Attachment 1	Palo Verde Nuclear Generating Station Performance Improvement Plan, October 15, 2005
Attachment 2	NRC Reactor Oversight Process Action Matrix Summary, 4Q/2005
Attachment 3	NRC Letter from Bruce Mallet, NRC Regional Administrator to James Levine, APS Executive Vice President, Generation dated January 27, 2006 Subj: Palo Verde Nuclear Generating Station – NRC Supplemental Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012
Attachment 4	NRC Annual Assessment Letter to Mr. Gregg R. Overbeck dated March 2, 2005
Attachment 5	NRC Annual Assessment Letter to Mr. James M. Levine dated March 2, 2006
Attachment 6	Palo Verde CRDR Number 2780273, NRC Crosscutting Issue Human Performance dated September 16, 2005, pages 1-23.
Attachment 7	Palo Verde CRDR 2780286, Rev. 1 Crosscutting Issue with Problem Identification and Resolution dated September 22, 2005
Attachment 8	Significant Root Cause Investigation Report 2775015
Attachment 9	CRDR Number 2777226 Upper Oil Seal O-Ring Failure, pages 25-48
Attachment 10	CRDR Number 2782680 Emergency Diesel Generator 1A Failure to Attain Rated Voltage/Frequency, Rev. 0, pages 1-17
Attachment 11	CRDR Number 2825485, Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup, pages 1-15
Attachment 12	CRDR Number 2824258, U-2 3.03 Shutdown Due to CPC Software dated 11/30/2005, pages 1-18
Attachment 13	CRDR 2835132 Evaluation of RWT Suction Behavior during SIS and CSS Transition to RAS and Related Design Interface Criteria, page 161
Attachment 14	CRDR 2809138 Pressurizer Heater Failures at Palo Verde and Waterford Root Cause Investigation Report dated October 4, 2005, pages 61-89

Attachment 15 Palo Verde 2005 Replacement Power Costs

Attachment 16 Estimated Impact Off-System Sales Margins Due to Imprudent Forced Outages

Attachment 17 Adjustment to APS Interest on Fuel Under-Recovery Balances Due to Imprudent Outages

Attachment 18 Summary of Cost Disallowances for Imprudent Outages

ACRONYMS

ACC: Arizona Corporation Commission
AFI: Areas for Improvement
APS: Arizona Public Service Company
AVR: Automatic Voltage Regulator
CPC: Core Protection Calculators
CRAI: Condition Report Action Item
CRDR: Condition Report Disposition Request
ECCS: Emergency Core Cooling System
EDG: Emergency Diesel Generator
EFOR: Effective Forced Outage Rate
ESI: Engine Systems Incorporated
GDS: GDS Associates
INPO: Institute of Nuclear Power Operations
LCO: Limiting Condition for Operation
LER: Licensee Event Report
NRC: Nuclear Regulatory Commission
PDA: Primary Disconnect Assembly
PIP: Performance Improvement Plan
PSA: Power Supply Adjustor
PVNGS: Palo Verde Nuclear Generating Station
RAS: Recirculation Actuation Signal
RCI: Root Cause Investigation
RCP: Reactor Coolant Pump
RFO: Refueling Outage
RWT: Refueling Water Tank

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REVIEW OF PALO VERDE 2005 OUTAGES
FINAL REPORT
8/17/06

EXECUTIVE SUMMARY

Palo Verde Performance

Performance of the Palo Verde Nuclear Generating Station ("Palo Verde" or "Plant") in 2005 was poor by almost any measure. Generation and capacity factors were low and production costs were high compared to historical performance. The NRC ranked Palo Verde in the next to the lowest regulatory category and the Institute of Nuclear Power Operations ("INPO") [redacted]. In addition to two refueling outages, Palo Verde experienced eight unplanned outages and one planned outage in 2005. Because the capital cost of Palo Verde embedded in base rates is high, the Plant must operate well to take advantage of the relatively low fuel and variable costs of the Plant. As a result of this poor performance, the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff") retained GDS Associates, Inc. of Marietta, Georgia to investigate the reasons for Palo Verde's poor performance, to make recommendations to improve performance, and to reduce the likelihood of future unplanned outages. GDS conducted this investigation by reviewing documents, such as APS' root cause evaluations and NRC inspection reports. GDS also visited the Palo Verde site, conducted interviews of APS officials at the senior management level, and attended meetings between APS and the NRC.

While the operating and regulatory performance of Palo Verde during 2005 was poor, GDS has not found any evidence or indication that operation of the plant has compromised safety. None of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shutdown the plant when any safety concerns were identified. Palo Verde was safely operated throughout 2005.

APS has implemented an aggressive Performance Improvement Plan to return Palo Verde performance to the desired level of excellence. While it is too early to know

with certainty if the plan will succeed, the plan is comprehensive and APS has committed substantial management and financial resources to ensure success. Based on our experience with similar plans at other nuclear plants, GDS is optimistic that APS will be successful in achieving improved performance at Palo Verde.

Palo Verde Outages

GDS determined that, of the eleven 2005 outages, four were avoidable and the result of imprudent actions by APS, three were the result of faulty or defective vendor supplied equipment, and one cannot be completely evaluated at this time. GDS did not identify any imprudence related to the remaining three outages. As shown in Table 3 in this report, APS' estimate of the net replacement power cost is $16.269 million for the four imprudently incurred outages in 2005 of which $14.944 million was incurred during the period of April through December when the Power Supply Adjustor ("PSA")was in effect. APS' request for $44.564 million for recovery of replacement power costs for 2005 Palo Verde forced outages should be reduced by $14.944 million.[1] Attachment 18 provides Staff's quantification of the total cost impact of these imprudent outages including lost opportunity costs and claimed interest expense. This amount is $18.996[2] million for the imprudently incurred outages.

Conclusions

1. Performance of the Palo Verde Plant has declined significantly over the past three years.
2. The number of outages in 2005 was much higher than normal and the capacity factor and generation were lower than should be expected.

[1] See Section VI of this report for a detailed explanation of the minor adjustment needed to account for the forced outage replacement power costs included in the PSA base rate.
[2] $17.373 million from page 1 of Attachment 18 for outages for the period April through December 2005 plus $1.623 million from page 2 of Attachment 18 for outages for the period prior to PSA implementation (January through March 2005).

3. APS acknowledges the decline in performance and has implemented an aggressive Performance Improvement Plan ("PIP") to return the Plant to its former levels of performance.
4. Four of the 2005 outages were avoidable and the result of imprudence.
5. Some of the unplanned Palo Verde outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent.
6. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem, which continued into 2006. Additional investigation will be needed to determine the cause of and responsibility for this outage.
7. Although APS received a yellow finding from NRC in 2004 regarding safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

Recommendations

1. The Commission should disallow the additional costs resulting from outages identified as avoidable and imprudent in this report. The resulting disallowance is $17.373 million (see Table 5). The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.
2. An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the

pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' action.

3. The Commission should establish a Nuclear Performance Standard that would establish minimum acceptable levels of performance for Palo Verde and penalties for periods during which the performance of Palo Verde falls below the minimum levels. The Nuclear Performance Standard should be considered in APS' pending rate case.
4. The Commission should order APS to submit a semi-annual report to the Commission's Docket Control, describing plant performance, explaining any negative regulatory reports by the NRC or INPO, and providing details of corrective actions taken. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.
5. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.
6. The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to

improve receipt inspection and pre-installation verification of parts at Palo Verde.

I. INTRODUCTION

Palo Verde is a vital component of Arizona Public Service Company's ("APS") generation resources, providing 17.9% of APS' total generating capacity. During 2005, Palo Verde experienced more outages than normal. Both capacity factor and generation were lower than expected. Because of this, the Commission Staff issued a Request for Proposals for a qualified firm to investigate the reasons for this lower level of performance at Palo Verde, to make recommendations to improve performance, and to reduce the likelihood of future unplanned outages. In January 2006, the Staff selected GDS Associates ("GDS") of Marietta, Georgia to conduct this investigation.

Operating performance of Palo Verde is of great interest to the Commission and to APS ratepayers. Nuclear power plants have the highest capital costs of any central power station. This high capital cost is embedded in base rates and APS ratepayers pay for this high capital cost whether or not the plant is in operation. Nuclear power is an economic source of electrical generation because the high capital cost of a nuclear power plant is offset by low fuel and low variable costs. However, low operating costs are sufficient to offset the high capital costs only when the plant is operated at a high capacity factor. Such high capital cost plants must be operated at a high capacity factor for the ratepayers to receive proportionate economic benefits. In addition, when the Palo Verde plant is out of service, the lost generation must be replaced by higher cost generation. If an outage is the result of imprudent operations or management, APS should be held responsible for the additional costs incurred.

II. DESCRIPTION OF WORK

GDS initiated the investigation of Palo Verde's 2005 performance by reviewing the publicly available documents on the Nuclear Regulatory Commission ("NRC") website. At the same time, GDS submitted an extensive request for information concerning all aspects of Palo Verde's operation. Following this initial activity, additional tasks as stated below have been accomplished:

- Reviewed NRC inspection reports, licensee event reports and other relevant documents;
- Reviewed APS responses to GDS' data requests;
- Developed additional data requests as needed to evaluate each outage;
- Conducted a preliminary review and evaluation of each forced and planned outage at Palo Verde in 2005;
- Attended meetings with the ACC Staff;
- Attended the Open Meeting with the ACC Commissioners and NRC Region 4 management;
- Conducted an inspection of the Palo Verde site;
- Interviewed the Palo Verde senior management team;
- Reviewed confidential reports of plant evaluations conducted by the Institute of Nuclear Power Operation ("INPO").
- Conducted an interview of the NRC Senior Resident Inspector.
- Conducted follow-up interviews of Palo Verde managers.
- Attended by telephone APS' presentation of the Performance Improvement Plan at NRC Regional office in Arlington, Texas.
- Attended the NRC Annual Assessment meeting in Tonopah, Arizona.

GDS' evaluation and analysis of the information gathered through the activities described above is provided in the following report.

III. PALO VERDE PERFORMANCE

By almost any measure, the performance of Palo Verde in 2005 was poor. Nuclear generation, capacity factors and production costs for each Palo Verde unit for the past 5 years are shown in the table below:

Table 1. Palo Verde Performance Metrics 2001 to 2005[3]

Metric	Year				
Net Capacity Factor (%)	**2001**	**2002**	**2003**	**2004**	**2005**
PV1	88	89	97	85	66
PV2	93	92	78	91	82
PV3	84	102[4]	88	75	84
Total Plant	**88**	**94**	**87**	**84**	**77**
Net Generation APS Share (MWH)	**2001**	**2002**	**2003**	**2004**	**2005**
PV1	2,781,838	2,824,162	3,080,847	2,687,616	2,098,779
PV2	2,934,303	2,915,578	2,455,817	3,102,661	2,743,327
PV3	2,668,583	3,241,073	2,778,048	2,392,985	2,666,717
Total	**8,384,724**	**8,980,813**	**8,314,712**	**8,183,262**	**7,508,822**
Production Cost ($/MWh)	**2001**	**2002**	**2003**	**2004**	**2005**
Total Plant	**13.10**	**12.94**	**13.03**	**14.50**	**16.94**

[3] APS response to Data Request PB 4.7

[4] Capacity factor may be greater than 100 percent if the plant operates at a generating capacity greater than that assumed in the capacity factor calculation for some periods during the year. For example, during the winter months, the generating capacity will be significantly greater than the Maximum Dependable Capacity ("MDC") which is determined during the hottest summer months. If the capacity factor is based on the MDC, a capacity factor greater than 100 percent is possible.

As seen in this Table, the capacity factor and nuclear generation declined significantly in the past two years. Palo Verde generated 1,051,261 million (APS share) fewer megawatt-hours in 2005 than were generated on average in the years 2001 thru 2003. From 2002 to 2005, Production Costs have increased over 30% from 12.94 $/MWH to 16.94 $/MWH. Other plant metrics including Effective Forced Outage Rate ("EFOR") and the INPO Performance Indicator Index show a similar decline in performance.

It is useful to put Palo Verde's performance in perspective by comparison to the performance of other nuclear plants in the United States. A recent article in Nuclear News[5], a publication of the American Nuclear Society, provides comparisons of the capacity factors achieved by all U.S. nuclear plants. Table I of this article provides the Net Capacity Factor based on Design Electric Rating of the 104 individual nuclear units in the United States for the period 2003 through 2005[6]. For this period, the Net Capacity Factor of Palo Verde 3 ranked 99th, Palo Verde 1 ranked 97th and Palo Verde 2 ranked 93rd of all 104 U.S. nuclear plants. Since Browns Ferry 1 was not in operation, only 4 nuclear plants had a lower Net Capacity Factor than Palo Verde 1 for this period. Table II in the article ranked nuclear plants based on the change in capacity factor from the 2000-2002 period to the 2003-2005 period. In this comparison, Palo Verde 3 ranked 104th of 104 (greatest decrease in capacity factor of all U.S. nuclear plants), Palo Verde 1 ranked 100th and Palo Verde 2 ranked 93rd. Finally, Table III provided the Net Capacity Factor for all multi-reactor sites. The Palo Verde site ranked 35th of 36 multi-reactor sites in the United States. The performance of Palo Verde during the 2003 to 2005 period was at the bottom of the U.S. nuclear industry.

[5] "U.S. Capacity Factors: Leveled off at last", Nuclear News, May 2006
[6] A two year rolling average is used to normalize the effect of refueling outages.

On October 15, 2005, APS issued the Palo Verde Performance Improvement Plan. The intent of this plan is to provide a strategic overview of Palo Verde performance improvement activities and to provide tactical actions to achieve improved performance. Section 1 of the PIP presents the following discussion of the decline of performance at Palo Verde.

> In late 2002 or early 2003 performance indicators at Palo Verde began a downward trend relative to the sustained high performance levels in previous years. A cause of this trend appears to have been the realignment of key site leadership that in turn caused the team to be more focused on day-to-day tactical matters, and less focused on strategic planning, standards and accountability. Additionally, in 2004, two significant events occurred at Palo Verde. They are the three unit trip in June 2004 that resulted from a grid disturbance and, the discovery, in July 2004, of the absence of water in portions of Emergency Core Coolant System piping ("RAS[7] Sump Event"). These events also revealed issues with regard to various Palo Verde programs and processes that are in need of improvement.[8]

APS' Performance Improvement Plan also states that Palo Verde site leadership did not fully accept that Palo Verde performance indicators reflected actual declining performance until mid-2005 in part because of ten previous years of good performance. In response to the recognition in mid-2005 of declining performance, APS management initiated the Performance Improvement Plan to return Palo Verde to a higher level of performance. At this time, it is too early for the effectiveness of the PIP to be known. However, the PIP is a comprehensive plan with substantial resources and the full backing and commitment of APS management. Palo Verde management is acutely aware of the need to improve performance at Palo Verde and has involved personnel at all levels of the plant organization in development and implementation of the PIP. While the results

[7] "RAS" stands for Recirculation Actuation Signal, the signal that allows the Emergency Core Cooling Systems to take suction from the Containment Sump during a Loss of Coolant Accident.
[8] Palo Verde Nuclear Generating Station Performance Improvement Plan, October 15, 2005, page 1 (Attachment 1)

of the PIP cannot be predicted with total certainty, GDS is optimistic that the PIP will be successful in improving the performance of Palo Verde to the desired level.

Regulatory Performance

Regulatory performance at Palo Verde has also declined. In 2004, the NRC issued a yellow finding to Palo Verde for failure to maintain certain safety-related piping full of water. A yellow finding is a finding with substantial importance to safety. At the end of 2005, only one other plant in the United States (Kewaunee Nuclear Power Plant) had an open yellow finding. Based on this yellow finding and the NRC's evaluation of overall plant performance, Palo Verde is rated in the third column of the NRC's Reactor Oversight Process Action Matrix[9] as a plant with a "degraded cornerstone." Only the Kewaunee Nuclear plant shares this rating along with two plants that are in the 4th column, the Multiple/Repetitive Degraded Cornerstone column. While APS officials attempt to minimize this rating, stating that Palo Verde is in the 3rd column only because of the yellow finding, the NRC clearly states on Attachment 2 that the Action Matrix Summary "reflects overall plant performance and is updated regularly to reflect inputs from the most recent performance indicators and inspection findings." In addition, the NRC has conducted a follow-up inspection and, based on the results of this inspection, has declined to close the yellow finding. In the cover letter for the follow-up inspection, the NRC states:

> However, the NRC also concluded that, while you performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the

[9] NRC Reactor Oversight Process Action Matrix Summary (Attachment 2)

> implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or follow-up, to ensure that corrective actions were effective in improving performance in the affected areas.[10]

Thus, the yellow finding will remain open until the NRC is convinced that the corrective actions are broad enough to resolve the problems and that the corrective actions have been effectively implemented.

In addition to the open yellow finding, in its Annual Assessment Letter dated March 2, 2005, the NRC has identified substantive cross-cutting issues in the areas of human performance and problem identification and resolution. Substantive cross-cutting issues indicate an NRC concern that the nuclear plant operator has had multiple performance deficiencies that had commonality in the central cross-cutting areas of human performance, problem identification and resolution, and/or safety conscious work environment.

The NRC stated that the adverse trend in human performance issues indicated that Palo Verde had not effectively addressed the underlying causes associated with this substantive crosscutting area. The NRC further stated that the adverse trend in problem identification and resolution indicates that Palo Verde had not addressed the underlying causes associated with this substantive crosscutting issue.[11] These issues were addressed again in the NRC's Annual Assessment Letter dated March 2, 2006. In this letter the NRC states:

> During this assessment period, we continue to identify findings with the same cause and common themes in both

[10] NRC Letter from Bruce Mallet, NRC Regional Administrator to James Levine, APS Executive Vice President, Generation dated January 27, 2006 Subj: Palo Verde Nuclear Generating Station – NRC Supplemental Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012 (Cover letter and NRC Inspection Report are provided as Attachment 3)

[11] NRC Annual Assessment Letter to Mr. Gregg R. Overbeck dated March 2, 2005 (Attachment 4)

> cross-cutting areas. There were 16 Green findings with cross-cutting aspects in the areas of human performance. Our assessment indicates that your actions to date have not completely corrected the root causes associated with procedural compliance, procedural adequacy, and the interactions between engineering and operations personnel when assessing degraded and nonconforming conditions. Additionally, there were 12 Green and Severity Level IV findings with cross-cutting aspects in the area of problem identification and resolution. Our assessment indicates that your actions to date have not completely corrected the root causes associated with the identification of non-conforming conditions, the evaluation of conditions adverse to quality, particularly engineering and operations personnel and the implementation of effective corrective actions for deficient conditions.[12]

APS' corrective actions in the areas of human performance and problem identification and resolution were ineffective in resolving the NRC's concerns in these areas.

APS conducted root cause evaluations of these cross-cutting issues and reached the following conclusions:

> Root Cause of the Human Performance Cross-Cutting Issue[13]
>
> The Palo Verde organization does not demonstrate ownership and leadership of the human performance culture. Since the entire organization demonstrates a weakness in human performance culture, the culpability for station behavior lies with the highest levels of management.
>
> - Palo Verde Management does not emphasize that excellence in human performance will result in excellence in plant performance.
> - Leaders sometimes model behaviors inconsistent with site expectations.

[12] NRC Annual Assessment Letter to Mr. James M. Levine dated March 2, 2006 (Attachment 5)
[13] Palo Verde CRDR Number 2780273, NRC Crosscutting Issue Human Performance dated September 16, 2005. Note that CRDR stands for Condition Report Disposition Request. It is the mechanism to report and track problems in Palo Verde's Corrective Action Program (Attachment 6)

- There are little apparent negative consequences to HP[14] events, especially when compared to plant performance (accountability).
- Palo Verde often rewards heroic actions. This was pointed out in the September 2004 self-assessment on Supervisory Effectiveness.
- There are numerous daily meetings focused on plant performance and plant concerns and few, if any, focused on human performance.
- CRDRs are sometimes not generated as expected (additional details can be found in CRDR 2780286, NRC Crosscutting Issue with Problem identification and resolution).
- Corrective actions seem to be aimed at closing CRDRs and not at fixing problems (see CRDR 2780286 for additional details).

Root Cause of the Problem Identification and Resolution Crosscutting Issue[15]

The root cause of a workforce that does not effectively use the corrective action program to improve performance is the result of ineffective management behaviors, such as accepting substandard performance regarding the Corrective Action Program. Regardless of intent, management behaviors have devalued the CAP and diminished people's ability to effectively use the corrective action program as the cornerstone to a continuous improvement culture.

Contributing Causes:

- Continuous Improvement Culture not Anchored – Management behaviors have not promoted a continuous improvement culture, which is essential to the resolution of the Problem Identification and Resolution crosscutting issue.
- Failed to Address Personnel's Frustration with the Corrective Action Program.
- Station Vision is not Globally Understood – the site management team has not motivated the staff with a site-wide vision.
- Mismatched Management Styles – Some of the management team members have not been able to achieve high standards for the corrective action program because of their inflexible management style.
- Lack of Mentoring and Coaching in Leadership Development.

[14] HP - Human Performance
[15] Palo Verde CRDR 2780286, Rev. 1 Crosscutting Issue with Problem Identification and Resolution dated September 22, 2005 (Attachment 7)

APS' evaluation of the crosscutting issues in Human Performance and Problem Identification and Resolution laid the blame squarely on Palo Verde management.

INPO Evaluation Results

In addition to the NRC, a private nuclear industry organization called the Institute of Nuclear Power Operation ("INPO") closely monitors and evaluates the operation of all nuclear power plants in the United States. INPO was established by the nuclear utility industry following the accident at Three Mile Island. INPO's mission is to promote excellence in the operation of nuclear power plants and it is supported by dues paid by all nuclear plant operators. INPO conducts periodic inspections of each nuclear power plant and also provides assistance when requested by the plant operator. A typical INPO evaluation consists of a team of 15 to 20 experienced evaluators on site for a period of 2 weeks. Following the evaluation, INPO provides a report which identifies strengths and areas for improvement ("AFI"). In addition, INPO provides a rating for the plant based on its findings. [redacted]. Finally, each nuclear plant tracks key performance indicators identified by INPO and uses these performance indicators to develop an INPO Performance Index for the plant.

[redacted]

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[redacted]

Safety

While the operating and regulatory performance of Palo Verde during 2005 was poor, GDS has not found any evidence or indication that operation of the plant has compromised safety. Palo Verde managers stress nuclear safety as a top priority and all decisions consider nuclear safety. GDS found the decisions of APS management to be conservative and the plant Technical Specifications that govern plant operation were strictly followed. None of the outages investigated resulted in or from unsafe operations and, in fact, demonstrated that APS was willing to shutdown the plant when any safety concerns were identified. Palo Verde was safely operated throughout 2005.

IV. PRUDENCE STANDARD

In our analysis, we have evaluated APS' performance by comparison to the reasonable decisions and actions of a qualified and experienced utility manager given what was known or should have been known at the time without the benefit of hindsight. Thus, the actions and decisions of Palo Verde personnel must be judged on what they knew, or reasonably should have known, at the time the action was taken or the decision was made without benefit of hindsight.

V. REVIEW OF 2005 PALO VERDE OUTAGES

The following is a summary of the 2005 Palo Verde outages including a description of the cause of each outage, APS' estimate of the replacement power cost associated with each outage, a determination of whether or not the outage was avoidable, and a determination of whether or not the outage was the result of imprudent actions or decisions by APS.

Unit 1 Outages

A. Unit 1 13.8 kV Bus Failure and Reactor Coolant Pump ("RCP")-1B Upper Oil Seal Failure

Date: 02/09/ - 02/19/05

Type: Unplanned

At 10:19 PM on 2/06/05 with Unit 1 operating at 100% power, a 'B' train loss of power occurred in Unit 1 when an electrical fault within cubicle 1E-NAN-S06J resulted in circuit breaker 1E-NAN-S06H tripping open on over-current. The Train "B" Emergency Diesel Generator ("EDG") started as a result of under-voltage and loaded the emergency bus as designed. This event resulted in entry into Technical Specification Limiting Condition for Operation ("LCO") 3.8.1 which required that the bus be restored to operable condition or the plant be shutdown within 72 hours. Unit 1 began a shutdown in the early morning of 2/9/05. During the startup on 2/16/05 at 0110, RCP-1B experienced failure of the upper oil seal. This seal failure delayed the startup until 2/19/05.

Cause:

As discussed in APS' Significant Root Cause Investigation Report 2775015,[16] the direct cause of the bus 1E-NAN-S06 failure was an electrical fault in cubicle 'J' within the line side primary disconnect assembly (rosette) compartment above the circuit

[16] Significant Root Cause Investigation Report 2775015. (Attachment 8)

breaker. The electrical fault and resulting explosion completely destroyed the bus side rosettes and upper portions of the primary circuit breaker bushings. APS found that the root cause of this event was indeterminate due to the extent of damage. However, APS determined that the most probable root cause was that the 'C' Primary Disconnect Assembly ("PDA") was damaged as a result of an electrical three-phase fault in the rear of switchgear cubicle 1ENANS06J that occurred in 1992. A possible contributing cause was the lack of inspection of the switchgear cubicle and line PDAs anytime following the 1992 electrical fault event.

During startup from this unplanned outage, excessive oil leakage from the RCP-1B thrust bearing upper seal was observed. The cause of the leakage was determined to be an O-ring of incompatible material that had been installed in the seal.[17]

Net Replacement Power Cost: $[redacted]

Net Replacement Power Cost due to O-ring delay: $[redacted]

References:

Significant Root Cause Investigation Report 2775015

CRDR 2777226 Upper Oil Seal O-Ring Failure

Analysis:

The Root Cause Investigation ("RCI")speculates that the bus failure could have been caused by damage to the PDA which occurred in a prior electrical fault in 1992. However, due to the extent of damage, this could not be confirmed. No inspection was performed following the 1992 event. However, there is no assurance that an inspection would have revealed a fault that took some 13 years to cause failure. The bus failure that initiated this outage could not have been foreseen and was unavoidable. Concerning the RCP oil seal failure, the receipt inspection and the inspection prior to installation did not identify that the O-ring provided by the vendor was made of the incorrect material. The

[17] Condition Report / Disposition Request (CRDR) 2777226 Upper Oil Seal O-Ring Failure. (Attachment 9)

delay in startup caused by the RCP oil seal failure was avoidable by a more diligent effort and attention to detail, including a more comprehensive receipt inspection and verification of the proper O-ring material prior to installation as is now being conducted. This view is supported by APS' analysis of the event in CRDR 2777226 which states "...it would be most beneficial to ensure the TB Seal O-rings were composed of the correct material before they are installed, and preferably at the receipt inspection stage of the procurement process." However, APS' response to PB-5.1(b) states:

> The incorrect O-ring materials were shipped as the result of factory error. The correct material was ordered; however, the factory shipped the wrong O-rings to Palo Verde with documentation for the "correct" O-rings. The incorrect O-rings received had the same size and appearance as the "correct" O-rings but were designed for water application and not oil.

Based on this explanation, and without prior similar events, APS' prior inspection practices were reasonable. Therefore, this outage extension is found to be the result of vendor error.

B. Unit 1 Emergency Diesel Generator 'A' Governor Failure

Date: **03/18 - 03/21/05**

Type: **Unplanned**

On March 17, 2005 Emergency Diesel Generator 'A' failed to start during a post maintenance retest. The EDG reached approximately 100 RPM for 15 seconds and then tripped. It was determined that the failure to start was due to a governor failure. The faulty governor was replaced. Re-testing of the EDG involved a load rejection test which required that the unit be shutdown to perform in accordance with the Plant Technical Specifications.

Cause:

APS conducted a Root Cause Investigation of this failure as reported in CRDR 2782680. A sample of the governor lube oil was taken and the faulty governor was sent to the vendor, Engine Systems Incorporated ("ESI"), for testing. The oil sample was found to contain very high levels of water (5159 ppm vs an upper limit of 1500 ppm). Normal water content is in the 100-200 ppm range with new oil required to be less than 500 ppm. An internal inspection revealed rust in the oil seal retainer area, on the base, and on the accumulator springs. The RCI concluded that the direct cause of the governor failure was oil contamination inside the governor actuator. No root cause could be found for this event. However, the RCI identified three most probable causes of water introduction into the actuator lube oil sump:

1. Water was introduced at the Woodward Governor Company during refurbishment of the governor in June 2000 and never completely drained.
2. The governor was stored in the Palo Verde warehouse drained of oil for 9 months creating prime conditions for rust formation.
3. Water may have been introduced during an oil change in April 2004. This was deemed a lesser probability based on a walk down of the oil change procedure with no obvious discrepancies found.

Net Replacement Power Cost: $[redacted]

References:

Root Cause Investigation in CRDR 2782680

NRC Inspection Report IR 2005002

Licensee Event Report ("LER") 2005-006-00

Analysis:

The cause of the governor failure was water and rust in the lubricating oil. APS identified several possibilities of the cause of the water in the lube oil but could not identify the cause with certainty. Storage of the governor drained of oil in a warehouse that was not climate controlled is not a good practice. APS now requires that oil be added to governors when they are received in the warehouse to minimize the possibility

of rust formation. The Woodward Governor Technical Manual states "*oil contamination is the major cause of actuator troubles*" and *"Particles of dirt and water in the oil are the greatest causes of governor and actuator failures."*[18] This outage was the result of imprudence and was avoidable by ensuring that the storage conditions and pre-installation inspection of the re-furbished governor were commensurate with the importance of this equipment.

C. Unit 1 Emergency Diesel Generator 'B' Voltage Regulator Failure and Reactor Trip due to Operator Error

Date: **08/11-08/28/05**

Type: **Unplanned**

On August 9, 2005, EDG 'B' failed to maintain proper steady state output voltage during performance of a routine monthly surveillance test. Maintenance personnel were unable to correct the problem within the 72 hours allowed by the plant Technical Specifications and Unit 1 was shutdown on August 12, 2005. EDG 'B' was returned to operable status on 8/14. However, the startup was delayed due to several equipment problems including an oil leak on Reactor Coolant Pump ("RCP") "1A". On 8/26 during startup, the unit tripped due to an operator error in controlling the feedwater to the Steam Generator.

Cause:

The problem with EDG 'B' was a failed diode in the automatic voltage regulator ("AVR"). Several RCPs at Palo Verde have experienced the leaking oil seal problem. This problem is discussed in detail in connection with a forced outage of Unit 3 in July for the same problem. The cause of the August 26, 2005 trip during startup included individual and crew failures to implement expected requirements and good practices

[18] CRDR Number 2782680 Emergency Diesel Generator 1A Failure to Attain Rated Voltage/Frequency, Rev. 0, page 12 of 54 (Attachment 10)

prescribed by their training and procedures. The Root Cause Investigation of this event identified the following direct, root and contributing causes:[19]

> **Direct Cause #1:** The assigned dayshift licensed operator for Steam Generator feedwater control failed to request CRS[20] concurrence when placing the digital feedwater control system in manual when level was lower than desired under automatic control. This communication failure isolated the individual from supervisory oversight and the crew's ability to assess the overall plant condition. Subsequently, feedwater flow was increased by operator action at a rate in excess of the rate required to compensate for the steaming rate at that power level and resulted in a high steam generator level and subsequent MSIS[21] and reactor trip.
>
> **Direct Cause #2:** Crew members failed to provide the team support needed to ensure individual errors are promptly identified and corrected.
>
> **Root Cause #1**: Consistent standards of performance by Unit 1 Operations Crew C were not sufficiently anchored.
>
> **Root Cause #2**: Feedwater control system performance issues at low power levels have not been effectively resolved since the digital upgrade. This has led to acceptance of operational strategies to cope with system instability at low power levels.
>
> **Contributing Cause #1**: Procedures 40DP-9FT01&02, *Feedwater Pump Turbine A(B)* are not sufficiently human factored for all users, making them susceptible to performance error and resultant system perturbations.

[19] CRDR Number 2825485, Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup. Attachment 11)
[20] CRS - Control Room Supervisor
[21] MSIS – Main Steam Isolation Signal

Contributing Cause #2: Common belief existed among licensed operators that the DFWCS[22] cannot reliably control SG[23] level well at low power. This belief was not based on actual performance data and led to acceptance of the condition and mitigating strategies.

Contributing Cause #3: Training was not commensurate with the unidentified difficulty of putting the DFWCS into auto operation given the current procedure detail and system design. This has resulted in mis-operation of DFWCS components while in single element control.

Net Replacement Power Cost: $[redacted]

Net Replacement Power Cost due to 8/28 Reactor Trip: $[redacted]

References:

NRC IR 2005004

LER 2005-004-00

LER 2005-005-00

CRDR 2821210

CRDR 2811543

CRDR 2825485

Analysis:

The initiating event of this outage, failure of the Automatic Voltage Regulator diode, could not have reasonably been foreseen and was unavoidable. As will be discussed later, the extension of the outage due to the RCP seal oil leakage was avoidable but not the result of imprudent actions by APS. The 8/26/05 reactor trip and resulting outage extension would have been avoided with prudent operation and management. This reactor trip and outage extension exemplify the human performance problems at Palo Verde. The operator failed to follow procedures and failed to communicate his actions with shift management as required by the procedure. It is closely related to the

[22] DFWCS – Digital Feedwater Control System
[23] SG – Steam Generator

findings of the INPO evaluation including lack of consistent standards, lack of accountability and a willingness to accept longstanding equipment problems. This outage also is a consequence of the lack of effective problem resolution as identified in Root Cause #2 and in the NRC substantive cross-cutting issue in problem identification and resolution. In addition, even though the concern with the ability of the digital feedwater control system to maintain steam generator level at low power was well known in the operations department, training of the operators was not commensurate with the difficulty encountered putting the control into automatic mode. For these reasons, the delay in completion of this outage and resulting cost due to the reactor trip on August 26 is due to imprudence.

D. Unit 1 Refueling outage and Steam Generator Replacement

Date: **10/8-12/27/05**

Type: **U1 Refueling**

This planned refueling outage included refueling Unit 1 and replacement of the Steam Generators. The outage was planned for 75 days and the actual duration was 77 days, 1 hour and 44 minutes.

Cause:

Planned refueling and Steam Generator Replacement

Cost: NA

References:

APS07243

Analysis:

The actual duration of 77 days, 1 hour and 44 minutes is very fast for a Steam Generator replacement outage. Radiation exposure was very low and costs were within budget. This was a complex outage that was well planned and executed.

E. Unit 1 Shutdown Cooling Line Vibration

Date: **12/27-12/31/05**

Type: **Reduced Power Operation**

Unit 1 operated at a reduced power level of 25 to 30% since startup from the fall 2005 refueling outage through the end of 2005 because of excessive vibrations in the Shutdown Cooling Line. Vibration levels trended upward during the prior operating cycle. Modifications were installed during the refueling outage. However, upon return to service, higher vibration levels were experienced. This outage continued into 2006.

Cause:

As of the end of 2005, the cause of the high vibration levels had not been determined.

Cost: $[redacted]

References:

APS presentation to ACC

Interviews at Palo Verde site

Analysis:

This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem. Additional investigation will be needed to determine the cause of and responsibility for this outage.

Unit 2 Outages

F. Unit 2 Refueling Outage

Date: **04/02-05/20/05**

Type: **Planned Refueling**

This outage was a standard refueling outage ("RFO") for Unit 2. It was scheduled for 35 days and the actual duration was 48 days, 21 hours and 50 minutes. The duration of this outage was approximately 14 days longer than scheduled.

Cause:

Completion of the refueling outage was delayed due to a number of equipment problems including problems with the refueling machine and spent fuel handling machine.

Net Replacement Power Cost: $[redacted]

References:

APS response to PB 1.9

Interviews with Peter Borchert and Bill Chapin

APS Response to PB 5.5

Analysis:

APS had numerous problems with the refueling equipment that delayed the completion of this outage. It appears that some of these problems had occurred previously while others were experienced for the first time during this RFO. APS outage managers reviewed each of the outage delays with GDS personnel. APS conducted extensive maintenance on the fuel handling equipment prior to the outage. However, the refueling equipment is old and prone to failure even with extensive pre-outage maintenance. APS is planning to replace the refueling equipment prior to the next refueling outage. GDS concludes based on interviews with APS outage management personnel and review of documentation that APS' preparations for the April refueling outage were reasonable because of the extensive pre-outage maintenance to eliminate known problems, the efforts to minimize delays when problems were found and the emphasis on safety during the outage. The outage delays were not the result of imprudence.

G. Unit 2 Core Protection Calculators ("CPC") Inoperable

Date: **08/22-08/26**

Type: **Unplanned**

On August 22, 2005, Unit 2 was shutdown when all four channels of the Core Protection Calculators were declared inoperable. The CPCs consist of four separate,

redundant channels. Each channel is a computer system that continuously calculates thermal conditions and thermal limits within the reactor. The CPC system is an integral part of the plant protective system in that it provides two trips to the reactor protection system. On August 22, 2005, control room personnel declared all four channels of the CPCs inoperable and the unit was shutdown in accordance with Technical Specifications.

Cause:

On May 18, 2005, Westinghouse personnel became aware of a potential problem with the version of the CPC software installed in Unit 2. It was discovered that the installed version of the CPC software was not consistent with the system requirements regarding the system response to analog input module errors. In other words, the CPC would not trip the plant when required under all conditions. Due to errors in the installed software, the CPCs would not generate a trip as required when both analog input modules within a CPC channel indicated an error. On August 18, Westinghouse completed an apparent cause analysis and concluded that the issue was a nuclear safety concern. Palo Verde personnel were alerted to this problem during an August 22 conference call. After performing a test in the shop that confirmed the problem, Palo Verde personnel notified the Unit 2 Shift Manager and the decision was made to shutdown the unit. The direct cause of the issue was a 2002 revision of the software requirements specification that led to an inconsistency with the system requirements specification. APS found that the root cause of this inconsistency was that no formal communication plan existed with the internal Westinghouse "downstream" users of the reactor trip.

Net Replacement Power Cost: $[redacted]

References:

LER 2005-005-00

CRDR2835132

Analysis:

As described in CRDR Number 2824258,[24] this outage was the result of flawed software provided by the vendor, Westinghouse. Westinghouse's internal communication in development of this software was inadequate. This outage could not have reasonably been foreseen by APS.

H. Unit 2 Refueling Water Tank Inoperable

Date: **10/11-10/20/05**

Type: **Unplanned**

On October 11, 2005 with Palo Verde Units 2 and 3 at 100% power, both trains of Emergency Core Cooling System ("ECCS") and Containment Spray were declared inoperable in both units because the Refueling Water Tanks ("RWT") for both units were declared inoperable. The RWT provides suction to the safety injection pumps and the containment spray pumps in the event of a loss of coolant accident. With both trains of ECCS and Containment Spray inoperable, the plants were shutdown in accordance with the Technical Specifications.

Cause:

During a supplemental NRC inspection resulting from the yellow finding in 2004 (which also dealt with a concern that air entrainment could endanger the operability of the ECCS and Containment Spray pumps), NRC inspectors raised a question concerning the possibility that air would be entrained in the suction from the RWT under certain postulated conditions. The concern was that a large amount of entrained air could damage the critical safety pumps and render them inoperable. APS was unable to demonstrate that air entrainment from the RWT was not a concern and the plant was shutdown while APS conducted the necessary analysis. APS ultimately concluded and demonstrated to the NRC that air entrainment from the RWT was not a safety issue.

Net Replacement Power Cost: $[redacted]

References:

[24] CRDR Number 2824258, U-2 3.03 Shutdown Due to CPC Software dated 11/30/2005. (Attachment 12)

LER 2005-005-00

CRDR2835132[25]

Analysis:

The RWT air entrainment issue was identified by the NRC during the NRC's 95002 Supplemental Inspection in the fall of 2005. This inspection was a part of the additional oversight that resulted from the yellow findings in 2004 due to containment sump piping being left empty. The RWT air entrainment issue is closely related to the 2004 yellow finding in that the fundamental concern of both issues is the possible damage to safety-related pumps due to air entrainment either from the empty sump piping or from the drain down of the RWT. Numerous evaluations of Palo Verde described above in this report have identified problems with Palo Verde's Corrective Action Program including the crosscutting issues in Problem Identification and Resolution. One of the problems identified is that the analyses of problems have been too narrow. Even though the RWT was within the boundary of the evaluation of the yellow finding event, and the primary concern was the potential for damage to safety related pumps due to air entrainment, APS personnel did not identify the RWT concern until it was pointed out by NRC inspectors during the 95002 inspection in October 2005. A more comprehensive root cause evaluation with a broader focus should have identified this concern in 2004. For these reasons, this 2005 outage was avoidable.

This outage was discussed with Palo Verde's NRC Senior Resident Inspector Mr. Greg Warnick on March 28, 2006. Mr. Warnick stated that he believed this outage to be avoidable and referenced the NRC's conclusions found in Inspection Report 200512 dated January 27, 2006 which presents the results of the 95002 Supplemental Inspection. Section 4OA5.1 of this report addressed the RWT air entrainment issue. In its report, the NRC states

[25] CRDR 2835132 pages 16 through 162, Evaluation of RWT Suction Behavior during SIS and CSS Transition to RAS and Related Design Interface Criteria (Attachment 13)

> During preparation of this inspection, the inspectors reviewed the transportability analysis included in the Condition Report/Disposition Request (CRDR) 2726509, "ECCS Sump Suction Piping Discovered in an Unanalyzed Condition," Revision 1. This report included extent of condition and extent of cause evaluations for the ECCS sump issue (event date July 29, 2004). The inspectors noted this report included the RWT in its scope, but did not address the RWT as a potential source of air entrainment into the ECCS. The inspectors also noted that the PVNGS design did not include automatic closure of the RWT isolations valves with a recirculation actuation signal (RAS). The inspectors noted that the licensee did not fully understand the plant design basis and the dynamic of the system at the time of a RAS. Based on these observations, the inspectors questioned licensee personnel further on the potential of air entrainment from the RWT into the ECCS.[26]

A full and complete understanding of the plant design basis is critical to safe operation of a nuclear power plant. The NRC also concluded that Palo Verde personnel's "attention to detail was lacking and there was poor inter- and intra-group coordination" as described in more detail in the NRC inspection report below[27]:

- The inspectors determined that the licensee extent of cause and extent of condition reviews were narrowly focused. The licensee defined very extensive design criteria and features that could be pertinent to the original (Yellow) violation. However, if some design document or interface document addressed the design criteria, the licensee performed no further review. There was not a thorough effort by the licensee to validate the design criteria. This was clearly demonstrated in the RWT voiding issue. Examples included the licensee's misunderstanding of the maximum RWT Temperature, and their reliance on a Combustion Engineering interface requirement, for piping elevations, to meet all dynamic thermal-hydraulic design criteria for ECCS piping.

- The licensee also noted, in other ongoing programs at the facility, that design basis information was not handled with appropriate attention to detail. Examples

[26] Palo Verde Nuclear Station – NRC Supplemental Inspection Report 05000528/200512; 05000529/200512; 05000530/200512 dated January 26, 2006, pages 7 - 8. (Attachment 3)
[27] Palo Verde Nuclear Station – NRC Supplemental Inspection Report 05000528/200512; 05000529/200512; 05000530/200512 dated January 26, 2006, pages 10 - 12. (Attachment 3)

included the licensee's evaluation statements that their UFSAR[28] validation process, under 10 CFR 50.54(f), was shallow; quality assurance reviews indicated that engineers did not verify reference values or conditions for design calculations; and various design organizations did not interface well with each other for multi-disciplinary issues.

- The inspectors determined that the licensee's evaluation of technical issues was iterative, which demonstrated a lack of thoroughness in reviews. The inspectors noted that engineering personnel would address one particular aspect or consideration when a design problem was presented. However, when questioned by the inspectors or engineering management, more discrepancies would be identified by the engineering personnel. The inspectors determined that design engineering personnel were making broad assumptions of criteria in their reviews, and in several cases, were using unverified or unstated assumptions from other groups. An example was the stroke times of the containment sump isolation valves used by design engineers in their RWT required volume calculations. There was no stated basis for the times used, and design engineers could not explain to the inspectors where the values came from. Additionally, other engineering personnel were not challenging these assumptions in peer or supervisory reviews. These organizational and human performance issues caused the inspectors to question the appropriateness of the extent of cause review for the (Yellow) Design Control violation.

- The inspectors noted a lack of communication between organizations, and a lack of attention to detail when coordinating critical design evaluations between organizations. During discussions of this RWT voiding issue, engineering personnel inappropriately described system operation to operators while discussing the operability of ECCS (see Section 4OA5.1). One shift test engineer informed an inspector that on October 8, 2005, he was told by the operator he was relieving, that "I believe we may be in 3.0.3,"[29] based on the emergent RWT voiding issue. The individual apparently did not address this to his crew supervision because he had not had time to reconcile his own questions. Subsequently, the operations crew and the lead shift test engineer reviewed the RWT information, without consulting engineering, and concluded the previous operator's questions were not of concern. The inspectors were concerned that this demonstrated problem resolution by isolated groups, and did not look across organizational boundaries.

[28] UFSAR – Updated Final Safety Analysis Report
[29] Technical Specification 3.0.3 requires that the plant be shutdown when the condition of the plant is found to be outside the plant's design basis.

- The inspectors determined that the licensee had a very limited use of operating experience for the RWT issue. The licensee previously identified that ineffective use of operating experience was a contributor to the (Yellow) ECCS violation. The licensee also had several self-identified findings of ineffective operating experience use in the last year, following reviews of their substantive crosscutting problem identification and resolution issue and their engineering program review. However, during the review of the RWT issue, the licensee did not consider all relevant operating experience. The inspectors brought to the licensee's attention a similar finding in 2003 at the Brunswick Nuclear Power Station, and a specific American Society of Mechanical Engineers' study for uncovering the RWT vortex breaker at the Donald C. Cook facility in 2001. This study not only included detailed flow modeling of the same system, it partly refuted the original operability determination that the licensee performed under OD 301 by stating air would enter the suction piping.

- The inspectors determined that the schedule for effectiveness reviews did not ensure a timely review of the adequacy of corrective actions. Two root causes, and one of the contributing causes, were addressed by a condition report action item (CRAI) 2825679, which at the time of the inspection was already closed. This corrective action included all-hands communications from senior management to communicate the need for effective questioning attitudes and technical rigor. This corrective action was closed on September 9, 2005, after such meetings were conducted to "emphasize that it is essential that all employees have a strong and effective questioning attitude and technical rigor, and to challenge assumptions and/or any situations which do not seem safe, or per design, or per procedure, or per expectation, or in general do not seem appropriate". The licensee stated this was placed in effectiveness review process, but that specific review of effectiveness of these actions was not planned until 2006. The inspectors determined that the effectiveness review was untimely in that unacceptable performance continued without additional corrective actions being implemented.

Based on these findings by the NRC and the documented poor performance in the area of Problem Identification and Resolution and deficiencies in the Corrective Action Program, GDS concludes that the RWT outages for units 2 and 3 in August 2005 were avoidable and imprudent.

Unit 3 Outages

I. Unit 3 Pressurizer Heater Replacement and Reactor Coolant Pump Seal Oil Leak

Date: **05/22-06/24/05**

Type: **Planned**

Pressurizer heaters are cylindrical heaters that are used to assist in controlling the pressure in the reactor coolant system. Water in the pressurizer is heated to increase the saturation pressure of water in the pressurizer and thus increase the pressure in the reactor coolant system. In the fall 2004 refueling outage, Unit 3's pressurizer heaters were replaced with heaters supplied by [redacted]. The new [redacted] heaters began failing shortly after startup in November 2004. On May 22, 2005, Unit 3 was shutdown for reactor coolant pump maintenance and to replace nine heaters. During startup from this outage, five more [redacted] supplied heaters failed. APS decided to replace all of the [redacted] heaters with heaters from a different manufacturer, and of the original design.

Cause:

[redacted]

[30] CRDR 2809138, page 61 – 87, Pressurizer Heater Failures at Palo Verde and Waterford Root Cause Investigation Report dated October 4, 2005. (Attachment 14)

5. [redacted]

Net Replacement Power Cost: $[redacted]

References:

NRC Inspection Report IR2005003

CRDR2809138

CRDR2805701

Analysis:

This outage was caused by faulty or defective vendor supplied equipment. The equipment supplier was imprudent in [redacted]. A review of the facts associated with this outage indicate that APS could not have reasonably foreseen the [redacted], and APS' decision to replace the remaining suspect heaters prior to the summer season was prudent.

J. Unit 3 Reactor Coolant Pump Seal Oil Leak

Date: **07/06-07/13/05 and 10/02-10/07/05**

Type: **Unplanned**

Unit 3 was shutdown in July 2005 and again in October 2005 to replace leaking Reactor Coolant Pump thrust bearing oil seals. Oil was leaking past the upper thrust

bearing and being collected in the lower thrust bearing at which time it would be pumped back to the upper thrust bearing. While this was not a nuclear safety problem, the oil lift pump was not designed for the near continuous duty required, and APS was concerned that failure of the oil lift pump would result in a plant outage. In addition, other outages were extended or impacted due to RCP seal oil leakage including the Unit 1 Diesel Generator outage in August 2005 and the Unit 3 pressurizer heater outage in May 2005.

Cause:

Oil leakage from the RCP upper thrust bearing seal has been a recurring problem at Palo Verde but had not caused a plant outage prior to 2004. In 2004, Palo Verde personnel began a program to implement modifications to the oil seals to reduce leakage to a more acceptable level. In the words of Palo Verde Director of Nuclear Engineering, Carl Churchman, these modifications "took the problem from chronic to acute." In other words, APS' attempts to resolve the problem in fact made it worse. Westinghouse has completed a root cause analysis of the leakage problem and APS is in the process of developing a comprehensive root cause analysis. In addition, APS is conducting a program to develop a new seal design to eliminate the leakage problem.

Net Replacement Power Cost: $[redacted] for July outage and $[redacted] for Oct. outage

References:

CRDR 2808859

CRDR 2811543

Interviews with Carl Churchman

Analysis:

Problems with the RCP upper thrust bearing oil seal were identified during the early days of operation at Palo Verde. While the leakage was not enough to cause an outage, it was greater than the desired level and was thought to be a potential fire hazard in containment. In 2004, Palo Verde personnel initiated an engineering program to attempt to reduce the leakage past the oil seals. While the modifications were not

successful, and in fact made the leakage worse, the actions were a proactive attempt to improve a problem in the plant. While the RCP oil seal outages could perhaps have been avoided by a more measured approach to the seal modifications, or by doing nothing, the actions taken to improve the seal oil leakage were reasonable and prudent. It should be noted, however, that the success of the current actions to develop and install a newly designed seal will not be known for some time to come. If the oil leakage is eliminated or reduced to the desired level and no future outages are experienced due to this problem then the actions taken will have been successful. While the actions taken to date have been reasonable and prudent, no final conclusions regarding their effectiveness can be made at this time.

K. Unit 3 Refueling Water Tank Inoperable

Date: **10/11-10/20/05**

Type: **Unplanned**

Note: This is the same as the RWT Unit 2 Outage.

On October 11, 2005 with Palo Verde Units 2 and 3 at 100% power, both trains of Emergency Core Cooling System and Containment Spray were declared inoperable in both units because the Refueling Water Tanks in both units were declared inoperable. The RWT provides suction to the safety injection pumps and the containment spray pumps in the event of a loss of coolant accident. With both trains of ECCS and containment spray inoperable, the plants were shutdown in accordance with the Technical Specifications.

Cause:

During a supplemental NRC inspection resulting from the yellow finding in 2004, NRC inspectors raised a question concerning the possibility that air would be entrained in the suction from the RWT under certain postulated conditions. The concern was that a large amount of entrained air could damage the critical safety pumps and render them inoperable. APS was unable to demonstrate that air entrainment from the RWT was not a

concern and the plant was shutdown while APS conducted the necessary analysis. APS ultimately concluded and demonstrated to the NRC that air entrainment from the RWT was not a safety issue.

Net Replacement Power Cost: $7.672 million

References:

LER 2005-005-00

CRDR2835132

Analysis:

See the Unit 2 Refueling Water Tank Inoperable outage for a detailed analysis of this outage. As stated in the analysis of the Unit 2 RWT outage, based on these findings by the NRC and the documented poor performance in the area of Problem Identification and Resolution and deficiencies in the Corrective Action Program, the RWT outages for units 2 and 3 in August 2005 were avoidable and imprudent.

Summary of Imprudent 2005 Palo Verde Outages

The following table presents a summary of the outages or outage extensions that were the result of imprudence and does not include additional disallowances for lost margins and interest costs.

Table 3. SUMMARY OF IMPRUDENT PALO VERDE OUTAGES 2005

OUTAGES OR OUTAGE DELAYS DUE TO IMPRUDENCE			
Description	**Date**	**Cause**	**Cost**[31]
Unit 1 – Diesel Generator Governor Failure	3/18 – 3/21/05	Oil and rust in governor	[redacted]
Pre-PSA Amount			[redacted]
Unit 1 – Outage extension due to reactor trip on high steam generator level	8/26 – 8/28/05	Reactor trip due to operator error	
Unit 2 – RWT inoperable	10/11-10/20/05	RWT declared inoperable	[redacted]
Unit 3 – RWT inoperable	10/11-10/20/05	RWT declared inoperable	[redacted]
Post PSA Amount			[redacted]
Total Replacement Power Cost Due to Imprudence			**$16.269 million**

[31] Costs shown in this table present APS' estimates of replacement power only and reflect the 90/10 split for outages after April 1, 2005. Staff's quantification of the total cost impact of the imprudent outages is addressed in Section VI of this report.

VI. TREATMENT OF COSTS ASSOCIATED WITH PALO VERDE OUTAGES

As part of the Settlement in Docket No. E-01345A-03-0437, APS was allowed to implement a Power Supply Adjustor ("PSA") to allow for the recovery of changes in fuel and purchased power costs. The fuel and purchased power costs recoverable under the PSA are subject to a prudency review by the Commission and may be disallowed if it is found that "the costs were not prudently incurred." The PSA provision also includes an incentive mechanism that only allows 90% of the increased costs or savings to be passed through to customers.

This Report addresses Palo Verde's unplanned outages for all of 2005. However, the PSA provision became effective on April 1, 2005. Any power replacement costs for unplanned Palo Verde outages from January 1, 2005 through March 31, 2005 cannot be recovered under the PSA. Since power replacement costs for imprudent Palo Verde outages from January 1, 2005 through March 31, 2005 fall within the test year in APS' pending rate case, these costs should be addressed in that proceeding. Power replacement costs for imprudent Palo Verde outages from April 1, 2005 through December 31, 2005 can be addressed in APS' upcoming rate case or another proceeding. This Report identifies the costs associated with imprudent Palo Verde outages for January-March of 2005; April-December of 2005, and the total for 2005.

A. APS' Replacement Power Cost Analysis

APS has developed a Statistical Analysis System (SAS) model to estimate the replacement power costs during the 2005 unplanned Palo Verde outages. The SAS model first determines the amount of nuclear energy that was lost as a result of the unplanned outage, i.e., the amount of replacement energy that was needed for each outage. Second, the cost of the replacement power or energy is determined by the model. Based upon APS' analysis, the replacement energy is provided from: (1) increased generation at APS

power stations and (2) purchases of power from other utilities. Next, APS estimates the amount of nuclear fuel expense that was not incurred, or was "avoided" as a result of each unplanned outage, i.e., the portion of nuclear fuel expense that would be recovered in base rates but was not incurred due to the unplanned outage. To determine the amount of replacement power costs that should be recovered in the PSA, APS then reduces the total replacement power cost by the nuclear fuel costs that were not incurred due to the outage but were included in the PSA base cost of fuel and purchased power. A monthly summary of the results of this APS' analysis was provided in response to data request number 1-7(k).

Next, APS further reduces the monthly amount of replacement power costs for unplanned Palo Verde outages by the monthly amount of replacement power costs included in the PSA base cost for a "normal" level of unplanned outages based upon an assumed forced outage rate. APS' analysis presumes that these "normal" replacement power costs included in the PSA base cost should be subtracted from the total replacement power costs for actual unplanned outages since APS claims those costs have already been recovered in base rates. This presumption assumes that all of the actual unplanned outages were prudent.

The following Table 4 summarizes the results of APS' analysis of replacement power costs due to Palo Verde unplanned outages since the PSA provision became effective:

Table 4. SUMMARY OF APS' CLAIMED REPLACEMENT POWER COSTS FOR PALO VERDE FORCED OUTAGES

Month of 2005	APS' Gross Estimated Replacement Power Cost ($ x 1,000)	Nuclear Fuel Expense Avoided ($ x 1,000)	APS' Claimed Replacement Power Cost Less Avoided Fuel ($ x 1,000)	"Normal" Replacement Power Costs in PSA Base Cost ($ x 1,000)	APS' Claimed Net Replacement Power Costs ($ x 1,000)
April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May					
June					
July					
August					
September					
October					
November					
December					
Total	**$ 60,790**	**$3,868**	**$56,922**	**$7,407**	**$49,516**
			Less	**10%(1)**	**$4,952**
Net Total					**$44,564**

Note: (1) 10% reduction stems from the 90/10 sharing between APS and the ratepayers.

Based upon the PSA provisions, APS is only allowed to recover 90% of the total amount of net replacement power costs. Accordingly, APS is claiming that 90% of $49,516,000, or $44,564,000 should be recoverable under the PSA. Again, APS's claim assumes that all of the unplanned outages were prudent.

B. Results of Analysis of Cost Impacts of Imprudent Palo Verde Outages

GDS reviewed the results of the SAS model used by APS, including the inputs used by APS and other information provided by APS. Based upon our review and

analysis of APS' replacement power cost calculation, two revisions need to be made to APS' methodology. In addition, once these two revisions are made, then the amount of interest on the balance of fuel and purchased power cost under-recoveries needs to be recalculated. Each of these revisions and adjustments is explained below.

1. Netting the PSA base cost amount from the total replacement power cost amount.

As discussed in section VI. A. above, APS' analysis reduces the monthly amount of replacement power cost for unplanned Palo Verde outages by the amount included in the PSA base cost for assumed "normal" levels of unplanned outages. In other words, for any amount of replacement power costs disallowed for imprudence, APS' analysis would reduce that disallowed amount by the amount of replacement power cost for unplanned outages included in the PSA's base cost. While this adjustment may be an appropriate assumption for outages not due to imprudence, the adjustment should not be made to reduce disallowed fuel costs related to imprudent Palo Verde outages. If the outage is imprudent, the Commission should disallow all of the replacement power costs. Accordingly, any replacement power costs related to Palo Verde outages determined to be caused by imprudence should be disallowed in their entirety and should not be off-set by any amounts included in the PSA base cost.

Page 1 of Attachment 15 to this report provides a quantification of the replacement power costs due to imprudent Palo Verde outages to be disallowed from recovery in the PSA. Column (c) on page 1 of Attachment 15 provides APS' monthly amount of replacement power costs for all unplanned Palo Verde outages in 2005 after implementation of the PSA. Column (d) is the portion of replacement power costs in column (c) related to imprudence. The recommended disallowance amounts are shown in column (e) which are the replacement power cost amounts in column (d) reduced by the 90/10 recovery ratio provided for in the PSA. Page 2 of Attachment 15 provides the

2005 replacement power costs for imprudent outages prior to the implementation of the PSA, or prior to April 1, 2005. Page 3 of Attachment 15 provides the replacement power costs both for forced outages due to faulty equipment and for all other forced outages not found to be imprudent.

2. Palo Verde outage impacts on off-system sales margins

APS regularly makes off-system sales into the wholesale power markets from available excess generation. The margins earned on these off-system sales are used to reduce the amount of fuel and purchased power expenses recoverable through the PSA. When the excess generation is needed to replace Palo Verde generation due to an unplanned outage, then APS has fewer opportunities to make off-system sales. In response to Staff Data Request 2.19, which asks whether APS' replacement power cost analysis considered lost opportunity sales due to the unplanned outages, APS states that:

> The replacement power cost methodology captures only realized costs incurred in serving native load customers and does not attempt to measure lost opportunity sales. Such a calculation would necessarily require the use of some spot market price index to serve as the basis for assigning value to a sale that did not happen, which would correspondingly require significant assumptions about the availability and depth of the market at any point in time relative to that market index. Additionally, assessments of which generating units would truly be available to make such sales would require that operating constraints on the transmission system and spinning and non-spinning reserves be adequately accounted for.

It is clear that reduced levels of nuclear generation due to unplanned outages at Palo Verde would result in lost off-system opportunity sales. The margins on such lost opportunity sales would have been used to offset the fuel and purchased power expenses that APS is seeking to recover through the PSA. APS' failure to quantify the impact due to such lost opportunity sales will reduce the cost impact of any imprudent unplanned

outages, and thereby overstates the amount of any claimed fuel cost under-recovery. APS' claim that this quantification is complex should not be an excuse that results in increased costs to customers. APS has the data, western regional power market experience, and resources to do the analyses. GDS does not have access to the same market information available to APS and does not have APS' day-to-day western regional power market experience. Ideally, the APS analysis should determine both the additional net margins for the off-system sales that were lost and the reduced margins on the off-system sales that did occur.

In addition to lost opportunity sales, the unplanned outages at Palo Verde also reduce the margins on the off-system sales that were made during the outage. As shown on APS' Power Supply Adjustor report for December 2005, several of APS' off-system sales actually had negative margins. Also, in that same report, APS states that "due to unplanned unit forced outages, those sales were supplied out of higher cost generation units than anticipated." In other words, APS committed to the off-system sales assuming the Palo Verde units were running. When the unplanned outages occurred, those off-system sales were either less profitable or made at a loss. The result is that the net margins on off-system sales were less than "anticipated." These reduced margins must be considered as part of the cost impact of the imprudent outages at Palo Verde.

GDS estimates the impact of lost off-system sales opportunities and reduced margins on off-system sales due to imprudent Palo Verde outages to be $2,103,169 (Attachment 16, Column e, Line 11). The calculation of this amount is provided on Attachment 16. As shown in Attachment 16, the estimated amount is determined by multiplying the average margin amount per MWh for off-system sales from April through December 2005 times the MWh reduction in nuclear generation due to each imprudent Palo Verde outage. If APS does not provide an analysis of the reduced margins, then these estimated amounts should be used to reduce any amount of fuel and purchased

power cost under-recovery to be flowed through the PSA. If APS does provide an analysis of off-system sales margins, we would be glad to review the reasonableness of that analysis.

3. Interest

As shown on its monthly Power Supply Adjustor reports, APS is seeking to collect interest on under-recovered fuel and purchased power expenses. Should the Commission disallow the recovery of any APS claimed fuel and purchased power expense under-recoveries, the amount of APS' claimed interest needs to be reduced as well. Based on the recommended disallowances in this report for imprudent Palo Verde outages, the interest amount should be reduced by $85,539 (Attachment 17, Column f, Line 10) through the end of 2005. The calculation of this interest adjustment is provided on Attachment 17. If the interest adjustment calculation is carried through to July 1, 2006, the reduction should be $325,934 (Attachment 17, Column f, Line 18). Also, for each month beyond June 2006, the additional reduction in interest per month is approximately $40,000 (Attachment 17, Column f, Lines 11-16). We have generally used the interest calculation methodology shown on APS' Power Supply Adjustor reports.

C. Summary

In Section V above and in this section, the unplanned outages at Palo Verde that were due to imprudence are identified and the amount of replacement power costs related to these outages is provided. For the 2005 imprudent outages that occurred after implementation of the PSA (April 1, 2005 through December 31, 2005), the recovery of the related replacement power costs through the PSA should be disallowed.

In addition to the replacement power cost impact of the imprudent Palo Verde outages, APS experienced reduced margins on off-system sales and lost opportunity sales due to the imprudent Palo Verde outages. Margins on off-system sales are used to offset fuel and purchased power costs recovered through the PSA. The reduced margins caused by the imprudent outages should be adjusted (increased) to exclude the impacts of these outages, i.e., APS' fuel expenses should be reduced by the adjusted (increased) margin amount. Also, the amount of interest APS is allowed to recover on its under-recovered fuel and purchased power expense balances should be reduced to reflect the disallowed costs and lost margins related to the imprudent Palo Verde outages.

The total cost impact for imprudent Palo Verde outages for 2005 is $18.996 million, including replacement power cost, lost opportunity sales, and interest through June 2006. For the period April 1, 2005 through December 31, 2005 (the period that the PSA was in effect), the recommended disallowance is $17,373,103 (Attachment 18, Page 2, Column f, Line 18). The following table summarizes the components of this disallowance:

Table 5. RECOMMENDED PSA DISALLOWANCES

Component	Amount ($ x 1,000,000)
Imprudent Replacement Power Costs	$14.944
Margins on Lost Opportunity Sales	2.103
Total Interest Adjustment(1)	0.326
TOTAL DISALLOWANCE	$17.373

Note: (1) Includes Interest Adjustment through June 2006.

A more detailed schedule of the recommended disallowances is provided as Attachment 18. The portion of the recommended $14.944 million disallowance for replacement

power costs that is related to APS' claim of $44.564 million for recovery of replacement power costs for 2005 Palo Verde forced outages is $14.401 million.[32] If APS' claim for replacement power costs is adjusted to exclude the portion that was related to imprudent unplanned outages, the remaining amount would be $30.163 million ($44.564 million less $14.401 million).

The Commission should consider how to treat the cost of imprudent unplanned outages at Palo Verde in APS' pending rate case.

[32] The reason that the $14.401 million amount is lower than the recommended disallowance of replacement power costs is that APS reduces its claim for replacement power costs by the amount of replacement power costs for "normal" forced outage levels recovered in the PSA base cost (See Section VI.A.1 above). The $0.543 million is the amount included in the next to last column of Table 4 that is related to imprudent forced outages.

VII. CONCLUSIONS

GDS' investigation of Palo Verde's performance during 2005 has resulted in the following conclusions:

1. Performance of the Palo Verde plant declined significantly over the past three years by almost any measure of performance.
2. The number of outages during 2005 was much higher than normal and the generation and capacity factors were lower than should be expected.
3. APS acknowledges the decline in performance and has implemented a comprehensive and aggressive Performance Improvement Plan to return the plant to its former levels of performance. APS has changed the Palo Verde organization to allow greater focus by the senior management team members on their areas of responsibility. It is too early to assess the effectiveness of the performance improvement plan or the new Palo Verde organization. However, GDS is optimistic that PIP, the new Palo Verde organization, and the commitment of Palo Verde's senior management team will be successful in returning performance at Palo Verde to the desired level.
4. As described in Section V of this report, GDS identified outages and outage extensions during 2005 that were avoidable and were the result of imprudence.
5. Some of the unplanned Palo Verde outages were caused by faulty or defective vendor supplied equipment. We have evaluated APS' actions related to these specific outages and have concluded that APS' actions were not imprudent
6. It is too soon to determine the prudence of the Unit 1 shutdown associated with the shutdown cooling line vibration. This is a unique problem. It appears that APS has made a concentrated effort to resolve the vibration problem. Additional investigation will be needed to determine the cause of and responsibility for this outage once.

7. Although APS received a yellow finding from NRC in 2004 regarding safety related issues of substantial importance, it is GDS' conclusion that there is no evidence or indication that operation of the plant in 2005 has compromised safety.

VIII. RECOMMENDATIONS

1. Ratepayers should not be required to pay for additional costs resulting from imprudent outages or outage extensions. The Commission should disallow all costs resulting from the imprudent outages as presented in Section VI of this report. The amount of $17.373 million incurred after the PSA mechanism was in place, April 1, 2005, should be expressly disallowed from recovery under the PSA mechanism. The amount of $1.623 million incurred before April 1, 2005 should not be eligible for consideration in establishing base fuel costs in the pending rate case.
2. An issue related to the unplanned Palo Verde outages attributable to faulty or defective vendor-supplied equipment is the degree to which APS has sought appropriate legal or other remedies. This report does not address this issue, but instead recommends that the Commission address it in the pending rate case. APS should be given the opportunity to demonstrate the steps that it has taken in this regard, and the Commission should evaluate APS' actions.
3. The Commission should establish a Nuclear Performance Standard that would establish a minimum level of performance for Palo Verde and provide penalties if Palo Verde performance fails to meet this minimum level. Only when Palo Verde is operated at a high capacity factor do APS ratepayers receive the economic benefit of the high capital cost of Palo Verde. A Nuclear Performance Standard would ensure that ratepayers do not suffer economic harm if the performance of Palo Verde is below acceptable levels. Establishment of a Nuclear Performance Standard should be considered during the pending APS rate case.

4. The Commission should order APS to file a semi-annual report with the Commission's Docket Control, describing the plant performance levels, explaining any negative reporting by NRC and INPO Inspectors, and, finally, providing details of the corrective actions taken by the utility. This report should also include information on the replacement cost of power resulting from forced outages of the Palo Verde units. APS should submit this report semi-annually until the Commission decides that it is no longer necessary.
5. Effective programs must be developed to deal with aging equipment issues. The Palo Verde units are now 20 years old and age related problems will become more numerous. The Commission should order APS to evaluate its programs to deal with aging equipment at Palo Verde. This evaluation should consider industry experience with aging equipment, programs established at other nuclear plants that have been successful in managing aging equipment issues, and recent experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve APS' management of aging equipment issues.
6. Procedures for 1) receipt inspection of materials and 2) verification of materials and equipment prior to installation should be improved. Two of the 2005 outages could have been avoided with better inspection of parts and components prior to installation. The Commission should order APS to evaluate its programs for receipt inspection and verification of parts prior to installation. This evaluation should consider industry experience, programs established at other nuclear plants that have been successful in avoiding outages due to installation of incorrect parts, and experience at Palo Verde. APS should submit a report to the Commission within 120 days of the Commission's order in this matter describing the findings of the evaluation and the actions taken to improve receipt inspection and pre-installation verification of parts at Palo Verde.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE INQUIRY INTO THE FREQUENCY OF UNPLANNED OUTAGES DURING 2005 AT PALO VERDE NUCLEAR GENERATING STATION, THE CAUSES OF THE OUTAGES, THE PROCUREMENT OF REPLACEMENT POWER AND THE IMPACT OF THE OUTAGES ON ARIZONA PUBLIC SERVICE COMPANY'S CUSTOMERS.	DOCKET NO. E-01345A-05-0826

REPORT OF

GDS ASSOCIATES, INC.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

ATTACHMENTS 1 - 18

PUBLIC VERSION
REDACTED

August 17, 2006

ATTACHMENT 1

Palo Verde Nuclear Generating Station

Performance Improvement Plan ("PIP")

October 15, 2005

APS07267

PALO VERDE NUCLEAR GENERATING STATION

PERFORMANCE IMPROVEMENT PLAN

INDEX

PART 1: STRATEGIC DISCUSSION 1

1.0 BACKGROUND 1

1.1 Indications of Performance 2

1.1.1 Monthly Trend Reports 2

1.1.2 Assessments 3

1.2 The 2005 Business Plan 3

2.0 PERFORMANCE IMPROVEMENT ORGANIZATION 5

3.0 DEVELOPMENT OF FIVE FOCUS AREAS 5

3.1 Standards 7

3.2 Accountability 7

3.3 Leadership 8

3.4 Human Performance 8

3.5 Corrective Action Program/Problem Identification & Resolution("PI&R") 8

4.0 REVISED Palo Verde MISSION STATEMENT 8

5.0 ALIGNMENT OF Palo Verde MISSION STATEMENT WITH THE PIP 9

6.0 PIP/BUSINESS PLAN RELATIONSHIP 9

7.0 PIP IMPLEMENTATION 10

7.1 PIP Implementation Responsibilities 10

7.1.1 Senior Vice-President Nuclear 10

7.1.2 General Manager Regulatory Affairs and Plant Improvement 10

7.1.3 Director Performance Improvement Team 11

7.1.4 Focus Area Owner 11

7.1.5 Action Plan Owner 11

7.2 PIP Scheduling and Tracking 11

7.3 Focus Areas 11

7.4 Action Plans 12

7.5 Action Plan Revisions 12

7.6 Action Step Closure Process 12
7.7 Action Plan Closure Process 12
7.8 Focus Area Closure Process 12
7.9 Leadership Review Team 12
8.0 PERFORMANCE MONITORING & EFFECTIVENESS REVIEWS 13
9.0 PIP CLOSURE 13

APPENDIX A – Palo Verde Nuclear Generating Station Organizational Chart
APPENDIX B – Leadership Standards and Expectations
APPENDIX C – Palo Verde Performance Monitoring Options

PART 2: TACTICAL ACTIONS TO IMPROVE PERFORMANCE

PALO VERDE NUCLEAR GENERATING STATION
PERFORMANCE IMPROVEMENT PLAN

This Performance Improvement Plan ("PIP") sets out clear direction for how performance improvement will be achieved at the Palo Verde Nuclear Generating Station ("Palo Verde"). The PIP will be a supplement to the 2006 Business Plan and is composed of two parts. Part 1 presents an assessment of performance at Palo Verde and provides a *strategic* overview of corresponding Palo Verde performance improvement activities. Part 2 provides *tactical* actions to achieve improved performance. Specifically, Part 1 identifies five Focus Areas for improvement and Part 2 provides associated Action Plans and Action Steps that will ensure improved performance. Part 2 of the PIP is a "living document" and will be revised and expanded as needed. A new organization will be put in place at Palo Verde to implement the PIP and focus on continuous improvement. This new organization is called the Performance Improvement Team ("PIT").

PART 1: STRATEGIC DISCUSSION

1.0 BACKGROUND

This section presents an assessment of recent performance at Palo Verde and concludes that Palo Verde continues to be operated in a prudent manner that protects the public health and safety. When assessing performance at a nuclear power plant different measures can be used. One measure is economic performance which is measured by production costs. Another measure is how well the plant is doing in implementing the various programs and processes that support the day-to-day operation of the plant. As discussed in more detail below, while the economic performance at Palo Verde continues to be at or near the top industry quartile there is a need for improvement in implementing programs and processes.

In late 2002 or early 2003 performance indicators at Palo Verde began a downward trend relative to the sustained high performance levels in previous years. A cause of this trend appears to have been the realignment of key site leadership that in turn caused the team to be more focused on day-to-day tactical matters, and less focused on strategic planning, standards and accountability. Additionally, in 2004, two significant events occurred at Palo Verde. They are the three unit trip in June 2004 that resulted from a grid disturbance and, the discovery, in July 2004, of the absence of water in portions of Emergency Core Coolant System piping ("RAS Sump Event"). These events also revealed issues with regard to various Palo Verde programs and processes that are in need of improvement.

Site leadership did not fully accept that the Palo Verde performance indicators reflected actual performance until mid 2005. Management's mindset resulted in part from ten previous years of Palo Verde operation at top quartile levels of performance. For

example, the Institute of Nuclear Power Operations ("INPO") awarded Palo Verde a 10 Year Excellence Award in 2004 after INPO had given Palo Verde top ratings for five consecutive INPO review cycles. Similarly, U.S. Nuclear Regulatory Commission ("NRC") performance indicators remained all green during this time, and successful inspections caused Palo Verde management and the workforce to be less receptive to declining performance indicators and resulting performance-based criticism. Moreover, Palo Verde is an industry leader in the efficient and economic production of power, as its production costs consistently rank in or near the top quartile relative to industry averages.

1.1 Indications of Performance

Data confirms that Palo Verde performed well from 1993 through most of 2002. This high level of performance was evident from such diverse performance indicators ("PIs") as Reactor Trips, Radiation Exposure, Preventable Recordable Injuries, Capacity Factor, Forced Outage Rate, Net Generation, Average Annual Refueling Time, Production Cost, and Staffing. In late 2002, certain PIs began a downward trend.

1.1.1 Monthly Trend Reports

The Palo Verde Monthly Trend Reports ("MTR") from 2003-2005 reflect a downward trend in performance indicators at Palo Verde. Each PI is given a color rating as follows:

Green – Significant Strength
White – Satisfactory
Yellow – Improvement Needed
Red – Significant Weakness

PI ratings over time are shown in the following table of Palo Verde Performance Indicators.

MTR Date	Green	White	Yellow	Red
December 2002	26	8	3	5
August 2003	14	13	6	10
December 2003	16	8	6	13
August 2004	14	8	2	18
December 2004	14	9	3	16
August 2005	13	15	1	13

This table demonstrates that PIs reflect a downward trend in performance beginning in the first half of 2003, that the trend continued through the last half of 2003, and bottomed in the latter half of 2004. Although the current 2005 MTR PIs show an improving trend as compared to the end of 2004, they confirm that Palo Verde's performance is not at the sustained high level of performance as in previous years.

1.1.2 Assessments

Throughout 2004 and 2005, several assessments were conducted at Palo Verde, many of which concluded that performance at Palo Verde had declined. Some of these assessments are listed below:

- Palo Verde Nuclear Generating Station Nuclear Safety Culture Assessment, ("Synergy"), April 2005
- INPO Mid-Cycle Self-Assessment Report, November 2004
- Utilities Service Alliance ("USA") Safety Culture Assessment, July 2004
- Supervisory Effectiveness Self-Assessment, March 2005
- Root Cause Expert Panel, Observations on Significant Investigation Process & RCEP Self-Assessment, March 2005
- 2005 WANO/INPO Peer Review Report, July 2005
- CRDR 2789716, Failure to Perform A 50.59 When Changing Plant Procedures To Leave The RAS Piping Dry
- CRDR 2780286 NRC Crosscutting issue: PI&R
- CRDR 2729600, Plant Response to RAS Events
- Independent Review of Palo Verde Performance, February 2005
- CRDR 2780273, NRC Crosscutting Issue: Human Performance
- NRC Annual Assessment Report (for 2004), March 2005
- NRC Mid-Cycle Performance Review and Inspection Plan, August 2005
- CRDR 2817300 re, "Operations Assessment of Corrective Actions Contained in CRDR 2729600, 'Station Response to Identification of Voided Emergency Core Cooling System Recirculation Piping', November 2005"
- Various Consultant Assessments

When the above assessments are viewed individually, they identify specific programs in need of attention. However, when these assessments are viewed collectively, they indicate common contributors that require a broader approach to assure improved performance. This conclusion is supported by the results of a streaming analysis and the resultant five Focus Areas discussed in Section 3.0 below.

1.2 The 2005 Business Plan

Based, in part, on the PIs, assessments and plant events occurring in 2004, the Palo Verde Senior Management Team developed and published a significant revision to the Palo Verde Business Plan in January 2005. The 2005 Business Plan represented a departure from traditional business plans of the past. The 2005 Business Plan listed four major focus areas for improving performance – Nuclear Safety, Behaviors, Generation Reliability and Cost. These focus areas are centered on the Palo Verde Mission of "*We will be the industry leader in the safe and efficient production of electricity through the values of: Trust, Clarity, Teamwork, Simplicity, Execution and Positive Attitude.*"

The 2005 Business Plan prioritized these four major focus areas into nine key strategic priorities:

(1) Regulatory Interface Improvements,

(2) Equipment Reliability Improvements,

(3) Leader Development,

(4) Improve Human Performance through Behaviors, Standards, and Expectations,

(5) Efficient Outages,

(6) Program Simplification,

(7) Industrial Safety,

(8) Staffing, and

(9) Communications.

The 2005 Business Plan also listed Level 1 Projects for each key strategic priority, and different groups of senior managers were assigned responsibility for developing the actions necessary to implement each of the nine key strategic priorities. Tactical Priorities were also listed in the 2005 Business Plan.

Subsequent to initial publication of the 2005 Business Plan, the Nuclear Assurance Department ("NAD") cited numerous examples of failure to follow procedures. The NRC also noted a number of examples of failure to follow procedures. Due to the frequency of findings regarding the failure to adhere to procedures, it became apparent that management had not been consistently holding itself and the workforce accountable for inadequate performance. As a result, Senior Management modified the 2005 Business Plan in April 2005 to replace *"Execution"* with *"Accountability"* as one of the mission statement values. Around this time, Senior Management also implemented mandatory departmental procedure stand down meetings emphasizing the need to get "back to basics" with regard to procedure use and adherence.

Although actions under the 2005 Business Plan appear to have reversed the downward trend in performance indicators relative to 2004, the actions have not resulted in Palo Verde's performance returning to the level of performance as in previous years. The 2005 Business Plan did not assure coordinated implementation of improvement initiatives, and targets associated with the 2005 Business Plan were not strictly adhered to. In addition, neither the key strategic priorities nor the tactical priority activities contained measures to confirm resolution of targeted issues. Also, no single person or organization was assigned to coordinate all activities. This resulted in a silo approach toward implementation of the 2005 Business Plan.

The PIP addresses the weaknesses related to the implementation of the 2005 Business Plan by communicating a clear roadmap of how performance improvement actions are determined, implemented, and how progress will be monitored. Through creation of the PIP, performance improvement activities have been separated from routine business

objectives so that the workforce can focus on daily plant issues, but also have a clear understanding of PIP objectives and their role in contributing to performance improvement at Palo Verde. Also, the PIP has designated Senior Management sponsors, the General Manager Regulatory Affairs and Plant Improvement and the Director PIT, who are responsible and accountable for ensuring that PIP objectives are met. The Director PIT also is responsible for ensuring that the workforce understands PIP objectives and their role in its implementation.

2.0 PERFORMANCE IMPROVEMENT ORGANIZATION

In order to achieve sustained, improved performance, and to do so with a renewed sense of urgency, the Executive Vice President Generation established a new organization at Palo Verde to supervise the implementation and completion of PIP activities and assist Senior Management in improving performance As discussed earlier, this organization is called the Performance Improvement Team. Additionally, in order to better align the station to support performance improvement, the Executive Vice President Generation reorganized the Palo Verde organization as illustrated in Appendix A to the PIP. The new organizational structure allows line managers to focus on day-to-day plant operation, while the PIT is responsible for overseeing performance improvement initiatives.

3.0 DEVELOPMENT OF FIVE FOCUS AREAS

As discussed in Section 1.0 above, there is a large volume of information on performance at Palo Verde. To better understand the interrelationship between this data and the causes underlying the performance reflected in this data, a team, using streaming analysis techniques, performed a review of this information.[1]

The streaming analysis process used by the team consisted of a vertical and horizontal evaluation component. The vertical evaluation involved: (1) reviewing, tabulating, and binning corrective action documents; Condition Report Disposition Requests ("CRDRs") and Condition Report Action Items ("CRAIs") into bin categories to determine which areas received the most focus during internal and external assessments ("what" statements) and (2) developing the apparent causes ("why" statements) from the bins.

The horizontal component of the streaming analysis looked for similarities between the bins with the most entries. The objective of this part of the review was to identify global corrective actions that would have the greatest performance improvement impact in multiple areas.

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1 The team performing the streaming analysis included representatives from Nuclear Regulatory Affairs, Nuclear Assurance, Nuclear Fuel Management, the Senior Vice President Nuclear, the Executive Vice President Generation, the Plant Manager, other key internal personnel and an outside consultant with expertise in performance improvement strategy.

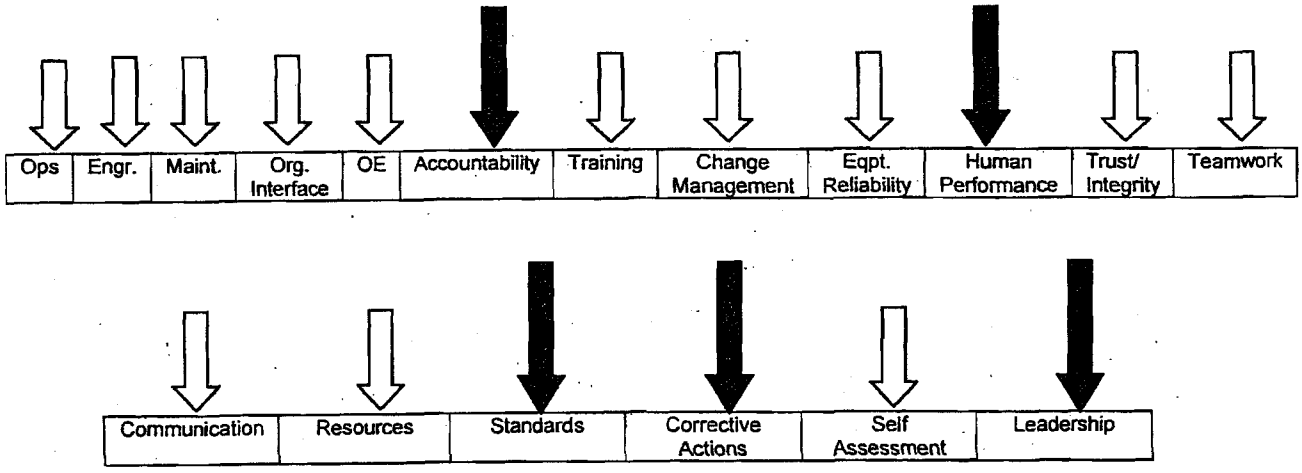
The team then developed corrective actions that corresponded with the horizontal evaluation-related "why" statements. Another team, that worked on the development of Part 2 of the PIP, then compared the corrective actions identified by the team that conducted the streaming analysis against already existing corrective actions in various CRDRs and CRAIs. This effort is reflected in Part 2 of the PIP, which is linked to the Corrective Action Program through CRDRs and CRAIs.

ILLUSTRATION OF STREAMING ANALYSIS PROCESS

Step 1: *Bin findings from review of source documents (grouping of "what" statements).*

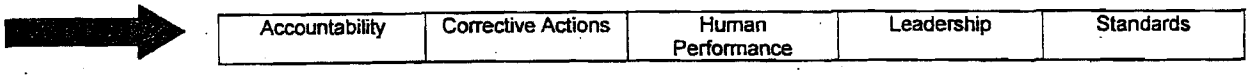
The streaming analysis team evaluated the previously referenced documents (See Part 1, Section 1.1.2 of the PIP) for the first step in the binning process.

Step 2: *Determine Most Populated Bins (⬇). These bins become the Focus Areas.*



Step 3: *Determine "why" for each entry into most populated bin.*

Step 4: *Perform Horizontal analysis of similar "why" statements among the bins.*



Step 5: *Determine necessary corrective actions for horizontal "why" statements. The common Step 4 "why" findings become Action Plans.*

Step 6: *Compare necessary corrective actions to actions already being taken (gap analysis).*

Step 7: *Initiate new corrective actions as necessary. These become Action Steps.*

The binning process highlighted five areas as having the most causal relationship to improved performance. The five Focus Areas are:

- Standards
- Accountability
- Leadership
- Human Performance
- Corrective Actions

The focus of the PIP is on these five Focus Areas which Palo Verde management believes are necessary for prompt and effective performance improvement. In Part 2 of the PIP, each of the five Focus Areas have corresponding Action Plans and Action Steps which in turn are linked to the Corrective Action Program through CRDRs or CRAIs.[2] For each Action Plan, Part 2 also identifies corresponding acceptance criteria.

The following provides a problem statement associated with each of the five Focus Areas.

3.1 Standards

The leadership team has not consistently held the organization to high standards. More directly stated, too many exceptions are made to well-known standards to more easily accommodate a current situation.

3.2 Accountability

Palo Verde leaders have not consistently held themselves and the workforce accountable for the implementation of and compliance with program and process requirements. Accountability must begin with the leadership team. A leader must hold himself or herself accountable to standards and expectations. Leaders must also hold the workforce accountable. Finally, individual employees must hold themselves and their co-workers accountable for individual performance improvement.

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[2] Two of the Focus Areas, Corrective Actions (i.e., PI&R) and Human Performance were also identified by the NRC as substantive cross cutting issues in the NRC's Annual Assessment Letter dated March 2, 2005. Corrective actions were developed for these Focus Areas as part of the reviews associated with Significant CRDR 2780286 NRC Crosscutting Issue: PI&R and Significant CRDR 2780273 NRC Crosscutting Issue: Human Performance, and they are included in Part 2 of the PIP.

3.3 Leadership

Palo Verde leaders have not consistently demonstrated fundamental leadership skills. These skills include clearly communicating standards of performance; leading by example with regard to those standards; maintaining focus on the Palo Verde mission, goals and objectives; engaging the workforce, and holding themselves and the workforce accountable for meeting expectations.

3.4 Human Performance

Human performance has been identified as a substantive crosscutting issue by the NRC. Significant CRDR 2780273 "NRC Crosscutting Issue: Human Performance" was written to address human performance deficiencies. The problem statement for this CRDR is: *"Palo Verde experienced an increase in human performance (HP) errors between 2001 and 2004.... Some of the human errors have resulted in human performance events. Palo Verde has not effectively communicated and addressed the underlying causes associated with this trend."*

3.5 Corrective Action Program/Problem Identification & Resolution ("PI&R")

PI&R has been identified as a substantive crosscutting issue by the NRC. Palo Verde has not, in all cases, adequately evaluated problems, developed corrective actions and assessed effectiveness such that issues are permanently resolved. Palo Verde has opened Significant CRDR 2780286 to address PI&R-related performance deficiencies. That CRDR adopts the NRC's problem statement from the NRC's March 2005 annual assessment letter *"The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area."*

Additionally, as new issues arise, they will be entered into the Palo Verde Corrective Action Program. The PIT will also continuously evaluate trends from the Corrective Action Program, as well as feedback from internal and external organizations or assessments to determine if the scope and emphasis of the PIP needs to be adjusted. In addition, the PIT will monitor MTR trends to ensure the PIP is having the desired result and whether additional actions are necessary.

4.0 REVISED Palo Verde MISSION STATEMENT

The 2005 Business Plan mission statement is:

"We will be the industry leader in the safe and efficient production of electricity through the values of: Trust, Clarity, Teamwork, Accountability, Simplicity, and Positive Attitude,"

The current level of performance requires a change to the mission statement to better focus on the need for improved performance. The following new mission statement will be incorporated into the 2006 Business Plan:

> *Palo Verde Nuclear Generating Station employees will work as a team, with relentless dedication and focus, to promote high standards of performance, permanently correct problems, and maintain alignment to return Palo Verde to its position as the industry leader in the safe and efficient production of electricity. Our focus is not only on getting the job done, but getting the job done RIGHT the first time.*

5.0 ALIGNMENT OF PALO VERDE MISSION STATEMENT WITH THE PIP

The initial focus of the PIP is to ensure that the near and long-term goals of the leadership team are aligned with the mission statement. The first step in assuring alignment is the development and implementation of Leadership Standards and Expectations, a copy of which is attached to this PIP as Appendix B. These Leadership Standards and Expectations, along with the "Palo Verde Expectations and Standards" booklet set out the foundation for how business will be conducted at Palo Verde. The Leadership Standards and Expectations establish common behavior that will be expected of all leaders, dependent on their level within the organization. A major part of leader accountability will be whether leaders conduct themselves in accordance with these Standards and Expectations, and the Standards and Expectations will form the basis for how leader performance is measured.

In addition, all Palo Verde employees will be briefed on the PIP so that each individual has the opportunity to better understand what actions are being taken by management to improve performance, why they are being taken, and to better understand each individual's role in contributing to performance improvement.

6.0 PIP/BUSINESS PLAN RELATIONSHIP

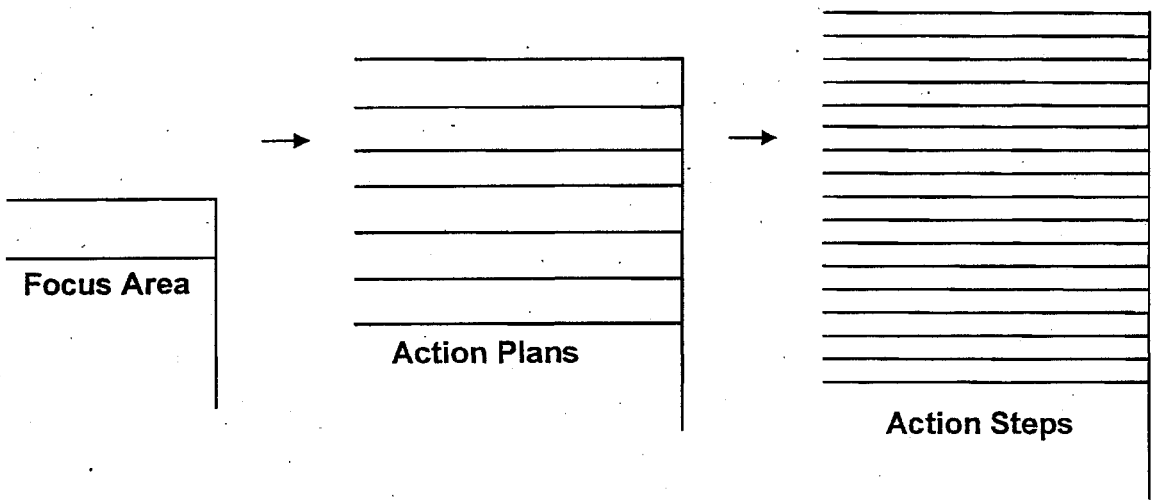
The PIP will be a supplement to the 2006 Business Plan. The 2006 Business Plan will be issued by December 1, 2005. The 2006 Business Plan will address more routine plant activities such as power production goals, capacity factor, and O&M and capital costs. The PIP focuses on actions necessary for improved performance. While some of these activities necessarily overlap (resources and budget), generally the 2006 Business Plan will be managed by the Senior Management Team. The PIP will be managed by the PIT. All Palo Verde personnel will be responsible for implementing aspects of both the 2006 Business Plan and the PIP. Performance improvement activities have been separated from routine business objectives so that the workforce can focus on daily plant issues, but also have a clear understanding of the objectives of the PIP and their role in contributing to performance improvement at Palo Verde.

As previously noted, PIP Focus Areas and Action Plans are being implemented to promptly improve performance. As performance improves, Part 2 of the PIP will be used

as a central document to capture and ensure coordination between new initiatives and ongoing Action Plans. The PIT will be a long-term organization, and the Director PIT will be responsible for working with the Palo Verde Business Plan "owners" to ensure coordination and efficiency of related efforts and to ensure continuous improvement at Palo Verde.

7.0 PIP IMPLEMENTATION

The following figure depicts how the five Focus Areas will be addressed through Action Plans, which in turn will contain more specific Action Steps. Each Action Plan will have corresponding acceptance criteria.



7.1 PIP Implementation Responsibilities

Every Palo Verde employee is responsible for improving performance at Palo Verde and the successful implementation of the PIP. Every member of the Senior Management Team is responsible for ensuring that adequate planning and resources are provided to implement the PIP successfully and in a timely manner. Other more specific responsibilities and accountabilities are described below.

7.1.1 Senior Vice President Nuclear

Responsible and accountable for the *strategic*-based implementation of PIP (Part 1) and is accountable for ensuring that PIP completion will result in the desired improvements in performance. Typically, performance improvement progress will be monitored, in part, through the use of appropriate performance indicators.

7.1.2 General Manager Regulatory Affairs and Plant Improvement

Responsible and accountable for ensuring that the Performance Improvement Team has the necessary resources and support so that PIP objectives can be met.

Responsible for chairing meetings of the Leadership Review Team ("LRT"). The purpose of the LRT is discussed in Section 7.9 below. Consults with the Senior Vice President Nuclear on strategy and setting priorities within the PIP. Responsible for monitoring PIP progress.

7.1.3 Director Performance Improvement Team

Responsible and accountable for day-to-day *tactical*-based implementation of PIP (Part 2), including PIP schedule adherence, and quality of closeout documents so that PIP objectives can be met. The Director PIT approves revisions/closure of Action Plans and recommends closure of Focus Areas to the LRT. The Director PIT, working with the Senior Management Team has the responsibility for reviewing the adequacy of the current PIs. The Director PIT also has the responsibility for the development, and recommendation for approval to the LRT, of a core group of PIP PIs for Palo Verde that are directly related to the PIP and provide key performance-based information regarding PIP implementation and performance improvement.

7.1.4 Focus Area Owner

Focus Area Owners report to the Director PIT and are responsible and accountable for ensuring on-time and effective implementation and completion of all Action Plans in an assigned Focus Area. As a result, a Focus Area Owner must stay apprised of the progress made by Action Plan Owners in the implementation of individual Action Steps.

7.1.5 Action Plan Owner

Individual who is responsible and accountable for ensuring the on-time completion of all Action Steps associated with an Action Plan. The Action Plan Owner must ensure that the Action Steps achieve the defined Action Plan objective and recommends closure of the Action Plan as discussed below in Section 7.7.

7.2 PIP Scheduling and Tracking

Action Steps are entered into and monitored by the Palo Verde Corrective Action Program and are included in the CRDR tracking system. A PIP implementation schedule will be developed for the implementation of overall PIP activities. CRDRs that are related to the PIP will be mile-stoned within the PIP implementation schedule. The PIP implementation schedule will be monitored by the Director PIT, Focus Area Owners and Action Plan Owners. The PIP implementation schedule will also be reviewed with the Palo Verde Senior Management Team as a part of PIP Progress Review Meetings.

7.3 Focus Areas

Focus Areas are those areas at Palo Verde in need of prompt and effective improvement. Improvement in a Focus Area is addressed through Action Plans, which in turn contain specific Action Steps.

7.4 Action Plans

Action Plans, which have defined acceptance criteria, document the primary Action Steps to address Focus Area problem statements. Action Steps, which are linked to the Corrective Action Program through CRDRs and CRAIs, are assigned to individuals and have firm start and finish dates.

7.5 Action Plan Revisions

The need may arise to modify an Action Plan to address emergent issues or to improve effectiveness. Action Plan revisions (*e.g.*, deletion of Action Steps, addition of Action Steps, and change in end dates) require approval by the Action Plan Owner, the Focus Area Owner, and the Director PIT prior to implementation. Regulatory Affairs Department reviews revisions that may impact NRC commitments.

7.6 Action Step Closure Process

The closure of each Action Step in an Action Plan will be accomplished in accordance with the Palo Verde Corrective Action Program.

7.7 Action Plan Closure Process

Following completion of the Action Steps associated with an Action Plan, the Action Plan Owner prepares a final closure report that provides justification for closure of the Action Plan. The Focus Area Owner reviews the closure report. If the Focus Area Owner agrees with the justification for closure of the Action Plan, then the Action Plan Owner and the Focus Area Owner sign the closure report and forward it to the Director PIT for review and approval. If the Focus Area Owner or the Director PIT do not agree with the recommendation for closure of an Action Plan, the reasons will be documented and appropriate actions to address identified concerns will be documented and taken. After the above reviews occur and necessary approvals received, NAD will conduct a final review of the closure of an Action Plan and associated Action Steps in accordance with the Corrective Action Program.

7.8 Focus Area Closure Process

Focus Areas, which are composed of multiple Action Plans, may be closed only when all associated Action Plans have been completed and approved in accordance with Section 7.7. LRT approval is also needed for the closure of a Focus Area.

7.9 Leadership Review Team

A newly formed Leadership Review Team evaluates performance improvement progress on a periodic basis to ensure adequacy of PIP implementation. The LRT is comprised of members of Palo Verde Senior Management who are the direct reports to

the Senior Vice President Nuclear.[3] Other senior managers or external consultants may be invited to participate in LRT activities; however, the responsibility of this team to oversee achievement of PIP objectives cannot be delegated. The LRT provides feedback to the PIT and assesses implementation of the Palo Verde mission statement consistent with leadership standards and expectations, as needed. The LRT approves PIP related PIs. The LRT approves Focus Area closures when requested by the Director PIT and Focus Area Owner and ultimately is the organization that recommends closeout of the PIP to the Executive Vice President Generation.

8.0 PERFORMANCE MONITORING & EFFECTIVENESS REVIEWS

Senior Management currently monitors overall performance at Palo Verde to ensure success and to prevent recurrence of performance deficiencies. Senior Management monitors performance through a variety of means including: status update meetings, performance indicators, self-assessments and NAD effectiveness reviews. NAD will perform effectiveness reviews associated with PIP activities in accordance with the Corrective Action Program. Options for monitoring overall performance at Palo Verde are discussed in more detail in Appendix C to the PIP.

9.0 PIP CLOSURE

After the LRT reviews Action Plan closure packages associated with the closure of a Focus Area, performance indicator assessments, NAD audit and assessment report results, and considers input from Senior Management meetings, the LRT may recommend PIP closure to the Executive Vice President Generation. Only the Executive Vice President Generation, however, may approve closure of the PIP.

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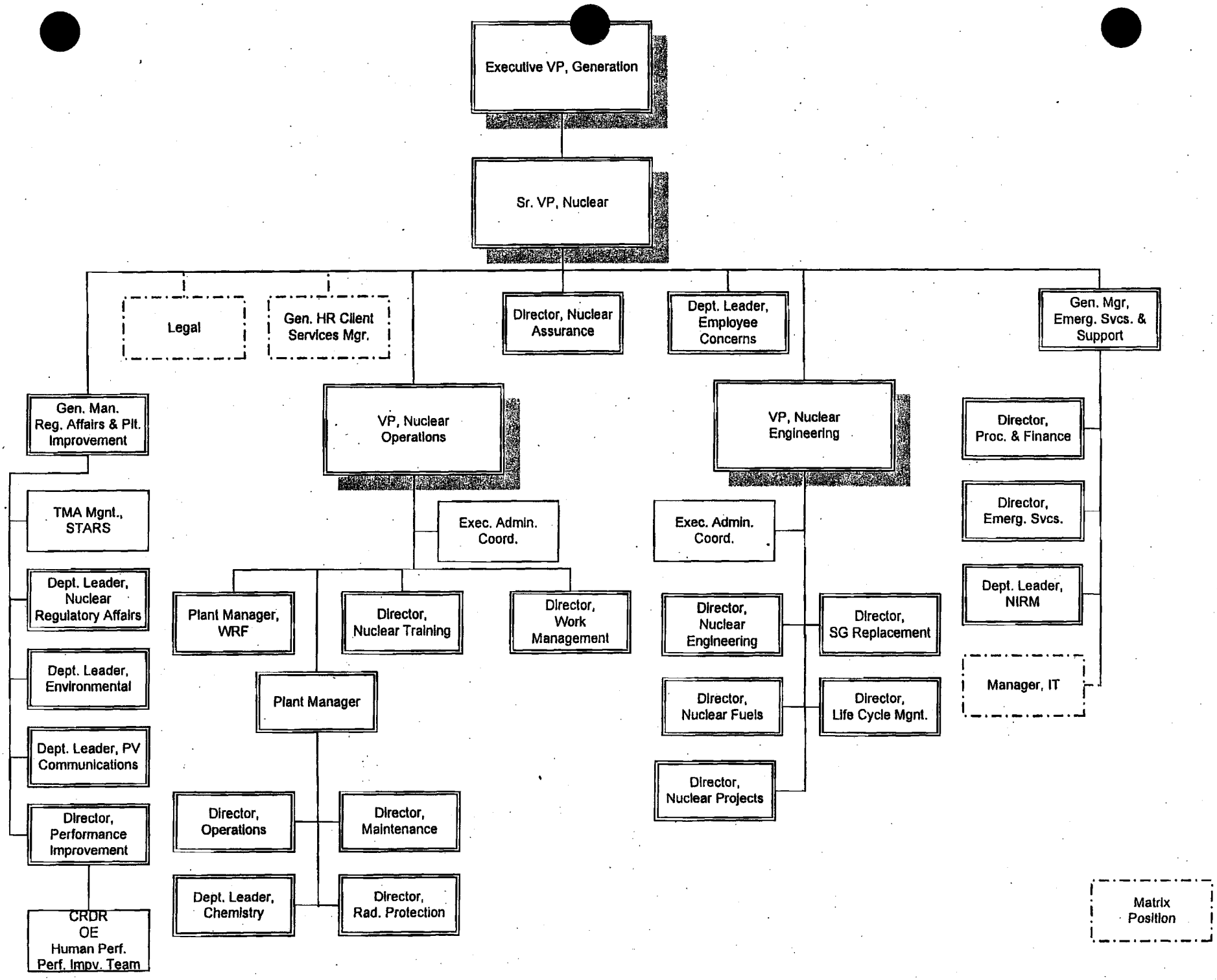
[3] The LRT will be comprised of the Vice President Operations, Vice President Engineering, General Manager Regulatory Affairs and Plant Improvement, General Manager Emergency Services and Support, Director Nuclear Assurance and the Department Leader Employee Concerns.

APPENDIX A

PALO VERDE NUCLEAR GENERATING STATION ORGANIZATIONAL CHART


Executive VP, Generation
Sr. VP, Nuclear
Legal
Gen. HR Client Services Mgr.
Director, Nuclear Assurance
Dept. Leader, Employee Concerns
Gen. Mgr, Emerg. Svcs. & Support
Gen. Man. Reg. Affairs & Plt. Improvement
VP, Nuclear Operations
VP, Nuclear Engineering
Director, Proc. & Finance
TMA Mgnt., STARS
Exec. Admin. Coord.
Exec. Admin. Coord.
Director, Emerg. Svcs.
Dept. Leader, Nuclear Regulatory Affairs
Plant Manager, WRF
Director, Nuclear Training
Director, Work Management
Director, Nuclear Engineering
Director, SG Replacement
Dept. Leader, NIRM
Dept. Leader, Environmental
Plant Manager
Director, Nuclear Fuels
Director, Life Cycle Mgnt.
Manager, IT
Dept. Leader, PV Communications
Director, Nuclear Projects
Director, Performance Improvement
Director, Operations
Director, Maintenance
Dept. Leader, Chemistry
Director, Rad. Protection
CRDR
OE
Human Perf.
Perf. Impv. Team
Matrix Position

APPENDIX B

LEADERSHIP STANDARDS AND EXPECTATIONS

Palo Verde Executive/Director
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign this it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Emphasize human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Achieve standards & expectations
- Own actions to resolve identified issues/problems per commitment
- Establish quality as the underlying requirement for all work

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Create PVNGS mission and resource-loaded business plan with metrics as the cornerstone for site results
- Tenaciously pursue execution and closure
- Drive for simplicity and effectiveness
- Remove organizational barriers to site efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Champion continuous improvement (across the site/all levels)
- Sponsor development in new technical/functional knowledge – promote benchmarking/use of external resources
- Question identified trends and assumptions using analysis, experience, wisdom, and judgment
- Do not allow Analysis Paralysis
- Fully utilize and support the Corrective Action Program
- Balance short-term priorities with long-term opportunities
- Address both site & enterprise needs in decision-making
- Simplify

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals were team member.*

- Broadly share both responsibility and authority
- Assure common understanding when delegating
- Draw on talents/expertise of team members
- Establish timelines and milestones
- LET GO! … but monitor & give feedback

Planning/ Organizing/Time Management – *Develops of and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Establish organization goals with metrics
- Assure that schedules are adhered to
- Identify and address conflicting issues and priorities
- Require contingency plans
- Assure that resources are used effectively toward site goals
- Optimize meetings

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information, and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Understand how site performance impacts financial side of the company and vice versa
- Set and maintain appropriate budget levels based on the business plan
- Integrate site work/project budgets so that overall site remains on or under budget
- Prioritize and allocate funds

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for one's actions.*

- Voice opinions, questions, agreement, or disagreement immediately – be in the game
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall site plan
- Seek out those with differing opinions - commit to what's right for the site (Common Purpose)
- Assure full compliance with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, actions, and decisions are consistent with and promote PV Values, Standards, and Goals.*

- Stay abreast of industry and regulator trends and adjust strategies & objectives accordingly
- Develop the vision; get input; create objectives, expectations, and metrics; then share with your people and implement
  - Accept nothing less than full compliance with expectations
  - Reinforce with employees at every opportunity
  - Monitor metrics and adjust strategies to achieve goals
- Make the tough decisions that support PV Values
- Demonstrate & reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – assure that appropriate change management approach is used
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that the leadership team is unified – from peers to DL, SL, and TL

LEADERSHIP BEHAVIORS (CONTINUED).

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised – No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
- Assure person responsible learns from missed accountabilities
- Insist on behaviors that promote team success
- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
- Assure all leaders meet the requirements of this document

Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guiding employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance*

- Implement and manage Succession Plan for Director & DL levels
- Accelerate development of high-performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop potential
- Evaluate ways to increase creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution: use rewards as appropriate
- Establish development as a necessary part of dept. operations

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- KEEP YOUR HEAD UP; Maintain a high-level perspective by:
  - Identify/Evaluate leading indicators and initiative timelines
  - Sr. Team planning and initiatives
  - Assuring planned objectives and site commitments are met
- Display a positive attitude
- Get out and engage employees by listening, coaching and being accessible & visible to employees
- Move decisions to lower levels to develop employee skills, demonstrate confidence, maintain your own independent thought and coach decision process as needed
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments
- Maintain an achievable schedule

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

Palo Verde Department Leader
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Reinforce focus on human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Monitor operation for compliance to standards & expectations
- Work with leaders/others to resolve identified issues/problems per commitment
- Establish quality as the underlying requirement for all work

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Develop resource-loaded departmental plan with metrics to assure efforts are aligned with site objectives
- Tenaciously pursue execution and closure
- Drive for simplicity and effectiveness
- Removes organizational barriers to department efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Demonstrate continuous improvement (your dept.)
- Prioritize & Budget for development of employees in new technical/functional knowledge
- Decisions involve others using analysis, experience, wisdom, and judgment
- Conduct risk analysis for various courses of action
- Avoid Analysis Paralysis – use formal decision tools as able
- Fully utilize and support the Corrective Action Program
- Balance short-term priorities with long-term opportunities
- Consider site view in decision-making
- Simplify to minimize resource demands

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals.*

- Obtain input and place ownership for execution at the appropriate level
- Assure common understanding when delegating
- Establish timelines and milestones
- Trust people to perform, but monitor & give feedback

Planning/ Organizing/Time Management – *Develops and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Align departmental objectives with organization goals – assure leaders understand connection to site goals
- Assure execution of scheduled department commitments
- Identify and address conflicting issues and priorities
- Anticipate roadblocks and oversee contingency plans
- Direct that resources are used effectively toward site goals

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Know how operations impacts financial side of the site
- Develop appropriate department budgets based on the business plan
- Seek cost saving ideas from others
- Deliver overall department work/projects on or under budget
- Define departmental overtime expectations
- Evaluate and justify funding for proposed emergent work

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for own actions.*

- Voice questions, agreement, or disagreement promptly
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall dept. plan
- Seek out those with differing opinions - commit to Common Purpose
- Assure fully compliance with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, decisions, and actions are consistent with and promote PV Values, Standards, and Goals.*

- Understand the vision, framework and general expectations, then share with your people and assure their commitment
  - Accept nothing less than full compliance with expectations
  - Reinforce with employees at every opportunity
  - Manage work to achieve metrics goals
- Make the tough decisions that support our Values
- Demonstrate & Reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – assure that appropriate change management approach is used
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that the leadership team is unified – SLs and TLs are all on the same page

LEADERSHIP BEHAVIORS (CONTINUED)

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised– No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
- Assure person responsible learns from missed accountabilities
- Insist on behaviors that promote team success
- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
- Assure all leaders meet the requirements of this document

Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guide employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance.*

- Accelerate development of high-performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop their potential
- Evaluate ways to increase creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution; use rewards as appropriate
- Provide the planning and time necessary for development

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- Display a positive attitude
- Maintain focus on department goals but with a site-wide perspective. Emphasize:
  - Managing leading indicators and initiative timelines
  - Engaging leaders and employees – listening and coaching
  - Effective work planning and execution of initiatives
  - Assure department commitments are met
- Engage in decision-making with leaders in your group, as well as appropriate peers, specialists from other groups.
- Delegate responsibility for your effectiveness and for employee development/confidence
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments
- Maintain an achievable schedule

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

Palo Verde Section/Team Leader
STANDARDS AND EXPECTATIONS

Palo Verde is engaged in an effort to return the site is to sustained high levels of performance. A key requirement for success is alignment of the leadership team and the absolute commitment of each leader to understand, accept, and demonstrate the standards and expectations listed below. Please review this document with your leader and sign it, committing that your actions and behaviors will be conducted in accordance with these leader standards and expectations.

RESULTS ORIENTATION

Operational Excellence – *Proactively identifies and addresses conditions that might erode the reliability and availability of the plants, systems, or equipment, or that may erode the quality of products and services; hold self and others to high standards of quality.*

- Maintain optimal human performance with constant regard for Nuclear, Radiological, and Industrial Safety
- Verify employee compliance to standards & expectations
- Work with employees to resolve identified issues/problems per commitment
- Assure that workers take the time to do it right the first time

Drive for Results - *Proactively asserts influence over events to achieve goals, often taking action beyond what is required.*

- Consistently achieve objectives of department plan in support of site objectives
- Tenaciously pursue execution and closure
- Assures process simplicity and effectiveness
- Removes barriers to employee efforts
- Maintain Accountability-Confront non-performers/recognize key contributors

Improvement Seeking/Decision-Making/Problem-Solving - *Generates simple and creative solutions after identifying relevant facts and evaluating viable alternatives and their possible consequences.*

- Continually strive to improve performance/process
- Assign development to employees in new technical/functional knowledge
- Use combination of analysis, experience, wisdom, and judgment to arrive at a solution or decision
- Identify/provide all relevant data for higher level decisions
- Be prepared to act promptly when decisions are finalized
- Fully utilize and support the Corrective Action Program
- Consider department/work plan and achievement of site objectives in decision-making
- Generate simpler alternative solutions

Delegation - *Assigns appropriate decision-making and responsibility to appropriate individuals were team member.*

- Plan/assign work, monitor progress to hold staff accountable
- Assure common understanding when assigning work
- Solidify employee accountability for projects/tasks with timelines and milestones
- Trust people to perform, but monitor & give feedback

Planning/ Organizing/Time Management – *Develops of and manages a course of action for each of multiple projects and priorities while maintaining organization and effectiveness to completion.*

- Align daily activities with department objectives with overall objective of achieving higher site goals
- Assure completion of work as scheduled in work plan
- Identify and address conflicting issues and priorities
- Anticipate roadblocks and develop contingency plans
- Use resources effectively and efficiently toward site goals

RESULTS ORIENTATION (CONTINUED)

Financial Management/Resource Effectiveness - *Analyzes cost information, and develops alternatives, then pursues courses of action that save on costs (or other resources) while maintaining high levels of performance and reliability.*

- Know how operations impacts financial side of the site
- Allocate resources effectively
- Manage to budget levels in dept. budget
- Seek cost saving ideas from others
- Deliver work/projects on or under budget
- Ensure overtime limitations are met
- Identify and elevate emergent work for funding

LEADERSHIP BEHAVIORS

Courage & Integrity – *Takes personal responsibility for one's actions.*

- Voice questions, agreement, or disagreement promptly
- Challenge what isn't right and the "status quo"
- Be accountable - Own your part and the overall dept. plan
- Recognize those with differing opinions - commit to Common Purpose
- Fully comply with company/site procedures and policies (ethics, etc)

PV Values, Standards, and Goals – *Words, actions, and decisions are consistent with and promote PV Values, Standards, and Goals.*

- Understand how the vision, framework and general expectations impact your group - share with your people and seek their commitment
  - Reinforce with employees at every opportunity
  - Accept nothing less than full compliance with expectations
  - Direct work in support of metrics goals
- Make the tough decisions in keeping with PV Values to achieve PV Goals
- Demonstrate & Reinforce PV Values daily

Communications and Interpersonal Skills – *Critically listens and effectively communicates; Values and respects the need of others for inclusion, for being heard, and for having access to information.*

- Ask questions rather than direct to assess level of understanding, develop decision skills, or show respect for employee input/capability
- Involve those who are stakeholders
- Follow-thru with communications, respecting the needs & resources of others
- Validate that the info you receive is correct
- Do it face-to-face or by phone, avoid e-mail whenever possible
- Watch for shifts to silence or violence in yourself or others – address it!
- Recognize the significance of changes – use appropriate change management approach
- Stop and listen to employees voicing ideas or concerns.
  - Promptly try to resolve the issue and discuss with employee
  - If you cannot resolve it, help bring it to the right person/level
- Demonstrate on-going interest in employee welfare

Teamwork/Relationship Management – *Works effectively with others throughout the organization to accomplish PV goals and to identify and resolve issues.*

- Be a strong and reliable team member – demand the same of others
- Insist that each employee deliver as expected
- Challenge resistance and do not tolerate disrespect
- Listen to show you value others
- Share credit publicly, blame privately
- Assure that you are unified with the direction of the leadership team.

LEADERSHIP BEHAVIORS (CONTINUED)

Performance Management - *Sets and delivers on challenging goals and expectations in alignment with organizational priorities, tracks results, promptly provides both positive and constructive feedback, and initiates necessary development.*

- Demonstrate Accountability through your actions – As Promised, When Promised– No Surprises
- Create a shared understanding of how the job will be done
- Get agreement to accountabilities
- Address poor performance early and firmly
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- Maintain high standards and perception of fairness – define & calibrate high standards for high ratings
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Developing/Inspiring Others - *Uses appropriate styles to coach, inspire, and guiding employees to achieve goals. Identifies employee strengths/weaknesses and provides feedback and support to improve and sustain performance*

- Accelerate development of high performing employees
  - Delegate projects/responsibilities to employees for grooming
  - Identify specific development expected when placing employees on special assignments
- Identify employee-specific motivators to increase ownership
- Mentor for increased performance and flexibility
- Cross train to broaden their experience and develop their potential
- Evaluate ways to increase employee creativity for tasks and process improvement
- Engage uniquely skilled employees in knowledge transfer accountabilities to assure continuity of required capability
- Recognize noteworthy individual and team contribution; use rewards as appropriate
- Effectively utilize the time allocated for development

Stay In Your Role/Play Your Part – *Maintains the proper strategic focus, employee engagement, and tactical (technical/problem-solving) involvement for assigned role; Respects the ability of others to fulfill their role.*

- Display a positive attitude
- Maintain focus on work-group goals but with recognition of overall site-wide objectives. Emphasize:
  - Effective execution of planned work and other initiatives
  - Oversee employee activities, provide feedback & raise standards
  - Assure group commitments are met
- Engage employees in decision-making to develop employee skills, demonstrate confidence, increase ownership, and broaden your perspective.
- Delegate responsibility for your effectiveness and for employee development/confidence
- Continuously challenge for improvement and alignment with site values & goals
- Follow-up on assignments

As a member of the Palo Verde Leadership Team,
I am committed to meet the standards and expectations listed in this document.

_____	_____	_____
Leader	Date	One-over Signature

APPENDIX C

Palo Verde PERFORMANCE MONITORING OPTIONS

The following options will be used to monitor overall performance at Palo Verde.

Status Update Meetings:

The following key meetings will be held at Palo Verde:

- 9:00 AM Plant Status Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held every Tuesday, Wednesday, Thursday, and Friday at 9 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of the meeting is to discuss plant status, provide a forum for presentations to the Senior Management Team, and allow for the discussion of other station-related events and issues.

- PIP Progress Review Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held every Thursday at 10 a.m. However, depending on the success of performance improvement at Palo Verde, the frequency of this meeting may be adjusted. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. PIT Action Plan Owners and Focus Area Owners may participate in the PIP Progress Review Meetings as requested, as well as other Palo Verde personnel. The purpose of this meeting is to update the Senior Management Team on the status of the PIP, or other activities related to performance improvement at Palo Verde. The current status of Level 1s as well as the results of Nuclear Assurance oversight activities associated with the PIP will also be reviewed during these meetings.

- Monthly Trend Report (MTR) Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 2nd Friday of every month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the Palo Verde MTR.

- O&M Budget Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 3rd Friday of every month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the current status of the Palo Verde O&M Budget.

- Capital Budget Meeting--This meeting, which is chaired by the Senior Vice President Nuclear, will be held the 4th Friday every other month at 10 a.m. Attendees will include the direct reports to the Senior Vice President Nuclear, the Vice President Nuclear

Operations, the Vice President Nuclear Engineering and certain other designated members of the Senior Management Team. If a regular attendee is unable to attend the meeting, then an alternate should be designated to attend. The purpose of this meeting is to discuss the current status of the Palo Verde Capital budget.

Performance Indicators

Palo Verde has identified Performance Indicators (PIs) that monitor "critical attributes" of plant and personnel performance. An Action Plan under the PIP is to benchmark these PIs against top quartile performers and modify them as appropriate. These PIs will be captured in the MTR and the current status of the PIs will be discussed during the monthly MTR Meeting.

Self-Assessments

Self-assessments, particularly effectiveness reviews will play an important role in measuring performance improvement at Palo Verde. Self-assessments related to performance improvement will be conducted not only by the PIT, but by other departments at Palo Verde as well. If needed, external resources may be used to assist in conducting self-assessments.

Each Focus Area Owner will schedule self-assessments to monitor Focus Area and Action Plan effectiveness. The plan embodies a variety of self-assessment methods to identify performance gaps when compared to internal and external standards. The PIT may credit self-assessments planned by various departments, if the focus of the department assessment is consistent with the PIP. Conversely, plant departments may credit PIT generated self-assessments as satisfaction for departmental self-assessment requirements if the PIP assessment focuses on appropriate departmental issues.

The PIT oversees the scheduling and implementation of PIP-related self-assessments to ensure they focus on key site issues and that completed self-assessment activities are of a high quality.

Monitoring By the Nuclear Assurance Department

NAD independently monitors PIP progress through audits and assessments. If NAD concludes that the PIP is not being implemented adequately or is not resulting in the desired performance improvement, it is responsible and accountable for notifying the Senior Management Team and identifying deficiency areas requiring corrective action.

ATTACHMENT 2

4Q/2005 ROP Action Matrix Summary

The assessment program collects information from inspections and performance indicators (PIs) in order to enable the agency to arrive at objective conclusions about the licensee's safety performance. Based on this assessment information, the NRC determines the appropriate level of agency response, including supplemental inspection and pertinent regulatory actions ranging from management meetings up to and including orders for plant shutdown. The Action Matrix Summary listed below reflects overall plant performance and is updated regularly to reflect inputs from the most recent performance indicators and inspection findings. Physical Protection information is not publicly available and the associated performance indicators and inspection findings are not integrated into the Action Matrix Summary.

Notes have been added to plants that are not in the licensee response column of the Action Matrix.

Licensee Response Column	Regulatory Response Column	Degraded Cornerstone Column	Multiple/Repetitive Degraded Cornerstone Column	Unacceptable Performance Column
Arkansas Nuclear 1	Brunswick 2[1]	Kewaunee[2]	Perry 1[3]	
Arkansas Nuclear 2	Columbia Generating Station[4]	Palo Verde 1[5]	Point Beach 1[6]	
Beaver Valley 1	Crystal River 3[7]	Palo Verde 2[8]	Point Beach 2[9]	
Beaver Valley 2	Davis-Besse[10]	Palo Verde 3[11]		
Braidwood 1	Fort Calhoun[12]			
Braidwood 2	Hatch 1[13]			
Browns Ferry 2	Hatch 2[14]			
Browns Ferry 3	Indian Point 2[15]			
Brunswick 1	Oyster Creek[16]			
Byron 1	Three Mile Island 1[17]			
Byron 2	Turkey Point 3[18]			
Callaway	Turkey Point 4[19]			
Calvert Cliffs 1				
Calvert Cliffs 2				
Catawba 1				
Catawba 2				
Clinton				
Comanche Peak 1				
Comanche Peak 2				
Cooper				
D.C. Cook 1				
D.C. Cook 2				
Diablo Canyon 1				
Diablo Canyon 2				
Dresden 2				
Dresden 3				

Duane Arnold
Farley 1
Farley 2
Fermi 2
FitzPatrick
Ginna
Grand Gulf 1
Harris 1
Hope Creek 1[20]
Indian Point 3
La Salle 1[21]
La Salle 2[22]
Limerick 1
Limerick 2
McGuire 1
McGuire 2
Millstone 2
Millstone 3
Monticello
Nine Mile Point 1
Nine Mile Point 2
North Anna 1
North Anna 2
Oconee 1
Oconee 2
Oconee 3
Palisades
Peach Bottom 2
Peach Bottom 3
Pilgrim 1
Prairie Island 1
Prairie Island 2
Quad Cities 1
Quad Cities 2
River Bend 1
Robinson 2
Saint Lucie 1
Saint Lucie 2
Salem 1[23]
Salem 2[24]
San Onofre 2
San Onofre 3
Seabrook 1
Sequoyah 1
Sequoyah 2
South Texas 1
South Texas 2
Summer

Surry 1
Surry 2
Susquehanna 1
Susquehanna 2
Vermont Yankee
Vogtle 1
Vogtle 2
Waterford 3
Watts Bar 1
Wolf Creek 1

▲ Note 1: Brunswick unit 2 is in the regulatory response column due to one white performance indicator in the Initiating Events Cornerstone (Unplanned Power Changes per 7000 Critical Hours) originating in 4Q/2005.

▲ Note 2: Kewaunee is in the degraded cornerstone column due to one white inspection finding in the mitigating systems cornerstone originating in 3Q/2005 and one yellow finding in the mitigating systems cornerstone originating in 4Q/2005.

▲ Note 3: Perry is in the multiple/repetitive degraded cornerstone column due to the mitigating systems cornerstone being degraded with multiple white findings for greater than 4 consecutive quarters. In particular, the ESW pump failure finding from 3Q/2003 is being held open in accordance with MC 0305 for greater than 4 quarters because corrective actions were ineffective and the pump failed again in May 2004. This finding, in conjunction with the 4Q/2003 finding involving inadequate venting of the RHR/LPCI keep fill system, which is also being held open in accordance with MC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies, resulted in greater than 4 consecutive quarters in the degraded cornerstone column and placed the plant in the multiple/repetitive degraded cornerstone column. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2004 was held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies which were verified to be complete on December 9, 2005. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update.

▲ Note 4: Columbia Generating Station is in the regulatory response column due to one white performance indicator (Safety System Unavailablity, High Pressure Injection System) in the mitigating systems cornerstone originating in 1Q/2005.

▲ Note 5: Palo Verde unit 1 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 6: Point Beach unit 1 is in the multiple/repetitive degraded cornerstone column due to a red finding and a yellow finding in the mitigating systems cornerstone originating in 1Q/2002 and 1Q/2003, respectively. Both findings are being held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2005 is not being considered in the Action Matrix due to a deviation approved by the NRC Executive Director for Operations.

▲ Note 7: Crystal River unit 3 is in the regulatory response column due to one white inspection finding in the Mitigating System Cornerstone (Fire Protection) originating in 3Q/2005.

▲ Note 8: Palo Verde unit 2 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing

causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 9: Point Beach unit 2 is in the multiple/repetitive degraded cornerstone column due to two red findings in the mitigating systems cornerstone originating in 1Q/2002 and 1Q/2003, respectively. Both findings are being held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies. In addition, a white finding in the emergency preparedness cornerstone originating in 4Q/2005 is not being considered in the Action Matrix due to a deviation approved by the NRC Executive Director for Operations.

▲ Note 10: Davis-Besse is in the regulatory response column due to one white finding in the emergency preparedness cornerstone originating in 4Q2004. This finding was held open in accordance with IMC 0305 for greater than 4 quarters pending the implementation of effective corrective actions to address performance deficiencies which were verified to be complete on October 21, 2005. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update.

▲ Note 11: Palo Verde unit 3 is in the degraded cornerstone column due to one yellow finding in the mitigating systems cornerstone originating in 4Q/2004. The significance determination for this final yellow finding and corresponding notice of violation were issued on April 8, 2005. The supplemental inspection was completed in December 2005. The team determined that the yellow finding would remain open, because not all of the licensee's root and contributing causes were fully developed, many of the corrective actions were narrowly focused or ineffective, and effectiveness reviews were not adequate. The NRC will perform a follow-up inspection after receiving written notification from the licensee that they have completed additional corrective actions and are ready to support the inspection.

▲ Note 12: Fort Calhoun is in the regulatory response column due to one white finding in the mitigating systems conerstone originating in 1Q/2005.

▲ Note 13: Hatch unit 1 is in the regulatory response column due to one white inspection finding in the Emergency Preparedness Cornerstone (TSC removed from service greater than 7seven days) originating in 2Q/2005.

▲ Note 14: Hatch unit 2 is in the regulatory response column due to one white inspection finding in the Emergency Preparedness Cornerstone (TSC removed from service greater than 7seven days) originating in 2Q/2005.

▲ Note 15: Indian Point 2 is in the regulatory response column due to one white inspection finding in the mitigating systems cornerstone originating in 2Q/2005. The white finding related to nitrogen gas that was discovered in the safety injection (SI) system. The 95001 inspection for this finding was completed in December 2005, and provided a positive assessment of the licensee's corrective actions. Therefore, this finding will be closed and no longer be considered in the Action Matrix with the 1Q/2006 update. On October 31, 2005, the EDO approved a Deviation from the ROP Action Matrix to provide a greater level of oversight for the Indian Point 2 plant. The Deviation includes oversight activities to monitor licensee action to: 1) Characterize and remediate tritium found onsite, and 2) improve the reliability of the emergency siren system.

▲ Note 16: Oyster Creek is in the regulatory response column due to one white inspection finding in the emergency preparedness (EP) cornerstone originating in 3Q/2005. The white finding involved an inadequate response to an event involving grassing of the intake structure.

▲ Note 17: Three Mile Island is in the regulatory response column due to a white inspection finding in the emergency preparedness cornerstone originating in 2Q/2005. The white inspection finding involved training of the Emergency Response Organization.

▲ Note 18: Turkey Point unit 3 is in the regulatory response column due to one white performance indicator in the Mitigating System Cornerstone (Heat Removal System, (AFW), Unavailability) originating in 4Q/2005.

▲ Note 19: Turkey Point unit 4 is in the regulatory response column due to one white performance indicator in the Mitigating System Cornerstone (Heat Removal System, (AFW), Unavailability) originating in 4Q/2005.

▲ Note 20:

On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope

Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

▲ Note 21: One white inspection finding in the initiating events cornerstone originating in 2Q/2005 was determined to be an old design issue in accordance with IMC 0305, and is not considered as an input to the assessment program.

▲ Note 22: One white inspection finding in the initiating events cornerstone originating in 2Q/2005 was determined to be an old design issue in accordance with IMC 0305, and is not considered as an input to the assessment program.

▲ Note 23: On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

▲ Note 24: On July 29, 2005, the Executive Director for Operations approved a renewal of a deviation from the ROP Action Matrix to provide a greater level of oversight for the Salem and Hope Creek Generating Stations. The deviation includes oversight activities to monitor licensee improvement efforts in SCWE and related performance attributes.

Last modification: Feb 15, 2006

ATTACHMENT 3

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

January 27, 2006

EA-04-221
EA-05-051

James M. Levine, Executive Vice
President, Generation
Arizona Public Service Company
P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: PALO VERDE NUCLEAR GENERATING STATION - NRC SUPPLEMENTAL INSPECTION REPORT 05000528/2005012; 05000529/2005012; AND 05000530/2005012

Dear Mr. Levine:

On December 12, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection using Inspection Procedure 95002, "Inspection For One Degraded Cornerstone Or Any Three White Inputs In A Strategic Performance Area," at your Palo Verde Nuclear Generating Station. The enclosed report documents the results of the inspection, which were discussed on December 16, 2005, with you and other members of your staff.

This supplemental inspection was conducted to review your corrective actions for both of the violations issued to you on April 8, 2005. The first was a violation regarding 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to adequately control the designed configuration of the containment sump safety injection suction piping of all three units. Specifically, a significant portion of this piping was not consistently maintained full of water since initial operation of all three units. In conjunction with this finding, the NRC also issued a Severity Level III violation of 10 CFR 50.59, with a monetary civil penalty, for a previous change to the facility that was performed without required prior NRC approval. Specifically, a station administrative procedure was changed to maintain the condition of the piping drained instead of filled. Your performance, which led to these violations, was determined to be reflective of that of a degraded cornerstone (i.e., degraded Mitigating Systems Cornerstone) in our Action Matrix. The specific purposes of this inspection, as described in the Objectives Section of Inspection Procedure 95002, were to (1) provide assurance that the root causes and contributing causes for the violations, which resulted in the degraded cornerstone, were understood; (2) independently assess the extent of condition and extent of cause for the violations; and (3) provide assurance that your planned corrective actions were sufficient to address the root causes and contributing causes for the violations and to prevent their recurrence. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

As further detailed in the enclosed report, the NRC concluded that you performed an adequate evaluation and implemented corrective and followup actions necessary to reasonably prevent repetition of the 10 CFR 50.59 Severity Level III violation. Therefore, we have closed this finding. However, the NRC also concluded that, while you performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that your planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. We request that you inform us in writing once you have completed steps to assure that your corrective actions are of sufficient scope and breadth to address the subject performance deficiencies. The NRC will then perform additional inspections as necessary to assess the effectiveness of your actions. Pending completion of this followup inspection activity, the subject Design Control violation in the Mitigating Systems Cornerstone will remain open.

This inspection report describes four NRC identified and two licensee identified findings of very low safety significance (Green), involving violations of NRC requirements. Additionally, two summary findings are provided to describe our assessment of your evaluation and implementation of corrective actions associated with the 10 CFR 50.59 and Design Control violations, in accordance with NRC Manual Chapter 0612, Appendix C, "Guidance for Supplemental Inspections." Because of the very low safety significance of these violations, and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations consistent with Section VI.A of the NRC Enforcement Policy. If you contest these noncited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

//RA//

Bruce S. Mallett
Regional Administrator

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

Enclosure:
NRC Inspection Report 05000528/2005012;
05000529/2005012; and 05000530/2005012
w/Attachment: Supplemental Information

cc w/enclosure:
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C:DRS/EB1	SRI:DRP/E	SRI:DRS/EB1	RI:DRP/D	RI/RIII/DRS
JAClark/lmb	MCHay	DLProulx	MASitek	SNSheldon
/RA/	**/RA/ E**	**/RA/ E**	**/RA/ E**	**/RA/ E**
1/11/05	1/11/06	1/13/06	1/11/06	1/11/06

C:D/DRP	DD:NRR/DIRS	C:DRS/EB1	D/DRP	RA	
TWPruett	SARichards	JAClark	ATHowell	BSMallett	
/RA/	**/RA/ E**	**/RA/**	**/RA/ By AV**	**/RA/**	
1/26/06	1/13/06	1/27/06	1/27/06	1/27/06	

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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-528; 50-529; 50-530
Licenses:	NPF-41; NPF-51; NPF-74
Report:	05000528/2005012; 05000529/2005012; 05000530/2005012
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1; 2; and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	September 12 through December 12, 2005
Inspectors:	J. Clark, Branch Chief M. Hay, Senior Resident Inspector, Projects Branch E D. Proulx, Senior Reactor Inspector, Engineering Branch 1 S. Sheldon, Reactor Inspector, Division of Reactor Safety, Region III M. Sitek, Resident Inspector, Projects Branch D
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Approved By:	Bruce S. Mallett Regional Administrator

TABLE OF CONTENTS

SUMMARY OF FINDINGS . . . . . -1-

REPORT DETAILS . . . . . -6-

1. REACTOR SAFETY . . . . . -6-

4OA5 Other Activities . . . . . -6-
Inspection Scope . . . . . -6-
.1 Independent NRC Inspection: Refueling Water Tank Voiding . . . . . -7-
.2 Independent NRC Inspection: Auxiliary Feedwater Useable Volume . . . . . -13-
.3 Independent NRC Inspection: Refueling Water Tank Instrument Calibration . . . . . -17-
.4 Independent NRC Inspection: Operability Determinations . . . . . -19-
.5 Corrective Action Effectiveness . . . . . -23-
.6 Assessment of Licensee Evaluations and Conclusions . . . . . -27-

4OA6 Meetings, Including Exit . . . . . -28-
Exit Meeting Summary . . . . . -28-

4OA7 Licensee Identified Violations . . . . . -28-

ATTACHMENT A-1
SUPPLEMENTAL INFORMATION A-1
KEY POINTS OF CONTACT A-1
LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED A-2
LIST OF DOCUMENTS REVIEWED A-3
LIST OF ACRONYMS A-13

SUMMARY OF FINDINGS

IR 05000528/2005012; 05000529/2005012; 05000530/2005012; 09/12/05 - 12/12/05; Palo Verde Nuclear Generating Station, Units 1, 2, and 3; Supplemental Inspection Report; Inspection Procedure 95002.

This report documents a supplemental inspection by a branch chief, two resident inspectors, two reactor inspectors, accompanied by a consulting engineer and a team assistant. The inspection identified four noncited violations and two findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified Findings:

Cornerstone: Mitigating Systems

•• N/A. The U.S. Nuclear Regulatory Commission (NRC) performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with an inappropriate change to an emergency core cooling system procedure without prior NRC approval. This procedure change rendered portions of the system inoperable because of voiding. This performance issue was previously characterized as a Severity Level III violation of 10 CFR 50.59 and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. During this supplemental inspection, performed in accordance with Inspection Procedure 95002, the inspectors determined that the licensee's evaluation identified the primary root causes of the performance issue to be: (1) The site procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) The corrective action program implementation was ineffective. The licensee also identified overlap and interface problems between the corrective action program, the engineering evaluation request program, and the instruction change request program. These issues, in conjunction with inadequate training to recognize a corrective action condition, contributed to the failure of station personnel to initiate a corrective action program input document in 1992 for the potential pipe voiding concern. The inspectors concluded that the licensee's evaluation and implemented corrective actions were appropriate to reasonably prevent repetition of the 10 CFR 50.59 violation.

Given the licensee's acceptable performance in addressing the inappropriate procedure change and 10 CFR 50.59 program deficiencies, the Severity Level III violation is closed. (Section 4OA5.6)

- N/A. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with potential air entrainment into the emergency core cooling system. The licensee failed to incorporate original design requirements into the plant to maintain piping between the containment sump isolation valves filled with water. This performance issue was previously characterized as a 10 CFR 50, Appendix B, Criterion III, violation having substantial safety significance (Yellow), and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. The inspectors determined that the licensee's evaluation identified a direct cause, nine root causes, and nine contributing causes of the performance issue. The evaluation was also used to develop an extensive list of corrective actions. The inspectors found the licensee's methods of evaluation to be appropriate.

  The NRC concluded that, while the licensee performed an adequate root cause evaluation of the Design Control violation, certain corrective actions were incomplete at the time of this inspection. Specifically, the team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that the planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. Therefore, the (Yellow) violation (VIO 2004/014-01) will remain open for further NRC review. (Section 4OA5.6)

- Green. The inspectors identified a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to potential air entrainment into the emergency core cooling system suction header from the refueling water tank. Specifically, the inspectors determined that the water level in the refueling water tank could fall below the level of the tank discharge pipe and associated vortex breaker during the transfer from the refueling water tank to the containment sump during design basis accidents. As a result, air could be drawn into the emergency core cooling system piping under accident conditions. This issue was applicable to both trains of all three units. Contrary to proper design control, engineering personnel failed to effectively implement design requirements to prevent potential air entrainment into the emergency core cooling system.

  The inspectors considered this finding to be more than minor, in accordance with NRC Manual Chapter 0612, "Power Reactor Inspection Reports," since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of design and configuration control. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low

safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2835132), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.1)

- Green. The inspectors identified two examples of a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for failure to translate the design basis volume of 300,000 gallons of usable volume in the condensate storage tank (CST) and reactor water makeup tank (RWMT) into the station's instructions, procedures, or drawings. Without this information, operators were unaware that Technical Specification minimum levels, specified in feet, may not provide sufficient usable volumes of water for auxiliary feedwater pump operation. Contrary to proper design control, the licensee failed to effectively implement design requirements to ensure operability of the auxiliary feedwater system.

  These two examples of a violation affect the Mitigating Systems cornerstone and are more than minor because they were similar to Example 3.I of Manual Chapter 0612, and design calculations were required to be re-performed to assure accident requirements were met. In both instances, the originally calculated available inventory was less than the actual required design basis inventory of 299,700 gallons. Subsequent calculations by engineering personnel, including significant reduction in margins, demonstrated that minimum required volumes in the CST and RWMT were maintained. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition requests (CRDRs 2839337, 2840186, and 2841773), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.2)

- Green. The inspectors identified a noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," for failure to translate design basis information into the calibration of refueling water tank level instruments. Without this information, operators were unaware that a Technical Specification listed minimum level in this tank may not provide sufficient usable volume of water for emergency core cooling system operation. Specifically, engineers failed to density compensate these instruments for allowable ranges of both temperature and boric acid concentration of the tank. Contrary to proper design control, the licensee failed

to effectively implement design requirements to ensure operability of the refueling water tank.

This issue was determined to affect the Mitigating Systems cornerstone and was more than minor based upon review of Example 3.j of Manual Chapter 0612, Appendix E. The errors were considered more than a minor calculation error because the deficiencies required re-performance of the calculations, significantly reduced the overall margin, and could be applicable to other such instrumentation calculations. However, engineering personnel demonstrated that while there was a loss of margin, there was no actual loss of function because of the inaccuracies in the RWT level instrument calibrations. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2840920), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. (Section 4OA5.3)

•• Green. The inspectors identified three examples of a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, these examples involved the licensee's failure to follow a procedure and to provide appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished, consistent with the facility's administrative procedure for the operability determination process. In the first case an engineer evaluated a concern in a condition report/disposition request without notifying the control room so an operability assessment could be performed. In the other cases, there was inadequate guidance given to operators to address when an operability assessment would be required.

The inspectors considered this finding to be more than minor, in accordance with Manual Chapter 0612, since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of procedure quality and human performance. However, subsequent evaluations completed by the licensee verified that actual safety functions were not lost in any of these examples. The inspectors performed a Phase 1 significance determination, using NRC Manual Chapter 0609, and determined this issue screens out as having very low safety significance (Green) because a safety function was not lost. Because the violation was determined to be of very low safety significance and has been entered into the corrective action program as condition report/disposition request (CRDR 2838626), this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy. The inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. (Section 4OA5.4)

B. Licensee-Identified Violations:

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

1. REACTOR SAFETY

4OA5 Other Activities

Inspection Scope

In August 2004, the U.S. Nuclear Regulatory Commission (NRC) identified a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," that involved a failure to adequately control the designed configuration of the containment sump safety injection suction piping at all three Palo Verde Nuclear Generating Station (PVNGS) units. Specifically, a significant portion of this piping was not consistently maintained full of water since initial operation of all three units. The finding was originally documented in NRC Inspection Report 05000528; 529; 530/2004014 (ADAMS ML050050287). This violation was subsequently determined to be of substantial safety significance (Yellow) through the application of NRC Manual Chapter 0609, "Significance Determination Process." In conjunction with this finding, the NRC also identified a Severity Level III violation of 10 CFR 50.59 for a previous change to the facility that was performed without prior NRC approval. Specifically, a station administrative procedure was changed to maintain the condition of the piping drained instead of filled.

Each year, the NRC conducts integrated assessments of nuclear power plant performance. These assessments are based upon the risk significance of the inspection findings by the NRC's resident and region-based inspectors and the insights gained from the licensee-provided performance indicators. As discussed in a followup letter to our most recent annual end-of-cycle assessment, and the current mid-cycle assessment letter, plant performance for PVNGS was categorized within the Degraded Cornerstone Column of the NRC's Manual Chapter 0305, "Operating Reactor Assessment Program," Action Matrix. This was based on the open (Yellow) finding in the Mitigating Systems Cornerstone. The NRC's performance of this supplemental inspection was based upon the licensee's performance, and is consistent with the Action Matrix.

This supplemental inspection was conducted to obtain information for the NRC to determine if the licensee provided reasonable assurance that the problems associated with the degraded Mitigating Systems cornerstone were thoroughly understood, the cause and effects were properly evaluated, and sufficient corrective actions have been taken to prevent recurrence. The inspectors reviewed the licensee's actions for completeness, thoroughness, and effectiveness. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. The inspectors also performed focused inspection activities to independently assess the validity of the licensee's conclusions. Specific items reviewed are documented in the attachment, or in the following discussions of NRC assessments and findings.

The inspectors primarily used the guidance of Inspection Procedure 95002, "Inspection for One Degraded Cornerstone or Any Three White Inputs In A Strategic Performance

Area," to conduct the inspection. This supplemental inspection was conducted to review the licensee's corrective actions for both of the violations issued on April 8, 2005. The specific purposes of this inspection, as described in the Objectives Section of Inspection Procedure 95002, were to (1) provide assurance that the root causes and contributing causes for the violations, which resulted in the degraded cornerstone, were understood; (2) independently assess the extent of condition and extent of cause for the violations; and (3) provide assurance that the licensee's planned corrective actions were sufficient to address the root causes and contributing causes for the violations and to prevent their recurrence. This inspection procedure also called for a customized plan to assess the validity of the licensee's conclusions. This plan was derived from Inspection Procedures 71111.02, "Evaluations of Changes, Tests, or Experiments," 71111.17, "Permanent Plant Modifications," 71111.21, "Safety System Design and Performance Capability," and 71152, "Identification and Resolution of Problems." Specifically, the inspectors reviewed:

- The translation of original design basis requirements into plant procedures, calculations, setpoints, and modifications. Primary emphasis was on mitigating systems
- The licensee's processes to maintain and control the design basis of the facility
- Revisions to operating, maintenance, and testing procedures to ensure design and 10 CFR 50.59 aspects were addressed
- Interfaces with operations personnel on evaluations and corrective action program implementation
- The use of operating experience
- How the licensee's overall evaluations of the escalated findings, and their proposed corrective actions, addressed all of the previous criteria

.1 Independent NRC Inspection: Refueling Water Tank Voiding

Introduction. The inspectors identified a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to potential air entrainment into the emergency core cooling system (ECCS) suction header from the refueling water tank (RWT). Specifically, the inspectors determined that the water level in the RWT could fall below the level of the tank discharge pipe and associated vortex breaker during the transfer from the RWT to the containment sump after an accident. As a result, air could enter the ECCS piping system under accident conditions. This issue was applicable to both trains of all three units.

Description. During preparation for the this inspection, the inspectors reviewed the transportability analysis included in Condition Report/Disposition Request (CRDR) 2726509, "ECCS Sump Suction Piping Discovered in an Unanalyzed Condition," Revision 1. This report included extent of condition and extent of cause evaluations for the ECCS sump issue (event date July 29, 2004). The inspectors noted this report included the RWT in its scope, but did not address the RWT as a potential

source of air entrainment into the ECCS. The inspectors also noted that the PVNGS design did not include automatic closure of the RWT isolation valves with a recirculation actuation signal (RAS). The inspectors noted that the licensee did not fully understand the plant design basis and the dynamics of the system at the time of a RAS. Based on these observations, the inspectors questioned licensee personnel further on the potential of air entrainment from the RWT into the ECCS.

The inspectors found the applicable design calculation was Calculation 13-MC-CH-201, "Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Make-Up Water Tank (RWMT) Sizing," Revision 6 (issued July 13, 1999). This calculation included an analysis to demonstrate that "the final RWT level following a RAS was adequate, relative to the minimum water level in containment, to ensure that the suction piping would not void and gas-bind the ECCS pumps." The pumps of concern are in the containment spray system (CSS) and safety injection system (SIS). The associated analysis was based on a minimum containment pressure of 23 psia (approximately 8.5 psig). Revision 0 of this calculation (issued April 20, 1979) was also based on a minimum containment pressure of 23 psia. The inspectors questioned whether the 23 psia value was conservative. Engineering personnel stated that more recent "best-estimate" analyses had indicated that the actual minimum containment pressure was 17.5 to 18.5 psia (approximately 3 to 4 psig).

In response to the inspectors' questions, engineering personnel initiated CRDR 2835132 on October 6, 2005. This CRDR raised a concern that the original Combustion Engineering (CE) design interface requirements, included in Updated Final Safety Analysis Report (UFSAR), Section 6.3.1.3.M.2, may not "preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation" as stated in the UFSAR. This interface requirement stated, in part, "The piping for each safeguards train is designed such that the piping junction of the suction pipe, that runs to the refueling water tank and the containment recirculation sump, is located at least 16 feet below the top of the recirculation containment sump, which is 4 feet below the minimum water level in the containment during recirculation. This provides adequate static hydraulic head margin for the minimum containment pressure of -3.5 psig, as described in Subsection 6.2.1, to preclude the possibility of drawing air from the RWT to the safeguards pump suction during recirculation." The inspectors were concerned that, while this was a design interface requirement, it was intended to be a bounding design consideration for the ECCS, especially during dynamic flow conditions.

Operability Determination (OD) 301, Revision 1, was initiated on October 6, 2005, to address this issue. The operability evaluation concluded the ECCS was operable. It stated, in part, "Engineering believes that further evaluation will demonstrate that with appropriate assumptions for containment pressure and water inventory in the RWT/containment, the minimum water level will remain above the vortex breaker in the RWT which eliminates the potential for air entrainment. Based on this information, reasonable assurance exists that the ECCS is capable of performing its specified design function and therefore remains operable." Operability Determination 301 was approved on October 8, 2005.

The licensee also sought additional engineering assistance from outside organizations, including Westinghouse. On October 11, 2005, engineering personnel were informed

that containment pressure analyses, performed by Westinghouse, were based on an assumed RWT temperature of 120•F. This is the maximum assumed RWT temperature allowed by Technical Specifications, and would be a conservative assumption for containment response calculations evaluating high pressures. However, Westinghouse informed engineering personnel that the maximum RWT temperature was nonconservative for determining the minimum containment pressure under accident conditions. Based on preliminary calculations, the correlation between RWT temperature and minimum containment pressure was: 90•F/ 2.0 psig, 105•F/3.8 psig, and 120•F/4.3 psig. The minimum containment pressure required to prevent uncovering the RWT vortex breaker was 4.3 psig. As stated previously, recent licensee containment modeling determined containment pressure could be approximately 3 to 4 psig, indicating negative margin. As a result, during a licensee management review team meeting, held on October 11, 2005, it was determined that the ECCS of both trains of all three units were outside design bases and were declared inoperable at 1333 hours. Units 2 and 3 entered limiting condition of operation (LCO) 3.0.3, "Unanalyzed Condition," and performed orderly shutdowns to Mode 5. Unit 1 was shutdown at this time for scheduled refueling outage activities. Operability Determination OD 301 was subsequently canceled.

On October 17, 2005, the licensee determined that the ECCSs were operable and restart of Units 2 and 3 was approved. The determination that the ECCSs were operable was based on the conclusions of Report FAI/05-107, "The Potential for Air Intrusion and RWT Check Valve Response Following RAS," Fauske & Associates, Inc., Revision 0. This report was transmitted to Palo Verde Nuclear Generating Station (PVNGS) in Westinghouse Letter CVER-05-75, dated October 17, 2005. As documented in the operator logs, the report concluded, in part, "The design of the PVNGS SIS and CSS suction piping meets the subject interface requirement and supports operability of the SIS and CSS. Report FAI/05-107 confirms that the PVNGS plants RWT and containment sump arrangements meet the explicit intent of the CE Interface Requirement 4.3.1.1, such that, there is no possibility of air being drawn into the ECCS pumps during continuous recirculation operation. Also using a conservative and limiting approach, Report FAI/05-107 demonstrates that the design, as implemented, meets the objective of the interface requirement during transition to recirculation at the initiation of RAS. Specifically, water level in the RWT suction piping does not drop below the elevation at the top of its junction with the containment sump piping." The operator logs also stated, "Based on the above, a degraded or non-conforming condition did not exist and the emergency core cooling systems at PVNGS have been operable."

On October 17, 2005, the licensee initiated CRDR 2838368 to address the non-conservative assumption in Calculation 13-MC-CH-201 that the containment pressure at the time of RAS would be no less than 8.5 psig.

After detailed review of the licensee's operability determination and design calculations, the inspectors questioned the conclusion that "a degraded or nonconforming condition did not exist." The inspectors determined that ECCS design basis analyses including Calculations 13-MC-CH-201, Revision 6; 13-MC-SI-018, "Containment Spray System Interface Requirements Calculation," Revision 6; and 13-MC-SI-017, "Safety Injection System Interface Requirements Calculation," Revision 5 were based on the suction

header piping remaining full of water under post accident conditions. Contrary to this, Report FAI/05-107, Revision 0, predicted that the RWT level would fall below the RWT vortex breaker and that some air would enter the piping system. Although this report concluded that the air would not reach the pump suctions, air entrainment in the piping system was not consistent with the design basis. In addition, the inspectors observed that UFSAR, Section 6.5.2.8, "CESSAR Interface Evaluations," addressed potential air entrainment from the RWT. Subsection (RA) 7.16.1 stated, in part, "In addition, vortexing tendencies within the tank are precluded by a suction cage within the tank, similar in design to the cage installed in the containment emergency sump. The minimum required RWT level and volume are the useful level and volume above the volume that is unusable due to vortex considerations."

In response to these questions, PVNGS personnel concluded that this condition did not conform to the design basis and that additional actions were required to correct the condition. Most of these corrective actions were still in progress at the close of this inspection, under CRDR 2835132. However, the licensee did provide Revision 1 of Report FAI/05-107 to the inspectors, which demonstrated that although air could enter the ECCS suction header, that the resultant void fraction would be below the maximum allowable for safe operation of the pumps. The licensee also described proposed actions of increased training and controls for operators, and a proposed modification to the containment sump isolation valves to operate them automatically from a RAS. The inspectors concluded these actions, if implemented, would contribute to mitigating the degraded condition.

In addition to the noncited violation, the inspectors noted several other performance deficiencies during their document review and interaction with station personnel. Based upon the below listed deficiencies, the inspectors also determined this issue had cross-cutting aspects of human performance. Specifically, the licensee's attention to detail was lacking and there was poor inter- and intra-group coordination. These deficiencies are discussed below:

- The inspectors determined that the licensee extent of cause and extent of condition reviews were narrowly focused. The licensee defined very extensive design criteria and features that could be pertinent to the original (Yellow) violation. However, if some design document or interface document addressed the design criteria, the licensee performed no further review. There was not a thorough effort by the licensee to validate the design criteria. This was clearly demonstrated in the RWT voiding issue. Examples included the licensee's misunderstanding of the maximum RWT temperature, and their reliance on a Combustion Engineering interface requirement, for piping elevations, to meet all dynamic thermal-hydraulic design criteria for ECCS piping.

- The licensee also noted, in other ongoing programs at the facility, that design basis information was not handled with appropriate attention to detail. Examples included the licensee's evaluation statements that their UFSAR validation process, under 10 CFR 50.54(f), was shallow; quality assurance reviews indicated that engineers did not verify reference values or conditions for design calculations; and various design organizations did not interface well with each other for multi-disciplinary issues.

- The inspectors determined that the licensee's evaluation of technical issues was iterative, which demonstrated a lack of thoroughness in reviews. The inspectors noted that engineering personnel would address one particular aspect or consideration when a design problem was presented. However, when questioned by the inspectors or engineering management, more discrepancies would be identified by the engineering personnel. The inspectors determined that design engineering personnel were making broad assumptions of criteria in their reviews, and in several cases, were using unverified or unstated assumptions from other groups. An example was the stroke times of the containment sump isolation valves used by design engineers in their RWT required volume calculations. There was no stated basis for the times used, and design engineers could not explain to the inspectors where the values came from. Additionally, other engineering personnel were not challenging these assumptions in peer or supervisory reviews. These organizational and human performance issues caused the inspectors to question the appropriateness of the extent of cause review for the (Yellow) Design Control violation.

- The inspectors noted a lack of communication between organizations, and a lack of attention to detail when coordinating critical design evaluations between organizations. During discussions of this RWT voiding issue, engineering personnel inappropriately described system operation to operators while discussing the operability of ECCS (see Section 4OA5.1). One shift test engineer informed an inspector that on October, 8, 2005, he was told by the operator he was relieving, that "I believe we may be in 3.0.3," based on the emergent RWT voiding issue. The individual apparently did not address this to his crew supervision because he had not had time to reconcile his own questions. Subsequently, the operations crew and the lead shift test engineer reviewed the RWT information, without consulting engineering, and concluded the previous operator's questions were not of concern. The inspectors were concerned this demonstrated problem resolution by isolated groups, and did not look across organizational boundaries.

- The inspectors determined that the licensee had a very limited use of operating experience for the RWT issue. The licensee previously identified that ineffective use of operating experience was a contributor to the (Yellow) ECCS violation. The licensee also had several self-identified findings of ineffective operating experience use in the last year, following reviews of their substantive crosscutting problem identification and resolution issue and their engineering program review. However, during the review of the RWT issue, the licensee did not consider all relevant operating experience. The inspectors brought to the licensee's attention a similar finding in 2003 at the Brunswick Nuclear Power Station, and a specific American Society of Mechanical Engineers' study for uncovering the RWT vortex breaker at the Donald C. Cook facility in 2001. This study not only included detailed flow modeling of the same system, it partly refuted the original operability determination the licensee performed under OD 301 by stating air would enter the suction piping.

- The inspectors determined that the schedule for effectiveness reviews did not ensure a timely review of the adequacy of corrective actions. Two root causes, and one of the contributing causes, were addressed by a condition report action item (CRAI) 2825679, which at the time of the inspection was already closed. This corrective action included all-hands communications from senior management to communicate the need for effective questioning attitudes and technical rigor. This corrective action was closed on September 9, 2005, after such meetings were conducted to "emphasize that it is essential that all employees have a strong and effective questioning attitude and technical rigor, and to challenge assumptions and/or any situations which do not seem safe, or per design, or per procedure, or per expectation, or in general do not seem appropriate." The licensee stated this was placed in the effectiveness review process, but that specific review of effectiveness of these actions was not planned until 2006. The inspectors determined that the effectiveness review was untimely in that unacceptable performance continued without additional corrective actions being implemented.

Analysis. The inspectors determined that the potential of air entrainment into the ECCS suction header from the RWT was a licensee performance deficiency. This condition did not conform to the plant design basis and had not been analyzed. The finding affected the Mitigating Systems cornerstone because of the potential for the safety injection and containment spray systems to be degraded because of air reaching the pump suctions under accident conditions. The inspectors considered this finding to be more than minor, in accordance with NRC Manual Chapter (MC) 0612, "Power Reactor Inspection Reports," since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of design and configuration control. The PVNGS engineering staff had to perform additional analyses, and an operability evaluation because of this condition.

The inspectors determined that the specific accident conditions that could have challenged the ECCS have not existed. The licensee also determined that although potentially degraded, the safety injection and containment spray systems remained operable based on engineering analysis. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Criterion III, "Design Control," of 10 CFR 50, Appendix B, states that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Criterion III also states that measures shall be established for the identification and control of design interfaces and for coordination among participating design organizations. Specifically, the licensee failed to effectively translate into station specifications, procedures, and instructions the design requirement to prevent air entrainment into the ECCS system. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2835132, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-01, Improper Design Control for ECCS Sump and RWT Swapover.

.2 Independent NRC Inspection: Auxiliary Feedwater Useable Volume

Introduction. The inspectors identified a noncited violation, with two examples, of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to translate the design basis usable volume of 300,000 gallons in the condensate storage tank (CST) and RWMT into plant instructions, procedures or drawings. Specifically, Calculation 13-MC-CT-205, demonstrated that 330,000 gallons of usable volume existed in the CST when taking into account vortexing and air entrainment of the auxiliary feedwater pumps, only if operations personnel took action to close the auxiliary feedwater pump minimum flow recirculation valves. However, the inspectors determined that this operator action was not incorporated in normal, abnormal, or emergency operating procedures. Without shutting the valve on low CST level, the licensee's calculations revealed that only 292,900 gallons of usable volume existed, which is less than the 300,000 gallons credited in the UFSAR and the Technical Specification Bases. Technical Specification Bases 3.7.6 also credits 300,000 gallons of usable inventory for auxiliary feedwater usage with the RWMT at 26 feet. With instrument uncertainties and vortexing concerns, Calculation 13-JC-CH-0214 verified that only 273,000 gallons of usable inventory were available with the RWMT at 26 feet.

Description. As part of the licensee's extent of cause/condition review for the (Yellow) violation, the licensee generated a matrix that detailed if statements in the UFSAR were reflected in calculations, design basis manual, Technical Specifications, and implementing procedures. As with the previously described RWT potential voiding issue (Section 4OA5.1), the inspectors questioned whether the licensee thoroughly reviewed design considerations, or simply accepted that a design aspect was already mentioned in a reference document. Section 9.2.6 of the UFSAR stated that the CST had a usable volume of 300,000 gallons plus 30,000 gallons to support 8 hours at hot standby followed by a cooldown to 350•F at 75•F per hour. This volume requirement was based on the NRC Branch Technical Position RSB 5-1, "Alternate Safe Shutdown Analysis," which required a usable CST volume adequate to support 4 hours at hot standby followed by a cooldown to conditions that allow shutdown cooling to be initiated. Technical Specification 3.7.6 required that the CST be at 29.5 feet. The bases for Technical Specification 3.7.6 stated that the 29.5 feet level in the CST is based on having 300,000 gallons of usable volume to support an 8 hour hold in Mode 3 (Hot Standby) followed by a cooldown to shutdown cooling entry conditions (350•) at 75•F per hour. The inspectors also determined that previous to PVNGS's conversion to Improved Technical Specifications in 1996, the Technical Specification value was the volume of the tank instead of the level. Therefore, it would be incumbent on the licensee to continue to demonstrate the relationship between the tank volumes and required minimum levels for Technical Specifications.

The inspectors determined that the licensee only performed an initial review of the CST volume requirements, with no additional validation. Because of concerns with the licensee's calculations associated with the RWT, on October 17, 2005, the inspectors questioned engineering personnel to determine if the CST volume calculations had been similarly verified.

Following the inspectors' questioning, engineering personnel reviewed Calculation 13-MT-CT-205, Revision 3, which established the amount of available CST

inventory. The inspectors determined that, in 1994, this calculation revealed that the usable volume of the CST was based on ensuring that adequate net positive suction head was available to the auxiliary feedwater pumps, taking into account pump vortexing, and air entrainment. The calculated level initially corresponded to 25 feet in the CST. However, engineering personnel noted that this level did not sufficiently address air entrainment when the minimum flow recirculation valve was open and did not account for instrument uncertainty. With 25 feet of CST inventory, Calculation 13-MT-CT-205 determined that 270,000 gallons of usable inventory existed in the CST. This was less than the credited 300,000 gallons.

On April 4, 1992 engineering personnel generated Engineering Evaluation Request (EER) 89-AF-048 to disposition the recommendations from the calculations. Engineering personnel recommended that the Technical Specification minimum level be revised to 29.5 feet. The EER stated that with the auxiliary feedwater minimum flow recirculation valve open, the usable CST volume at 29.5 feet corresponded to a volume of 292,900 gallons (less than the 300,000 gallons of usable inventory credited in UFSAR, Section 9.2.6, and Technical Specification 3.7.6). To resolve this concern, engineering personnel initiated Instruction Change Request (ICR) 38795 to the Operations Department to request that the minimum flow recirculation valves for the auxiliary feedwater pumps be closed when CST level approached 6.5 feet. This was to prevent air entrainment of the auxiliary feedwater pumps. If the minimum flow recirculation valve is closed then the air entrainment concerns no longer existed, ensuring the 300,000 gallons plus 30,000 gallons of reserve inventory for a total usable volume of 330,000 gallons in the CST. Operations responded to ICR 38795 by stating that closing the auxiliary feedwater pump minimum flow recirculation valves was not advisable because it could lead to pump damage, so that the recommended action when CST level approached 6.5 feet was to switch to the alternate water source (RWMT). The corrective action, including the usable volume question, was then closed by operations personnel without further resolution of the discrepancies.

In May 2001, Calculation 13-MC-CT-205 was updated to incorporate the calculation results and conclusions of EER 89-AF-048. Again, the inspectors found that no further verification was performed to ensure that the design basis was met or that previously described operator actions were incorporated into procedures.

In December of 2001, Calculation 13-MT-CT-205 was revised to determine if the amount of usable volume was adequate to support power uprate of Unit 2 from 3876 to 3990 million watts-thermal (MwT). With the revised reactor thermal power, engineering personnel calculated that 299,700 gallons of usable inventory were necessary to support 8 hours in Mode 3 followed by a cooldown at 75• •per hour to 350• • Since Calculation 13-MC-CT-205 stated that the CST had a usable volume of 330,000 gallons (assuming operator actions to shut the minimum flow recirculation valves), engineering personnel believed that no further procedure or design basis actions were necessary with respect to CST inventory to support the Unit 2 power uprate. The inspectors considered this another missed opportunity to address the CST usable volume discrepancy. The inspectors noted that without crediting the operator action to shut the minimum flow recirculation valves, the usable inventory in the CST (292,900 gallons) was less than that necessary to meet the design basis (299,700 gallons) to support the Unit 2 power uprate. In September 2003, the NRC issued Amendment 149 to the Unit 2 operating

license, approving an uprate to 3990 MwT. Similarly, the licensee submitted power uprate license amendment requests for Units 1 and 3 in July 2004, also with no change to the required CST level or inventory. The failure to incorporate operator action into procedures to ensure adequate CST volume, or other actions such as requiring swapover to the RWMT, was the first example of a violation of 10 CFR 50, Appendix B, Criterion III. The licensee initiated CRDR 283927 to enter this item into the corrective action system.

The licensee determined that resolving the CST inventory discrepancies, by incorporating the operator action to shut the minimum flow recirculation valves upon low CST level, was not a prudent action because it could result in damage to the operating auxiliary feedwater pumps. Therefore, engineering personnel revised the applicable calculations for the amount of water necessary to support the cooldowns, through the removal of available margin, and intended to revise the Technical Specification Bases to support these calculations. In addition, the licensee revised the calculations to more accurately determine the unusable volume because of air entrainment. When these new calculations were completed, engineering personnel determined that 300,000 gallons are currently available, and that less that 292,900 gallons of water is necessary for all accident scenarios and to meet the UFSAR requirement to support 8 hours in Mode 3 followed by a cooldown to shutdown cooling entry conditions. These calculation revisions demonstrated there was no actual loss of safety function.

On October 23, 2005, following discovery of the discrepancies with the usable volume of the CST, the inspectors questioned the usable volume of the RWMT. The RWMT is the Technical Specification referenced alternate source of water to the CST. Technical Specification 3.7.6 allows the RWMT to be used as an alternative source of water for the auxiliary feedwater pumps, for up to seven days of the CST being inoperable, but does not address being used in conjunction with the CST (i.e., available volume from both tanks). Additionally, Technical Specifications stated that the CST and the RWMT must each have minimum volumes of 300,000 gallons to be declared operable. The licensee reviewed Calculation 13-JC-CH-0214 that verified the usable volume of the RWMT when used as a backup auxiliary feedwater source of water. The licensee noted that the calculations for the usable volume in the RWMT, when taking into account vortexing, air entrainment, and instrument uncertainties, revealed that 26 feet in the RWMT corresponded to only 273,000 gallons. The licensee initiated CRDR 284173 to enter this item into the corrective action system. The licensee performed revised calculations (including instrument uncertainty and vortexing concerns) and determined that the minimum level for the RWMT to serve as a backup source for the CST was 28 feet, which demonstrated the Technical Specification Bases was nonconservative. However, the inspectors noted that the RWMT was administratively controlled by a non-surveillance procedure to greater than 33 feet. The licensee plans to revise surveillance procedures and the Technical Specification Bases to require the RWMT to be greater than 28 feet to be declared operable for supplying the auxiliary feedwater system. The licensee performed a review and found no examples in which the RWMT was credited for the CST and the level was less than 28 feet. The failure to adequately translate the design basis into procedures, by requiring 28 feet in the RWMT, is a second example of violation of 10 CFR 50, Appendix B, Criterion III.

Based upon a review conducted after the inspectors' questioning, the licensee identified another minor design control issue with respect to the usable inventory for the CST. Review of calculations for the feedwater line break revealed that the vendor calculations assumed a cooldown from Mode 3 to only 400•F, while the design basis, UFSAR and Technical Specification assumed a cooldown to 350•F. The inspectors considered this to be a minor violation of 10 CFR 50, Appendix B, Criterion III, for inadequate design control. With this assumption, Westinghouse calculated that 253,000 gallons of water were necessary to support the 8 hour hold and subsequent cooldown. The licensee contacted the vendor to perform the proper calculation with the UFSAR and design basis cooldown to 350•F. The revised calculations resulted in a increased required inventory to approximately 270,000 gallons. However, this was less than the available 300,000 gallons. Therefore, the issue was similar to Example 3.I of MC 0612, in which only a minor reduction in margin was noted and the amount of water was sufficient to meet the design basis. Thus, the failure to implement adequate design controls for the feedwater line break analysis is considered an additional minor example of the violation, and is not subject to enforcement action.

In addition to the noncited violation, the inspectors noted several other licensee performance deficiencies during their document review and interaction with station personnel on this issue. The inspectors also determined this noncited violation had cross-cutting aspects of human performance. Specifically, attention to detail was lacking and there was poor inter- and intra-group coordination. These deficiencies are discussed below:

- The licensee established key systems and design parameters for review under the evaluation of the (Yellow) ECCS finding, consistent with Inspection Procedure 95002 criteria. Both the safety injection system and the auxiliary feed system were selected for these key reviews. Similar to the RWT voiding issue (Section 4OA5.1), the inspectors found several deficiencies in an area that was specifically reviewed by the licensee.

- The inspectors determined that the licensee's evaluation of technical issues was iterative. The inspectors noted that engineering personnel would address only a particular aspect or consideration of a design problem. Specifically, during the review of CST and RWMT calculations, inspectors identified multiple problems, during several successive meetings, over the period of a week. This was done because the licensee relied on unstated or inaccurate assumptions in the evaluation, and accepted unverified design criteria from other groups. When additional discrepancies were raised by the inspectors, the licensee required additional rounds of evaluation. The similar organizational and human performance issues in this area, to the original finding, demonstrated lack of effectiveness in the extent of cause review for the (Yellow) ECCS voiding issue.

- The inspectors determined that the effectiveness reviews did not ensure timely review of the adequacy of corrective actions. Two root causes and one of the contributing causes of the (Yellow) ECCS voiding issue were addressed by a condition report action item (CRAI 2825679), which at the time of the inspection was already closed. Similar to that described with the RWT voiding violation (Section 4OA5.1), this corrective action appeared to be ineffective in that

engineering evaluations for the CST and RWMT issues lacked thorough and critical reviews.

- The inspectors found multiple examples of design control findings, and failures to communicate and coordinate design issues between organizations. The inspectors concluded that the licensee had not effectively addressed cross-cutting aspects of problem identification and resolution.

Analysis. These two examples of a violation affect the Mitigating Systems cornerstone and are more than minor because they were similar to Example 3.I of MC 0612, and design calculations were required to be re-performed to assure accident requirements were met. In both instances, the originally calculated available inventory was less than the actual design basis inventory of 299,700 gallons required for Unit 2 (and Units 1 and 3 after power uprate) to support the assumed 8 hours at hot standby followed by a cooldown to 350•F at 75•F per hour. Subsequent calculations by engineering personnel, including significant reduction in margins, demonstrated that minimum required volumes in the CST and RWMT were maintained. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Title 10, CFR 50, Appendix B, Criterion III, states, in part, that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Contrary to this requirement, two examples were identified where applicable regulatory requirements, and the design basis, were not adequately translated into specifications, procedures, and instructions. Specifically, in Example 1, Technical Specification 3.7.6 and its bases, required 300,000 gallons of usable inventory in the CST, but Calculation 13-MT-CT-205 required an operator action (closing the auxiliary feedwater minimum flow recirculation valve) that was not translated into procedures to ensure that the design basis CST inventory was available. In Example 2, Technical Specification 3.7.6 credited the RWMT as the alternate source of water if the CST was inoperable. The bases for Technical Specification 3.7.6 stated that 300,000 gallons of usable inventory were available at 26 feet, but Calculation 13-JC-CH-0214 (as revised) stated that a level of 28 feet in the RWMT was required for 300,000 gallons to be available. Although an original design calculation error was made in 1992, the licensee missed several recent opportunities in 2004 and 2005 to resolve these discrepancies. Because the two noncited violation examples were of very low safety significance and have been entered into the corrective action program as CRDRs 2839337, 2840186, and 2841773, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000529/2005012-02, Improper Design Control for CST and RWMT Usable Volume to Auxiliary Feedwater.

.3 Independent NRC Inspection: Refueling Water Tank Instrument Calibration

Introduction. The inspectors identified a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," related to improper design calculations used to calibrate RWT level instruments. Specifically, the inspectors determined that the RWT level instruments were not properly compensated for either the effects of the

tank's Technical Specification allowable range of temperature, or the tank's allowable Technical Specification range of boric acid concentration. Therefore, the indications to the operators, and the automatic RAS could be in error. This affected both trains of indication on all three units.

Description. The inspectors selected a review of instrumentation for the RWT under the independent inspection portion of Inspection Procedure 95002. Errors in design basis assumed volumes could lead to earlier than anticipated voiding of the RWT discharge piping and, therefore, an earlier onset to potential air entrainment into ECCS piping. The inspectors found that Section 5.3 of design Calculation 13-JC-CH-0209, Revision 6, which was specified to address these uncertainties, was inappropriately deleted in a previous calculation revision. Design engineers subsequently provided calculations to the inspectors that showed how the effects were compensated for in the RWT instrument calibration. However, the inspectors noted that compensation was unidirectional, in that, temperature compensation was performed for only the highest design temperature of the RWT, and that solution density was only compensated for the highest concentration of boron in the RWT. The inspectors verified that the RWT has UFSAR design ranges of 40 to 120•F for temperature, and 4000 to 4400 ppm for boron concentration. The inspectors also verified that the RWT has both maximum and minimum design volumes for various UFSAR accident assumptions, thus, requiring the instruments to account for bi-directional uncertainties. The inspectors found this to be another example of engineering personnel either not understanding, or missing, important design interface requirements needed to properly address design calculations. Engineering personnel were subsequently able to demonstrate that the calculations could be adjusted for this uncertainty without the RWT instruments being declared inoperable. The licensee initiated CRDR 2840920 to address the corrective actions of this issue, including the review of similar systems where bi-directional uncertainties may not have been addressed.

Analysis. The inspectors determined that the engineering personnel's failure to include proper design basis information in the calibration of RWT level instrumentation was a performance deficiency. This issue was determined to affect the Mitigating Systems cornerstone and was more than minor based upon review of Example 3.j of MC 0612, Appendix E. The errors were considered more than a minor calculation error because the deficiencies required re-performance of the calculations, significantly reduced the overall margin, and could be applicable to other such instrumentation calculations. However, engineering personnel demonstrated that while there was a loss of margin, there was no actual loss of function because of the inaccuracies in the RWT level instrument calibrations. Using the MC 0609, "Significance Determination Process," Phase 1 worksheet, the inspectors determined that the issue was of very low safety significance (Green) because there was no actual loss of safety function.

Enforcement. Title 10, CFR 50, Appendix B, Criterion III, "Design Control," states that the applicable regulatory requirements and the design basis shall be correctly translated into specifications, procedures, and instructions. Contrary to this requirement, the licensee failed to translate the design basis into specifications, procedures, and instructions. Specifically, the licensee did not include the UFSAR and Technical Specification minimum and maximum ranges of temperature and boric acid concentration into level instrument calibration design calculations and procedures.

Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2814209, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-03, Improper Design Control for RWT Level Instrument Calibration.

.4 Independent NRC Inspection: Operability Determinations

Introduction. The inspectors identified three examples of a (Green) noncited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to follow a procedure and to provide appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished, consistent with the facility's administrative procedure for the operability determination process. These deficiencies resulted in several failures to perform timely or required operability determination evaluations by operations personnel following identification of degraded or nonconforming conditions.

Description. The inspectors evaluated the licensee's operability determination process in order to assess the effectiveness of corrective actions developed for engineering and operations interface problems. These problems were identified by the licensee as contributing factors of both the (Yellow) Design Control and 10 CFR 50.59 violations. The inspectors noted there were a number of deficiencies identified with the operability evaluation process during the special inspection of the original issue in August 2004. NRC inspectors also observed similar problems in 2005. As described in NRC Special Inspection Report 05000528; 05000529; 5000530/2004014, a number of deficiencies were identified involving the failure to implement the operability determination process in accordance with procedural guidance. These identified deficiencies involved: (1) engineering personnel failing to immediately inform the shift manager of the affected units after identifying that a voided condition could adversely affect the operability of the high pressure safety injection and CSS pumps; (2) the licensee operated the facility without a reasonable assurance of operability; (3) operations personnel did not implement a continuous operability determination process; (4) operations personnel did not declare the SIS and CSS inoperable even though mounting evidence suggested the final analysis would conclude equipment would not perform its intended safety function; and (5) operations personnel did not perform an initial operability determination for the as-found conditions of the SIS and CSS.

The inspectors reviewed several CRDRs that documented degraded or non-conforming conditions in order to conduct this assessment. This was done, in accordance with Inspection Procedure 95002, to ensure previous corrective actions for the (Yellow) ECCS finding were properly addressed. In a limited sample size, the inspectors identified several examples where implementation of the operability determination process was inadequate. The inspectors determined that these deficiencies were a result of the failure to follow the procedural guidance and ambiguous/inadequate procedural guidance. The inspectors determined that these deficiencies resulted in the failure to perform operability determinations for the following examples of identified degraded or nonconforming conditions:

- The inspectors reviewed CRDR 2822162, dated August 12, 2005. The CRDR addressed the omission of a design basis requirement from the design basis manual and associated plant procedures. Updated Final Safety Analysis Report, Section 6.3.1.3, stated, in part, that no single failure shall allow the compressed nitrogen system delivery pressure (to the safety injection tanks) to exceed 700 psig. The CRDR identifed that the nitrogen supply relief valve setpoint was 725 psig, which exceeded the 700 psig limitation. The licensee concluded that the condition would not over-pressurize the safety injection tanks because they were provided with adequate relief valves, with setpoints of 700 psig.

  The inspectors questioned if the 725 psig nitrogen supply relief valve was adequately sized to provide relief of the nitrogen air system to prevent over-pressurizing safety-related parts of the system. Following review of this question, engineering personnel determined that the relief valve capacity was not adequate and could result in over-pressurization of nitrogen system containment isolation valve, J-GAA-UV0001, and associated piping. The licensee added this newly identified deficiency into the corrective action process as a revision to CRDR 2822162, even though it involved a different degraded condition. Subsequently, the inspectors questioned if this condition had been reviewed for operability by operations personnel. Engineering personnel stated that the technical justification for operability was included in the revised action item, but that the issue had not been reviewed by operations.

  As a result of these discussions, on October 28, 2005, operations personnel were informed of this nonconforming condition by engineering personnel and an operability determination was performed for the potential over-pressurization condition. The inspectors reviewed the technical basis for operability and also concluded that integrity of the containment isolation valve and piping would be maintained for this nonconforming condition.

  The inspectors noted that Administrative Procedure 90DP-0IP10, "Condition Reporting," Revision 21, stated that if a condition is a nonconforming condition or degraded condition that may affect the ability of a system, structure, or component to perform its safety function the originator shall immediately notify the shift manager of the affected unit(s). Additionally, Administrative Procedure 40DP-90P26, "Operability Determination," Revision 14, stated that all site personnel are to promptly notify the shift manager upon discovery of any degraded/nonconforming condition potentially impacting a system, structure, or component. The inspectors determined that engineering personnel failed to follow procedural guidance to promptly notify the shift manager of the potential over-pressurization condition in order to evaluate the operability of affected structures, systems, or components (SSC).

- The inspectors identified that the licensee failed to perform an operability determination prior to plant restart on October 18, 2005, for a nonconforming condition involving potential air entrainment into the ECCS suction piping from the RWT following a RAS, as described in Section 4OA5.1 of this report. On October 11, 2005, Units 2 and 3 were shut down based on this condition having the potential to adversely affect the operability of the SIS and CSS. While the

units were in a shutdown condition, the licensee performed an analysis that determined the affected systems would not be adversely affected by entrained air, however, the inspectors noted that this analysis concluded that air would be entrained into the systems suction piping constituting a nonconformance with the facility licensing basis. The facility licensing basis assumed that the piping systems would be maintained filled with water and that this condition would remain throughout a loss of coolant accident (LOCA) as demonstrated by the systems available net positive suction head analysis.

The inspectors determined the licensee inappropriately concluded that the analysis supported the facility licensing basis resulting in the failure to consider it a nonconforming condition. Additionally, licensed operators informed the inspectors that the facility procedural guidance did not require an operability determination for this issue because the analysis that was performed demonstrated there was no adverse impact affecting the ability of the systems to perform their specified safety function. Specifically, Administrative Procedure 40DP-9OP26, "Operability Determination," Revision 14, Section 3.1.2, states, that "entry into the operability determination process is not required for degraded/nonconforming conditions that do not impact a specified safety function." The inspectors determined that an operability determination was required for this nonconforming condition since it placed the facility in an unanalyzed condition departing from that described in the UFSAR and departing from the design basis net positive suction head calculations that assumed the piping systems would be maintained full of water.

Additionally, the inspectors noted that Administrative Procedure 40DP-9OP26, "Definitions and Abbreviations," Revision 14, Section 4.0, stated that the definition of operability determination is the process of determining whether or not an identified degraded or nonconforming condition has an impact on the operability of Technical Specification related SSC's and all necessary support systems required to perform the SCC's specified safety function. This definition supported the inspectors' conclusion that an operability determination was warranted to evaluate the identified nonconforming condition. Therefore, the inspectors determined that the ambiguity in the licensee's operability determination process contributed to their failure to perform an operability determination.

- The inspectors reviewed CRDR 2822116, which was initiated on August 12, 2005 (19 days). This CRDR was initiated by engineering personnel following a system walkdown of the Unit 2 safety injection system. The CRDR documented two concerns. The first concern questioned the condition of the oil in containment spray pump Motor 2MSIAP03. The CRDR documented that there had been a history of contaminated oil or the use of incorrect oil being added to those pumps and motors. The second concern documented a "severe" packing leak on high pressure safety injection Valve 1JSIBUV0626.

The inspectors noted that both of the concerns documented in the CRDR potentially impacted the ability of an SSC to perform its specified safety function. As a result, the potentially degraded conditions should have been processed

through the licensee's operability determination process. The inspectors noted that the CRDR was not sent to the control room for review until August 31, 2005. As previously discussed, Administrative Procedure 90DP-0IP10, Revision 21, stated that if a condition is a nonconforming condition or degraded condition that may affect the ability of an SSC to perform its safety function the originator shall immediately notify the shift manager of the affected unit(s). Additionally, the inspectors noted that the control room only addressed the operability of the potentially degraded containment spray pump motor oil and not the degraded high pressure safety injection valve. An engineering evaluation of both conditions was performed and documented in the CRDR on September 2, 2005, where it was determined that operability of the components was not adversely impacted.

The inspectors reviewed Procedure 40DP-9OP26, Revision 14, which addresses when the operability determination process should be implemented. The inspectors determined that the procedural guidance for when an OD is necessary was inadequate. Section 1.2 of the procedure stated that the OD process is entered when the ability of an SSC to perform its specified safety function is questioned. However, Section 3.1.2 stated entry into the OD process is not required when degraded or nonconforming conditions do not impact a specified safety function. Finally, Section 3.2 required entry into the OD process when the control room review of a CRDR cannot readily evaluate the impact on an SSC's ability to perform its specified safety function. The inspectors interviewed various personnel from operations and engineering in order to assess how those groups implemented the OD procedure. The interviews revealed that there was an inconsistent understanding of the phrase "impact a specified safety function." Some personnel indicated that they believed that the phrase meant a complete loss of a safety function as opposed to the degradation of a function. The examples previously cited in this section all question the ability of an SSC to perform its specified safety function or, at a minimum, this ability was not able to be readily evaluated. Either of the conditions required entry into the OD process as described in Sections 1.2 and 3.2 of Procedure 40DP-9OP26. The interpretation by some personnel that the specified safety function was not impacted by these conditions prevented entry into the OD process as described in Section 3.1.2 of Procedure 40DP-9OP26. The inspectors also concluded that the procedure lacked guidance or reference to Regulatory Information Summary 05-020, "Revision to Guidance Formerly Contained in NRC Generic Letter 91-18," (Part 9900 Guidance).

Analysis. The inspectors determined that the licensee's failure to follow and properly implement the station equipment operability procedure was a performance deficiency. The inspectors considered this finding to be more than minor, in accordance with MC 0612, since it potentially affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, and it affected the attributes of procedure quality and human performance. However, subsequent evaluations completed by the licensee verified that actual safety functions were not lost in any of these examples. The inspectors performed a Phase 1 significance determination, using MC 0609, and

determined this issue screens out as having very low safety significance (Green) because a safety function was not lost.

Enforcement. Title 10, CFR 50, Appendix B, Criterion V, states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, and that appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Specifically, the inspectors determined that Administrative Procedure 40DP-90P26, "Operability Determination," Revision 14, was not followed and did not specify appropriate acceptance criteria. Because the finding is of very low safety significance and has been entered into the corrective action program as CRDR 2838626, this violation is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000528; 05000529; 05000530/2005012-04, Failure to Properly Implement Station Procedure for Equipment Operability (Technical Specification 5.4.1.a).

.5 Corrective Action Effectiveness

.a Scope of Review

Consistent with Section 02.03 of NRC Inspection Procedure 95002, the team performed inspections to determine that appropriate corrective action(s) were specified for each root/contributing cause or that there was an evaluation that no actions was necessary; determine that the corrective actions have been prioritized with consideration of the risk significance and regulatory compliance; determine that a schedule has been established for implementing and completing the corrective actions; and determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence.

.b Corrective Actions for Severity Level III 10 CFR 50.59 Violation

The inspectors reviewed the licensee's corrective actions associated with the Severity Level III violation for an improper 10 CFR 50.59 evaluation of a change to the plant, resulting in the previously mentioned voided condition. The inspectors determined that the licensee performed a comprehensive evaluation of the 10 CFR 50.59 issue, including overall deficiencies identified with the program. The evaluation identified the primary root causes of the performance issue to be (1) The procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) CRDR program implementation was broadly ineffective. The licensee also identified overlap and interface problems between the CRDR, EER, and ICR programs in conjunction with inadequate training to recognize a CRDR condition contributed to the failure of personnel to initiate a CRDR in 1992 for the RAS piping concern.

The licensee's root-cause evaluation, and extent of cause/condition reviews, noted a number of previous procedural and human performance vulnerabilities with the 10 CFR 50.59 processes. These vulnerabilities accounted for most of the licensee's failures in this area. The inspectors noted that recently completed corrective actions, focused on the 10 CFR 50.59 process, implemented revised station procedures, and

provided mandatory training on handling of changes, test, and experiments. These changes brought the licensee's process in very close alignment with the regulatory requirements of 10 CFR 50.59 and with industry standards such as Nuclear Energy Institute 96-07, "Guidelines for 10 CFR 50.59 Implementation." The inspectors attended licensee training sessions and critically reviewed station procedures for evidence of remaining vulnerabilities. The inspectors did not find any concerns with the licensee's current program. Therefore, the inspectors concluded that corrective actions were effectively developed and implemented for the Severity Level III violation of 10 CFR 50.59 requirements.

The inspectors had a minor concern with the licensee's extent of condition and extent of cause reviews for the previous 10 CFR 50.59 screening and evaluation process. This review was conducted on a limited sampling, based on statistical criteria, to review a representative group of such changes. A body of 116 previous changes were reviewed. The licensee's success criteria was established as there being no missed evaluations requiring prior NRC approval. While the licensee did meet this criteria in their sampling, they also identified 11 cases where they missed performing screenings. While the inspectors agreed with this concept from a risk and statistical approach, they concluded that the process still left the licensee vulnerable to having missed older screenings. However, the underlying requirement of 10 CFR 50.59 is to perform evaluations for issues that may require prior NRC approval. Neither the licensee nor the inspectors had examples of a missed screen leading to a missed evaluation. The inspectors noted that the licensee may want to consider further historical reviews for missed screenings and evaluations during ongoing efforts in design engineering reviews, UFSAR validation, and system safety function inspections.

.c Corrective Actions for Yellow Design Control Violation

The inspectors noted there was some confusion regarding the "problem statement" used in this evaluation. The official problem statement was, "The ECCS suction piping was supposed to be filled with water, but was inappropriately voided." The inspectors were concerned this statement was too narrowly focused to adequately investigate all of the potential performance deficiencies of this issue. However, the inspectors found that a more appropriate statement, "are there any physical or procedural conditions in the plant that differ from the conditions assumed in the plant design basis" was actually being used by many of the licensee's groups investigating the issue. While this would appear to be only an administrative issue, it did not align with the "iterative" process described in the licensee's root-cause methods (i.e., to loop back through the process with subsequently identified problems). In conjunction with this, some problems from this evaluation were worked in parallel to other programmatic issues and corrective actions that were ongoing at PVNGS (e.g.: human performance, engineering performance, corrective actions, etc.). Specific examples included finding problems with the UFSAR while doing system reviews for the ECCS violation, and interface issues between operations and engineering personnel in regard to equipment operability determinations. While the inspectors concluded that appropriate corrective actions were

identified for the ECCS violation, they could not determine whether the violation evaluation, or another site review process, was responsible for implementing the appropriate actions. Therefore, both the licensee and the inspectors had difficulties in assessing the overall resolution of issues, from the problem evaluation process, through implementation of corrective actions.

The inspectors noted the licensee identified the failure to effectively use operating experience as one of the contributing causes of this issue. The inspectors found additional examples of the failure to use available operating experience, as demonstrated under the RWT voiding issue (Section 4OA5.1). The inspectors also found additional examples of human performance issues identified in the evaluation that were contributors to the findings of this inspection. Of particular concern were additional examples of a lack of inter- and intra-group communications regarding engineering design issues as they pertained to equipment design and operability. Specifically, even after management communications with operations and engineering personnel regarding attention to detail, equipment operability, and critical thinking regarding equipment issues, the inspectors observed additional cases where this was not adopted by station personnel (reference CRAIs 2825677, 2825678, and 2825679). These additional cases were evident in all four of the NRC identified noncited violations of this inspection. The additional examples of poor communication of technical issues during this inspection led the inspectors to conclude that these attributes are ongoing deficiencies at PVNGS. At the time of the inspection, the inspectors could not conclude whether this was because of inappropriate corrective actions, or whether additional time was needed for the corrective actions to take effect. In either case, the inspectors concluded that the licensee did not adequately demonstrate the effectiveness of these corrective actions.

Some corrective actions were developed with no direct evidence of plans to periodically review for continuing problems, or to determine if additional or different corrective actions needed to be implemented. Based upon the inspectors' review, and interviews with station personnel, it was determined that the licensee was dealing with such deficiencies by channeling them back into the corrective action program. The NRC has identified there are substantive cross-cutting issues with PVNGS's corrective action program that are currently being addressed by the licensee. Also, the licensee described, in both this and the 10 CFR 50.59 issue evaluation, that there were a number of contributing issues stemming from the corrective action program. The inspectors noted that the licensee had not established additional direction or methods (i.e., contingencies) to deal with ineffective corrective actions from this significant condition investigation.

One specific example of this was evident in CRAI 2785352. The action was, "verify objective evidence (e.g., inspection, surveillance, or completion of fill and vent procedure) that demonstrate the suction lines are filled in each unit and are being maintained in a filled condition while operability requirements dictate." This action was in response to the ECCS voiding violation to ensure the piping between the inboard and outboard containment isolation valves remained filled with water. The measure of success was that no excessive or abnormal air was vented from the system. However, the inspectors noted that since the original Priority 2 corrective actions to fill the pipe (CRDR 2726509, Direct Cause 1) were closed in December of 2004, at least three

CRDRs had been entered into the corrective action program for excessive venting problems in this piping. However, there did not appear to be any specific mechanism to feed results of the corrective action program back into the evaluation of the Yellow finding, or into the assessment of effectiveness of the corrective actions for the Yellow finding. The inspectors were concerned that this could lead to corrective actions being taken independent of the original finding, or potentially being lowered in priority and closed to another process because there was no tie to the significant condition. In response to questions from the inspectors, the licensee stated that effectiveness reviews for this attribute (CRAI 2785352) were not due until February 2006. Therefore, the inspectors could not determine that appropriate success criteria have been developed for determining the effectiveness of these corrective actions to prevent recurrence. Also, in some cases it did not appear that the licensee considered effectiveness reviews to be a part of the corrective action process. The inspectors noted these reviews were not assigned, or maintained at, a priority commensurate with the issue. Therefore, the inspectors could not determine that corrective actions had been prioritized with consideration of the risk significance and regulatory compliance.

The licensee identified approximately 90 corrective actions associated with the Yellow finding. While scope and content of these actions would appear to be appropriate from a technical or logical point of view, further efforts are required to determine if they are effective (especially towards preventing repetition of the root causes). Specific examples include actions developed to improve attention to detail of personnel, actions to implement management expectations for engineering design, calculation reviews, and actions to develop appropriate thresholds for trend reviews. Also, while the corrective actions themselves were considered high priority, the licensee considered effectiveness reviews to be very low priority (Priority 4), consistent with that given to action enhancements. Such priority classification did not require completion ties to the original corrective actions and could allow closure without the formal reviews required for corrective actions to prevent recurrence. Again, coupled to the importance of the issue, and the fact that the licensee and the NRC have identified ongoing areas of concern with the corrective action program, the inspectors were concerned with the adequacy of followup to some important corrective actions. Some of the corrective actions were recently implemented, and effectiveness reviews were not yet formulated. An example of this is the development of human performance error codes for binning CRDRs with specific categories of engineering human performance errors or deficiencies. The inspectors found that personnel had a rough concept of doing this in the future, but they did not have any plan or resources established to do so. Overall, the inspectors could not determine, with some confidence, that these actions will prove to be effective in preventing repetition of the original issue.

The inspectors concluded that some of the attributes the licensee already established for acceptance of corrective actions for this issue, either by effectiveness reviews or by corrective action tracking and trending, did not appear to be appropriate. Examples of such attributes included "no licensee event reports written for failure of a system safety function" because of missed design interfaces (CRAI 2785362), or "no negative trends for significant or noteworthy events" (CRAI 2825633). The inspectors considered the acceptance criteria too high in that other issues of concern, such as system degradation or unanalyzed conditions, should also initiate a review of corrective actions. Another example was the use of terms that lacked content in the acceptance criteria. Repeated

use of the term "rigor" was applied to various corrective actions and even program changes (CRAI 2825632). It was described that an action or program lacked "rigor," that additional "rigor" would be added, and that effectiveness reviews would ensure "rigor" had been increased. The inspectors did appreciate the fact that many of the corrective actions were new, and that some actions are overlapping with other activities at PVNGS. The inspectors also understood that, for some of these issues, the licensee will need additional development or maturity of the actions to come to effectiveness conclusions. However, at the time of the inspection, the inspectors could not determine that measures of success have been developed for determining the effectiveness of all of the corrective actions to prevent recurrence.

.6 Assessment of Licensee Evaluations and Conclusions

a. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with an inappropriate change to an emergency core cooling system procedure without prior NRC approval. This procedure change rendered portions of the system inoperable because of voiding. This performance issue was previously characterized as a Severity Level III violation of 10 CFR 50.59 and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. During this supplemental inspection, performed in accordance with Inspection Procedure 95002, the inspectors determined that the licensee's evaluation identified the primary root causes of the performance issue to be: (1) The site procedure revision process (01AC-0AP02) was inadequate, in that, the procedure allowed 'pre-screening' of changes that could potentially bypass performing a 10 CFR 50.59 screening for changes to the facility as described in the licensing basis; and (2) The corrective action program implementation was ineffective. The licensee also identified overlap and interface problems between the corrective action program, the engineering evaluation request program, and the instruction change request program. These issues, in conjunction with inadequate training to recognize a corrective action condition, contributed to the failure of station personnel to initiate a corrective action program input document in 1992 for the potential pipe voiding concern. The inspectors concluded that the licensee's evaluation and implemented corrective actions were appropriate to reasonably prevent repetition of the 10 CFR 50.59 violation.

Given the licensee's acceptable performance in addressing the inappropriate procedure change and 10 CFR 50.59 program deficiencies, the Severity Level III violation (VIO 2004/014-01) is closed.

b. The NRC performed this supplemental inspection, in part, to assess the licensee's evaluation and corrective actions associated with potential air entrainment into the emergency core cooling system. The licensee failed to incorporate original design requirements into the plant to maintain the containment sump suction piping filled with water. This performance issue was previously characterized as a 10 CFR 50, Appendix B, Criterion III, violation having substantial safety significance (Yellow), and was originally identified in NRC Inspection Report 05000528; 529; 530/2004014. The inspectors determined that the licensee's evaluation identified a direct cause, nine root causes, and nine contributing causes of the performance issue. The evaluation was also used to develop an extensive list of corrective actions. The inspectors found the

licensee's methods of evaluation to be appropriate. Additionally, the inspectors found that the corrective actions generally matched the causal factors.

The team determined that for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. In addition, some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective. Also, the team concluded that criteria and reviews were not established, for auditing or followup, to ensure that corrective actions were effective in improving performance in the affected areas. Consequently, the team did not have assurance that planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. Therefore, the Yellow violation (VIO 2004-014-01) will remain open pending further NRC review.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On December 16, 2005, the NRC inspectors leader presented the results of the supplemental inspection, conducted under Inspection Procedure 95002, to Mr. J. Levine, Executive Vice President of Generation, and other members of his staff. The licensee acknowledged the findings presented. The inspectors noted that while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee Identified Violations

The following violations of very low significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as noncited violations.

.1 The licensee identified several violations of 10 CFR 50.59, "Changes, Tests and Experiments," or the accompanying Station Procedure 93DP-0LC07, "10 CFR 50.59 and 72.48 Screening and Evaluations," during their investigation of the Severity Level III violation. These were associated with failures to follow the station procedure, or the guidance of 10 CFR 50.59 when reviewing potential changes, tests, or experiments at PVNGS. The inspectors reviewed the following items and verified the issues were not greater than very low safety significance (Green), were not repetitive, and were entered into licensee's corrective action program. Missed or improperly performed screenings and evaluations were also verified to not require prior NRC approval.

.a The licensee identified that a change to Procedure 73ST-9SI06, "Containment Spray Pumps and Check Valves - Inservice Test", changed the minimum Containment Spray pump miniflow flowrate from 150 gpm to 132 gpm. This change was made to support the flowrate change specified in Calculation 13-JC-SI-0231. Two 10CFR 50.59 Screenings (S-04-0310 and S-05-0225) were performed to support the changes to these two documents. Both screenings concluded that there was no adverse impact from the change; subsequently, no 50.59 evaluation was conducted. A subsequent review of these two screenings by the licensee found no reference to UFSAR section 6.5.2.7, paragraph

(A)7.13.13. This paragraph stated "Each CS pump bypass flow line shall be capable of passing 150 gpm with its CS pump operating at design operating conditions." The licensee has subsequently changed the CS pump miniflow back to the original 150 GPM. This finding was documented in CRDR 2829177.

.b The licensee identified multiple 10 CFR 50.59 Screenings that were not performed. Subsequent screenings by the licensee revealed no revisions that should have received a 10 CFR 50.59 evaluation. These include:

- A revision to Procedure 36ST-9SI04, "Safety Injection/Shutdown Cooling System Instrumentation Surveillance Test Train A," was made in 2004 with inconsistent instructions for testing the shutdown cooling valve interlocks. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2800782.

- A revision to 41ST-1DG02, "Diesel Generator B Test," was made in 1993 that reduced a pressure acceptance value in the non-conservative direction without a source document reference. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2799463

- A revision to Procedure 73ST-9SI10, "HPSI Pumps Miniflow Inservice Test," was made in 2001 that inadvertently removed steps from the procedure. The procedure in error was never physically implemented before the error was discovered. The error was corrected upon discovery. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2792530.

- A revision to Procedure 43ST-3AF02, "Auxiliary Feedwater Pump AFA-P01 Operability Test," was made in 1994. The procedure revision specified new operational guidance for the pressurizer. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2809070.

- A revision to Procedure 36ST-9AF02, "Post Accident Monitoring Auxiliary Feedwater Flow Instrument Calibration," was made in 2001 based on calculation revisions made in 1997, 1998, and 2000. Instruments were calibrated with revised acceptance criteria and a 10 CFR 50.59 screening was not performed for either the surveillance test revision or the 1998 and 2000 calculation revisions (the 1997 calculation revision did have a 10 CFR 50.59 screening performed). The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2788278.

- A revision to Procedure 41OP-1EW01, "Essential Cooling Water System Train A," was made in 2000 that deleted a component from a table requiring verification of adequate cooling flow. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2807325.

- A revision to Procedure 40OP-9SI02, "Shutdown Cooling Initiation," was made in 2004 that deleted a requirement for containment pressure to be less than 0.5 psig when checking the RAS sump level. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810735.

- A revision to Procedure 40OP-9DG02, "Emergency Diesel Generator B," was made in 1999 that allowed the diesel to be shutdown without resetting safety signals. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810830.

- A revision to Procedure 74OP-9SP01, "Manual Chemical Additions to the ESPS," was made in 1999 that added extra steel skid basins were added to the plant. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2810961.

- A revision to Procedure 41OP-1SI03, "Safety Injection Tank Operations," was made in 1987 that changed the operation of the HPSI system during Safety Injection Tank fill. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2812165.

- A revision to 41OP-1SI01, "Shutdown Cooling Initiation," was made in 1995 that changed the LPSI pump operating temperature band from a high temperature limit of 300••F to a limit of 350••F. In addition, the shutdown cooling initiation time following a tornado damage event was changed from 10.5 hours to 13 hours. The change received no 10 CFR 50.59 screening and the issue was documented in CRDR 2812185.

.c Criterion XI, "Test Control," of 10 CFR 50, Appendix B, requires that a test program be established to assure that all testing required to demonstrate that structures, systems and components will perform satisfactorily in service. Contrary to this, the licensee identified cases where test programs were not established. The inspectors reviewed the following items and verified the issues were not greater than very low safety significance (Green), were not repetitive, and were entered into the licensee's corrective action program.

- The licensee identified that required performance tests on the instrument air system have not been performed. The Instrument Air Design Basis Manual, Table 3.1, "System Performance Parameters and Limits," provides specifications and acceptance criteria for the purpose of defining the air quality in terms of clean, dry, and oil free, and table 8.1, "Design Requirements," lists ISA S7.3, "Quality Standard for Instrument Air," as the standard for establishing performance limits for the delivery of clean, dry oil free air. Procedure 73MT-9IA01, "Instrument Air System Quality Testing," implements the testing requirements specified in the design standard for establishing the instrument air system capability for delivering clean, dry and oil free air. The licensee identified that the last

three consecutive semi-annual repetitive task work orders have been either waived or cancelled and the last successful performance of this test procedure was in the fall of 2003. This finding was documented in CRDR 2813390.

- UFSAR Table 9.5-8, "Diesel Generator Fuel Oil Storage and Transfer System Design Specifications," stated the diesel fuel oil day tank has a capacity of 1,170 gallons. Additionally Section 9.5.4.2.3, "Diesel Generator Fuel Oil Day Tanks," stated each diesel generator fuel oil day tank has a capacity of 1170 gallons. Contrary to this requirement, engineering design reference document Drawing M018-218, Rev. 12 indicated each tank only had a capacity of 1100 gallons. The discrepancy is a result of an incorrect volumetric calculation that uses the outer tank dimensions. The licensee plans to submit a license amendment and update the UFSAR to address the discrepancy. This finding was documented in CRDR 2825638.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Bauer, Department Leader, Regulatory Affairs
P. Borchert, Director, Work Management
D. Carnes, Director, Nuclear Assurance
P. Carpenter, Unit Department Leader, Operations
C. Churchman, Director, Engineering
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J. Copsey, Department Leader, Employee Concerns
E. Dutton, Section Leader, Performance Improvement
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D. Marks, Section Leader, Regulatory Affairs - Compliance
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R. Stroud, Senior Consultant, Regulatory Affairs
J. Taylor, Department Leader, Operations Support
T. Weber, Section Leader, Regulatory Affairs
D. Wheeler, Section Leader, Nuclear Assurance

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000528; 05000529; 05000530/2005012-01	NCV	Improper Design Control for Emergency Core Cooling System Sump and Refueling Water Tank Swapover (Section 4OA5.1)
05000529/2005012-02	NCV	Improper Design Control for Condensate Storage Tank and Reactor Water Makeup Tank Usable Volume to Auxiliary Feedwater (Section 4OA5.2)
05000528; 05000529; 05000530/2005012-03	NCV	Improper Design Control for Refueling Water Tank Level Instrument Calibration (Section 4OA5.3)
05000528; 05000529; 05000530/2005012-04	NCV	Failure to Properly Implement Station Procedure for Equipment Operability (Technical Specification 5.4.1.a) (Section 4OA5.4)
05000528; 05000529; 05000530/2005012-05	FIN	Summary Finding. 95002 Inspectors Assessment of IR2004-14 Severity Level III Violation for 50.59 Issue (Section 4OA5.6.a)
05000528; 05000529; 05000530/2005012-06	FIN	Summary Finding. 95002 Inspectors Assessment of IR2004-14 (Yellow) 10CFR50, App B, Criterion III Violation (Section 4OA5.6.b)

Closed

05000528; 05000529; 05000530/2004014-04	VIO	Failure to Obtain Prior NRC Approval for a Change to the Facility Involving Maintaining a Significant Segment of Containment Sump Safety Injection Recirculation Piping Void of Water

Discussed

05000528; 05000529; 05000530/2004014-01	VIO	Failure to Maintain Design Control of Containment Sump Recirculation Piping

LIST OF DOCUMENTS REVIEWED

In addition to the documents called out in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

CRDRs

2480956	2735332	2788278	2812536	2820942	2825651
2545839	2735671	2789716	2812581	2820943	2825655
2564840	2736059	2792412	2813174	2822116	2825656
2591324	2736344	2792530	2813390	2822162	2825666
2596717	2736931	2793982	2813941	2822173	2825945
2597959	2739903	2796054	2815762	2822179	2826158
2598002	2739903	2799463	2816891	2822183	2826516
2600100	2739906	2799503	2817300	2822185	2827637
2622935	2739907	2800782	2817663	2822188	2828923
2629963	2749131	2806832	2817867	2822189	2829113
2632229	2761657	2807325	2818727	2822199	2829157
2651672	2773847	2807967	2818957	2822493	2832412
2651750	2773947	2808867	2819031	2822997	2833766
2667754	2776864	2808871	2819057	2823022	2833962
2687507	2779536	2809070	2819277	2823174	2833976
2707325	2779536	2810138	2819291	2823205	2834900
2711241	2779903	2810228	2819345	2823598	2835132
2720228	2780273	2810735	2819366	2823676	2838079
2726509	2780286	2810830	2819394	2824540	2838308
2726522	2781196	2810929	2819903	2825078	2838314
2729600	2781602	2810961	2819904	2825103	2838368
2733983	2781795	2811543	2820580	2825209	2839337
2734065	2781949	2811670	2820583	2825354	2840186
2734089	2782645	2811940	2820731	2825638	2840920
2735052	2783898	2812165	2820745	2825644	2841773
2735329	2785296	2812185	2820920	2825647	2841872

CRAIs

2480956	2692688	2780273	2812581	2822183	2837332
2563861	2715910	2780286	2817300	2822493	2833754
2600100	2715911	2781602	2817867	2825655	2833755
2622935	2726522	2789716	2819291	2825666	2833766
2629963	2729600	2792412	2819394	2832381	2833962
2632229	2774508	2799463	2820920	2832809	2837332
2667754	2779903	2810228	2822173	2837051	

Calculations:

NUMBER	TITLE	REVISION
13-MC-SI-017	Safety Injection System Interface Requirements Calculation	5
13-MC-SI-018	Containment Spray System Interface Requirements Calculation	6
13-JC-DG-204	Diesel Generator Starting Air Receiver Pressure Loops J-DGN-P-0221,0222, 0223, & 0224 Uncertainty Calculation	0
13-MC-DF-306	As Built Calc for Sizing of Diesel Fuel Oil Storage and Day Tanks	6
13-MC-SI-230	Containment Spray System Maximum Flow Rate Evaluation	3
13-MC-SI-018	Containment Spray System Interface Requirements	6
13-JC-CH-0206	Refueling Water Tank Level Instruments (CHA-L-200 and CHBL-201) Setpoint and Uncertainty Calculation	7
13-JC-CH-0209	Refueling Water Tank Level Instrument (CHx-L-203x,x=A,B,C,D) Setpoint and Uncertainty Calculation	6
13-MC-CH-201	Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Makeup Water Tank (RMWT) Sizing	6
13-MC-CH-201	Refueling Water Tank (RWT), Hold-Up Tank (HT) and Reactor Makeup Water Tank (RMWT) Sizing	0
13-MC-CT-205	Condensate Storage Tank	4
13-MC-CT-307	CST Minimum Level Setpoint	4
FAI/05-106	Technical Assessment of the Check Valve Response for the Refueling Water Tank (RWT) Suction Line	0
FAI-05/06	Summary Report of MAAP4 LOCA Analysis in Support of Past Operability Assessment of Degraded HPSI Performance During Containment Recirculation at Palo Verde	0
FAI/05-107	The Potential for Air Intrusion and RWT Check Valve Response Following RAS	0

Calculations:

NUMBER	TITLE	REVISION
FAI/05-107	The Potential For Air Intrusion Following RAS	1
MISC-REC-249	ECCS Piping Interface Requirement per "Outstanding CESSAR Review Matter" Number 38, dated January 19, 1976	

Procedures:

NUMBER	TITLE	REVISION
01AC-0AP02	Review and Approval of Nuclear Administrative and Technical Procedures	1
01AC-0AP02	Review and Approval of Nuclear Administrative and Technical Procedures	2
01DP-0AP01	Procedure Process	19
01TD-0AP01	Technical Dictionary	11
12DP-0MC29	Warehouse Discrepancy	13
12DP-0MC29	Warehouse Discrepancy	14
12DP-0MC29	Warehouse Discrepancy	15
30DP-9WP02	Work Document Development and Control	34
30DP-9WP02	Work Document Development and Control	35
30DP-9WP02	Work Document Development and Control	36
40AL-9DG02	Diesel Generator B Alarm Panel Responses	16
40DP-9AP08	Loss of Coolant Accident Technical Guideline	14
40DP-9AP14	Functional Recovery Technical Guideline	16
40DP-9OP06	Operations Department Repetitive Task Program	80

Procedures:

NUMBER	TITLE	REVISION
40DP-9OP25	Special Variance	9
40DP-9OP26	Operability Determinations	14
40EP-9EO03	Loss of Coolant Accident	20
40EP-9EO09	Functional Recovery	25
40EP-9EO10	Standard Appendices	35
40OP-9SI01	Shutdown Cooling Initiation	35
40OP-9ZZ10	Mode 3 to Mode 5 Operations	43
40OP-9ZZ11	Mode Change Checklist	64
40OP-9ZZ23	Outage GOP	36
41ST-1ST09	ECCS System Leak Test	1
60DP-0QQ02	Trend Analysis and Coding	12
64DP-0QQ08	Vendor Corrective Action Report	7
64DP-0QQ08	Vendor Corrective Action Report	8
70DP-0EE01	Equipment Root Cause of Failure Analysis	12
70DP-0EE01	Equipment Root Cause of Failure Analysis	13
70DP-0EE01	Equipment Root Cause of Failure Analysis	14
70DP-0MR01	Maintenance Rule	11
73DP-0AP01	Writer's Handbook for Surveillance Test Procedures	
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	16
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	17

Procedures:

NUMBER	TITLE	REVISION
73DP-9XI01	Containment Spray Pumps and Check Valves - Inservice Test	18
81DP-0CC04	Calculations	0
81DP-0CC04	Calculations	1
81DP-0CC05	Design and Technical Document Control	27
81DP-0CC11	Specifications	3
81DP-0CC26	Impact Process	9
81DP-0CC28	Classification of Structures, Systems and Components	
81DP-0DC13	Deficiency Work Order	14
81DP-0DC13	Deficiency Work Order	15
81DP-0DC16	Engineering Document Change	15
81DP-0DC17	Temporary Modification Control	14
81DP-0EE10	Plant Modifications	11
90DP-0IP09	Differing Professional Opinion	8
90DP-0IP10	Condition Reporting	15
90DP-0IP10	Condition Reporting	16
90DP-0IP10	Condition Reporting	17
90DP-0IP10	Condition Reporting	18
90DP-0IP10	Condition Reporting	19
90DP-0IP10	Condition Reporting	20
90DP-0IP10	Condition Reporting	21

Procedures:

NUMBER	TITLE	REVISION
91DP-0EN02	Environmental Regulatory/Permit Review Form	4
93DP-0LC03	Licensing Document Maintenance	13
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	0
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	1
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	2
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	3
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	4
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	5
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	6
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	7
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	8
93DP-0LC07	10 CFR 50.59 and 72.48 Screening and Evaluations	9

10 CFR 50.59 Screenings

S-04-0207 Rev 1	S-05-0211 Rev 0	S-05-0238 Rev 0	S-05-0291 Rev 0
S-04-0310 Rev 0	S-05-0215 Rev 0	S-05-0242 Rev 0	S-05-0292 Rev 0
S-05-0175 Rev 0	S-05-0217 Rev 0	S-05-0251 Rev 0	S-05-0304 Rev 0
S-05-0198 Rev 0	S-05-0218 Rev 0	S-05-0264 Rev 0	S-05-0305 Rev 0
S-05-0199 Rev 0	S-05-0220 Rev 0	S-05-0265 Rev 0	S-05-0306 Rev 0
S-05-0201 Rev 0	S-05-0222 Rev 0	S-05-0280 Rev 0	S-05-0307 Rev 0
S-05-0204 Rev 0	S-05-0224 Rev 0	S-05-0281 Rev 0	S-05-0308 Rev 0
S-05-0208 Rev 0	S-05-0225 Rev 0	S-05-0289 Rev 0	S-05-0309 Rev 0
S-05-0209 Rev 0	S-05-0230 Rev 0	S-05-0290 Rev 0	S-05-0329 Rev 0
S-05-0210 Rev 0	S-05-0234 Rev 0		

10 CFR 50.59 Evaluations

E-04-0001 Rev 0	E-04-0016 Rev 1	E-05-0007 Rev 0	E-05-0014 Rev 0
E-04-0003 Rev 0	E-04-0017 Rev 3	E-05-0008 Rev 0	E-05-0016 Rev 1
E-04-0004 Rev 0	E-04-0019 Rev 0	E-05-0009 Rev 0	E-05-0017 Rev 0
E-04-0009 Rev 1	E-04-0021 Rev 1	E-05-0010 Rev 0	E-05-0020 Rev 0
E-04-0010 Rev 2	E-05-0001 Rev 0	E-05-0011 Rev 0	E-05-0021 Rev 0
E-04-0011 Rev 2	E-05-0002 Rev 1	E-05-0012 Rev 0	E-05-0022 Rev 0
E-04-0012 Rev 0	E-05-0003 Rev 0	E-05-0013 Rev 0	E-05-0024 Rev
E-04-0015 Rev 0	E-05-0005 Rev 0		

Work Orders

2785677	2797835	2810262	2820785
2785680	2799903	2811953	2821677
2785683	2799906	2812589	2821687
2785686	2802503	2818161	2822503
2785688	2808406	2818162	2822503
2785691	2808866	2818599	2838626

Licensee Event Reports

2000-003-00	2004-009-00

Miscellaneous

NUMBER	TITLE	REVISION /DATE
01-M-CHP-002	P& I Diagram Chemical and Volume Control System	44
01-P-SIF-201	Safety Injection System ESF Pump Suction Lines - Train A	6
03-M-SIP-001	P& I Diagram Safety Injection & Shutdown Cooling System	25
102-03859-JML/AKK/GAM	Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Nos. STN 50-528, 50-529, and 50-530 Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Bases Information	2/11/97
102-05336-GRO/TNW/GAM	Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Docket Nos. STN 50-528, 50-529, and 50-530 Response to Request No. 2 in NRC Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors."	9/1/05

Miscellaneous

NUMBER	TITLE	REVISION /DATE
10407-13-MM-601	Model Testing of ECCS Containment Sump	
161-01159-EEVB/BJA	Units 1, 2, and 3 Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	7/8/88
161-01270-DBK/BJA	Units 1, 2, and 3 Additional Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	8/28/88
161-02345-WFC/RAB	Units 1, 2, and 3 Supplemental Response to NRC bulletin No. 88-04 File: 88-A-056-026, 88-055-026	9/21/89
161-04032-WFC/MEP/JMQ	Follow up to the Letter from W. F. Conway, APS, to NRC, 161-02345, dated September 21, 1988 - Reference C and Response to Action #3 of NRC Bulletin 88-04	7/1/91
255-01092-JJH	APS letter to Fauske and Associates, "PVNGS Transmittal of Qualified Data References for Report FAI/05-107"	
88-DG-042	Engineering Evaluation Request	3/11/88
Audit 2004-005	Corrective Actions	4/29/04
Audit 2005-005	Design Control	4/29/05
Audit 2004-010	Dry Cask Storage/ISFSI	9/22/04
Audit 2004-012	Maintenance	11/5/04
Audit 2005-004	Procurement and Material Control	4/14/05
Audit 2004-006	Refueling/Operations	6/25/05
Audit 2004-011	Technical Specifications/Admin Controls	10/8/04
CRDR Report 2726509	ECCS Sump Suction Piping Discovered in an Unanalyzed Condition	1
CVER-05-75	Westinghouse Letter, Evaluation of RWT Suction Behavior during SIS and CSS Transition at RAS and Related Design Interface Criteria	10/17/05
ER-05-0192	Nuclear Assurance Evaluation Report	
LDCR 2003-F039	Fire Protection Change Review	0

Miscellaneous

NUMBER	TITLE	REVISION /DATE
MP2-014-05	Operability Determination MP2-014-05	0
OD 301	Operability Determination #301	10/6/2005
OD 279	Operability Determination #279	7/31/2004
PG 120	PVNGS Self-Assessment and Benchmarking	5
PV-E0039 Ver. 6	Environmental Screening Worksheet	
PV-E0073 Ver. 7	Calculation Form	
PV-E0097 Ver. 4	Independent Verification Checklist	
PV-E0104 Ver. 4	Palo Verde Nuclear Generating Station Weld Data Sheet – 1 for Butt and Groove Welds	
PV-E0105 Ver. 3	Palo Verde Nuclear Generating Station Weld Data Sheet – 2 for Fillet and Socket Welds	
PV-E0117 Ver .8	Engineering Document Change Form	
PV-E0129 Ver. 5	Design Basis Manual Revision	
PV-E0303 Ver. 1	Specification/Revision Title Sheet Form	
PV-E0412 Ver 1	SWMS Associations Screen Changes for Calculation	
PV-E0436 Ver. 2	T-Mod Justification Review Worksheet	
SYS80-PE-IR20	NSSS Interface Requirements for Chemical and Volume Control System	6
	Chemical and Volume Control System Design Basis Manual	11
	Daily Earthmoving Log for Routine Operations & Maintenance Form	0
	Daily Earthmoving Log for Projects Form	0
	Diesel Generator, Class 1E Standby Generation, Fuel Oil Storage and Transfer System Design Basis Manual	15
	Operations Logs, Units-1, 2, and 3	10/28/05
	Operations Logs, Units-2 and 3	10/11/05
	Operations Logs, Units-2 and 3	10/7/05

Miscellaneous

NUMBER	TITLE	REVISION /DATE
	Operations Logs, Units-2 and 3	10/17/05
	Operations Logs, Units-2 and 3	10/16/05
	Operations Logs, Units-2 and 3	10/12/05
	Operations Logs, Units-2 and 3	10/8/05
	Operations Logs, Units-1, 2, and 3	10/6/05
	Safety Injection System Design Basis Manual	21
	Significant CRDR 2789716 Charter	0
	Significant CRDR 2789716 Charter	1
	UFSAR Verification Matrix, SI System	2

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
CAP	corrective action program
CEA	control element assembly
CFR	Code of Federal Regulations
CRAI	condition report action item
CRDR	condition report/disposition request
CS	containment spray
CSS	containment spray system
CST	condensate storage tank
ECCS	emergency core cooling system
EER	engineering evaluation request
EPRI	Electric Power Research Institute
ESFAS	engineered safety features actuation system
gpm	gallons per minute
ICR	instruction change request
I&C	instrumentation and controls
LOCA	loss of coolant accident
LPSI	low pressure safety injection
MC	Manual Chapter
NCV	noncited violation
NDE	nondestructive examination
NRC	Nuclear Regulatory Commission
OD	operability determination
PID	Performance Improvement Department
ppm	parts per million
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVNGS	Palo Verde Nuclear Generating Station
RAS	recirculation actuation signal
RCS	reactor coolant system
RWMT	reactor water makeup tank
RWT	refueling water tank
SFP	spent fuel pool
SFHM	spent fuel handling machine
SIS	safety injection system
SSC	structure, system, and component
UFSAR	Updated Final Safety Analysis Report
VIO	violation

ATTACHMENT 4

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

March 2, 2005

Gregg R. Overbeck, Senior Vice
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P.O. Box 52034
Phoenix, AZ 85072-2034

SUBJECT: ANNUAL ASSESSMENT LETTER - PALO VERDE NUCLEAR GENERATING STATION (REPORT 05000528/2005001; 05000529/2005001; 05000530/2005001)

Dear Mr. Overbeck:

On February 3, 2005, the NRC completed its end-of-cycle plant performance assessment of the Palo Verde Nuclear Generating Station. The end-of-cycle review for Palo Verde involved the participation of reactor technical divisions in evaluating performance indicators for the most recent quarter and inspection results for the period from January 1 through December 31, 2004. The purpose of this letter is to inform you of our assessment of your safety performance during this period and our plans for future inspections at your facility so that you will have an opportunity to prepare for these inspections and to inform us of any planned inspections that may conflict with your plant activities.

This performance review and enclosed inspection plan do not include physical protection information. A separate end-of-cycle performance review letter designated and marked as "Exempt from Public Disclosure in Accordance with 10 CFR 2.390" will include the physical protection review and resultant inspection plan.

Overall, Palo Verde operated in a manner that preserved public health and safety and fully met all cornerstone objectives. Plant performance for the most recent quarter, as well as for the first three quarters of the assessment cycle, was within the Licensee Response Column of the NRC's Action Matrix, based on all inspection findings being classified as having very low safety significance (Green) and all performance indicators indicating performance at a level requiring no additional NRC oversight (Green). However, two apparent violations, including the final significance determination of an associated potentially greater than Green finding, involving the voiding of the emergency core cooling system containment sump suction piping is still under review as part of the significance determination and traditional enforcement processes. These apparent violations were discussed at a conference on February 17, 2005.

During the assessment process, the staff identified a substantive crosscutting issue in the area of human performance. The adverse trend in human performance issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area. The substantive crosscutting issue involved 16 Green findings. These

findings shared several common performance characteristics; however, they were dominated by personnel errors (e.g., instances of failing to follow procedure) and resource issues (e.g., inadequate procedures and work instructions). These problems were identified across several cornerstones and involved multiple groups within your organization. Specifically, nine Green findings involving personnel errors were primarily associated with a failure to follow procedures. Three of these findings involved personnel failing to implement emergency procedures during the loss of offsite power event in June 2004, while other findings pertained to personnel errors involving the movement of irradiated fuel. In addition, four findings were identified regarding the adequacy of procedures and work instructions. In one example, the work instructions for pressurizer spray valve maintenance were not adequate and the valve failed open shortly after maintenance on the valve and valve positioner.

Additionally, a substantive crosscutting issue in problem identification and resolution has been identified based on a number of corrective action findings. The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area. The substantial crosscutting issue involved 18 Green findings. These findings were indicative of implementation problems within the specific areas of identifying problems and entering them in the corrective action program, evaluating conditions in the corrective action program, and implementing effective corrective actions. These problems were identified across several cornerstones and involved multiple groups within your organization. Specifically, four findings were identified with a common performance characteristic associated with the failure to adequately identify problems in your corrective action program. In two of these cases, NRC inspectors had to prompt Palo Verde staff members to enter problems into your program. In addition, seven findings shared a common performance characteristic associated with a failure to adequately evaluate conditions. Four of these examples involved the failure to promptly evaluate the operability of degraded or nonconforming equipment. This included the failure to promptly evaluate voided suction piping in the emergency core cooling systems. Also of concern were seven Green findings with a common performance characteristic associated with inadequate corrective actions. Several of these findings resulted in plant events or the failure of safety equipment to operate correctly during an event. For example, the failure to take adequate corrective actions for a failure of an emergency diesel generator excitation circuit contributed to the failure of the Unit 2, Train A emergency diesel generator to respond as designed to the loss of offsite power event in June 2004.

Through implementation of the baseline inspection program, we will assess your actions to address both of these crosscutting issues. The closure of these issues will be based on whether your corrective actions reduce the number of findings.

As noted in our previous annual assessment letter, a meeting was conducted at the NRC Region IV Office on January 14, 2004, to discuss aspects of safety conscious work environment at Palo Verde. This issue was discussed again in our midcycle assessment letter, dated August 30, 2004. During the January 14 meeting, you discussed plans to conduct additional employee training related to safety conscious work environment and conduct a site survey in 2005 to gauge the work environment and employee willingness to raise safety issues. We understand that the training has been completed and the site survey is scheduled to be completed by March 2005. We will continue to focus our baseline inspection activities on your actions to address your assessments in this area.

The enclosed inspection plan details the inspections, less those related to physical protection, scheduled through September 30, 2006. In addition to the baseline inspections, NRC will also be conducting inspections related to Inspection Procedure 50001, "Steam Generator Replacement Inspection," Temporary Instructions 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," and 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)." The inspection plan is provided to minimize the resource impact on your staff and to allow for scheduling conflicts and personnel availability to be resolved in advance of inspector arrival onsite. Routine resident inspections are not listed due to their ongoing and continuous nature. The inspections in the last 9 months of the inspection plan are tentative and may be revised at the midcycle review meeting.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If circumstances arise which cause us to change this inspection plan, we will contact you to discuss the change as soon as possible. Please contact me at 817-860-8173 with any questions you may have regarding this letter or the inspection plan.

Sincerely,

/RA/

Troy W. Pruett, Chief
Project Branch D
Division of Reactor Projects

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

Enclosure:
Palo Verde Nuclear Generating Station
Inspection/Activity Plan

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M. Fields, NRR Project Manager **(MBF1)**

SISP Review Completed: TWP___ ADAMS: • •Yes • • No Initials: TWP__
• • Publicly Available • • Non-Publicly Available • • Sensitive • • Non-Sensitive

S:\DRP\DRPDIR\EOC 04\Assessment Letters\PV.wpd

RIV:DRP/D	D:DRS	D:DRP	For signature	
TWPruett;mjs	DDChamberlain	ATHowell	TWPruett	
/RA/	*/RA/*	*/RA/*	*/RA/*	
2/23/05	2/25/05	2/25/05	3/2/05	

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Palo V
Inspection / Activity Plan
03/04/2005 - 09/30/2006

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	OB-EP EX	**- EMERGENCY PREPAREDNESS EXERCISE**	**5**			
1, 2, 3	IP 7111401	Exercise Evaluation		02/28/2005	03/04/2005	Baseline Inspections
1, 2, 3	IP 7111404	Emergency Action Level and Emergency Plan Changes		02/28/2005	03/04/2005	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		02/28/2005	03/04/2005	Baseline Inspections
	EB17B	**- PERMANENT PLANT MODS**	**2**			
1, 2, 3	IP 7111117B	Permanent Plant Modifications		03/07/2005	03/11/2005	Baseline Inspections
	PEB-12B	**- MAINTENANCE EFFECTIVENESS**	**2**			
1, 2, 3	IP 7111112B	Maintenance Effectiveness		03/07/2005	03/11/2005	Baseline Inspections
	SG REPL	**- U1 STEAM GEN REPLACEMENT**	**4**			
1	IP 50001	Steam Generator Replacement Inspection		02/28/2005	12/31/2005	Other Routine
	EB	**- 10CFR50.59**	**1**			
1, 2, 3	IP 7111102	Evaluation of Changes, Tests, or Experiments		03/07/2005	03/11/2005	Baseline Inspections
	EB08P	**- ISI U2 - VESSEL VOL (TI 150/152) AS REQ**	**2**			
2	IP 2515/150	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02		04/04/2005	04/15/2005	Safety Issues
2	IP 2515/160	Pzr Pene Nozzles & Stm Space Piping Connections in U.S. PWRs [NRC Bulletin 2004-01]		04/04/2005	04/15/2005	Safety Issues
2	IP 7111108P	Inservice Inspection Activities - PWR		04/04/2005	04/15/2005	Baseline Inspections
2	IP 7111108P	Inservice Inspection Activities - PWR		04/11/2005	04/22/2005	Baseline Inspections
	OB-INIT	**- INITIAL EXAM**	**3**			
1	X02282	PALO VERDE UNIT1 (05/05) INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
2	X02283	PALO VERDE UNIT 2 (11/05) - INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
3	X02284	PALO VERDE UNIT 3 (11/05) - INITIAL EXAM		07/11/2005	07/15/2005	Not Applicable
1	X02282	PALO VERDE UNIT1 (05/05) INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
2	X02283	PALO VERDE UNIT 2 (11/05) - INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
3	X02284	PALO VERDE UNIT 3 (11/05) - INITIAL EXAM		08/01/2005	08/05/2005	Not Applicable
	EB08P	**- ISI U1 - VESS VOL (TI 150/152) AS REQ**	**2**			
1	IP 2515/160	Pzr Pene Nozzles & Stm Space Piping Connections in U.S. PWRs [NRC Bulletin 2004-01]		10/10/2005	10/14/2005	Safety Issues
1	IP 7111108P	Inservice Inspection Activities - PWR		10/10/2005	10/14/2005	Baseline Inspections
1	IP 7111108P	Inservice Inspection Activities - PWR		10/24/2005	10/28/2005	Baseline Inspections
	ACRSA	**- ACCESS CONTROL TO RAD SIGNIFICANT AREAS**	**1**			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		10/17/2005	10/21/2005	Baseline Inspections
	EB21	**- ENG-SSD&PC**	**6**			
1, 2, 3	IP 7111121	Safety System Design and Performance Capability		01/09/2006	02/24/2006	Baseline Inspections
	OB-EP2	**- EMERG PREPAREDNESS PROGRAM INSPECTION**	**1**			
1, 2, 3	IP 7111402	Alert and Notification System Testing		01/23/2006	01/27/2006	Baseline Inspections
1, 2, 3	IP 7111403	Emergency Response Organization Augmentation Testing		01/23/2006	01/27/2006	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Palo V
Inspection / Activity Plan
03/04/2005 - 09/30/2006

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	OB-EP2	**- EMERG PREPAREDNESS PROGRAM INSPECTION**	**1**			
1, 2, 3	IP 7111404	Emergency Action Level and Emergency Plan Changes		01/23/2006	01/27/2006	Baseline Inspections
1, 2, 3	IP 7111405	Correction of Emergency Preparedness Weaknesses and Deficiencies		01/23/2006	01/27/2006	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		01/23/2006	01/27/2006	Baseline Inspections
	ALARA1	**- ALARA PLANNING AND CONTROLS**	**1**			
1, 2, 3	IP 7112102	ALARA Planning and Controls		02/13/2006	02/17/2006	Baseline Inspections
	PEB-05T	**- TRIENNIAL FIRE PROTECTION**	**4**			
1, 2, 3	IP 7111105T	Fire Protection		04/10/2006	04/14/2006	Baseline Inspections
1, 2, 3	IP 7111105T	Fire Protection		04/24/2006	04/28/2006	Baseline Inspections
	EB08	**- U3-ISI**	**1**			
2	IP 7111108P	Inservice Inspection Activities - PWR		04/03/2006	05/05/2006	Baseline Inspections
	ACRSA	**- ACCESS CONTROL TO RAD SIGNIFICANT AREAS**	**1**			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		04/10/2006	04/14/2006	Baseline Inspections
	PEB	**- PV PIR INSPECTION**	**3**			
1, 2, 3	IP 71152B	Identification and Resolution of Problems		05/08/2006	05/12/2006	Baseline Inspections
1, 2, 3	IP 71152B	Identification and Resolution of Problems		05/22/2006	05/26/2006	Baseline Inspections
	PEB	**- HX PERFORMANCE**	**1**			
1, 2, 3	IP 7111107B	Heat Sink Performance		06/05/2006	06/09/2006	Baseline Inspections
	OB-RQ	**- PV REQUALIFICATION INSP**	**3**			
1, 2, 3	IP 7111111B	Licensed Operator Requalification Program		08/07/2006	08/11/2006	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

ATTACHMENT 5

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

March 2, 2006

James M. Levine, Executive
Vice President, Generation
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P.O. Box 52034
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SUBJECT: ANNUAL ASSESSMENT LETTER - PALO VERDE NUCLEAR GENERATING STATION (NRC INSPECTION REPORT 05000528/2006001; 05000529/2006001; 05000530/2006001)

Dear Mr. Levine:

On February 8, 2006, the NRC staff completed its performance review of the Palo Verde Nuclear Generating Station. Our technical staff reviewed performance indicators for the most recent quarter and inspection results for the period from January 1 through December 31, 2005. The purpose of this letter is to inform you of our assessment of your safety performance during this period and our plans for future inspections at your facility.

This performance review and enclosed inspection plan do not include physical protection information. A separate letter designated and marked as "Official Use Only - Security Related Information" will include the physical protection review and resultant inspection plan.

Overall, Palo Verde Nuclear Generating Station, Units 1, 2, and 3, operated in a manner that preserved public health and safety and met all cornerstone objectives with moderate degradation in safety performance. Plant performance for the most recent quarter for all three units was within the Degraded Cornerstone column of the NRC's Action Matrix based on one Yellow finding in the Mitigating Systems Cornerstone involving a significant section of containment sump safety injection piping that was void of water at all three Palo Verde Nuclear Generating Station units.

Our May 3, 2005, Assessment Follow-Up Letter identified that Palo Verde Nuclear Generating Station's performance was within the Degraded Cornerstone column of the NRC's Action Matrix. On June 14, 2005, the Arizona Public Service Company requested postponement of the planned NRC supplemental inspection in order to allow sufficient time to complete the root cause evaluations and develop corrective actions. Accordingly, the NRC staff delayed the inspection until the fourth quarter of 2005. In December 2005, the NRC completed the implementation of Supplemental Inspection Procedure 95002, "Supplemental Inspection for One Degraded Cornerstone or Any Three White Inputs in a Strategic Performance Area." This supplemental inspection reviewed your root cause, extent of cause and condition, as well as, the corrective actions for: (1) the Yellow finding involving the failure to adequately control the design configuration of the containment sump safety injection suction piping of all three units; and

(2) the Severity Level III violation for the failure to perform a 10 CFR 50.59 safety evaluation and receive prior NRC approval of a change to an emergency core cooling system (ECCS) leak test procedure. The results of the supplemental inspection were documented in NRC Inspection Report 05000528/2005012; 05000529/2005012; 05000530/2005012.

The NRC concluded that, while you performed an adequate root cause evaluation of the design control violation for the Yellow finding, certain corrective actions were incomplete at the time of the inspection. Specifically, for each of the root and contributing causes, not all corrective actions were sufficiently developed to ensure that the identified performance deficiencies were adequately addressed. Some of the corrective actions were narrowly focused, or the implementation of those actions was not fully effective at the time of the inspection. Additionally, monitoring criteria and reviews were not fully established to ensure that corrective actions were effective in improving performance. Consequently, we did not have assurance that your planned corrective actions were sufficient to address the causes for the performance deficiencies associated with the violation. We request that you inform us in writing once you have completed steps to assure that your corrective actions are of sufficient scope and breadth to address the subject performance deficiencies. The NRC will then perform additional inspections as necessary to assess the effectiveness of your actions. Pending completion of this follow-up inspection activity, including an NRC assessment that your corrective actions are sufficient to address the performance deficiencies, the Yellow finding in the Mitigating Systems Cornerstone will remain open.

For the violation involving the NRC's identification of a failure to perform a 10 CFR 50.59 safety evaluation and receive prior NRC approval for a change of an ECCS leak test procedure, the NRC concluded that you performed an adequate evaluation and implemented corrective and followup actions necessary to reasonably prevent repetition of the 10 CFR 50.59 Severity Level III violation. Therefore, this violation was closed.

In our Annual Assessment letter, dated March 2, 2005, and our midcycle assessment letter, dated August 30, 2005, we advised you of substantive crosscutting issues in the areas of human performance and problem identification and resolution. During this assessment period, we continued to identify findings with the same causes and common themes in both crosscutting areas. There were 16 Green findings with crosscutting aspects in the area of human performance. Our assessment indicates that your actions to date have not completely corrected the root causes associated with procedural compliance, procedural adequacy, and the interactions between engineering and operations personnel when assessing degraded and nonconforming conditions. Additionally, there were 12 Green and Severity Level IV findings with crosscutting aspects in the area of problem identification and resolution. Our assessment indicates that your actions to date have not completely corrected the root causes associated with the identification of non-conforming conditions, the evaluation of conditions adverse to quality, particularly by engineering and operations personnel, and the implementation of effective corrective actions for deficient conditions.

During the assessment period, the NRC performed periodic reviews of your corrective actions associated with both crosscutting areas. Following the issuance of the August 30, 2005, midcycle assessment letter, you completed re-analyses of the human performance and problem identification and resolution concerns. You also approved the Performance Improvement Plan in November 2005 and began briefing station personnel on improvement initiatives in

January 2006. Nevertheless, as of the end of the period, the implementation of the improvement initiatives had not completely addressed the original causes of the issues identified in our previous letters and discussed during public meetings conducted in April, May, and August 2005.

A meeting has been scheduled for March 30, 2006, in Arlington, Texas, to discuss the Performance Improvement Plan and corrective actions taken or planned to improve performance relative to these substantive crosscutting issues. You are requested to address these two issues during the Annual Assessment Meeting on April 5, 2006, in Tonopah, Arizona. Additionally, you are requested to provide a written response within 30 days of the date of this letter to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; and the NRC Resident Inspector at the Palo Verde Nuclear Generating Station, Units 1, 2, and 3, facility. Specifically, your written response should identify the probable causes, corrective actions you have taken or plan to take, and the estimated corrective action completion dates for performance deficiencies associated with: (1) the failure of personnel to follow procedures, (2) the use of inadequate procedures, (3) ineffective interactions between engineering and operations personnel when assessing degraded and nonconforming conditions, (4) inadequate identification of nonconforming conditions, (5) inadequate evaluation of conditions adverse to quality by engineering and operations personnel, and (6) inadequate and ineffective corrective actions.

Our midcycle assessment letter, dated August 30, 2005, also discussed the August 18, 2005, public meeting, in which your staff informed us of the results of the site-wide employee survey. The survey results included some conflicting results (e.g., positive statistical results of survey questions relative to negative write-in comments), and your staff discussed the need for further actions. The NRC focused on safety conscious work environment issues, including actions taken in response to the survey, as part of our routine baseline inspection activities and during the January 2006 problem identification and resolution inspection. No instances were identified in which plant personnel would not raise safety concerns. However, several personnel indicated that they did not believe management would resolve minor concerns when identified. Your 2005 Business Plan and Performance Improvement Plan include actions to address safety conscious work environment issues at the Palo Verde Nuclear Generating Station. We will continue to focus on your initiatives in this area as part of our baseline inspection program to monitor your corrective actions for these issues.

The August 30, 2005, midcycle assessment letter also discussed a Severity Level III violation issued on June 27, 2005. The violation involved the NRC's identification of a change to the Palo Verde Nuclear Generating Station Emergency Plan without prior Commission approval, which decreased the plan's effectiveness. The NRC staff conducted an inspection of your root cause analyses and corrective actions as part of the January 2006 problem identification and resolution inspection. The results of this inspection will be documented in NRC Inspection Report 05000528/2006008; 05000529/2006008; 05000530/2006008.

The enclosed inspection plan details the inspections, except those related to physical protection, scheduled through September 30, 2007. In addition to the baseline inspections, NRC will be implementing Inspection Procedure 50001, "Steam Generator Replacement

Inspection," relative to the planned replacement of the Unit 3 steam generators. We will conduct a follow-up Supplemental Inspection Procedure 95002 after receiving notification from you that the corrective actions for the Yellow finding are of sufficient scope and breadth (including the establishment of appropriate effectiveness measures) to address the subject performance deficiencies. We also plan to perform an additional problem identification and resolution inspection in early 2007 to further evaluate the effectiveness of your corrective actions in resolving the substantive crosscutting issues. The inspection plan is provided to allow for the resolution of any scheduling conflicts and personnel availability issues well in advance of inspector arrival onsite. Routine resident inspections are not listed due to their ongoing and continuous nature. The inspections in the last 9 months of the inspection plan are tentative and may be revised at the midcycle review.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If circumstances arise which cause us to change this inspection plan, we will contact you to discuss the change as soon as possible. Please contact Mr. Troy W. Pruett at (817) 860-8173 with any questions you may have regarding this letter or the inspection plan.

Sincerely,

/RA/

Bruce S. Mallett
Regional Administrator

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

Enclosure:
Palo Verde Nuclear Generating Station
Inspection/Activity Plan

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RidsNrrDirsIpab

SUNSI Review Completed: _twp__ ADAMS: ☒ Yes ☐ No Initials: __twp__
☒ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☒ Non-Sensitive

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TWPruett;mjs	DDChamberlain	ATHowell III	TPGwynn	BSMallett
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2/23/06	2/24/06	2/27/06	2/27/06	2/27/06

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Palo V
Inspection / Activity Plan
03/01/2006 - 09/30/2007

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	EB1-08P - U3-ISI		2			
3	IP 7111108P	Inservice Inspection Activities - PWR		04/10/2006	04/14/2006	Baseline Inspections
3	IP 7111108P	Inservice Inspection Activities - PWR		04/24/2006	04/28/2006	Baseline Inspections
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		04/10/2006	04/14/2006	Baseline Inspections
1, 2, 3	IP 7112102	ALARA Planning and Controls		04/10/2006	04/14/2006	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		04/10/2006	04/14/2006	Baseline Inspections
	EB2-07B - HX PERFORMANCE		1			
1, 2, 3	IP 7111107B	Heat Sink Performance		06/05/2006	06/09/2006	Baseline Inspections
	EB1-21 - CDB		8			
1, 2, 3	IP 7111121	Component Design Bases Inspection		07/31/2006	08/04/2006	Baseline Inspections
1, 2, 3	IP 7111121	Component Design Bases Inspection		08/14/2006	08/25/2006	Baseline Inspections
	OB-RQ - PV REQUALIFICATION INSP		2			
1, 2, 3	IP 7111111B	Licensed Operator Requalification Program		09/18/2006	09/22/2006	Baseline Inspections
	EB1-08P - ISI U2		1			
2	IP 7111108P	Inservice Inspection Activities - PWR		10/16/2006	10/20/2006	Baseline Inspections
2	IP 7111108P	Inservice Inspection Activities - PWR		10/30/2006	11/03/2006	Baseline Inspections
	SG REP - U3 SG REPLACEMENT ACTIVITIES		1			
3	IP 50001	Steam Generator Replacement Inspection		01/01/2007	12/31/2007	Other Routine
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		01/08/2007	01/12/2007	Baseline Inspections
1, 2, 3	IP 7112102	ALARA Planning and Controls		01/08/2007	01/12/2007	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		01/08/2007	01/12/2007	Baseline Inspections
	EB2-12B - MAINTENANCE RULE INSPECTION		2			
1, 2	IP 7111112B	Maintenance Effectiveness		01/22/2007	01/26/2007	Baseline Inspections
	PIR - PIR INSPECTION		1			
1, 2, 3	IP 71152B	Identification and Resolution of Problems		01/22/2007	01/26/2007	Baseline Inspections
1, 2, 3	IP 71152B	Identification and Resolution of Problems		02/05/2007	02/09/2007	Baseline Inspections
	RP TEAM - RADIATION SAFETY TEAM		5			
1, 2, 3	IP 7112103	Radiation Monitoring Instrumentation and Protective Equipment		01/29/2007	02/02/2007	Baseline Inspections
1, 2, 3	IP 7112201	Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems		01/29/2007	02/02/2007	Baseline Inspections
1, 2, 3	IP 7112202	Radioactive Material Processing and Transportation		01/29/2007	02/02/2007	Baseline Inspections
1, 2, 3	IP 7112203	Radiological Environmental Monitoring Program (REMP) And Radioactive Material Control Pr		01/29/2007	02/02/2007	Baseline Inspections
	EP1 - PV EP EXERCISE		3			
1, 2, 3	IP 7111401	Exercise Evaluation		03/05/2007	03/09/2007	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

Palo V
Inspection / Activity Plan
03/01/2006 - 09/30/2007

Unit Number	Inspection Activity	Title	No. of Staff on Site	Planned Dates Start	Planned Dates End	Inspection Type
	EP1 - PV EP EXERCISE		3			
1, 2, 3	IP 7111404	Emergency Action Level and Emergency Plan Changes		03/05/2007	03/09/2007	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		03/05/2007	03/09/2007	Baseline Inspections
	EB1-08P - ISI U1		1			
1	IP 7111108P	Inservice Inspection Activities - PWR		04/02/2007	04/13/2007	Baseline Inspections
	RP-ORS - OCCUPATIONAL RADIATION SAFETY		1			
1, 2, 3	IP 7112101	Access Control to Radiologically Significant Areas		04/09/2007	04/09/2007	Baseline Inspections
1, 2, 3	IP 7112102	ALARA Planning and Controls		04/09/2007	04/09/2007	Baseline Inspections
1, 2, 3	IP 71151	Performance Indicator Verification		04/09/2007	04/09/2007	Baseline Inspections
	EXAM - INITIAL EXAM		3			
1	X02351	PV UNIT 1 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
2	X02352	PV UNIT 2 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
3	X02353	PV UNIT 3 - INITIAL EXAM (08/07)		07/09/2007	07/13/2007	Not Applicable
1	X02351	PV UNIT 1 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
2	X02352	PV UNIT 2 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
3	X02353	PV UNIT 3 - INITIAL EXAM (08/07)		07/30/2007	08/03/2007	Not Applicable
	EB2-05T - TRIENNIAL FIRE PROTECTION		4			
1, 2, 3	IP 7111105T	Fire Protection [Triennial]		07/23/2007	07/27/2007	Baseline Inspections
1, 2, 3	IP 7111105T	Fire Protection [Triennial]		08/13/2007	08/17/2007	Baseline Inspections

This report does not include INPO and OUTAGE activities.
This report shows only on-site and announced inspection procedures.

ATTACHMENT 6

CONFIDENTIAL

PALO VERDE

CRDR NUMBER: 2780273
NRC CROSSCUTTING ISSUE
HUMAN PERFORMANCE

September 16, 2005

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Investigation Director: Larry J. Johnson
Larry Johnson, Radiological Services Department Leader

Plant Manager: Larry Johnson for DM Smith per telecon 9/16/05
David M. Smith

CRDR NUMBER 2780273
NRC CROSSCUTTING HUMAN PERFORMANCE ISSUE

CONFIDENTIAL

Table of Contents

Executive Summary 3

Problem Statement 4

Background Information 4

Evaluation Process/Methodology 4

Results of Stream Analysis 5

Validation Efforts 6

- BROADER SCOPE ANALYSIS OF HP ERRORS 6
- LEADER QUESTIONNAIRE 7
- SURVEY RESULTS 8
- OPERATING EXPERIENCE 9
  - *Industry* 9
  - *Palo Verde Operating Experience* 12

Safety Significance 17

Transportability 17

Conclusions 18

- ROOT CAUSE 18
- CONTRIBUTING CAUSES 19

Other Issues 21

Extent of Condition and Extent of Cause 37

Cause Analysis Methods 37

List of Documents Reviewed 37

List of Documents Reviewed (cont.) 38

List of Attachments 38

List of Appendices 38

Attachment A – Investigation Charter 40

Attachment B: Initial Cause Bins from Stream Analysis 41

Executive Summary

CONFIDENTIAL

In their annual assessment letter dated March 2, 2005, the NRC identified a substantive crosscutting issue in the area of human performance (HP). In response to the crosscutting HP issue, a significant investigation team was formed to evaluate the condition and determine causes.

This is not a significant event in the traditional sense, since there is no single event driving the investigation. The team determined the problem statement to be, "Palo Verde experienced an increase in HP errors between 2001 and 2004. Some of the human errors have resulted in HP events. Palo Verde has not effectively communicated and addressed the underlying causes associated with this trend." As such, the root cause identified by this team's efforts is not intended to prevent recurrence of a specific human performance event, only to reduce the overall number of HP errors that ultimately lead to events and are directly related to the identified root causes.

This investigation provides an in-depth evaluation using accepted social behavioral research methodologies which were used to determine *why* HP errors continue to occur. It began with a Stream Analysis performed on 46 significant CRDRs with human performance aspects dating back to January 2004. To ensure that Stream Analysis appropriately characterized the problem with station human performance, the PV significant investigation team used several additional methods to validate the results. These methods included an analysis of a broader scope of CRDRs than those used in the Stream Analysis (a total of 778 CRDRs), as well as reviews of leader and site wide survey data and operating experience. The results of each of these methods demonstrated validity of the Stream Analysis results used as the primary analytical tool in this investigation.

Based on the results of these efforts, the following contributing causes were identified:

- Management has not set clear standards and expectations.
- Management does not reinforce standards and expectations.
- Inappropriate decisions are made at various levels of the organization, sometimes with less than appropriate respect for industrial and nuclear safety

The team then went on to determine the root cause as:

> The Palo Verde organization does not demonstrate ownership and leadership of the human performance culture. Since the entire organization demonstrates a weakness in Human Performance culture, culpability for station behavior lies with the highest levels of management.

The root cause is demonstrated by:

- An organization that does not place the same value on excellence in human performance as it places on excellence in production.
- Leaders who sometimes model behaviors inconsistent with site expectations.
- No apparent consequences for HP events, especially when compared to consequences associated with plant performance (accountability).

Corrective actions to address these causes are documented in the body of the report. Corrective actions associated with both the cultural and structural elements of human performance have been developed. The key corrective actions address the ownership and leadership of the human performance culture at Palo Verde by initiating a cultural intervention and addressing accountability.

This investigation concluded that PVNGS has a continuing issue with human performance. This is not the first report to make such an assertion. In fact, in many ways this report presents findings that are very similar to those reported in other Palo Verde reports. Palo Verde's missed opportunity to collectively analyze those reports and initiate effective corrective action contributes to a lack of understanding and lack of improvement in human performance. An organization that champions all aspects of human performance and reports to executive management will help with not only recognizing, but understanding and correcting human performance issues.

Improvement in human performance will only be realized if there is a significant change in Palo Verde's culture. Individual behaviors at all levels need to be aligned to improve performance, reduce errors and prevent events. Behaviors must be clearly described, communicated, understood, and most importantly reinforced.

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Problem Statement

Palo Verde experienced an increase in human performance errors between 2001 and 2004 (see Appendix A1 in SWMS attached media). Some of the human errors have resulted in human performance events. Palo Verde has not effectively communicated and addressed the underlying causes associated with this trend.

Background Information

In their 2004 annual assessment letter dated March 2, 2005 (see SWMS attached media); the NRC identified a 'substantive crosscutting issue in the area of human performance'. The NRC letter goes on to state, "The adverse trend in human performance issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area. The substantive crosscutting issue involved 16 green findings (see Appendix B1 in SWMS attached media). These findings shared several common performance characteristics. However, they were dominated by personnel errors (e.g., instances of failing to follow procedures and work instructions). These problems were identified across several cornerstones and involved multiple groups within your organization. Specifically, nine green findings involving personnel errors were primarily associated with a failure to follow procedures."

Subsequent to the NRC letter, a common cause evaluation was conducted under CRDR 2780273 to identify the underlying causes for the trend in HP. The evaluation focused on 19 conditions associated with the 16 green findings related to procedure adherence and adequacy. The evaluation of the procedure adherence and adequacy issue is a credible investigation of this narrow aspect of the human performance crosscutting issue and as such the corrective actions specific to the procedure issue are still valid. However, to ensure an adequate evaluation of the extent of condition and extent of cause for human performance at Palo Verde the scope was broadened such that all areas of human performance and all Palo Verde departments are within the scope of this investigation.

Since receipt of the 2004 annual assessment letter, the NRC has identified four additional HP items (included in Appendix B1 in SWMS attached media). A review has determined that these four events align with events analyzed in this investigation and therefore do not impact the findings of this report.

Evaluation Process/Methodology

"Stream Analysis" was the method chosen to perform this investigation and has been used by INPO and other utilities to help determine the underlying reasons for station events. Stream Analysis is a common cause technique used to diagnose failings in organizational functions and then to plan, implement and track the needed change actions. The process was developed by Jerry Porras PhD at Stanford University. The process has been successfully used at Hewlett-Packard Laboratories, Bell Laboratories, and TRW International and has been adopted as the tool of choice by INPO for assisting utilities with HP issues.

The basic method for stream analysis consists of:

1. Collecting data
2. Categorizing and consolidating problems
3. Identifying interconnections
4. Analyzing the problem chart to identify drivers and themes of core problems
5. Formulating a plan of action

The 'streams' are used during the second step described above to categorize issues, or bin them, and then consolidate them. Once the binning of CRDRs is complete, an analysis of the data is performed to determine the "drivers" and "enablers" to the identified causes. The effort results in a better

CRDR 2780273 Page 246 of 294

understanding of the underlying causes to human performance events and helps focus on corrective actions to address them.

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Results of Stream Analysis

On June 29, 2005, the Palo Verde Senior Management Group (SMG) participated in a Stream Analysis session facilitated by INPO. The purpose of the INPO Assist visit was to perform a Stream Analysis on significant CRDRs with human performance errors dating back to January 2004 (note that one event dated back to 2002). Supplementing the population of significant CRDRs were those associated with the 2003 INPO AFIs in the areas of Performance Improvement and Organizational Effectiveness. The total number of CRDRs reviewed was 46.

The effort was lead by members of INPO's Human Performance and Organizational Performance departments. The INPO HP team has extensive experience in Stream Analysis and has assisted other plants in diagnosing human performance weaknesses.

Based on INPO's experience with Stream Analysis, four streams were used that have been used successfully in the past at other utilities. The streams used in this process were:

- People/Jobs, which includes selection, succession, training and individual attitude.
- Right Picture, which includes having the picture of excellence in expectations, behaviors, performance, vision, goals, strategy, and plan and passion for excellence.
- Process, which includes procedures, technology, work flow design, and the way we do business.
- Management coach/worker involvement, which includes communication, oversight, field time, rewards system, and team engagement.

Palo Verde's SMG met in a day long meeting to review each of the 46 CRDRs and determined into which of the streams it should be binned. In each case, a senior manager knowledgeable of the event explained the circumstances surrounding it, the most significant human performance cause and determined its bin. The SMG then discussed it in an open forum in an attempt to gain consensus on the binning. In those instances where a consensus could not be reached, the Plant Manager decided the binning. In twelve of forty-six events, the stream changed from the one identified by the senior manager to one determined more appropriate by either the SMG or the Plant Manager. Appendix C1 (in SWMS attached media) lists the 46 CRDRs and their binning.

After the SMG completed the initial streaming described above, the CRDRs in each stream were reviewed by the INPO team and the PV significant investigation team in an effort to consolidate the CRDRs into common problem statements. Due to time constraints, this portion of the effort was truncated and few consolidations were made.

Once the CRDRs were all assigned a stream, the SMG compared each problem statement on the streaming chart to every other problem statement on the chart to determine if one was responsible for driving the other. This resulted in identifying common drivers or causes for most of the events.

The PV significant investigation team recognized that because of the time constraints and limited understanding of the process during the consolidation step above, the results may be questioned. Therefore, in order to ensure the integrity of the Stream Analysis process, the team decided to re-consolidate the CRDRs. The original CRDR coding performed by the SMG was used during this re-consolidation/re-streaming effort. This resulted in the original data set of 46 CRDRs being consolidated into a set of 17 problem statements (see Attachment B to this report). The new

consolidation and streaming information was submitted to INPO for entry into proprietary Stream Analysis software.

Based on the streaming, both APS and INPO independently analyzed the data. The PV significant investigation team identified five major drivers, namely:

- Unclear standards and expectations
- Management not reinforcing standards and expectations
- Management expectations not clearly communicated
- No consequences for inappropriate actions
- Decision making

[REDACTED]

Validation Efforts

To ensure that Stream Analysis appropriately characterized the problem with station human performance, the PV significant investigation team used several methods to validate the results. The methods included the following:

- Analysis of a broader scope of CRDRs than those used in the Stream Analysis
- Leader Questionnaire
- Site Wide Survey
- Operating Experience

The results of each of these methods demonstrated validity of the Stream Analysis methodology used as the primary analytical tool in this investigation.

Broader Scope Analysis of HP Errors

The scope of the population of CRDRs used to perform the original Stream Analysis was broadened to include other CRDRs documenting human performance errors and events. The intent was to not only validate the data from the original Stream Analysis, but to ensure that any additional underlying cause of the significant crosscutting issue in human performance was not missed by focusing on too small a population of events.

To expand the scope for validation of the Stream Analysis, in addition to the 46 significant CRDRs originally streamed, the team selected the following groups of CRDRs:

- CRDRs for all Noteworthy and Significant Human Performance events between January 2003 and May 2005; and,
- CRDRs associated with the top two categories of human performance cause codes for the period between January 2004 and May 2005, namely 'documents not followed' and 'self checking'

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This resulted in a dataset of 778 CRDRs (see Appendix D1 in SWMS attached media).

Each of these CRDRs was reviewed to determine into which of the streams used in the Stream Analysis it should be binned. Based on analysis of this larger dataset, the team again determined the three major contributing causes of these errors to be:

- *Management has not set clear standards and expectations.*
- Management does not reinforce standards and expectations.
- Inappropriate decisions are made at varying levels of the organization, sometimes with less than appropriate respect for industrial and nuclear safety.

The significant investigation team also reviewed a sample population of CRDRs that were considered unrelated to human performance (i.e., equipment related) to ensure there were no underlying HP causes associated with them. A sample of 60 CRDRs was selected for review. Further review of equipment related CRDRs was determined to be unnecessary. The team concluded that this population of CRDRs had no impact on the results of this investigation.

Stream Analysis of the increased population of items identified the same major causes to human errors as the Stream Analysis performed on the original 46 events, thus validating those results.

During review of the 778 CRDRs documenting human performance errors, issues with Procedure Use and Adherence, Security, and Contractors/Vendors emerged as themes of human performance weakness. These issues are documented in the section of this report entitled "Other Issues".

Leader Questionnaire

During a Palo Verde Leader's meeting held on July 12, 2005, leaders were asked to provide their perspective (fill in the blank responses) on what they thought accounted for the three common causes or drivers identified during the Stream Analysis. The responses from leaders support the validity of these causes. Based on responses, less than 17% of leaders believe that expectations and standards are clear and reinforced. The following is a summary of the fifty-five leader responses (since some leaders provided more than one response, the number of responses exceeds 55).

<u>Leadership Expectations and Standards are not clear</u>

Although some leaders (9 responses) believe that expectations are clear, most leaders believe they are not. The top responses included:

- Lack of alignment of the organization (12 responses)
- Ineffective communication of information (11 responses)
- Expectations keep changing (7 responses)
- Expectations are vague in nature (6 responses)
- Management actions are inconsistent with expectations (5 responses)
- Too many expectations (4 responses)

<u>Leadership is not reinforcing Expectations and Standards</u>

Again some leaders disagreed with the above assertion (7 responses). However, most agreed and provided the following responses to explain:

- Management actions are inconsistent with expectations (17 responses)
- Inconsistencies with holding people accountable; leadership too soft (12 responses)
- Not enough time/too many distractions (10 responses)
- Don't understand/difficult to interpret (6 responses)

CRDR 2780273 Page 249 of 294

CONFIDENTIAL

Decision making

Most leaders recognize a concern and provided the following responses:

- There's not enough time (10 responses)
- Decisions are made too quick without doing the research (8 responses)
- Leaders looking for short term/quick fix (6 responses)
- Getting job done outweighs consequence (5 responses)
- No site standard for change management (4 responses)
- Decisions made at wrong level (2 responses)
- Hard to know all impacts, individual processes not consistent (2 responses)

Survey Results

A survey, on the subject of human performance was developed and presented to the entire Palo Verde organization using the PinWest web based survey tool. Since the survey was presented to the entire organization without exclusion, it is considered to be a 100% sample. Based on the organizational distribution of respondents, the survey results are representative of the station's perception.

The survey was a mix of both quantitative and qualitative questions and included a short demographic section. Data from the survey indicates that most people think human performance at Palo Verde is about average. Data further indicates that human performance at PV is functioning at about the same level today as it was a year ago, but is considered worse today than it was five years ago.

Generally, workers at Palo Verde understand what good human performance is. In the survey, 565 respondents answered the question "What is your definition of good human performance"? A vast majority gave very able descriptions of good human performance.

Some were very short,

"No mistakes"

And some more expansive,

"Good human performance, is where the individuals and teams perform activities and tasks by utilizing their prevent events tools such as procedure use and adherence, STAR techniques, peer checking etc. with the mindset that they are qualified, briefed on the task, familiar with the task, and are successful without taking shortcuts, etc. If the task cannot be performed within that guideline, then they stop and resolve the issue. Bottom line is to "do the right thing" as we know to do it".

Other than a small handful, the answers were on target. Common themes in the answers were:

- Safety (nuclear, industrial and radiological)
- Use our prevent events tools
- Do it right the first time
- Stop when unexpected conditions are encountered
- Professionalism
- Minimize errors
- Procedure use and adherence
- Individual responsibility
- Report errors so we can learn

CRDR 2780273 Page 250 of 294

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One answer used an acronym:

Personal Responsibility Insures Daily Excellence - PRIDE

It can be concluded that Palo Verde is able to identify good human performance when asked. The human performance vision may not be published but it is certainly well known by the staff.

Data from the qualitative questions was analyzed using a method of qualitative social research called "Grounded Theory". Grounded theory allows use of the comments from the survey in an analysis to determine why human performance is changing at PV and then to develop problem statements with respect to human performance. Using the grounded theory, two problem statements were developed which, if corrected, would restore influences on worker behavior to a proper balance, namely:

- Management has demonstrated that there are no negative consequences to making human performance errors as seen by the way leader's model inappropriate behavior and by the way they reward task completion.
- Management has fostered a system that allows the schedule to have precedence over human performance behaviors as seen by the way leaders provide incentive for schedule performance and not for human performance.

These two problem statements are conceptually similar to and can be seen as a subset of the two causes related to standards and expectations identified in the stream analysis discussed earlier in this report. This survey demonstrates validity of the Stream Analysis methodology used as the primary analytical tool in this investigation.

See Appendix E1 in SWMS attached media for details of the Site Wide Survey Results.

Operating Experience

Industry

Since the efforts made by this investigation are not in response to a specific event, operating experience is not applicable to this report in the traditional sense. However, Palo Verde is not the first plant to have human performance identified as a crosscutting issue by the NRC. While performing this investigation of the crosscutting HP issue, four of the other eight utilities identified with NRC identified HP crosscutting issues were contacted. The four plants include Diablo Canyon, Callaway, Cooper and Point Beach. In response to the NRC identified issue, each plant performed a thorough investigation into the reasons for their HP issues and documented their results. These reports were reviewed to identify causes for their HP crosscutting issues in an effort to learn from their experiences.

The review provides unique insight into the causes of crosscutting human performance issues at other utilities. The insights are similar in nature to the circumstances at Palo Verde and the root causes identified by these utilities align closely with the causes identified by this team. The list below provides each site's identified root causes and corrective actions.

An interesting observation comparing stand alone plants to fleet plants was made while identifying the NRC identified crosscutting issues in human performance. Of the 66 nuclear power plant sites, thirteen of them are 'stand alone' plants, and 53 of them are managed by eleven 'fleets'. There are ten HP crosscutting issues identified, nine active and one closed. Five of thirteen stand alone plants have HP crosscutting issues identified (or 38%) and five of the 53 fleet plants have HP crosscutting issues (or 9%). Three of six STARS plants have NRC identified crosscutting HP issues and account for 30% of the total number of plants with HP crosscutting issues. One could conclude that fleets perform

CRDR 2780273 Page 251 of 294

better with respect to human performance than the stand alone sites, presumably because of the benefit of an integrated HP program driven from the top of the organization. Additionally one can make the argument that STARS may not provide the benefits that one would expect from a fleet with respect to human performance.

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Diablo Canyon

Root Cause

As a result of three methods used to analyze human performance events and errors, Diablo Canyon identified the following root cause to their human performance issue:

> DCPP management has not demonstrated adequate ownership and institutionalization of the Human Performance Program.

Corrective actions

The recommended actions included:

- Develop station and department-level human performance plans
- Develop a standardized system to track, trend, analyze and utilize human performance data.
- Standardize, monitor and reinforce communication practices across the organization
- Implement an effective and efficient program to monitor and coach workers through observations, active listening, and questioning.
- Implement a supervisory development program to assure that supervisors monitor and coach workers through first-hand observation, active listening, and questioning.
- Improve the quality of procedures and work packages
- Implement station-wide verification practices that meet or exceed the standards set forth in INPO AP-931 "Verification Practices"

Callaway

Root Causes

Significant events were included in a stream analysis to determine the extent of condition, similar to the method used by Palo Verde. The stream analysis identified four root causes.

1. Callaway Plant does not have a clear picture of human performance excellence.
2. Insufficient supervisor and manager involvement in human performance, including less than adequate oversight and coaching of behaviors.
3. Ownership of the corrective action program is less than adequate to support prevent events.
4. Inadequate use of change leadership relating to training, communication, and roles/responsibilities of change.

Corrective actions

1. Create and anchor an Advisory Committee on Human Performance (High Impact Team – HIT) guided by newly hired individuals from industry who have a clear picture of human performance excellence. The HIT team will then identify champions and role models from the workforce to promote human performance initiatives throughout the organization. Both their peers and the management cadre will be expected to hold these individuals in high esteem.
2. The mission and charter for the HIT team will address manager and supervisor involvement in human performance through activities such as observations and coaching.

CRDR 2780273 Page 252 of 294

3. Two corrective actions were associated with root cause #3.
   - The mission and charter for the HIT team will address training of Senior Management on the administrative aspects of the Corrective Action Program.
   - Reinforce and complete corrective actions for three (3) corrective action reports and complete analysis / corrective actions for another referenced corrective action report (four CARs total)
4. Proceduralize Callaway's change management policy.

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Cooper

Root Causes

Cooper used a Common Cause Analysis and a 'WHY' staircase method to arrive at what they called four common causes. They include:

1. Standard techniques necessary to prevent latent errors and active failures are not consistently planned, applied, or implemented during task preparation activities. This is due to inconsistent reinforcement from supervisory oversight, peer oversight, training, work scheduling, and work planning. (i.e., Failure to make time to ensure proper preparation for work assignments contributes to both latent and active errors in maintenance, operations, and engineering.)
2. Inconsistent risk awareness contributes to a weakness in decision-making involving application of error prevention techniques. Risk assessment tools are primarily focused on nuclear risk and do not assess all risk categories or risk accumulation.
3. Gaps in strategic trending of precursors related to latent conditions and their implementing processes.
4. Lessons learned from past consequential events are not always internalized at departmental levels.

No corrective actions from Cooper were available at the time of this report.

Point Beach

Root Causes

Point Beach used standard data gathering techniques to collect pertinent information related to the 12 issues referred to in the NRC's end of cycle performance assessment. A stream analysis was applied to the 12 crosscutting issues in order to focus and prioritize corrective actions.

The evaluation identified the following root causes:

1. Point Beach Station Management has not demonstrated adequate ownership of, commitment to and prioritization of the Human Performance (HP) Program and needed HP improvement initiatives.

2. Weaknesses in the work planning and procedure revision processes have generated human performance error traps.

CRDR 2780273 Page 253 of 294

Corrective Actions

Essentially, Point Beach implemented action plans that were made into regulatory commitments. The report refers to a Point Beach Excellence Plan that establishes actions to address the root causes and contributing causes. Specifically, Point Beach actions included:

- Implementation of "ACEMAN" as a site model for improving individual human performance behaviors.
- Revitalization of a Human Performance Steering Team to monitor site expectations regarding human performance.
- Ensuring adequate human performance program management and oversight by appointing a full time individual to monitor and improve human performance.
- Implementation of actions to address work package quality issues.

Since there was no single site human performance point of contact, external operating experience was not effectively utilized to better educate and inform management on the increasing issues other sites were having in this area.

Palo Verde Operating Experience

In addition to reviewing reports from other utilities with NRC identified human performance crosscutting issues, several Palo Verde reports were reviewed. Reviewing site reports back to 2002, it becomes apparent that Palo Verde has lived with a high 'noise level' of human performance errors from year to year. From January 2001 to December 2002, the number of human performance errors was approximately 150 errors a month and increasing. Increases continued through 2004. Currently, Palo Verde experiences over 200 human performance errors a month. This increase in human performance errors is based on a fairly consistent number of CRDRs issued each year.

Numerous reports have provided indications of declining human performance at Palo Verde. Many of the same concerns leading to the crosscutting human performance issue have been identified in various reports. A total of eight (8) Quarterly Trend Reports (2002 and 2003 reports stated: "Overall, documents not followed correctly has the potential to be considered an NRC Crosscutting Human Performance Element". The reports went on to document justification for this "not" being a crosscutting issue. These reports, when viewed collectively, recognize all of the elements to the causes identified by this significant investigation, including worker and leader accountability, organizational alignment, lack of an effective observation program, etc. However, Palo Verde has not aggressively nor effectively addressed the causes of these self-identified human performance concerns.

While numerous reports provide indication of human performance issues at Palo Verde, very little effort is made to analyze these reports collectively. The Performance Improvement Department (PID) at Palo Verde provides trending information, but little collective analysis of the information. The lack of leading indicators contributes to inefficiencies with aggressively recognizing and responding to declines in human performance.

WANO/INPO Peer Review
July 2005

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CRDR 2780273 Page 254 of 294

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2005 Supervisory Effectiveness self assessment
March 2005.

The following recommendations were made as a result of the assessment:

- Create a continuing leadership training/development program. The program should consider the following:
  1. Increase one on one time between managers and supervisors in an effort to improve performance. Consider past training, other programs and future training as possible methods to accomplish this.
  2. To mentor their leaders, ensure a plan for each leader to improve performance is built into the performance management process.
  3. Individual development plans should be tied into the 360 degree feedback results.
  4. Develop approach to mentoring and tie to individual development plan.
  5. For leader accountability performance areas, identify developmental activities and resources for competencies.
     - Develop a site-wide accountability description.
     - Create focus groups to engage the workforce in the 2005 Business Plan and achieve buy-in throughout the organization.
     - Enhance the current communication plan for rolling out the Business Plan.
     - Use work groups to identify workload issues.
     - Develop guidelines to better use e-mail.
     - If the PILOT program is abandoned, use the lessons learned from it to develop a better observation program. The new program should also include a component that specifies managers conducting frequent paired observations.

CRDR 2780273 Page 255 of 294

These recommendations were documented on CRDR 2784371. The evaluation closes the recommendations to Level 1 plan 1190BP. Although the assessment touches on several aspects related to the human performance issues at Palo Verde, the level one does not go to the depth necessary to cause effective improvement.

O'Hanlan Report
February 2005

[REDACTED]

2004 Supervisory Effectiveness self assessment
September 2004

Some of the insights from this self assessment relating to this investigation include:

- Both team and section leaders provided examples where management's focus and subsequent performance has varied from stated goals and expectations. (from the executive summary)
- Based on interviews, a majority of leaders believe that the current standards and expectations are not clear, difficult to correlate to day-to-day activities, and in some instances are being misinterpreted by their groups.
- The leaders believe that time pressures and complacency are the main reasons contributing to human errors at Palo Verde.

CRDR 2780273 Page 256 of 294

- Forty-one leaders did not believe that any further actions were needed to have employees consistently demonstrate appropriate safety and work behaviors. However, leaders believe that certain expectations can be interpreted, based upon their own perception of the risk associated with the work activity. Common phrase used to describe this was "Preach Safety – Reward Production".
- 58% of the leaders believe they understand the vision and mission and are supporting it. However, many of them don't believe the mission is clear, that it has not been effectively communicated, have not internalized it, or have their own vision and mission.

2004 Significant Investigation Summary Report
February 2005

The Root Cause Expert Panel was assembled to improve significant investigations at Palo Verde. It was comprised of those people considered to be site experts on performing significant investigations. The Root Cause Expert Panel reviewed 45 significant CRDRs with the following results.

- The top human performance causes included procedures, self checking, supervisory management and managerial methods.
- The number one corrective action dealt with process improvements.
- With respect to organizational weaknesses, the biggest contributors dealt with non-conservative decision-making, safety culture, risk awareness, followed by goals and priorities.
- Knowledge based errors outnumbered skill based and rule based errors by a 2-1 margin.

2004 INPO Mid-Cycle self assessment
November 2004

[REDACTED]

Quarterly Trend Reports
2002, 2003, 2004

The 2002 fourth quarter Trend Report focuses on human performance and identifies 'self-checking' and 'documents not followed correctly' as the main contributors to human performance errors. The

CRDR 2780273 Page 257 of 294

report states that 'documents not followed correctly' has "the potential to be considered an NRC crosscutting human performance element."

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The 2003 second quarter Trend Report identifies an increase in the number of HP errors and explains that issues relating to 'documents not followed correctly' and 'self-checking not applied' are the primary contributors. The report goes on to state, "The issue of 'documents not followed correctly' has increased by approximately 33% for the first six months of 2003 as compared to the first six months of 2002. The report recognizes an ongoing issue with regards to 'documents not followed' and goes on to document that Performance Improvement generated CRDR 2605291 to perform an integrated evaluation of the issue to better understand the HP data. The CRDR went on to state that there was no declining trend.

The 2003 third quarter Trend Report identifies an increase in the number of human performance errors and again points to 'documents not followed' and 'self checking not applied' as the primary contributors. Adverse CRDR 2632229 was generated September 2, 2003 to document a noted increase in the station MTR performance indicator for performance improvement. There were also noted increases in human performance events and human performance errors. CRDR 2632229 Identifies four specific human performance concerns, as follows:

- HP error rate change increase (-2.02 to 10.98)
- Increase in the number of events, from 75 events year to date compared to 61 the same period in 2002
- 5 Significant HP events year to date (July 2003) compared to 2 for all of 2002
- PV HP errors twice (2x) next closest STARS utility

The evaluation of CRDR 2632229 was completed October 1, 2003. The CRDR was eventually closed in January 2005 to CRDR 2734665, having completed no actions to address the human performance issues.

CRDR 2734665 was generated to capture the recommendations from three self assessments performed in 2004. The three self assessments were the 2004 Integrated Self-Assessment for Supervisory Effectiveness, the 2004 USA Safety Culture Self-Assessment, and the 2004 INPO Mid-Cycle Self-Assessment. The team noted that CRDRs were not generated for the issues identified during these three self assessments at time of issuance, but were captured collectively when CRDR 2734665 was issued.

As a result of CRDR 2734665, CRAI 2759062 was generated in December 2004 to address a human performance improvement strategy with a due date of January 14, 2005. CRAI 2759062 was closed to Level One #1191-BP in July 2005. Level One #1191 is a large initiative that has 22 tasks and is still open.

The 2004 fourth quarter Trend Report identifies improved human performance in Operations based on a reduction of significant and noteworthy human performance events. However, an independent review of CRDR trend data identified a degrading trend in the effectiveness of self-checking and procedures not followed correctly in Operations.

CRDR 2780273 Page 258 of 294

CONFIDENTIAL

Safety Significance

This significant investigation is not based on a single event. However, many significant events were evaluated by this team. The investigation of each of those significant events addressed safety significance and ensured the appropriate License Event Reports and Operability Determinations were generated, as appropriate.

During the performance of this investigation, no collective concerns were identified that would indicate a safety significant concern beyond those identified in each of the individual events.

From a Safety Significance perspective it is the intent of this investigation to minimize future human performance errors and hence minimize the number of future Safety Significant Events.

Transportability

The issue is transportable and applies to all departments at Palo Verde.

CRDR 2780273 Page 259 of 294

CONFIDENTIAL

Conclusions

The contributing causes identified from the Stream Analysis (also discussed as the drivers to the events) were collectively evaluated by the team to determine what the root cause is for a significant number of the human performance errors and events at Palo Verde. Using the concept of the "why staircase", the team identified a statement that encapsulated the contributing causes. This statement was determined to be the root cause. Additional information is provided with the root cause to better identify components of the statement, such as what is the organization (all levels of management and frontline) and what comprises a human performance culture (emphasis on excellence in human performance, modeling behavior, rewards and consequences).

Root Cause

The Palo Verde organization does not demonstrate ownership and leadership of the human performance culture. Since the entire organization demonstrates a weakness in Human Performance culture, culpability for station behavior lies with the highest levels of management.

The following information is provided to understand why this root cause condition exists.

- Palo Verde Management does not emphasize that excellence in human performance will result in excellence in plant performance.
- Leaders sometimes model behaviors inconsistent with site expectations.
- There are little apparent negative consequences to HP events, especially when compared to plant performance (accountability).
- Palo Verde often rewards heroic actions. This was pointed out in the September 2004 self assessment on Supervisory Effectiveness.
- There are numerous daily meetings focused on plant performance and plant concerns and few, if any, focused on human performance.
- CRDRs are sometimes not generated as expected (additional details can be found in CRDR 2780286, NRC Crosscutting issue with Problem identification and resolution).
- Corrective actions seem to be aimed at closing CRDRs and not at fixing problems (see CRDR 2780286 for additional details).

Supporting indications:

- PV does not have a documented Human Performance Program.
- PV does not have a single person/group responsible for human performance monitoring and improvement activities.
- The PV Prevent Events Steering Committee is inactive and thus ineffective.
- The PV MTR only tracks lagging indicators of human performance, i.e., number of significant events.
- Most PV departments have Prevent Events Committees operating to individual charters and initiatives. Many of these department programs are inactive.
- Noteworthy Human Performance events are not analyzed to determine cause.
- The PV culture does not have a cultural synonym, such as the "Palo Verde WOW", for human performance excellence.
- Eight (8) NAD Quarterly Trend Reports for 2002 and 2003) discussed *documents not followed correctly* as a potential NRC crosscutting HP issues.

Contributing Causes

Contributing Cause #1

Management has not set clear standards and expectations.

This contributing cause is supported by the following CRDR's reviewed during the stream analysis, as well as the validation methods used which identified lack of vertical alignment on these standards and expectations. Lack of alignment is closely tied with ineffective communication. Clarity of expectations and standards may be as a result of them being vague in nature, thus requiring a "picture" of what excellence looks like in these areas. The Palo Verde Expectations and Standards booklet issued in June 2005 has been developed to provide a single, simple message of expectations and standards.

Supporting facts

[REDACTED]

CRDR 2559423: During the removal of spent fuel assembly (FA) M316 from the upender in the Unit 1 Fuel Building, Spent Fuel Handling Machine (SFHM) trolley movement to plant north was initiated prior to the hoist being raised to the up-limit. Auto sequence was also initiated and then stopped when it was noticed that the assembly was not at the up-limit. The bottom of the FA (approximately 7") was still in the upender when SFHM and upender movement was initiated. Directions to perform peer checks were not well communicated.

CRDR 2657316: Engineering determined this ST performance was invalid because check valve AFA-V015 had not been opened with pump flow. The intent of 73ST-9XI38 is to verify check valve AFA-V015 is closed following it being opened. Unclear expectation resulted in LER.

Contributing Cause #2

Management does not reinforce standards and expectations.

This contributing cause is supported by the following CRDR's reviewed during the stream analysis, as well as the validation methods used which identified inconsistencies in holding people accountable, which may be because of the inconsistent understanding and/or implementation of what's expected. The lack of visibility of consequences due to the need for confidentiality with positive discipline may have lead to questions of how leaders model and mentor to enforce the standards and expectations. The Palo Verde Expectations and Standards booklet issue in June 2005 now frames the minimum acceptable level of performance. The booklet covers the typical expectations and a standard of procedure use and prevent event tools, but also includes Nuclear Safety and Leadership. In these areas, "Doing it right the first time" is emphasized, which is trying to bring the value of human performance in balance with the need for production. There is NO expectation or standard that addresses production.

CRDR 2780273 Page 261 of 294

Supporting facts

[REDACTED]

CRDR 2781982: At approximately 1326 hours on 3/11/05, the U1 CRS was notified by the Fire Department Incident Commander of an injury at the VCC (Vertical Concrete Cask) fabrication facility. A scissors lift tipped over while in service, apparently due to one of the lift wheels transitioning from concrete to dirt.

CRDR 2699943: On 4/17 at approximately 0730 a flash fire occurred as welders began pre-heat to perform weld repairs in the FT'A' lower shell. As the torch got near a shell drain hole fiery liquid blew out of the hole. Both welders received burns to their faces and were transported off site for medical attention.

Contributing Cause #3

Inappropriate decisions are made at varying levels of the organization, sometimes with less than appropriate respect for industrial and nuclear safety.

This contributing cause is supported by the following CRDR's reviewed during the stream analysis , as well as the validation methods used which identified decisions being made, at all levels of the organizations, that are without focus or consideration do to lack of research or trying going to the short term fix.

Supporting facts:

CRDR 2639721: During removal and rigging out of the steam generator 1 west hydraulic snubber lever, the rigging bail failed resulting in dropping the lever approximately 10-12 inches onto the hydraulic snubber arm and platform. The lever weighed about 7000 pounds and was over shutdown cooling lines. The steamfitter who was acting as Signalman for the crane directed the crane operator to trolley the crane despite the fact that he had been ordered not to move the load by the Bechtel craft supervisor. This event also displayed willingness by PVNGS management to permit the polar crane to be operated with a known work-around.

CRDR 2654642: While performing 40ST-9ZZM6, start-up channel #2 was pegged low, reading INVALID on PMS and ERFDADS. Because the channel was off-scale low, no audible signal was available. I&C Maintenance evaluated the status of the channel and reported that all the parameters within the drawer indicated normal. Based on the I&C troubleshooting and engineering's input, the requirements of ZZM6 (ensure SU channel is energized and in-service, and a qualitative assessment of the SU CH #2 with respect to current operating conditions), were deemed satisfactory. As the first assembly was lowered next to SU CH #1, CPS increased as expected. However, as the second assembly was lowered next to SU CH #2, the SU CH indication did not change. Per Technical Specification 3.9.2, Startup channel 2 was declared inoperable and core alteration was suspended. The operations crew with advice from Engineering declared the channel Operable without verifying adequacy of the retest.

CRDR 2780273 Page 262 of 294

CRDR 2682312: During the Unit 1 power ascension COLSS ASI was at about -0.31 when power was brought above 20%. Going above 20% power is a condition change and subject to 3.0.4. Technical Specification 3.2.5 requires that ASI be below -0.28 before exceeding 20% power. The LER reports a Technical Specification violation where power was raised above 20 percent rated thermal power without meeting the Limiting Condition for Operation (LCO) for Axial Shape Index (ASI). The Shift Manager authorized increasing power due to a misunderstanding of the Technical Specification applicability. He also failed to consult with the SSM who would have provided an independent, highly experienced review of the decision.

CRDR 2697384: On 4/11/2004 at approximately 11:25, during U1R11 (Mode 6, de-fueling in progress), the Control Room was notified by Refueling Personnel that a remote "submarine" had entered the PC (Pool Cooling) 20' diameter suction line in the SW Corner of the SFP. The RP operating the submarine was having difficulty retrieving the submarine via the tether against the suction flow in the pipe. Based on request from the Refueling SRO the "A" Train Pool Cooling pump was stopped at 11:44 per CRS direction and restored to service approx. 16 minutes later after the submarine was successfully removed from the SFP.

At the time this event occurred, there were 164 spent fuel assemblies transferred from the Rx Vessel into the SFP, requiring both trains of Pool Cooling in service (with one train of SDC available) to satisfy U1C11 Shutdown Risk Assessment Requirements for SRP Decay Heat Removal. The individual operating the submarine failed to consult with the control room staff prior to placing the submarine in the Spent Fuel Pool. Clear guidance existed in the sensitive issues manual regarding management expectations for activities in the Spent Fuel Pool.

CRDR 2704269: On April 23, 2004, a Mechanical Maintenance worker sustained a laceration to the back of his left hand when he was struck by a 20 inch diameter end cap weighing about 75 pounds. Concerns with the method of supporting the end cap were raised, but the team chose to continue without taking further precautions.

CRDR 2717298: A plant worker modified a screw for the Hotwell Level Low-Low switch for the B Main Feedwater pump. The screw was longer than the original screw and had to be modified to fit by cutting to the appropriate length. The screw was not cut short enough, and it extended through the cardboard insulation behind the switch terminal board and contacted the metal backing plate resulting in a ground. The technician failed to consider the consequences of a potential ground and a less than adequate retest failed to surface the problem.

Other Issues

Procedures

Procedure use and adherence is a symptom of a larger human performance problem at Palo Verde. Recent station initiatives to deal with the procedure use and adherence issue can be seen as a stop-gap measure, basically attempting to stop a negative trend, until more global corrective actions for the underlying human performance issue(s) are defined and developed.

This is *not* meant to imply that the corrective actions relating to procedures initially assigned by this CRDR should be abandoned. It is fundamentally important to follow through with those actions, not only to address the procedure issues, but also to send a clear message to site personnel of management's intent to respond appropriately to concerns identified by individuals during the recent procedure training classes (i.e., NGH35 - Procedure Use & Adherence for PVNGS Personnel). The training class is one of the actions identified from the initial evaluation. As such, these actions have been incorporated into the corrective actions section of this investigation.

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A review of the report initially issued in response to this CRDR identified three common causes associated with procedure concerns. The report was thorough though specific in its review of procedure issues and thus requires no further review by this team into causes related to procedure concerns. The report is attached to SWMS, and details the analysis conducted. The report identifies three main causes to the procedures as follows:

1. Cognitive decisions were made to not follow procedures. Users rationalized decisions to depart from procedural direction. The expectation to 'stop when unsure' was not a consistent behavior.
2. Critical activities are being performed without consistently consulting written guidance. (e.g., workers relying on skill-of-the-craft or believing they know the procedure and therefore do not need to consult it) Criteria for determination and designation of level-of-use are not well understood or applied.
3. Non-conservative decisions were due to inadequate procedural guidance and/or poor anticipation of system and human interaction during procedure and document development.

These three causes essentially align with the common causes identified during the Stream Analysis. Specifically, lack of procedure use and adherence is seen to be enabled by the lack of reinforcement of the expectations and standards for procedures. This is supported by the increased population of CRDRs used to validate the Stream Analysis which included all human errors associated with 'documents not followed correctly' dating back to January 2003. The stream analyses from both efforts support the conclusion that effective corrective actions developed to address the three common drivers from this investigation should reduce the errors associated with procedure adherence and adequacy.

The team determined two additional actions were required to fully document the ongoing efforts of the original common cause investigation: [CRAI's 2830460 Pri-3, CRAI 2830538 Pri-4]

Contractor/Vendor Performance (Individuals that are not permanent PVNGS employees)

The CRDR trend information defines Contractor/Vendor performance as any issue that reflects less than desirable contractor/vendor performance. Included are issues such as not meeting schedule, poor safety performance, poor human performance, poor workmanship, cost overruns and less than expected results.

The significance of contractor/vendor related issues was recognized as a common theme in the 46 CRDRs reviewed during the stream analysis. These contractor/vendor events included the dropped snubber link plate, the dropped resin trap end cap, an unauthorized high radiation area (HRA) entry, the burning of two welders while working on the Feedwater Turbine casing, a 100 ton lattice boom crane tipping over, and the tipping over of a scissor lift.

Specifics:

- 2781982 Scissor lift injury
- 2780336 Inadvertent energizing 480 V close call
- 2764549 Inadvertent opening of relays on the Westwing 2 line
- 2760702 Crane tip over incident
- 2704269 Resin trap end cap injury
- 2699943 Isopropyl alcohol flash fire
- 2696454 S/G Bay HRA Violation
- 2639721 Polar Crane movement of hydraulic snubber

CRDR 2780273 Page 264 of 294

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Most of these relate to the following major causes identified during the stream analysis:

- Management has not set clear standards and expectations.
- Management does not reinforce standards and expectations.

The nine Condition Reports above cut across organizations (Maintenance, Refuel, TDS, etc.) Poor decision-making is inherent in several of them as well. For example, decisions to proceed with the resin trap work push the limits of the lattice boom crane, and move the polar crane with a bound load were non-conservative in nature and resulted in a potential for injury and equipment damage.

Contract Services needs to review the Human Performance events (above) for common cause(s) and refer to INPO AP-930, *Supplemental Personnel Process Description*, for site wide applicability. CRDR 2830201 was initiated to document Contract Services' review for common cause(s).

Security

The category of Security, defined as any condition involving plant security, including access authorization, control of ACADs, doors, keys, Licensee Designated Vehicles, visitors, hardware, lighting, tailgating, etc., was reviewed to determine if human errors in Security align with the causes identified during the Stream Analysis.
Of the 778 CRDRs reviewed during the team's binning process, 71 were related to Security. This observation was discussed with NAD. The 2nd Quarter 2005 NAD Trend Report states, "The trend for Security for 12 months reflects a slight increase in human performance issues, and ... the last 6 months of data reflects improvement".

NAD is currently tracking Security Human Performance as a potential item for the Significant Quality Issues List.

Normalization of Deviancy

Workers at Palo Verde have adopted a tolerance for defective equipment performance and maintenance conditions. This normalization of deviancy was a common theme discovered in many of the significant CRDRS from the Stream Analysis. Examples include:

- CRDR 2599869: PC valves would not remain closed due to configuration of remote operator.
- CRDR 2639721: the brake on the auxiliary hook on the polar crane required a work –around by the crane operator which was not communicated to the Bechtel personnel.
- CRDR 2714986: an electrician did not have adequate electrical prints for troubleshooting CD-1000.
- CRDR 2714269: adequate rigging not available to prevent resin trap end cap from injuring mechanic.
- CRDR 2721635: inability to maintain NPSH to run charging pumps on gravity feed line-up while BAMP running.
- CRDR 2776236: repeated letdown problems during shutdown to repair NANS06 contributed to need to secure charging pumps which required stopping the RCPs.
- CRDR 2784381: non functional door handle on pick-up resulted in partial finger amputation.

CRDR 2826487 was generated and specifies to conduct a survey to determine what long standing issues are currently impacting site performance. It recommends a determination of the aggregate impact of the issues with results provided to the plant manager for prioritization and resolution.

CRDR 2780273 Page 265 of 294

ATTACHMENT 7

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PALO VERDE

CRDR NUMBER: **2780286, REV. 1**

CROSSCUTTING ISSUE WITH PROBLEM IDENTIFICATION AND RESOLUTION

EVENT DATE: MARCH 2, 2005

INVESTIGATION TEAM

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Significant Root Cause Investigation Report

CRDR NUMBER HERE: 2780286

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Table of Contents

EXECUTIVE SUMMARY 3
BACKGROUND 4
DESCRIPTION OF PROCESS OR ACTIVITY 4
DESCRIPTION OF EVENT, FAILURE, OR CONDITION 5
SAFETY SIGNIFICANCE 8
CONCLUSIONS 10
OTHER ISSUES 13
OPERATING EXPERIENCE SUMMARY 16
CORRECTIVE ACTIONS 19
SEQUENCE OF EVENTS 26
TRANSPORTABILITY 27
MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE 28
REVISION HISTORY 28
ROOT CAUSE INVESTIGATION TECHNIQUE 28
LIST OF DOCUMENTS REVIEWED 30
LIST OF PEOPLE CONTACTED 30
LIST OF ATTACHMENTS 31

Notice: This is a Significant Condition Report Disposition Request (CRDR) root cause investigation report prepared in accordance with applicable Palo Verde Nuclear Generating Station procedures. It is a self-critical evaluation of events, activities, and processes intended to fully understand and correct a significant condition adverse to quality per 10CFR50, Appendix B. The consequences of the significant adverse condition, if any, are described in the report. Unless otherwise stated, PVNGS was at all times operated safely and in compliance with its operating licenses.

CRDR 2780286 Page 307 of 488

CONFIDENTIAL

EXECUTIVE SUMMARY

On March 2, 2005, the NRC distributed its Annual Assessment Letter of the Palo Verde Nuclear Generating Station. Within the letter, the NRC stated, "The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area." The Problem Identification and Resolution (PI&R) crosscutting issue is an adverse reflection of the overall effectiveness of the on-site corrective action programs (CAP); Condition Reporting/Disposition Requests (CRDRs), Work Control and Warehouse Deficiency Notification (WDN). The purpose of this CRDR investigation is to determine the cause of the substantive cross-cutting issue with Problem Identification and Resolution (PI&R) at Palo Verde. Successful resolution of this PI&R crosscutting issue will resolve the NRC issue and improve site performance.

The team utilized a technique referred to as Possibilities Analysis, which is a hybrid of two root cause techniques; 1) Change Analysis and 2) Failure Modes and Effects Analysis. The team was able to provide input to the Change Analysis technique from two perspectives. First, the team had extensive on-site experience to assess historical CAP differences. Second, they were able to compare Palo Verde's program to effective programs at four other nuclear facilities through benchmarking. The Failure Mode and Effects Analysis technique was used to graphically portray contributing possibilities, results, and potential resolutions, also known as considerations. Patterns with the considerations led the team to the identification of the Direct, Root and Contributing Causes.

The Direct Cause of the PI&R crosscutting issue is a culture that does not value the corrective action program. The staff did not effectively use the corrective action program as a means for continuous improvement and were not held accountable for effective problem resolution.

The Root Cause of the PI&R crosscutting issue is management behaviors. The weak PI&R culture is attributed to management behaviors that did not hold themselves and others to high standards relative to the Corrective Action Program.

Of the management behaviors that could cause the PI&R crosscutting issue, six were identified as contributing causes:

- The staff did not effectively use the Corrective Action Program because management 1) *Lacked a Continuous Improvement Culture*, 2) *Displayed Weak CAP Ownership* and 3) *Failed to Address the Staff's Frustration with the CAP.*
- High standards for problem resolution were not fully anchored within the Palo Verde staff because there was a 4) *Lack of a Clear Vision* and 5) *Mismatches in Management Style.*
- The management team missed opportunities to identify and correct the degrading PI&R culture because there was a 6) *Lack of Effective Mentoring and Coaching* in leader development.

Five other contributors to the PI&R crosscutting issue were identified that contributed to a weak CAP culture.

- *Lack of Effective Training* impacted site awareness and implementation of the CAP.
- *Multiple CAP Reporting Documents* adversely impacted initiation and screening.
- *SWMS*[1] *CRDR Process Frustration* caused people to seek solutions outside of the CAP.
- *CRDR Process Doesn't Encourage Ownership,* which results in weak commitments to issue resolution.
- *Ineffective Metrics* have misguided management oversight and staff priorities.

Corrective Actions to address the management behaviors and process issues that contributed to the PI&R crosscutting issue are addressed within this report.

[1] SWMS is an acronym for Station Work Management System.

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BACKGROUND

On March 2, 2005, the NRC distributed its Annual Assessment Letter - Palo Verde Nuclear Generating Station. The NRC stated, "The adverse trend in problem identification and resolution issues indicates that you have not effectively addressed the underlying causes associated with this substantive crosscutting area." Out of the 56 non-cited green violations, the NRC characterized 18 of the violations as a Problem Identification & Resolution (PI&R) issues. Palo Verde has grouped these as follows:

- 4 dealt with failure to adequately identify problems
- 7 dealt with failure to adequately evaluate conditions
- 7 dealt with failure to adequately establish corrective actions

This CRDR (2780286) was initiated on March 3, 2005 and a charter was drafted to perform a common cause evaluation on the same date. A team of three people was assigned to the common cause evaluation, which was completed on April 27, 2005 and closed.

On June 1, 2005, this CRDR was re-opened at management discretion as a part of a Self-Assessment in preparation of an NRC 95002 Inspection Procedure scheduled for September of 2005. On June 23, 2005, the CRDR was classified as Significant.

The Significant CRDR investigation team defined the problem statement based upon the following:

- NRC Annual Report of Palo Verde's 2004 performance
- Initial evaluation of Adverse CRDR 2780286

The purpose of this CRDR investigation is to determine the cause of the substantive cross-cutting issue with Problem Identification and Resolution at Palo Verde. Successful resolution of this PI&R crosscutting issue will improve site performance.

DESCRIPTION OF PROCESS OR ACTIVITY

Palo Verde corrective action is designed as a business process. It is based on the requirements of 10 CFR 50 Appendix B. Specifically, it utilizes two criteria in determination of nuclear applicability: (1) Adverse, which addresses nonconforming items (equipment, procedures or processes) and (2) Significant, conditions which are sufficiently severe as to require additional evaluation to prevent recurrence. A third criterion includes problems and issues that are not nuclear related; these are issues that challenge personnel safety, cost, or business effectiveness.

There are four programs that make up Palo Verde's Corrective Action Program: Condition Reporting / Disposition Request (CRDR), Work Control, Warehouse Deficiency Notices (WDNs) and Vendor Corrective Action Reports (VCARs). Adverse or degraded/nonconforming conditions may be addressed by any of the four lower tier corrective action programs. However, significant conditions, as defined in the Condition Reporting procedure, are required to be addressed as a CRDR.

These corrective action programs are relied upon to identify and correct identified deficiencies. Identification of a substantive crosscutting issue with Problem Identification and Resolution by the NRC communicates a significant concern with the effectiveness of on-site corrective action programs.

The scope of this report will address the Condition Report / Disposition Request, Work Control and Warehouse Deficiency Notices. The Vendor Corrective Action Reports were omitted from this report because their content is not directly reflective of on-site use of Corrective Action Programs.

DESCRIPTION OF EVENT, FAILURE, OR CONDITION

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During the 2004 calendar year, the NRC identified 56 green non-cited violations. The number of these violations is significant because of the high number relative to industry performance and it represents a step increase relative to Palo Verde performance in prior years. The NRC determined that several of these non-cited violations were related to weaknesses with PI&R.

Additional examples of PI&R issues were identified during the course of this investigation. As a part of the Possibilities Analysis, objective information was obtained to support Possibilities and subsequent Results. Some of this information is presented in the following sections.

Plant documents provided several indications of potential problems with the corrective action program.

- Quarterly Palo Verde trend reports have identified "human performance" as an issue starting in 2002. However, attempts to resolve the issue were not effective. Eventually, the Nuclear Regulatory Commission characterized the human performance problem as a substantive crosscutting issue.
- Operating Experience and Review CRDR backlogs have increased.
- Various elements of the corrective action program have been identified on the Nuclear Assurance Top Ten list for many years. While nuclear safety and production issues are addressed, other issues, such as eye wash stations, air washers, liquid radwaste systems, languish.
- The team found instances of transferring issues between the work order and CRDR processes without resolving the problem (e.g., CRDR 2783983 & 2407009)
- Past Palo Verde Business Plans contained objectives that were not fully achieved and were superseded by new objectives.
- Based on external feedback, CRDR 2780273, Human Performance Crosscutting issue was reopened after the initial adverse CRDR evaluation was complete. The subsequent evaluation was categorized as significant.
- Based on external feedback, the evaluation of the PI&R crosscutting issue (this CRDR) was reopened as a significant CRDR evaluation. The initial adverse CRDR evaluation had been completed.
- The discovery of the dry RAS pipe (CRDR 2726509) was originally assigned a significant CRDR classification. The CRDR was reopened for additional evaluation after being rejected.
- The on-site response to the CRDR 2729600 was reopened after completing the evaluation. The original evaluation was completed as a significant CRDR classification. This investigation has been reopened for revision following oversight from the on-site 95002 self-assessment team.
- CRDR 2789716 was initiated approximately five months after the NRC identified a weakness with the 50.59 process, relating to the RAS piping and a procedure change that was not screened for a 50.59. The condition was not recognized as being a valid deficiency until the NRC assigned a $50,000 civil penalty. The CRDR was not initiated because it was believed that an adverse condition did not exist.
- A self-assessment was completed on SOER 2002-04, Davis-Besse Event in May 2003. Of the equipment deficiencies identified in the assessment, 40% remain unresolved.
- Warehouse Deficiency Notice #2039792 is currently open and was initiated on 4/13/1992. This WDN is approximately 4900 days old.
- CRDR 2632229 was issued on 8/23/03 to document an adverse trend in Human Performance events that may result in a crosscutting issue. This CRDR was not effectively resolved.
- Work Mech. 2800334 was issued on 5/17/05 to document a LPSI pump seal failure that resulted in the pump being declared inoperable. CRDR 2800779 was not issued for Reportability and Maintenance Rule evaluations until the next day, contrary to the procedure.

Various reports have been recently issued, which identified weaknesses that further substantiate the PI&R finding.

[REDACTED]

- In March 2005, a Supervisory Effectiveness Self-assessment was conducted. Supervisory interviews during the assessment identified that:
  - management practices are ineffective,
  - supervisory input is typically not welcome,
  - management acts as though everything is a priority,
  - the Business Plan is meaningless, and
  - there are no site-wide expectations.
- In March 2005, the Supervisory Effectiveness Self-assessment noted that "mentoring by leaders is still not anchored as part of the culture at Palo Verde. The assessment team found some leaders who do not understand what mentoring is while others see no value in it."

[REDACTED]

- In March 2005, the Root Cause Expert Panel 2004 Significant Investigation Summary Report (Self-assessment) identified the need for improvements with:
  - timeliness of charters, interim reports and investigations,
  - the use of interim reports,
  - leadership pushback on investigations, and

CRDR 2780286 Page 311 of 488

CONFIDENTIAL

- organizational causes.

- In March 2005, the Root Cause Expert Panel 2004 Significant Investigation Summary Report (Self-assessment) also attributed weak Significant CRDR evaluations to:
  - other pressing priorities which have detracted ~~the members from spending sufficient time~~ on the issue,
  - inadequate guidance from management in breaking down barriers to success, and
  - a large influx of Significant CRDRs during 2004.

- In 2005, the Equipment Reliability Self-Assessment / Significant CRDR 2719208 Evaluation identified the staff is not taking an aggressive stance with respect to incorrect materials being issued to the field. The report found the staff was inclined to treat the incorrect material issued to the field as in process work, rather than a challenge to quality.

- In 2003, a Corrective Action Audit revealed a lack of ownership for degraded non-conforming conditions.

- The performance indicators for WDN Backlog have been Red since January 2005 (entire span of available data). These are not tracked and monitored at the Senior Management level.

- The low level of accessibility and visibility of the WDN process reduces the stations ability to identify and resolve issues in a timely manner. The absence of a published backlog report and lack of active oversight allows WDNs to remain open for extended periods of time. In some cases, the actions already taken are sufficient and minimal effort would be required to provide a final disposition. The use of a separate database to track WDNs negatively impacts the ability to track and trend for declining performance. It also inhibits the ability to associate related documents, complicating the ability to assess quality and completeness of WDNs.

The following is a summary of comments made during interviews with site personnel to acquire first hand opinions from a cross-section of the staff. While the comments varied, the team has categorized them into the following themes:

- There are varying degrees of frustration with Nuclear Assurance review of CRDRs.
- Station Work Management System (SWMS) is not user-friendly.
- Work scheduling methods are rigid, making it difficult to get some work done.
- Human performance tools are seen as an impediment because of excessive or inappropriate use.
- Some frontline personnel do not understand the business plan.
- CAP is viewed negatively; it does not produce positive results. CRDRs are generally viewed as a "necessary evil" and not as a way to fix problems.
- Some first line supervision feels they do not have the authority to make decisions that directly impact their organization (i.e., sign qualification cards, authorize overtime and assign work outside the schedule).
- Condition Report Action Items are occasionally written to satisfy Nuclear Assurance as opposed to fixing the problem.
- CRDRs drive workload and there are not adequate resources to deal with the backlog.

Plant events and conditions that illustrate or provide insight to the PI&R weaknesses are as follows:

- CRDR initiation is not evenly distributed. During the past 18 months, 4% of people with site access badges initiated 67% of the CRDRs, 21% of the people initiated the remaining 33% of the CRDRs and 75% of people did not initiate any CRDRs.
- CRDRs became less visible over the course of time by shifting from purple folders to a computerized SWMS inbox.

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- In the year 2003, Palo Verde's best performance with Corrective Maintenance backlog was achieved (492), yet none of the backlog goals were met because of an aggressive goal (345). The next year, the actual performance degraded to (668 actual) and the goal more than doubled to 800. Therefore, 2004 was reported as a successful year when performance actually degraded.
- Since 1994, the leadership history of Nuclear Regulatory Affairs (NRA) and the Nuclear Assurance Department (NAD) has not shown the same level of management stability that was present in Operations, Maintenance and Engineering.
- Some promotions to the Senior Management level have occurred without the benefit of a targeted development plan that included mentoring and coaching the individual for the position to which the leader is being assigned.
- The senior management team is heavily weighted with Operations experience. During recent organizational changes, senior management strengths were redistributed such that they did not align with the organization they were leading.
- Oversight (NAD and self-assessments) failed to identify PI&R as a significant weakness prior to NRC.
- During our investigation, we identified to a senior manager a procedure requirement for a self-assessment under their direction was not satisfied; a CRDR was required to document weaknesses and associated corrective actions. When identified, the team was initially told that "things were being fixed" and CRDRs were not needed.
- During our investigation, a Site Expectations and Standards booklet was issued without establishing problem identification and resolution attributes.
- CRDRs are not integrated into daily activities and discussed at the same level of detail as plant technical issues.
- Management relied on the number of overdue CRDR evaluations and closures as a primary indicator of program health.
- A walkdown conducted by a self-assessment team (95002) noted "... a general reluctance of site personnel to generate corrective action documents (CRDRs) when questions were raised during the document review phase of the system walk down preparations. For example, the team identified possible procedural deficiencies, calculation questions, UFSAR discrepancies, and possible LER and CRDR issues."

The team's benchmarking of industry best practice plants revealed:

- Strong ownership of the corrective action program by all levels of the organization.
- As a result of line ownership, Quality Assurance was able to focus on program oversight.
- Senior manager's calendars were found to have more open time and their time was rarely double booked.

SAFETY SIGNIFICANCE

This root cause evaluation did not address a specific plant event or condition. Therefore, no Licensee Event Report or NRC notification is required.

While there is no specific condition under investigation, the team appreciates the significance of the substantive crosscutting Problem Identification and Resolution issue identified by the NRC. Crosscutting issues are assigned by the NRC when they have identified a pattern of poor performance across a range of organizations, programs or their cornerstone areas. The current Corrective Action Program does not consistently result in the identification and adequate correction of plant deficiencies prior to regulatory interaction. A PI&R substantive crosscutting issue represents a significant weakness in our Quality Assurance Program and a negative impact on nuclear safety.

CRDR 2780286 Page 313 of 488

This investigation will determine the cause of this organizational weakness to reduce the likelihood of future events and improve nuclear safety at Palo Verde.

CONFIDENTIAL

CRDR 2780286 Page 314 of 488

CONFIDENTIAL

CONCLUSIONS

The purpose of this investigation is to determine the cause of the Problem Identification and Resolution crosscutting issue identified by the NRC in their annual report of Palo Verde's 2004 performance. The investigation team identified a direct cause, root cause and contributing causes.

Direct Cause:

As used in root cause terminology, a direct cause is the action or condition that occurred immediately prior to the event or failure. In this case, the event or failure is the PI&R substantive crosscutting issue.

Organizational Culture Caused the PI&R Crosscutting Issue

The Problem Identification and Resolution substantive crosscutting issue was directly caused by people, frontline and management that did not effectively use the corrective action program. Additionally, there was a lack of accountability to high standards for themselves and others relative to the corrective action program.

Root Cause:

A root cause is a causal factor to the event, which if it had not existed, the event or failure would not have occurred.

Management Behaviors Created the Culture

The root cause of a workforce that does not effectively use the corrective action program to improve performance is the result of ineffective management behaviors, such as accepting substandard performance regarding the Corrective Action Program. Regardless of intent, management behaviors have devalued the CAP and diminished people's ability to effectively use the corrective action program as the cornerstone to a continuous improvement culture.

In perspective, the team did not see the direct cause or the root cause as obvious. The team reached their conclusion after extensive analysis and discussion. Inappropriate management behaviors were not inherently obvious. The team concluded that management behaviors changed over a long period of time, which made it difficult to detect cultural issues before the CAP degraded to the point of becoming a PI&R crosscutting issue.

Contributing Causes:

In root cause terminology, a contributing cause is a causal factor that increased the likelihood or severity of the event. As the term is used in this investigation (non-event), contributing causes are specific management behaviors that either reduced the staff's accountability to or value of the CAP.

As these contributing causes are identified, it should be noted that these causes are not absolute. Management can point to activities that were intended to improve performance. However, it is the team's conclusion that the Corrective Action Program was adversely affected by management behaviors when the positive and negative factors are summed. This report will focus on the negative behaviors so they can be addressed.

#1: Continuous Improvement Culture Not Anchored

Management behaviors have not promoted a continuous improvement culture, which is essential to the resolution of the Problem Identification and Resolution substantive crosscutting issue. A pattern of additional program controls and higher management approvals has emerged that has caused the staff's accountability to be aligned to the controls and approvals rather than addressing issues. Therefore, management behaviors need to change to actively demonstrate acceptance of problem identification and support the staff in solving their issues.

CRDR 2780286 Page 315 of 488

CONFIDENTIAL

2: Corrective Action Program Not Owned by Site Management Team

Given the three on-site Corrective Action Programs; Condition Report/Disposition Request, Warehouse Deficiency Notices and Work Control, the team found the ownership of these programs was siloed. In the absence of shared ownership, issue resolution has become ineffective.

Based on interviews with plant staff (frontline and management), there is a perception that the CRDR program is owned by the Nuclear Assurance Department (Quality Assurance) and they are responsible for the success of the Condition Reporting Program. Site wide ownership for the program is weak as evidenced by repeat occurrences of ineffective and untimely problem resolution. This weakness was compensated by a few senior management team members that were advocates for the Condition Reporting program. The NAD ownership mentality became a liability when the few senior management advocates for the Condition Reporting Program left or were moved in the organization.

The second case of ownership problems impacting CAP effectiveness is the Work Control Program. A conflict in performance indicator goals exists between Maintenance, Planning and Scheduling. These conflicts have resulted in rigid boundaries of "area" ownership, adding complexity and diminishing focus on maintaining plant equipment. The team has identified cases where equipment issues lack ownership and have gone unresolved as a result of corrective action documents becoming lost in the department transfers. This has contributed to declining performance trends in system health and equipment reliability.

The third element of the Corrective Action Program is the WDN program. The Equipment Reliability self-assessment indicated that this program suffers from low visibility. There have been instances where materials incorrectly issued to the field are returned to the warehouse and treated as "in-process" work, not documented on a WDN or CRDR, resulting in a missed opportunity to improve accuracy and quality of spare parts. Additionally, WDNs are not resolved in a timely manner and are not visible at the Senior Management level.

Vendor Corrective Action Reports, the fourth element of the CAP, were not assessed. VCARs are used to document deficiencies of the supplier QA programs. A review of the NRC reports and cross-cutting issue evaluations at other stations did not indicate that VCARs are applicable to the NRC identified cross-cutting issue at PVNGS.

3: Failed to Address Personnel's Frustration with the Corrective Action Program

Field interviews reveal dissatisfaction with the CRDR, Work Control and Modification processes, which have been acknowledged in the PV Business Plan as needing simplification. The site management team has not adequately addressed the staff's frustration with the CRDR and Work Control processes. If people are frustrated with the program and think that it will not resolve their concern, they may not be inclined to document problems.

4: Station Vision Is Not Globally Understood

As identified in various self-assessments, the site management team has not motivated the staff with a site-wide vision. Instead, visions have become compartmentalized. Site-wide accountability to a successful corrective action program requires clarity of vision, which has not been achieved.

5: Mismatched Management Styles

Some senior manager's management styles were rigid in nature as opposed to the Situational Leadership™ principles, which require constant assessment of subordinates so the appropriate mix of direction, support and coaching can be utilized for their development. Directive management behaviors towards an individual in need of delegation may result in compliance, conflict or apathy, none of which promote high standards. On the other hand, an individual that is in need of direction may be free to establish their own lower standard if management relies upon a delegating style. Some of the management team has not been able to achieve high standards for the corrective action program because of their inflexible management style. A successful corrective action program is dependent on staff that is accountable to problem resolution, which is nurtured by an appropriate management style.

CRDR 2780286 Page 316 of 488

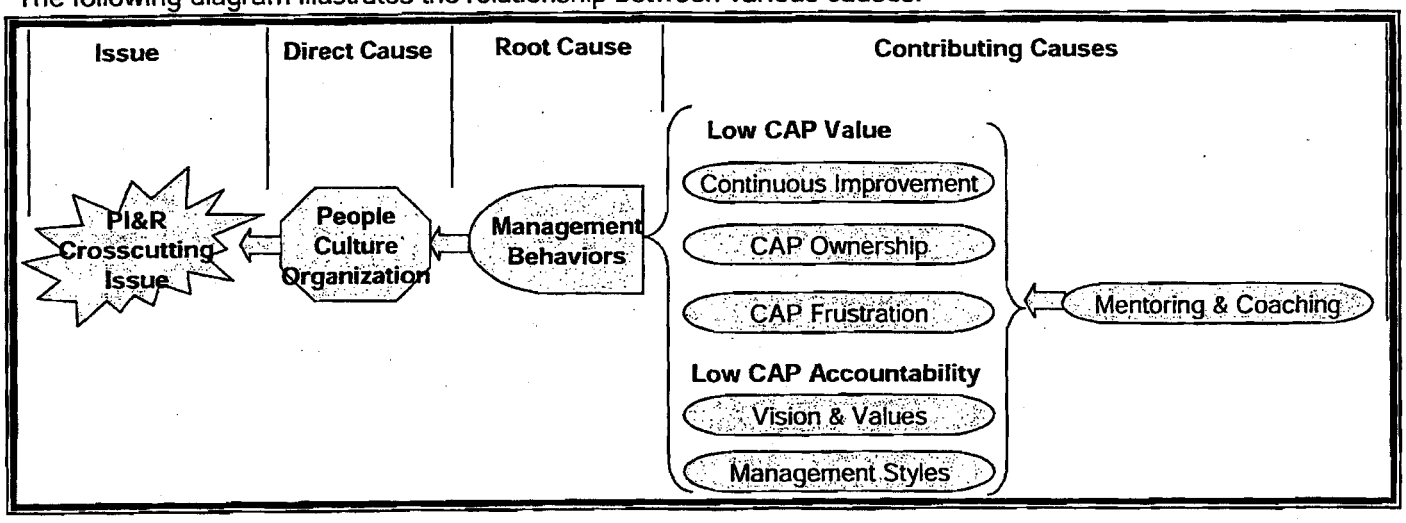
CONFIDENTIAL

6: Lack of Mentoring and Coaching in Leadership Development

The team believes there is a correlation with the PI&R crosscutting issue and the lack of effective mentoring and coaching during leadership development. Leadership development programs have not enabled the senior management staff to create a culture that embraces the Corrective ~~Action Program as the key to continuous~~ improvement. The nuclear work experience of the current senior leadership team was plotted and revealed minimal depth in the regulatory and quality assurance areas prior to reaching senior management level. The lack of mentoring and coaching, combined with the absence of oversight experience, contributed to a degraded CAP culture.

Relationship of Causes

The following diagram illustrates the relationship between various causes.



CRDR 2780286 Page 317 of 488

OTHER ISSUES

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This section will present other issues that were identified during the course of this investigation that contributed to the PI&R crosscutting issue. These other issues are related to processes, not behaviors.

 # 1: Lack of Effective Training

As a part of the Possibilities Analysis, numerous opportunities to improve CAP effectiveness via training were identified as considerations. Training needs were identified for the following groups:

- All station personnel (Problem Identification/Document Initiation)
- CRDR Evaluators (Rigor in Evaluations)
- Leaders (CRDR effectiveness, Problem Resolution)

Some station personnel are not fully aware of their responsibilities to the CAP:

- Relationship of CAP documents to other isolated databases
- Initiation requirements for CAP documents
- Appropriate Control Room notifications

Some Significant CRDR evaluations and Equipment Root Cause of Failure Analysis investigations lack the necessary rigor to allow effective resolution of the issue. There is insufficient information to determine the quality of Apparent Cause evaluations, since this is a new category. The quality of these investigations may suffer from a lack of investigator/evaluator knowledge.

Leaders may not always support CAP programs because they are not fully aware of their responsibilities.

 # 2: Multiple CAP Processes

The PI&R crosscutting issue may be impacted by multiple CAP processes. Examples were found where the appropriate CAP document had not been initiated. For example, a Work Mech. may have been initiated to repair a pump; however, a CRDR was not initiated to address issues like Operability Determinations, Reportability requirements and Maintenance Rule impacts. Therefore, the integration of corrective action programs is in need of improvement.

The Work Management Review Board (WMRB) and CRDR Review Committees (CRC) activities are similar and integration improvements may be achieved by combining these functions. Additionally, WDNs should be initiated in SWMS, to facilitate a review by the WMRB/CRC.

Multiple reporting systems may inhibit proper document initiation because of confusion. The lack of a single reporting system may adversely impact long-term CAP improvements.

 # 3: SWMS CRDR Process Frustration

Plant staff appears to be frustrated with SWMS as a means to implement the CRDR process. Problem identification may suffer as a result of this frustration; people are reluctant to report problems in a system that is viewed as difficult to use with little perceived benefit. The types of aggravations that impact users are as follows:

- Infrequent, casual users, of SWMS are not able to efficiently navigate within SWMS.
- Reporting issues can be confusing (e.g., people need to determine which document to use)
- It is difficult to determine if the degraded condition has already been documented.
- Sometimes leader reviews are untimely.
- Sometimes Control Room notifications are untimely.
- CRDR classifications are sometimes delayed, which compromises timely response needed for Significant Investigations or Equipment Root Cause of Failure Analysis.
- Time is lost when CRDRs are routed for Special Evaluations (e.g., reportability, Maintenance Rule Functional Failure determinations), prior to final evaluation.
- There appears to be inconsistent levels of rigor applied to evaluations, which is especially frustrating for low risk, review or adverse conditions.
- Inconsistencies with evaluations and associated cause codes reduce trending effectiveness.
- It is difficult to determine if proven solutions to the degraded condition have already been developed.

CRDR 2780286 Page 318 of 488

CONFIDENTIAL

The CRDR process is hindered by a staff frustration with SWMS.

 # 4: CRDR Process Doesn't Encourage Ownership

In addition to the management behaviors that promoted weak ownership of the CAP, there are opportunities with the CRDR program to improve ownership and promote involvement that are not being utilized. The CRDR process can be improved to address the following ownership issues:

- Sometimes the interface between the initiator and the evaluator is not occurring before, during and after the evaluation.
- The overall effectiveness of the CRDR process from the perspective of the initiator may not always be understood; there is no feedback loop.
- The recipient of a CRDR evaluation or CRAI may not receive advance notice of the routing.
- Sometimes the interface between lower-tier reporting systems (e.g., management tracking per Level 1s, management observations per PILOT, and minor radiation protection infractions per RP) and the CAP is not fully understood; inappropriate reporting of quality issues may occur.
- CRDR Corrective Action Owners are not held accountable because CAP metrics only focus on overdue CRDR owners.
- CRDR evaluations sometimes languish without a champion to get things done.
- Propensity to create procedure revisions or formal training as a corrective action to isolated occurrences reduces ownership and accountability.
- CRDRs are not integrated into daily work processes, in contrast to Work Mechs.

 # 5: Ineffective Metrics

PI&R crosscutting issues may have occurred as a result of Metrics that focus on "old things that aren't done." Metrics do not exist to bring attention to the behaviors that are necessary for success. The current metrics are inadequate causing the following problems:

- Motivate people to close records, not resolve issues.
- Motivate people to work on old work, not new work.
- Metrics are not visible to the people that can make a difference.
- Metrics do not rollup in a consistent manner, from frontline to station goals.
- Metrics do not lineup with objectives; effective metrics motivate to achieve desired result.
- Metrics are fragmented, presenting a partial picture of overall performance.
- Performance indicators are sometimes subjective based and lack a statistical basis.
- Targets may be changed so frequently that performance consistency is difficult to assess.
- Metrics do not compensate or balance for organizational responsibility.

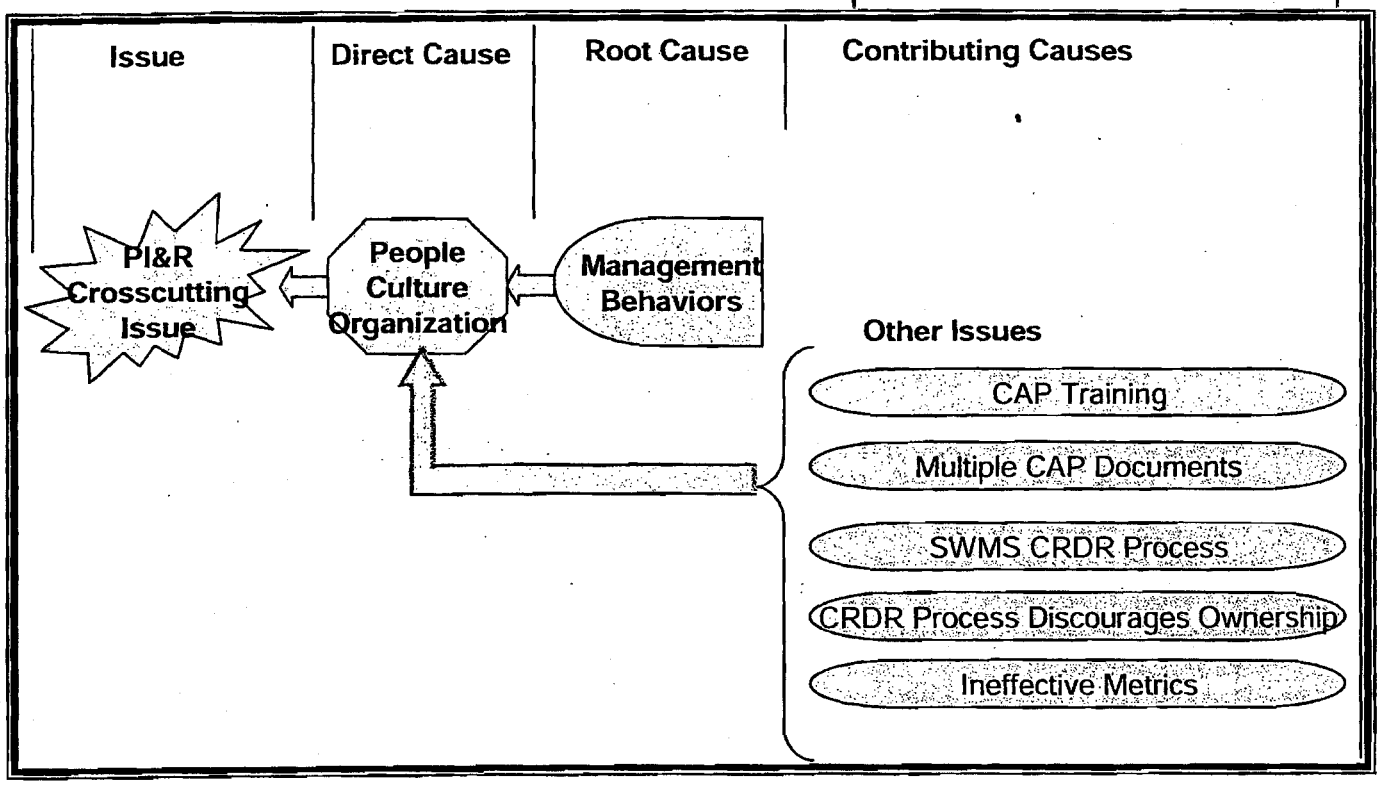
Metrics have not been consistently applied to drive organizational improvements.

CRDR 2780286 Page 319 of 488

CONFIDENTIAL

Relationship of Causes

The following diagram illustrates the relationship between the Other Issues and the Direct Cause.



CRDR 2780286 Page 320 of 488

OPERATING EXPERIENCE SUMMARY

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Industry Operating Experience

This CRDR does not address a specific event. It addresses an issue that is applicable to how PVNGS identifies and corrects deficiencies. The NRC has identified PI&R (Problem Identification and Resolution) crosscutting issues at 15 different power plants (including PVNGS). The reports from four plants (Diablo Canyon, Susquehanna, Cooper, and Point Beach) were reviewed for common themes. The root cause findings were utilized where available. In other cases, the contributing causes were interpreted from the action plans that were implemented as a result of their PI&R crosscutting issue.

The Diablo Canyon Evaluation for the PI&R crosscutting issue identified:

- Need to improve Senior management oversight
- Need to clarify CAP expectations to line organizations
- Need to develop line ownership and accountability of the CAP
- Need to ensure consistent and effective CAP implementation
- Need to improve operability assessments
- Need to improve organizational identification of adverse trends and common causes
- Need to improve metrics to monitor the health of the CAP

The Susquehanna evaluation for the PI&R crosscutting issue identified:

- Need to increase management oversight and ownership of the CAP
- Need to increase PI&R assessment and monitoring of the CAP
- Need to improve metrics to monitor the health of the CAP
- Need to improve technical rigor of evaluations

The Cooper evaluation for the PI&R crosscutting issue identified:

- Need to improve site wide behaviors that contributed to an inability to identify and resolve problems.
- Need to improve the quality of evaluations to prevent repeat occurrences
- Need to allocate resources that are impacting overall CAP performance
- Need to better utilize trending within the organization
- Need CAP to drive performance improvement
- Need to change attitudes towards CAP timeliness requirements
- Need to ensure all CAP programs are well understood

The Point Beach evaluation for the PI&R crosscutting issue identified:

- Need to improve the understanding of the CAP
- Need to improve CAP screening process for significant items
- Need to improve Corrective Action Review Board (CARB) oversight of the CAP
- Need to improve metrics to monitor the health of the CAP
- Need to improve implementation of the CAP by organizations.

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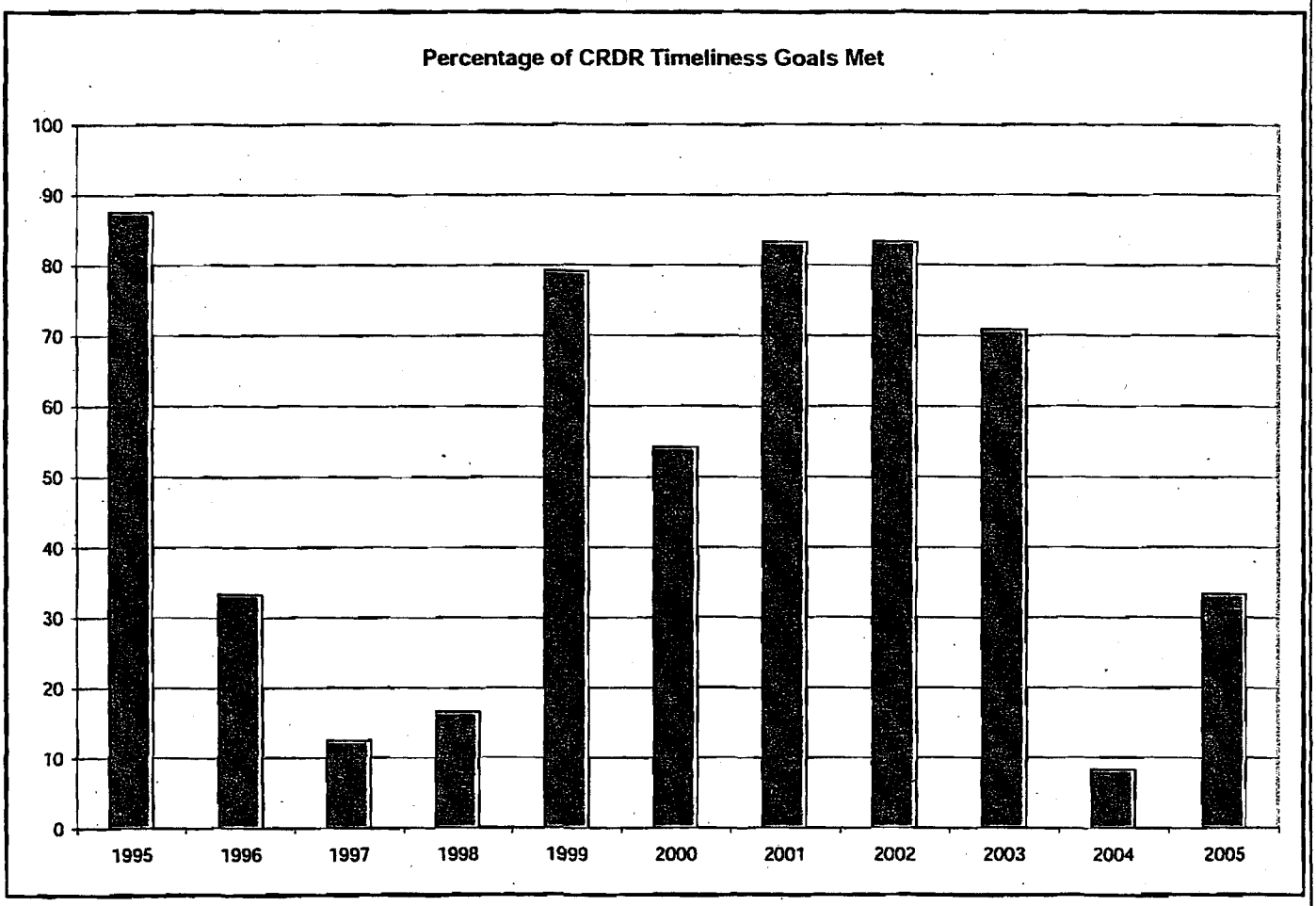
PVNGS Operating Experience

Historical evaluation of Palo Verde performance with CRDR timeliness was difficult because of various metrics and goals that were applied over the years. Therefore, the team decided to simply compare site-wide CRDR performance to goals that existed at the time. The following graph was prepared based on the percentage of monthly goals satisfied during the year. There are 24 data points per year, consisting of 12 evaluation goals and 12 closure goals. Hence, a higher percentage of goals met is a favorable condition.

The histogram reveals that Palo Verde has never excelled with CRDR performance. The best performances were 80% to 87.5% of the evaluations and closures being completed on time. Two periods of poor performance to the goal are visible. The first period of poor performance occurred in 1996 to 1998 and the second period began in 2004, immediately after the steam generator replacement project.



In March of 2004, a Corrective Action Audit was performed. At this point in time, the site was starting to miss CRDR timeliness goals (see above). The Corrective Action Audit report did not identify a significant problem with problem identification. The audit stated "In general, CRDRs were generated by plant personnel when required. Issues discovered during the audit where CRDRs were not written were considered infrequent when compared to the total number of records reviewed." This report identified:

- A need to improve the quality of non-ERCFA (Equipment Root Cause of Failure Analysis) significant investigations.
- A need to ensure NRC non-cited violation CRDRs effectiveness is evaluated.
- CRDR and evaluation ageing is a concern.
- Need for timely generation of CRDRs by the Performance Improvement Department (PID) when conditions are identified.

CRDR 2780286 Page 322 of 488

CONFIDENTIAL

Operating Experience Review Conclusions

Common themes from the industry experience with PI&R crosscutting issues are:

- a lack of management involvement,
- a lack of understanding of the CAP by the line organizations,
- inappropriate metrics to monitor the health of the CAP, and
- trending of the CAP is not utilized by line organizations to improve performance.

Industry behaviors (culture) of the line organizations were directly mentioned or could be inferred as a contributor to the ineffectiveness of the CAP at these facilities in all four of the reviewed reports.

The team benchmarked the Cooper, Byron, South Texas, and H.B. Robinson stations. Common themes noted at these plants are the overall site acceptance of the corrective action program as a part of day to day business and the active management involvement in the programs.

Internally, the increasing numbers of CRDR evaluations and corrective actions indicate Palo Verde has been unable to correct the underlying issue driving the decline of the CAP.

The team compared the findings of this report to Industry Operation Experience and concluded the proposed corrective actions are consistent with peer plants that have also received a PI&R crosscutting issue from the NRC.

CRDR 2780286 Page 323 of 488

CORRECTIVE ACTIONS

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Completed or in place (e.g., immediate, remedial, or interim)		
Cause	***Action Description***	***Completed***
DC 1	CRDR documents have been initiated to address each of the examples used by the NRC in the annual assessment of Palo Verde to illustrate a PI&R crosscutting issue. Appendix K provides the applicable CRDR number(s) for each event.	Various
RC 1 **CC 1** **CC 2** **CC 3** **OI 1**	Nuclear Assurance has developed and provided CRDR 101Training for Leaders, (Course # AMX-75). This course will help bring attention to the CRDR weaknesses. (CRAI 2789773)	In progress (Scheduled to be completed by 09/30/05)
RC 1 **CC 4** **OI 1** **OI 4**	Leader Meetings were held on various management topics in the Energy Information Center, including NRC crosscutting issues, 95002 topics and other related subjects. The PI&R Leader Meeting was held on June 30, 2005.	6/30/05
Rev. 0	Group briefings for regulatory interface protocol were provided at a Leaders meeting. Additionally, similar briefings were provided to all hands meetings, with voluntary attendance. (CRDR 2780286, Rev. 0, CRAI 2792295)	5/31/05
Rev. 0 **CC 2** **CC 3**	Apparent cause evaluations (ACE) were developed and incorporated into the Condition Reporting procedure. Guidance has been provided to determine when the ACE CRDR will be applied. (Rev. 0, CRAI 2792296)	6/9/05
CC 2	CRDR 2823676 was initiated to address an untimely Part 21 evaluation documented on a WDN.	08/19/05
CC 2	CRDR 2810138 was initiated to address two self-assessments that did not have CRDRs issued to document the assessment findings that required further action.	06/21/05
OI 2	Executive management decided that it is not currently necessary to fully integrate the Work Control, CRDR and WDN processes into a single reporting document.	08/30/05

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Required to Prevent Recurrence (CRDR Priority 2)

Cause	CRAI #	Action Description	Owner	Date Due
RC 1 CC 1 CC 2	2828389	Improve site-wide ownership and anchor a continuous improvement culture by changing routine 0900 senior management meeting agendas to discuss developing issues that have been identified in CAP. Success will be determined by survey(s) of senior management.	Carnes	11/30/05
RC 1 CC 1 CC 2 CC 6	2828390	Establish a management tool to evaluate individuals within the management team for their support of CAP and the concept of continuous improvement. Where necessary, appropriate training, coaching or other actions should be employed to ensure alignment. The objective is to improve organizational accountability by anchoring responsibility for the corrective action program within the current management team, from the top down, and employees in the succession plan. Success will be based on improved performance as measured by CAP metrics.	Overbeck	1/15/06
RC 1 CC 4	2828391	Revise Palo Verde Business Plan to reflect the Corrective Action Process as a strategic focus area.	Overbeck	12/15/05
RC 1 OI 5	2828392	Develop improved CAP metrics that reflect the overall health of and level of participation in the CRDR Program. The metrics should consider the following: • Manage to CRDR due dates (versus end of month overdue CRDRs) • Degree of participation • Leaders review effectiveness • Allow work units to roll up their contribution toward site-wide metrics • Holding action holders accountable	Sontag	11/15/05

RC 1
CC 1
CC 2
CC 3
OI 1
OI 2
OI 4
OI 5
	2828393	Develop an organization that reports to executive management outside of Nuclear Assurance to monitor all CAP processes. This group would be responsible for the following:
		• Owning the CRDR, CM/DFWO (degraded and nonconforming conditions), and WDN processes.
		• Establish training requirements for CAP coordinators
		• Establish training requirements for site personnel
		• Establish trending process using CAP coordinators
		• Establish appropriate metrics to monitor program health, such as:
		  • Self Identified, Identified by Others, Self Revealing
		  • Equipment Issues, Human Performance, Program Effectiveness
		  • CARB feedback scores
		  • Number of recurring issues, Trends, Effectiveness, Cognitive Trending
		  • Type of Corrective Action (Coaching, Procedure Change, Training, CM, MOD, PM)
		
		This group will establish a common committee to ensure newly initiated CAP documents are appropriately categorized and documented in the correct process.
		
		Note: The action item is to establish the organization by 12/15/05. The group will need to establish Pri-3 Corrective Actions to implement specific details.
			Overbeck	12/15/05

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Corrective Actions (CRDR Priority 3)

Cause	CRAI #	Action Description	Owner	Date Due
CC 1 CC 2 CC 3 OI 4	2828395	Develop a job description for CAP coordinators within the major organizations. The role of the CAP coordinator will be to monitor progress, make appropriate assignments and facilitate resolution of issues. This corrective action will establish at least one CAP Coordinator for Operations, Maintenance, Engineering, Work Control, Emergency Services and Nuclear Fuels. CAP Coordinator duties should include: • consulting on Control Room notification decisions • trending of department performance • monitoring department low level issues • monitoring department long standing issues • interface with other CAP coordinators	Schiavone	11/30/05
CC 1 CC 2 CC 3 OI 4	2828397	Fill the CAP coordinator position for Operations	Radtke	1/15/06
CC 1 CC 2 CC 3 OI 4	2828399	Fill the CAP coordinator position for Maintenance.	Shea	1/15/06
CC 1 CC 2 CC 3 OI 4	2828400	Fill the CAP coordinator position for Work Control.	Borchert	1/15/06
CC 1 CC 2 CC 3 OI 4	2828401	Fill the CAP coordinator position for Engineering.	Churchman	1/15/06
CC 1 CC 2 CC 3 OI 4	2828402	Fill the CAP coordinator position for Emergency Services.	Hesser	1/15/06
CC 1 CC 2 CC 3 OI 4	2828403	Fill the CAP coordinator position for Nuclear Fuels.	Chapin	1/15/06
CC 2 CC 4	2828404	Revise the Palo Verde Expectations and Standards booklet to include the corrective action program.	Riedel	12/30/05
CC 2 CC 3 OI 4	2828405	Revise the Corrective Action Review Board charter and associated processes to improve timeliness of management review, include the appropriate level of management membership and address recent CRDR process changes with the ACE CRDR and the team of Significant CRDR evaluators. The purpose is to assure high quality of Significant CRDRs and ensure Management involvement.	Carnes	10/15/05

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Cause	CRAI #	Action Description	Owner	Date Due
CC 1 OI 2 OI 3 OI 4	2828406	Revise the CRDR program / procedure(s) to reflect corrective actions.	Sontag	1/30/06
CC 1 OI 2 OI 3 OI 4	2828407	Revise the Work Control program / procedure(s) to reflect corrective actions.	Zell	1/30/06
CC 1 OI 2 OI 3 OI 4	2828409	Revise the Warehouse Deficiency Notification procedure(s) to reflect corrective actions.	Van Dop	1/30/06
CC 6	2830195	Develop a plan to improve leadership development and succession planning as necessary to assure CAP ownership is an integral part of the Palo Verde management standard. This plan will be developed and implemented as part of CRDR 2822493 (Apparent Cause Evaluation).	Overbeck	12/30/05
CC 5	2830198	Develop a plan to address impact of management style on culture as necessary to assure CAP ownership is an integral part of the Palo Verde management standard. This plan will be developed and implemented as part of CRDR 2822493 (Apparent Cause Evaluation).	Overbeck	12/30/05
CC 1 CC 2 OI 4	2828410	Coordinate a one-time review of CRDRs that are currently greater than 180 days old (evaluation complete and CRDR is open pending corrective action implementation) to address the following: • Has the condition degraded further, if so, are interim actions required? • Are there alternative solutions not considered in the original evaluation? • Statement of risk associated with the delay • Revised action plan schedule for completion • Repeat or similar occurrences This review may be limited to work groups with CRDRs that have potential safety risk.	Sontag	11/30/05
CC 1 CC 2 OI 4	2828411	Revise the CRDR process to require an evaluation of CRDRs greater than 180 days old. The review should include the following: • Has the condition degraded further, if so, are interim actions required? • Are there alternative solutions not considered in the original evaluation? • Statement of risk associated with the delay • Revised action plan schedule for completion • Repeat or similar occurrences	Sontag	1/30/06
CC 1 CC 2	2828413	Improve the reporting capabilities for WDNs to allow increased visibility, accessibility and cross-organizational review. Develop sufficient reporting and distribution capabilities to provide reasonable assurance that related issues can be tracked and trended.	Glover	10/30/05
CC-1 CC-2	2828414	Perform a one-time review of WDNs that do not meet their timeliness goals to evaluate the risk of further delay.	Glover	11/30/05
CC-1 OI 3 OI 4	2828416	Revise Palo Verde oversight and audits methods to provide appropriate focus on CAP. Limit NAD inline review to Significant CRDRs evaluations. Assure that oversight activities assess effectiveness of CAP implementation site-wide. Provide NAD evaluators with training on CAP quality standards. This action includes a representative sample of Operating experience. Timeframe will be coordinated with the implementation of the new Performance Improvement Department.	Carnes	2/28/06
OI 5	2828417	Develop an overall CAP effectiveness Metric for the Monthly Trend Report.	Brandjes	10/30/05

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Cause	CRAI #	Action Description	Owner	Date Due
OI 5	2828418	Publish site performance to CAP effectiveness in the Monthly Trend Report.	Mellody	12/15/05

Other Actions (CRDR Priority 4)

CC 2 CC 3 OI 3	2828420	Develop a CRDR reporting/evaluation tool that promotes simplicity and consistency, similar to commonly used IRS income tax software, like "TurboTax." • Early closure by Leader • Find it, fix it, forget it • Clarification for initiation • Clarification for cause codes • Clarification extent of condition/ cause • Improve Timeliness • Consistency in evaluation • Promote Problem Identification initiation • Capture sense of urgency • Canned problem descriptions and resolutions.	Brandjes	3/31/06
OI 3	2828421	Integrate the new "Autonomy" software with CRDR and Work Mech initiation to find similar problems.	Webb, R	6/30/06
OI 3	2828422	Improve SWMS interface, beyond the turbo CRDR Add a visible computer inbox flag to alert people to CAP documents received.	Webb, R	2/28/06
CC 3 OI 3 OI 4	2828423	Expand the existing CRDR Involvement function to include a "customer satisfaction survey" at the conclusion of the CRDR. Check for level of involvement in the; • Understanding the problem description, • Scope of the evaluation, • Suggested disposition, • Final disposition, and • Corrective actions. These surveys should be looked at on the local level and rolled up to a site-wide performance.	Webb, R	2/28/06
CC 1	2828424	Establish work group specific expectations for post-job de-briefings for the purpose of identifying deficiencies, lessons learned and possible improvements into the CAP and anchors the Questioning Attitude.	Smith, D	12/30/05
CC 1 CC 2	2828425	Place WDN process within SWMS for easier access and trending capabilities.	Glover	12/30/06
OI 3	2828426	Revise SWMS routing to facilitate the following: • Multiple routing, e.g., concurrent special evaluations • Facilitate a rapid response to emergent issues • Allow people to attach documents without having the CRDR in their inbox (e.g., multiple groups working on a common problem)	Webb	2/28/06
OI 1	2828415	Review CBT training to verify annual GET is current and accurate.	Brandjes	1/30/06

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Effectiveness Review Actions (CRDR Priority 4)

	2831675	Perform an effectiveness review of the preventive actions taken. Success will be defined by the following: • Clearly defined and implemented standards for CAP ownership as necessary to assure accountability is incorporated in Palo Verde management practices • CAP improvement as demonstrated through metrics – there should be no areas shown to be a significant weakness (Red) and areas that require improvement (Yellow) should show an improving trend • The CAP coordinator position and new Performance Improvement Department (single CAP process owner) should be established and determined to be effectively implemented • Trending process should be implemented by the site CAP Coordinators The results of this assessment should be used to establish future self-assessment needs and standards for the site.	Overbeck	04/30/06
	2828393	Implemented as a Priority 2 Corrective Action: Develop a series of metrics that reports corrective action quality: • Self Identified, Identified by Others, Self Revealing • Equipment, HP, Program • CARB feedback scores • Reoccurrence, Trend, Effectiveness, Cognitive Trending • Type of Corrective Action (Coaching, Procedure Change, Training, CM, MOD, PM)	Overbeck	12/15/05
	2825667	CRDR 2726509 established the CRAI to perform an integrated assessment of HP, OE, PI&R and SSFIs for the next five years.	Carnes	12/31/10

Status of Revision 0 CRAIs

Revision 0 to this CRDR identified numerous corrective actions. The following actions are applicable to the findings in Revision 1 of the CRDR and will remain associated with this CRDR.

CRAI #	Action Description Priority 3	Owner	Due Date	Action Status
2789773	Provide Condition Report Disposition Request (CRDR) initiation and processing training to leaders. This training will focus on the leader's role and how they can efficiently use the corrective action process as a tool to improve performance.	Fred Riedel	12/31/06	Working
2787236 (CRDR 2780273)	Capture feedback items provided from training participants involved with CRAI 2759419 action. Evaluate comments that address culture, process issues, and implementation attributes that impact station processes. Improvement needs identified all the assigned suitable CRAIs for incorporation by the appropriate work group. Initiated CRAIs will be assigned to this CRDR. Training will track identified items and provide closure documentation for improvements identified and initiated CRAIs.	T. Gavigan	12/31/05	Working
2792295	Develop and implement targeted group briefings for regulatory interface protocol.	M. Carnes	8/26/05	Turnover
2792296	Develop and implement prioritization matrix tool for apparent cause evaluations (ACE). This matrix tool will be used during initial screening of condition reports.	M. Sontag	6/30/05	Closed
2792297	Increase accountability in managing corrective action backlog to improve timeliness of corrective actions. This will include managing milestoned actions.	Ed Dutton	8/26/05	Working

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CRAI #	Action Description Priority 4	Owner	Due Date	Action Status
2795737	Revise PVNGS Trending Subcategories associated with Problem Identification and Resolution to align with PI&R crosscutting aspects of identification, evaluation, and Corrective Action. This will permit more effective assessment of PI&R effectiveness.	Ed Dutton	5/6/05	Closed

The following Revision 0 CRAIs do not support the Revision 1 conclusions. Their current status is shown.

CRAI #	Action Description Priority 3	Owner	Due Date	Action Status
2792032 (CRDR 2780273)	Institute periodic procedure use and adherence reviews and PVNGS. Leaders will facilitate the activity and coordinate feedback to improve processes, procedures, and programs with a focus on human performance.	Fred Riedel	12/31/06	Turnover
2787230 (CRDR 2780273)	Revise 01PD-OAP01, The Administrative Control Program Document, Chapter 1 to clarify the scope of documents that come under the usage requirement rules.	Ed Dutton	5/13/05	Turnover
2787233 (CRDR 2780273)	Revise 01DP-0AP01, Procedure Process, to clarify usage expectations on documents used to implement work activities at Palo Verde, i.e. continuous use (step by step), reference use (refer to the document prior to task completion), information only (periodic review). Additionally, revise 01DP-0AP01 to improve rigor in the procedure development. Develop a mechanism that validates the human, equipment and process interface during the review process to ensure all required participants and processes are involved.	N. Henry	5/31/05	Turnover
2787234 (CRDR 2780273)	Develop and publish Palo Verde Standards and Expectations regarding documented use and adherence. Anchor philosophy of stopping to fix procedures.	Johnson	5/31/05	Turnover

CRAI #	Action Description Priority 4	Owner	Due Date	Action Status
2749419 (CRDR 2729600)	Reinforce expectations for procedure use. Emphasize "Back to Basics" procedure use and adherence, specifically, procedures associated with the CRDR,OD, and 50.59 processes. It is recommended that small groups of station personnel (similar to previous IIRP training) receive training on the events	T. Gavigan	12/31/05	Working
2792305 (CRDR 2780273)	Develop accountability and protocol expectations for Leadership that promote and encourage a positive culture change concerning procedure use and adherence by PVNGS personnel.	M. Shea	5/20/05	Turnover
2789780 (CRDR 2780273)	Monitor trend codes associated with procedure use and adherence, include procedure adequacy to determine if there is a reduction in the number of occurrences at the station. Provide this information to station management on a monthly basis.	Ed Dutton	12/31/05	Working
2789780 (CRDR 2780273)	Evaluate future NRC inspection reports to determine if the number of findings related to procedure use and adherence and procedure adequacy is decreasing.	Ed Dutton	12/31/05	Working

CRDR 2780286 Page 330 of 488

SEQUENCE OF EVENTS

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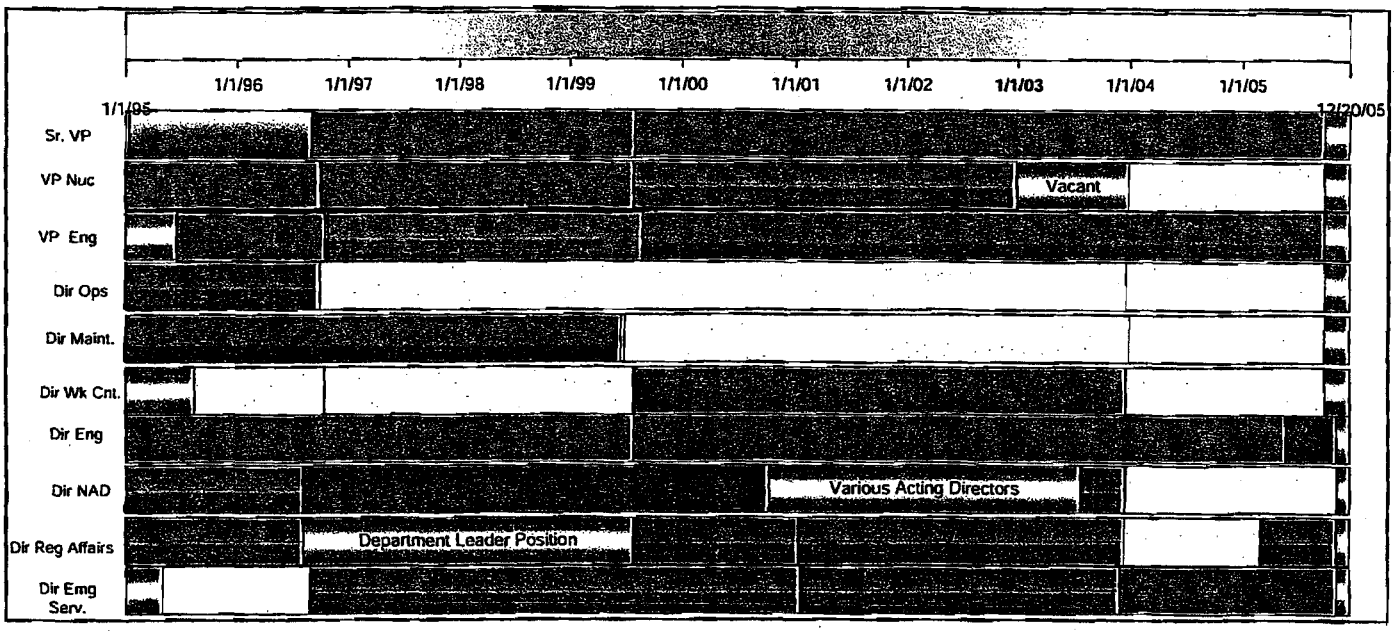
Timelines were constructed to gain insight to the potential causes of the NRC PI&R crosscutting issue. Senior management changes were of specific interest to the team because a crosscutting issue impacts multiple organizations. The team limited their timeline to the executive management and Directors of key organizations that are involved in the day-to-day operation of the plant; Operations, Maintenance, Work Control, Nuclear Assurance, Regulatory Affairs and Engineering. The dominant work experience was plotted on a timeline in the following chart. The chart is color coded based on background as follows:

- Operations – Yellow
- Engineering – Green
- Maintenance/Projects – Brown
- NAD/NRA – Pink
- Other – White
- No Director or Acting Director – Blue/White/Blue



The timeline reveals a decline in Nuclear Regulatory and Quality Assurance (Nuclear Assurance) experience in the senior management team over the past 8 years. Within the senior management team, there have been three to four leaders with regulatory or oversight experience until the beginning of 2004. There is currently one.

The timeline reveals a pattern with the leadership of the Nuclear Assurance Department (NAD) and Nuclear Regulatory Affairs (NRA) areas that suggests these functions were not valued, relative to other organizational functions. History shows the NAD/NRA functions were at times combined and other times split apart. There is a notable extended vacancy of the NAD Director position in 2001 and 2002. There have been more leadership changes in the NRA and NAD areas than any of the other key organizations. The NAD and NRA areas had two periods of extended senior management leadership vacancies.

The timeline also reveals a step increase in Operations experience within the senior management team at the beginning of 2004. Some of the new members of the senior management team with Operations experience had also acquired middle management experience in the Work Control areas. However, their roles in the Work Control organization were still weighted towards bringing an Operations perspective to Work Control, rather than acquiring maintenance experience, which is another common feeder group for Work Control.

A pattern with senior management leadership changes suggests prior work experience in the organization the senior manager is leading is not a critical attribute for leadership. At the Director level, only two of the current Directors acquired middle management experience in the organizations they now lead.

CRDR 2780286 Page 331 of 488

TRANSPORTABILITY

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Extent of Condition

There is a direct correlation between the Problem Identification and Resolution crosscutting issue and the overall health of Palo Verde's on-site Corrective Action Programs; Condition Reporting, Work Control and Warehouse Deficiency Notification. The performance of each of these corrective action programs is either already degraded or susceptible to degradation given the cultural weakness as a direct cause.

Condition Reporting

The team believes that all aspects of PI&R, identification, evaluation, and resolution, are currently impacting the Condition Reporting program. However, the team has identified our inability to effectively resolve issues as the fundamental cause of inconsistent use of the CRDR process. While there are numerous examples of issues resolved by CRDRs, there is a belief by some staff that CRDRs cannot be relied upon to effectively resolve issues.

If problem identification is essential to CRDR success, problems must be identified in order to address them and make improvement. However, there is far less direct management control of problem identification than issue resolution. Once the problem is documented, the problem can be managed. Problem identification is primarily dependent on site attitudes. Fancy slogans, frontline training or management speeches are not likely to convince people to effectively use the CRDR processes unless they believe in it. People must believe the rewards for initiating a CRDR is greater than the risk of not writing the document.

Currently, the staff perceives negative consequences for writing a CRDR document despite management encouragement to write them. The CRDRs are viewed as redundant and wasteful. Redundant activities are viewed as adding burden to an already overloaded staff. Wasteful activities are also frowned upon because of a site-wide acceptance of a cost conscious work environment and the need for budget adherence. On a positive note, people have not abandoned their efforts to fix things; they turned to resolve problems as "in process work" rather than write CRDRs. People are generally not ignoring problems, simply looking for alternative methods of effectively resolving issues.

Problem identification is addressed by improving the effectiveness of CRDR evaluations and closeout. People will naturally be more inclined to write CRDRs if they can see CRDRs as a means to get their issues effectively resolved in a timely manner.

Work Control

The team believes there is greater attention paid to the Work Control than the Condition Reporting process. Therefore, the Work Control process was considered to be in better shape than Condition Reporting. However, the future of Work Control may degrade because of similarities with Condition Reporting.

The team has noted that maintenance backlogs have increased, as occurred with CRDRs. The backlogs provide an overall indication of ineffective resolution. Given the previous discussion about the relationship that problem resolution has on problem identification, people may be less likely to initiate Work Mechs in the future if the maintenance backlog continues to grow. Field interviews conducted by the team revealed staff frustrations that are also likely to discourage initiation of Work Mechs. For example, people described frustration with Work Mechs that had been cancelled, with no action taken.

Warehouse Deficiency Notification

The team was uncertain about the overall health of the Warehouse Deficiency Notification process because it is virtually unnoticed by most of the plant staff. The WDN process may also be susceptible to PI&R problems. An Equipment Reliability Self-Assessment reported people tend to simply return incorrect material to the warehouse, rather than write a corrective action document, such as a WDN or CRDR.

Summary

The extent of condition extends into the CRDR, Work Control and WDN processes, which are included in the scope of this investigation.

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Extent of Cause

The root cause of a workforce that does not effectively use the corrective action program to improve performance is the result of inadequate management behaviors regarding the Corrective Action Program. A similar management related cause has been identified by a team evaluating the Human Performance NRC crosscutting issue (CRDR 2780273). Management behaviors (e.g., culture, organizational weaknesses, etc.) are also a contributing cause to Emergency Core Cooling System sump suction piping issue (CRDR 2726509, Rev. 1). CRDR 2822493 was issued to evaluate the extent of the management behavior issues on station culture.

MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE

There were no specific events evaluated within this CRDR. Therefore, no evaluation for Maintenance Rule Functional Failures and impact to performance criteria was necessary.

REVISION HISTORY

Revision 1 of this CRDR evaluation was issued as a complete rewrite. The original CRDR evaluation was prepared as an Adverse CRDR evaluation and was a common cause analysis of the NRC finding. On June 23, 2005, this CRDR was classified as a Significant CRDR. Therefore, the content of this report will not align with the initial evaluation. The corrective actions established in the original CRDR evaluation were reviewed based on the findings of this investigation and their current status is presented in Corrective Actions section of this report.

ROOT CAUSE INVESTIGATION TECHNIQUE

Investigation of a crosscutting issue with Problem Identification and Resolution (PI&R) presents some unique challenges. By its very nature, a crosscutting issue is a diverse problem as many organizations and programs are affected. Typical root cause investigation tools are oriented towards investigation of a single event, even though the causes may be diverse.

Our team considered using a technique known as Streaming Analysis, such as is being done with another team that is investigating a crosscutting issue with Human Performance at Palo Verde. Streaming Analysis relies upon documented events as the evidence to assess various contributors, from which further analysis yields organizational weaknesses. Unfortunately, Problem Identification is fundamentally a failure to document issues into one of the Corrective Action Programs. Therefore, there is insufficient evidence to explore the underlying reasons for not wanting to document a problem, other than the few examples identified by the NRC or by onsite staff.

The team developed a technique to investigate the Problem Identification and Resolution crosscutting issue and determining causes. The technique is a hybrid of two root cause techniques: 1) Change Analysis and 2) Failure Modes and Effects Analysis. The technique was developed to illustrate the openness and high degree of rigor that was put into the analysis. The team referred to the technique as a Possibilities Analysis.

The Possibilities Analysis method was used because of two factors that are related. The first factor was thoroughness. The second factor was openness. The need for an open analysis method became evident when we tried to determine what the options were to find the cause and the fix of our problem. Risk is increased when the cause is defined too narrowly. A narrowly defined cause results in a limited group of potential corrective actions. Therefore, the Possibilities Analysis method is good for this type of situation because it encourages asking more questions, digging deeper, and expanding further. It captures the thought processes and details along the way. Then, the thought processes can be tracked back to the original question. The end result of Possibilities Analysis is a list of potential actions that may fix the problem or contribute to the fix of the problem. The investigation flows naturally to potential conclusions rather than to a predetermined (perhaps biased) conclusion.

As the Possibilities Analysis thought generation process is examined, it provides an abundance of interconnected facts that can be assessed and prioritized. Root causes and contributing causes become visible as details are compiled. The Possibilities Analysis method allows open ended examination of a situation. This

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openness provides useful, possibly useful, and non-useful suggestions and ideas. The information is then examined in a separate step to quantify valid data for the investigation. These valid and non-valid data points help crystallize what is actually happening as they are sorted and evaluated. Often an open ended problem is not solved by a single solution. Many strategically selected solutions may be needed to address the problem from multiple directions.

Change analysis is a fundamental aspect of the Possibilities Analysis. Change Analysis compares at least two situations looking for differences that might produce greater insight to the problem. The team was able to use change analysis in two different ways. First, each of the team members had over 15 years of Palo Verde experience and was able to describe internal differences over time. Second, the team had benefited from four benchmarking trips, which enabled them to describe how Palo Verde differed from other plants with successful corrective action programs.

Possibilities analysis begins with a fundamental question and is then followed with a series of probing questions. In response to each question, the team would brainstorm possibilities. From these possibilities, the resulting impact on the organizations ability to identify and resolve issues was characterized. A drill down (a.k.a., another question with possibilities and results), was created if the results left the team pondering another question. In essence, the team used the drill down feature as a "why staircase" to seek greater understanding of the different facets of the PI&R crosscutting issue.

After the Questions, Possibilities and Results were recorded, the team continued to brainstorm potential corrective actions, which are identified as considerations. A graphical representation of the Possibilities Analysis process appears in Figure 1. The actual analysis appears in Appendix A. The Possibilities Analysis resembles a Failure Modes & Effects Analysis when the questions are linked together.

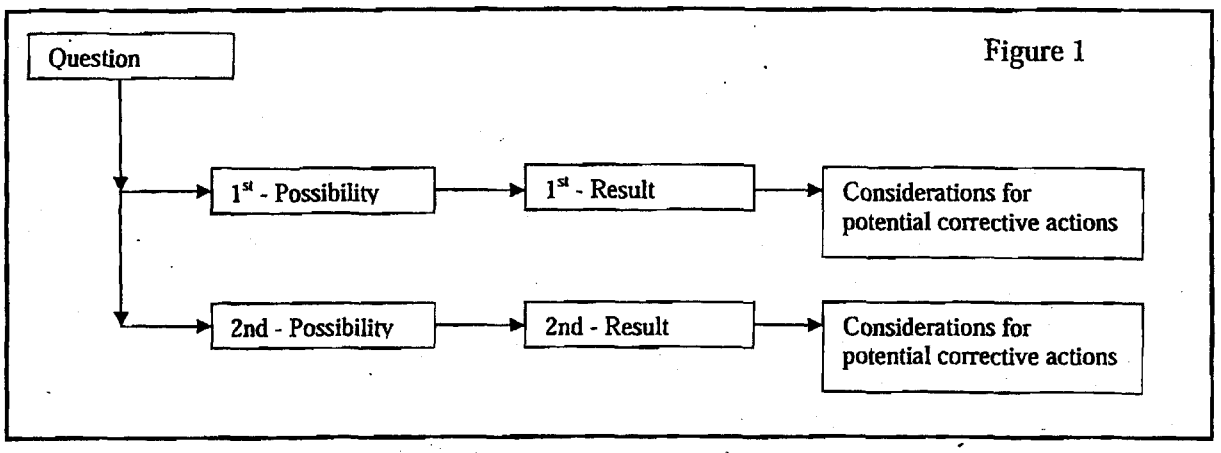

Figure 1

The primary criterion for the Possibilities Analysis is that similar level of detail or granularity should exist between the various possibilities that appear on any one chart. If the brainstorming produced a possibility that was too detailed or more global relative to the other possibilities on the graph, the possibility was elevated to a more fundamental question if global in nature or placed in a drill down for detailed possibilities.

The brainstorming results were captured with software called "Corporate Modeler." The software was designed as a process mapping tool. This allowed the team to quickly capture ideas graphically as they brainstormed the Possibilities Analysis.

As a result of the Possibilities Analysis, the team identified 17 key questions, 89 possible answers to the questions and 108 resulting impacts to the PI&R crosscutting issue. The team identified considerations (possible corrective actions) that could be implemented in response to the resulting impact. These considerations ranged from "do nothing" to large scale initiatives.

The considerations were prioritized, which enabled the team to look for patterns in the higher priority considerations. The analysis of the considerations ultimately led the team to the identification of the direct cause, root cause and contributing causes.

CRDR 2780286 Page 334 of 488

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LIST OF DOCUMENTS REVIEWED

- 90DP-0IP10, *Condition Reporting*
- 70DP-0EE01, *Equipment Root Cause of Failure Analysis*
- 70DP-0MR01, *Maintenance Rule*
- PVNGS Root Cause Investigation Manual
- 2005 Supervisory Effectiveness Self-assessment
- Performance Improvement Department Quarterly Trend Reports
- Monthly Trend Reports
- 2003 and 2004 Corrective Action Audits
- 2005 Nuclear Safety Culture Assessment (Synergy Survey)
- 2004 INPO Mid-Cycle Self-Assessment
- Operations Assessment of Corrective Actions contained in CRDR 2729600 (Mr. Notaro)
- 2005 Root Cause Expert Panel Self-Assessment
- 2002-2005 Palo Verde Business Plans
- 2001-2002 System Team Effective Profiling
- PI&R Crosscutting Issue Evaluations performed by Diablo Canyon
- PI&R Crosscutting Issue Evaluations performed by Cooper
- PI&R Crosscutting Issue Evaluations performed by Susquehanna
- PI&R Crosscutting Issue Evaluations performed by Point Beach
- INPO Principles for Effective Self-Assessment and Corrective Action Program (12/99)
- 2003 INPO Plant Evaluation of Palo Verde
- NRC Inspection Procedure 71152, Identification and Resolution of Problems
- NRC Inspection Procedure 95001, Inspection for One or Two White Inputs in a Strategic Performance Area
- NRC Inspection Procedure 95002, Inspection for One Degraded Cornerstone or any Three White Inputs in a Strategic Performance Area
- Palo Verde Expectations and Standards Preventing Events
- CRDR 2567077, SOER 2-4 Evaluation; Supporting Database, including Classroom Comments

Books:

- Group Dynamics, Donelson Forsyth
- The GE Work-Out, Ulrich, Kerr, and Ashkenas
- Bringing out the Best in People, Aubrey Daniels
- The Toyota Way, Jeffrey Liker
- Organizational Behavior, Fred Luthans
- Organizational Behavior, Griffin and Moorhead
- Human Behavior at Work: Organizational Behavior, Davis and Newstrom
- Personnel Management and Human Resources, Werther and Davis
- Management – A Problem Solving Process, Krietner
- Columbia Accident Investigation Board: Volume One, NASA
- Confronting Reality, Bossidy and Charan
- Execution: The Discipline of Getting Things Done, Bossidy and Charan

LIST OF PEOPLE CONTACTED

A cross-section of Palo Verde executives, leaders and frontline and were contacted. Additional input was provided by external consultants and personnel from H.B. Robinson, Byron Station, South Texas Project and Cooper Nuclear Station. Specific names are not provided because this investigation was an organizational assessment, not related to a specific event.

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LIST OF ATTACHMENTS

(Included as SWMS Attached Media)
Attachment – PI&R Charter (for Significant CRDR)
Attachment J– Possibilities Analysis
Attachment K – Analysis Verification Matrix

CRDR 2780286 Page 336 of 488

ATTACHMENT 8

PALO VERDE

CRDR NUMBER: 2775015

SWITCHGEAR CUBICLE 1ENANS06J ELECTRICAL FAULT

EVENT DATE: FEBRUARY 6, 2005

Approval Signatures

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Reason: I am approving this document
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Senior Manager: Carl Churchman
(Sign & date)

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Significant Root Cause Investigation Report

2775015: SWITCHGEAR CUBICLE 1ENANS06J ELECTRICAL FAULT

Table of Contents

EXECUTIVE SUMMARY 3
DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY 4
DESCRIPTION OF EVENT, FAILURE, OR CONDITION 4
FAILURE MODE INVESTIGATION 5
SAFETY SIGNIFICANCE 5
CONCLUSIONS (DIRECT CAUSE OR FAILURE MECHANISM, ROOT, AND CONTRIBUTING CAUSES) 6
OTHER ISSUES 8
OPERATING EXPERIENCE SUMMARY 9
CORRECTIVE ACTIONS 10
SEQUENCE OF EVENTS 11
TRANSPORTABILITY 12
MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE 13
ROOT CAUSE ANALYSIS METHODS 13
LIST OF DOCUMENTS REVIEWED 15
LIST OF PEOPLE CONTACTED 15
LIST OF ATTACHMENTS 15
LIST OF APPENDICES 15
APPENDIX A – Investigation Charter 16
APPENDIX B: Hazard- Barrier-Target Analysis 17
APPENDIX C – Events & Causal Factors Chart 18
APPENDIX D – Fault Tree Analysis 19

Notice: This is a significant Condition Report Disposition Request (CRDR) root cause investigation report prepared in accordance with applicable Palo Verde Nuclear Generating Station procedures. It is a self-critical evaluation of events, activities, and processes intended to fully understand and correct a significant condition adverse to quality per 10CFR50, Appendix B. The consequences of the significant adverse condition are described in the report. Unless otherwise stated, PVNGS was at all times operated safely and in compliance with its operating licenses.

CONFIDENTIAL

CRDR 2775015 Page 36 of 110

EXECUTIVE SUMMARY

Digital fault recorder data show the failure in 1ENANS06 initiated as a 'C' phase to ground fault which evolved into a three phase fault which was terminated when circuit breaker 1ENANS06H opened. Review of the protective relaying indicates operation to open the circuit breaker were within the design settings. Inspection of circuit beaker cubicle 1ENANS06J has identified the fault originated from the 'C' phase bus side primary disconnect assembly (rosette) in a compartment above the circuit breaker. The electrical fault and resulting explosion completely decimated the bus side rosettes and upper portions of the primary circuit breaker bushings. There was minimal damage to a couple of bus bars (four per phase) and the through wall bus bar insulators to adjacent circuit breaker cubicle 1ENANS06K were damaged. The control wiring in the wireway crossing cubicle 'J' was destroyed by the explosion fire/heat; this damage resulted in the loss of 125 VDC control power in 1ENANS06.

The direct cause of the 1E-NAN-S06 power failure was an electrical fault in cubicle 'J' within the bus primary disconnect assembly (rosette) compartment above the circuit breaker. This electrical fault initiated as a 'C" phase to ground fault and transitioned to a three phase fault. The electrical fault was terminated by the normal bus feeder circuit breaker 1ENANS06H opening due to protective relaying which actuated within the design settings.

The root cause is INDETERMINATE due to extent of damage. Out of the potential root causes for the damaged PDA bottle, the most probable root cause based on evidence/facts is that the 'C' phase Primary Disconnect Assembly (PDA) porcelain bottle was damaged as a result of the 1992 electrical three phase fault in the rear of switchgear cubicle 1ENANS06J documented on CRDR 9-2-495. The possible PDA porcelain bottle damage that may have ensued finally exhibited in the electrical 'C' phase to ground fault that initiated the event experienced on February 6, 2005. No primary disconnect assembly porcelain failure was found by the Industry Operating Experience review. The probability of more primary disconnect assembly porcelain bottles being cracked at PVNGS is very, very low based on no failures of this type discovered by the IOE review. The corrective action to prevent recurrence is to clean and inspect 1ENANS02, 2ENANS01, 3ENANS02, 3ENANS04 and 3ENANS06 switchgear cubicle bus and line PDA bottle exteriors which have been exposed to the significant electromagnetic forces of phase to phase faults. These locations plus switchgears 1ENANS06, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05 and 2ENANS06 were identified by the PVNGS Operating Experience review. Switchgear 1ENANS06, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05 and 2ENANS06 bus and line PDAs have been cleaned and inspected; 1ENANS06 prior to reenergization and the Unit 2 switchgear during outage 2R12. No PDA bottle degradation was found.

A possible contributing cause to the event was the lack of inspection of the switchgear cubicle 1ENANS06J bus and line PDAs anytime following the 1992 electrical fault event (CRDR 9-2-495) that occurred in the rear of the cubicle. Corrective action to address this contributing cause is to revise switchgear PM Bases to include cleaning and inspection of switchgear bus and line PDA exteriors periodically. Since the root cause is indeterminate and no operating experience was discovered, switchgear PDA porcelain bottle exteriors which have not been inspected will be inspected during the next preventative maintenance switchgear cleaning and inspection.

The apparent cause of loss of the switchgear 125 VDC internal control power was the single daisy chain feed design of the feeder conductor through the switchgear cubicles in the wire channel. This GE design exists in all M26 & M36 switchgear in the industry. Design Change Request/Evaluation #2802420 has been initiated to evaluate a change to the 125 VDC control power cubicle feeder wires in Magnablast switchgear enclosures.

CONFIDENTIAL

CRDR 2775015 Page 37 of 110

DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY

Each PVNGS Unit is provided two off-site power circuits from the switchyard. These circuits normally supply the 4.16 KV safety busses EPBAS03 and EPBBS04 and during startup the non-1E load groups via circuit breakers ENANS03B and ENANS04B to 13.8 KV switchgear busses ENANS01 and ENANS02. Power is supplied via three 525/13.8 KV startup transformers (AENANX01/2/3), 13.8 KV outdoor switchgear busses (ENANS03/4/5/6) with respective circuit breakers, overhead lines, 13.8/4.16 KV Essential Safety Features (ESF) service transformers (ENBNX03/4) and non-segregated busses (ENBNA0).

DESCRIPTION OF EVENT, FAILURE, OR CONDITION

At 22:19 on 2/06/05, a 'B' Train LOP (Loss of Power) occurred in Unit 1 when an electrical fault within cubicle 1E-NAN-S06J resulted in the switchgear normal supply circuit breaker 1E-NAN-S06H tripping open on overcurrent. This condition resulted in de-energization of busses 1E-NAN-S06, 1E-NAN-S04, and 1E-PBB-S04. DG 'B' started and restored power to 1E-PBB-S04 within approximately seven seconds.
Additionally, the 125 VDC control power in 1ENANS06 was lost due to the explosion/fire which resulted in loss of protective relaying for startup transformer AENANX01.

CRDR 2775015 Page 38 of 110

CONFIDENTIAL

FAILURE MODE INVESTIGATION

Refer to section "Root Cause Analysis Method" for investigation of fault that occurred in switchgear cubicle 1ENANS06J. An Adverse ERCFA (ADVERCFA) evaluation is included below for the loss of 125 VDC control power which resulted in de-energization of protective relaying for startup transformer AENANX01.

The switchgear 125 VDC control power is distributed to each of the cubicles via wires routed through a wire way channel extending the length of the switchgear enclosure. Each cubicle is supplied from the main feeder wires via a taped tap wire connections. This GE design is typical in all M26 switchgear in the industry. Hence; any failure of the main feeder conductors results in at minimum a loss of 125 VDC control power in all downstream cubicles. In the case of this event, the 125 VDC power loss to the AENANX01 protective relaying was due to the fire/explosion damage of the feeder conductors in cubicle 1ENANS06J. Control power was lost to cubicles; A, B, C, D, E, F, G, H and K. The apparent cause of loss of the switchgear 125 VDC control power was the single daisy chain feed design of the feeder conductor through the switchgear cubicles in the wire channel. Design Change Request/Evaluation #2802420 has been initiated to evaluate a change to the 125 VDC control power cubicle feeder wires in Magnablast switchgear enclosures.

Additionally, it was identified during this investigation that CRDR 2776470 to Operations for evaluation of alarm timeliness revised procedures 41/2/3AL-1RK1B; however did not indicate the changes would preclude delay of mitigating action (TS LCO impacts) if a loss of switchgear ENANS05/6 125 VDC control power occurs again. An additional action has been issued and assigned to Operations Standards to resolve this issue.

SAFETY SIGNIFICANCE

The failure of bus 1E-NAN-S06 resulted in a loss of power to Unit 1 busses 1E-NAN-S04 and 1E-PBB-S04. Diesel generator 'B' started and restored power to PBB-S04 within approx. 7 seconds. The loss of bus 1E-NAN-S04 also negates Fast Bus Transfer (FBT) of bus 1E-NAN-S02 which results in an atypical unit trip or shutdown (loss of one Reactor Coolant Pump in each loop and two Circulating Water Pumps). Technical Specification LCO 3.8.1 Condition 'A' (72 hour action statement) was entered. Unit 1 commenced shutdown early morning 2/09/05.

Additionally, it was identified 2/9/05 that loss of the 125 VDC control power in 1ENANS06 resulted in loss of protective relaying for startup transformer AENANX01. Hence a failure of transformer AENANX01 concurrent with the loss of the protective relaying could cause a loss of the switchyard. CRDRs 2775972 and 2776470 were initiated and subsequently Technical Specification LCO 3.8.1 Condition 'C' (24 hour action statement) was entered.

LER 1-2005-001-00 (Attachment 'L') was issued for the February 6, 2005 electrical fault event in switchgear cubicle 1ENANS06J. As per the LER:

> ASSESSMENT OF SAFETY CONSEQUENCES:
>
> The event did not result in any challenges to the fission product barriers or result in the release of radioactive materials. Therefore, there were no adverse safety consequences or implications as a result of this event and the event did not adversely affect the safe operation of the plant or health and safety of the public.
>
> The condition would not have prevented the fulfillment of any safety function and did not result in a safety system functional failure as defined by 10CFR50.73(a)(2)(v).
>
> The event did not result in a transient more severe than those analyzed in the updated Final Safety Evaluation Report Chapters 6 and 15. The event did not have any nuclear safety consequences or personnel safety impact.

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CRDR 2775015 Page 39 of 110

CONCLUSIONS (DIRECT CAUSE OR FAILURE MECHANISM, ROOT, AND CONTRIBUTING CAUSES)

Direct Cause

The direct cause of the 1E-NAN-S06 power failure was an electrical fault in cubicle 'J' within the bus primary disconnect assembly (PDA) compartment above the circuit breaker. This electrical fault initiated as a 'C" phase to ground fault and transitioned to a three phase to ground fault. The electrical fault was terminated by the normal bus feeder circuit breaker 1ENANS06H opening due to protective relaying. The 'C' phase to ground fault initiated from the 'C' phase PDA internal cluster fingers through the porcelain bottle to the adjacent side and back sheet metal walls. In order for this to occur, the 'C' phase PDA porcelain bottle had to be damaged.

Supporting Facts

- Digital fault recorder data: "C" Phase to Ground Fault (approximately .9 seconds); Three Phase to Ground Fault (approximately 1.4 seconds).
- Door of switchgear cubicle 'J' blown open by the fault explosion.
- Fault/Explosion/Fire/Smoke damage extensive within 'J' cubicle.
- Cubicle condition in proximity the location of "C" phase bus PDA.
- Bus PDA porcelain bottles and connection to breaker primary stabs destroyed.
- Geometry of the bus compartment and the fault arc strike holes indicates 'C' phase fault initiation from the 'C' phase PDA internal cluster fingers through the porcelain bottle to the side and back sheet metal walls adjacent to the lower back right corner of the bus PDA compartment.

Root Cause # 1 (Most Probable)

The cause is declared INDETERMINATE due to destruction of the Primary Disconnect Assembly (PDA) 'C' phase porcelain bottle. Out of the potential root causes for the damaged PDA bottle, the most probable root cause based on evidence/facts is that the 'C' phase PDA porcelain bottle was damaged as a result of the 1992 electrical fault in the rear of switchgear cubicle 1ENANS06J (CRDR 9-2-495). The PDA porcelain bottle damage that may have ensued probably exhibited in the electrical 'C' phase to ground fault initiated on February 6, 2005. PVNGS corrective action to prevent recurrence is to inspect primary disconnect assembly porcelain bottles in switchgear cubicles where the switchgear bus has previously been exposed to three phase fault current.

Supporting Facts

- In 1992; a fault (CRDR 9-2-0495) occurred in the rear of switchgear cubicle 1ENANS06J. The fault magnitudes experienced would have been similar to the 2/6/2005 fault; however it was of a shorter duration since the fault was terminated by the 1ENANS06J circuit breaker. The electromagnetic forces exerted on the bus bars as a result of the three phase fault probably damaged the "C" phase bus PDA.
- The through wall insulators (bus bar insulators) in the switchgear wall between cubicles 'J' and 'K' were found physically damaged (chipped, edges missing) either by the fault explosion (most likely) or by the electromagnetic forces exerted on the bus bars as a

CONFIDENTIAL

CRDR 2775015 Page 40 of 110

result of a three phase fault. The through wall bus bar insulators in the switchgear wall between cubicles 'J' and 'H' were not similarly damaged.

Contributing Cause # 1:

A contributing cause to the event may be the lack of inspection of the switchgear cubicle 1ENANS06J bus PDA bottle exterior anytime following the 1992 electrical fault event (CRDR 9-2-495) that occurred in the rear of the cubicle. The Vendor Technical Document VTD-E009-00384 mandates cleaning /inspection of bus/connection insulation and primary disconnect device (assembly) contacts (internal finger cluster and garter springs). PVNGS performs these activities during implementation of procedure 32MT-9ZZ91 Inspection/Cleaning of 13.8KV & 4.16KV Switchgear. An overall stipulation is made to "Thoroughly clean all equipment, removing all dust and other accumulations" within the VTD; there is no inclusion of primary disconnect assembly porcelain bottle exterior inspection. Therefore it is reasonable that PVNGS Preventative Maintenance Bases and procedures do not contain inspection activities or specific cleaning activities for the PDA porcelain. Based on contact with several other nuclear plants; it is concluded that PVNGS maintenance being performed for the switchgear primary disconnect assemblies is consistent with the general nuclear industry. However due to the INDETERMANATE cause determination and the failure experienced; PVNGS corrective action to cope with any future potential failures is to revise the switchgear PM bases and issue a task to clean and inspect the primary disconnect assembly porcelain bottle exteriors periodically.

Supporting Facts

- The busses and primary disconnect assemblies (PDAs) were not inspected anytime following the 1992 fault that occurred in the rear of cubicle 1ENANS06J.
- No PM Basis task exists for cleaning and inspection of the bus and line PDA porcelain bottle exteriors.

Apparent Cause # 1:

The apparent cause of loss of the switchgear 125 VDC control power was the single daisy chain feed design of the feeder conductor through the switchgear cubicles in the wire channel. Although this is the design for GE M36 and M26 switchgear and is consistent for this GE switchgear throughout the industry; PVNGS will evaluate a design change of the switchgear 125 VDC control power wiring and protection to provide better reliability in the event of failures within individual switchgear cubicles.

Supporting Facts

- The fire/explosion damage to the control wiring in the wireway channel within switchgear cubicle 1ENANS06J resulted in a loss of 125 VDC control power to switchgear cubicles A, B, C, D, E, F, G, H & K.

CONFIDENTIAL

CRDR 2775015 Page 41 of 110

OTHER ISSUES

Industry Operating Experience reviews were found indicating high resistance overheating of the primary disconnect assembly finger/stab connection as the prevalent failure. The applicable IOE identified high resistance overheating of the connection between primary disconnect assembly (rosette) fingers and circuit breaker bushing due to old hardened grease, misalignment and missing silver plating. Rosette fingers in the outdoor 13.8 KV switchgear are inspected and cleaned each refueling cycle as per maintenance procedure 32MT-9ZZ91. Proper rosette finger and circuit breaker bushing contact is validated during circuit breaker alignment as per maintenance procedure 32MT-9ZZ33. Primary Disconnect Assembly finger garter spring replacement or tension force checks should be pursued to additionally preclude this failure type from occurring in switchgear PDAs at PVNGS.

Additionally, the review of Preventative Maintenance (PM) Bases for Magneblast switchgear at PVNGS identified inconsistencies between the context/content for switchgear bus cleaning/inspection. Review of procedure 32MT-9ZZ91 sections 4.2.2 and 4.2.3 only clean and inspect "accessible" bus/supports/joints/connections. References in the PM Bases delineates "all" sections of Magneblast switchgear be cleaned and inspected on a regular bases. This program issue will be resolved in conjunction with the corrective action for contributing cause #1. No other program, procedure, process or human factors issues were identified.

CRDR 2775015 Page 42 of 110

CONFIDENTIAL

OPERATING EXPERIENCE SUMMARY

Industry Operating Experience (IOE)

Switchgear failures identified from INPO Operating Experience have been consolidated and listed in Table 1 of Attachment 'P'. The review found very few incidence of primary disconnect assembly (PDA) failure. No primary disconnect assembly porcelain failure was found by the IOE review. The primary disconnect assembly IOE identified high resistance overheating of the connections between PDA fingers and circuit breaker bushings due to old hardened grease, misalignment and missing silver plating.

PVNGS Operating Experience

PVNGS switchgear failures and incidents of switchgear exposure to faults identified from CRDR reporting have been consolidated and listed in Table 2 of Attachment 'P'. No failure of a switchgear primary disconnect assembly has previously been experienced at PVNGS. The only switchgear failure identified at PVNGS was a bus failure within switchgear 1ENANS02. Switchgear 1ENANS02, 1ENANS06, 2ENANS01, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05, 2ENANS06, 3ENANS02, 3ENANS04 and 3ENANS06 have been exposed to the significant electromagnetic forces developed from phase to phase fault currents as listed in the table below. Note, switchgear phase to ground fault currents are relatively insignificant as the current magnitudes are limited by neutral grounding resistors on the upstream transformers supplying power to the switchgear.

PVNGS Switchgear Significant Fault Exposure				
CRDR/EER	Swgr Exposed (Cub)	Fault Type	Equip Faulted	Date
88-NA-020	1ENANS02(A)	Phase to Phase	1ENANS02	7/6/1988
9-2-0495	1ENANS06(J)	Phase to Phase	1ENANS06J	8/28/1992
9-6-Q001	2ENANS02(L)/4/6	Phase to Phase	2ENANZ44	5/1994
2-5-0189	2ENANS01(M)/3/5	Phase to Phase	2MRCEP01A	3/21/1995
1-5-0174	1ENANS02(G)	Phase to Phase	1ENGNL20	8/21/1995
3-8-0244	3ENANS02(E)/4/6	Phase to Phase	3ENGNL02	9/22/1998
103022	1ENANS06(C)	Phase to Phase	AWNTNL52	9/19/1999
117565	1ENANS06(C)	Phase to Phase	AWNTNL72	4/22/2000
2330379	2ENANS02(D)/4/6	Phase to Phase	2ENGNL18	10/18/2000

Operating Experience Review Conclusions

The probability of more primary disconnect assemblies with porcelain cracked at PVNGS is very, very low based on no failures of this type identified during IOE. Rosette fingers in PVNGS switchgear are inspected and cleaned as per maintenance procedure 32MT-9ZZ91. Proper rosette finger and circuit breaker bushing contact is validated during circuit breaker alignment as per maintenance procedure 32MT-9ZZ33/4/5. Based on these procedure actions, there is reasonable assurance of a good circuit breaker bushing to PDA fingers connection.

Although no IOE of PDA porcelain failures was found; the probable root cause and the PVNGS OE incidence of switchgear exposures to phase to phase faults (significant electromagnetic forces) supports inspections of potentially impacted bus PDAs within switchgears 1ENANS02, 2ENANS01, 3ENANS02, 3ENANS04 and 3ENANS06 during the next outage maintenance opportunity (32MT-9ZZ91). Switchgear 1ENANS06, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05, 2ENANS06 bus and line PDAs have been cleaned and inspected; 1ENANS06 prior to reenergization and Unit 2 switchgear during outage 2R12.

CONFIDENTIAL

CRDR 2775015 Page 43 of 110

CORRECTIVE ACTIONS

Completed or in place (e.g., immediate, remedial, or interim)

Cause	Action Description	Completed
DC#1	T-Mod 2775284 (DIWO 2775338) - EOF & TSC temporary power from 1ENANS05K	2/11/05
DC#1	T-Mod 2776424 (DIWO 2776426) - Control wiring and line side bus connections to cubicle 1ENANS06K	2/14/05
DC#1	DFWO 2776409 (DIWO 2776428) - 1ENANS06 bus repair in cubicles H, J and K; cubicle J control wiring isolation	2/15/05
DC#1	CMWO 2775016 - primary disconnect assembly (rosette) inspection, bus inspection, circuit breaker H replaced, circuit breaker K inspect/adjust, circuit breaker alignment verification, control wiring replacement	2/15/05
RC#1	CMWOs 2779882, 2779883, 2779885 and 2779887 performed inspections of switchgear 2ENANS03/4/5/6 cubicle PDA porcelain bottles.	4/15/05, 5/4/05, 4/15/05, 5/10/05
RC#1	RMWO 2706930 performed inspections of switchgear 2ENANS02 cubicle PDA porcelain bottles.	4/26/05
CC#1	Procedure 32MT-9ZZ91 Rev 13 revised to perform 13.8 KV switchgear megger test at 15kV (CRDR 2778611)	4/15/05

Required to Prevent Recurrence (CRDR Priority 2)

Cause	CRAI or WO #	Action Description	Owner	Date Due
RC#1	2802393 2802852 2802397 2802849 2802850	CM - Switchgears 1ENANS02, 2ENANS01, 3ENANS02, 3ENANS04 and 3ENANS06 bus and line PDA inspections.	Weems	5/15/06
RC#1	2802401	CM - Rework (1R12) of switchgear cubicle 1ENANS06J to as designed condition.	Weems	12/31/05
Corrective Actions (CRDR Priority 3)				
CC#1	2802416	Revise Swgr PM bases 2692371, 247476, 247479 & 247480 and generate tasks with the optimum periodicity to inspect/clean external of PDA bottle porcelain.	Martin	8/15/05
AC#1	2802420	DM - Evaluate (DCR/DCE) Swgr internal 125 VDC control power design change.	Hooshman	12/16/05
AC#1	2802445	Operations to evaluate timeliness of alarm acknowledge for loss of S06 125 VDC.	Merriman	7/15/05
Other Actions (CRDR Priority 4)				
Lesson Learned from OE review	2802464	IOE reflects Primary Disconnect Assembly (PDA) high resistance connection problems experienced in the industry. Evaluate garter spring replacement or tension force checks on the PDA fingers.	Holmes	12/31/05
Effectiveness Review Actions (CRDR Priority 4)				
RC#1	2802465	System Engineering (Unit 9735) will review the effectiveness of the corrective action to prevent recurrence, CMWOs 2802393, 2802397 and 2802401. This review will document that the action was completed as intended. Additionally, CRAI 2802416 provides additional assurance necessary to preclude repetition. Action closure shall include a conclusion statement, which clearly states the action(s) was or was not effective in preventing recurrence. Ref. 90DP-0IP10 section 3.13.1 and Appendix E, Section 1.8.	Hooshman	6/30/06

CONFIDENTIAL

SEQUENCE OF EVENTS

*(See **Appendix C** for Events & Causal Factors Chart)*

Date /Time	*Source of Data*	*Data*
8/22/1992	CRDR 9-2-0495	Fault in rear of switchgear cubicle 1ENANS06J. Initiated as phase to ground fault; terminated in three phase fault.
4/8/2001	WO 2331224	32MT-9ZZ91 Switchgear Inspection /Clean performed. Megger of 100GΩ, 100GΩ, 100GΩ
8/13/2001	WO 2375294	32MT-9ZZ33 Overhaul install. Circuit breaker align and Primary Disconnect Assembly wipe verification performed.
10/2002	WO 2484986	32MT-9ZZ91 Switchgear Inspection /Clean performed. Megger documented as acceptable. No hard copy archived.
4/27/2004	WO 2611567	32MT-9ZZ91 Switchgear Inspection /Clean performed. Megger of 79 GΩ, 91GΩ, 74.5 GΩ
2/6/2005	CRDR 2775015	Fault in 1ENANS06J cubicle within the bus compartment occurring at the primary disconnect assembly. Initiated as 'C' phase to ground fault; terminated in three phase fault.

CRDR 2775015 Page 45 of 110

CONFIDENTIAL

TRANSPORTABILITY

The cause is declared INDETERMINATE due to destruction of the Primary Disconnect Assembly (PDA) 'C' phase porcelain bottle. Out of the potential root causes for the damaged PDA bottle, the most probable root cause based on evidence/facts is that the 'C' phase PDA porcelain bottle was damaged as a result of the 1992 electrical fault in rear of switchgear cubicle 1ENANS06J (CRDR 9-2-495). Appendix C; Events and Causal Factors Chart, documents the PVNGS maintenance history for the failed 'C' phase primary disconnect assembly porcelain bottle in switchgear cubicle 1ENANS06J.

Extent of Condition

Circuit breaker 1ENANS06J is located in an outdoor 13.8 KV GE switchgear enclosure. There are the following similar GE switchgear enclosures at PVNGS:

Twelve (4/unit) outdoor 13.8 KV Non-1E switchgear enclosures (E-NAN-S03/4/5/6); 37 breaker cubicles.

Six (2/unit) indoor 13.8 KV Non-1E switchgear enclosures (E-NAN-S01/2); 66 breaker cubicles.

Six (2/unit) indoor 4.16 KV 1E switchgear enclosures (E-PBA/B-S03/4); 81 breaker cubicles.

Six (2/unit) indoor 4.16 KV Non-1E switchgear enclosures (E-NBN-S01/2); 51 breaker cubicles.

Note, indoor 13.8 KV QAG switchgear enclosure AE-NAN-S07 has a different bus structure and the five respective GE Power-Vac vacuum circuit breakers are racked in horizontally; hence the condition is not transportable to AENANS07.

Industry Operating Experience (IOE) consolidated and reviewed found no incident of Primary Disconnect Assembly (PDA) porcelain failure. The probability of more primary disconnect assembly porcelain bottles being cracked at PVNGS is very, very low based on no failures of this type. Therefore primary disconnect assembly cracked porcelain is not deemed an immediate transportability concern.

The PDA porcelain bottles in Unit 2 switchgears 2ENANS03/4/5/6 were cleaned/inspected (outage 2R12) and no problems identified. Based upon the PVNGS Operating Experience review; the bus Primary Disconnect Assembly bottles in switchgears 1ENANS02, 1ENANS06, 2ENANS01, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05, 2ENANS06, 3ENANS02, 3ENANS04 and 3ENANS06 have been previously subjected to significant electromagnetic force as the result of phase to phase faults. Switchgears 1ENANS02, 2ENANS01, 3ENANS02, 3ENANS04 and 3ENANS06 shall be inspected for cracks in the porcelain exterior during the next performance of 32MT-9ZZ91. Switchgear 1ENANS06, 2ENANS02, 2ENANS03, 2ENANS04, 2ENANS05, 2ENANS06 bus and line PDAs have been cleaned and inspected; 1ENANS06 prior to reenergization and Unit 2 switchgear during outage 2R12.

Extent of Cause

The Primary Disconnect Assembly porcelain bottles provide an insulation barrier between the 13.8 KV power phases and each phase to ground. Porcelain is utilized in different electrical power applications as an insulation barrier. The difference in other applications is the accessibility of the porcelain for inspection and cleaning. The switchgear bus and line PDA porcelain bottles are compartmentalized within the interior of the switchgear enclosure where it is difficult to inspect and clean. No other porcelain insulators have been identified which are not accessible for inspection/ cleaning and have been exposed to potential damage by electromagnetic or mechanical forces.

There were no program, procedure or human performance issues identified for the most probable cause (1992 fault in 1ENANS06J).

CONFIDENTIAL

CRDR 2775015 Page 46 of 110

MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE

The electrical fault within cubicle 1E-NAN-S06J prevented the NA system from performing its MVA Key Safety Function and exceeded NA system performance criteria; therefore, the condition **is** a **Significant Maintenance Rule Functional Failure** (MRFF). Switchgear 1ENANS06**CKTBRK is identified as a Key component in SWMS. A Maintenance Rule Expert Panel has been convened, the NA system placed in a(1) for this issue and an a(1) goal established.

The loss of 125 VDC control power in switchgear 1E-NAN-S06 did not prevent the NA system from performing any of its Key Safety Function and the probability of an additional failure of startup transformer AENANX01 occurring in conjunction with the loss of the 125 VDC power to the startup transformer protective relaying is very low; therefore, the condition **is not** a **Maintenance Rule Functional Failure** (MRFF). Since 1ENANS06**CKTBRK is identified as a Key component in SWMS; the loss of 125 VDC control power in switchgear 1E-NAN-S06 is deemed **ADVERCFA**.

The complete MRFF Evaluation can be found in **SWMS Attachment N**.

ROOT CAUSE ANALYSIS METHODS

Fault Tree analysis was used to determine the causes of this event. Only the fault tree path supported by the facts is discussed below. Refer to Appendix D for the complete Fault Tree and causes ruled out by refuting facts.

1ENANS06J Fault

Based upon the evidence the electrical fault occurred within switchgear cubicle 1ENANS06J. The front door of the switchgear cubicle was found blown open by the fault explosion and extensive damage to internal switchgear compartment sheet metal from the fault explosion and arcing was found. Based upon digital fault recorder data, the electrical fault initiated as a 'C' phase to ground fault lasting approximately .9 seconds and then transitioned to a three phase bolted fault that lasted another 1.4 seconds approximately. Fault magnitudes were consistent with design fault resistances and protective relaying actuated within the design settings.

Primary Disconnect Assembly

The switchgear PDAs (bus and line) are the bus and load interface to the switchgear circuit breakers via its insulated bushings. The PDAs consists of a porcelain cylinder (bottle) containing cluster fingers encircled by two garter springs which maintain contact pressure when the breaker bushings are inserted. The PDA conductor bars are taped and the top of the PDA bottles sealed with non conductive Solarite. The PDA conductor bars are bolted to the switchgear bus drops and the bar/connection fully insulated by bus insulation tape. Thus an internal PDA finger to circuit breaker bushing connection is completely insulated from anything external to the PDA bottle. The Magnablast circuit breakers are vertically lifted to insert the insulated circuit breaker bushings into the PDA cluster fingers.

The post event conditions found internal to the 1ENANS06J switchgear cubicle clearly identified the bus side primary disconnect assembly (PDA) as the point of 'C' phase to ground fault conception and the successive three phase fault. The porcelain bottles of the bus PDA were completely decimated and the three phase fault completely melted the metal end of the circuit breaker bushings such that there was no longer any bus connection to the circuit breaker. The three phase fault clearly occurred at the bus PDA exposed cluster fingers. Holes were burnt in the side and back compartment sheet metal walls in the lower back corner adjacent to the where the 'C' phase PDA porcelain bottle is mounted. These arc holes were the result of the initiating 'C' phase to ground fault.

CONFIDENTIAL

CRDR 2775015 Page 47 of 110

Cracked Porcelain

The only way for the 'C' phase to ground fault to occur where it did is a breach of the 'C' phase PDA insulation. There was no fault arc exit damage to the PDA conductor bar insulation tape; nor was there any indication of heat degradation of the tape insulation Geometry of the bus compartment, the 'C' phase PDA bottle and the ground fault arc burn holes indicate a fault initiated from the internal lower PDA fingers garter spring through the porcelain bottle to the compartment side and back sheet metal. This assertion is based upon PDA/compartment physical parameters, approximate distance calculations and the as-found conditions.

1992 Fault in rear of cubicle 1ENANS06J

In 1992, a fault occurred in the rear of switchgear cubicle 1ENANS06J (CRDR 9-2-0495). The fault initiated in a phase to ground fault and terminated in a three phase fault. The fault magnitudes experienced would have been similar to the 2/6/2005 fault; however it was of a shorter duration since the fault was terminated by the 1ENANS06J circuit breaker. A phase to phase fault of large magnitude imparts huge electromagnetic forces of attraction/repulsion on the bus bars carrying the fault current. The through wall insulators bus bar insulators in the switchgear wall between cubicles 'J' and 'K' were found physically damaged after the 2/6/2005 fault; either by the fault explosion (most likely) or by the electromagnetic forces exerted on the bus bars as a result of a three phase fault. The location of the adjacent 'K' cubicle is at the end of the switchgear; hence the bus bars are less supported/constrained. The through wall bus bar insulators in the switchgear wall between cubicles 'J' and 'H' were not broken.

The electromagnetic forces exerted on the bus bars as a result of the 1992 three phase fault probably damaged the "C" phase bus PDA porcelain bottle.

CRDR 2775015 Page 48 of 110

CONFIDENTIAL

LIST OF DOCUMENTS REVIEWED

90DP-0IP10, *Condition Reporting*
70DP-0EE01, *Equipment Root Cause of Failure Analysis*
70DP-0MR01, *Maintenance Rule*
PVNGS Root Cause Investigation Manual
Standard Handbook for Electrical Engineers; Fink and Beaty; Eleventh Edition
CRDR 9-2-0495
Vendor Technical Document VTD-G080-0384
Vendor/Supplier Document 13-EN009-00601
Single Line Diagram 13-E-MAA-001
Single Line Diagram 01-E-NAA-002

LIST OF PEOPLE CONTACTED

C. Garcia	Wolf Creek
D. Turley	Calloway
L. Little	South Texas Project
L. DeMarco	Cook
M. Ekis	Arkansas Nuclear One
S. Foat	Diablo Canyon
B. Briner	Waterford
S. Gocek	Cooper
R. Moceri	Palisades

LIST OF ATTACHMENTS

(Included as SWMS Attached Media)
Attachment B – *Interim Report*
Attachment D – *Digital Fault Recorder Graphs*
Attachment F – *Control Room logs*
Attachment I – *Troubleshooting Plans*
Attachment L – *LER*
Attachment N – *MRFF Evaluation*
Attachment P – *Operating Experience Search Results*
Attachment R – *Inspection Photos*
Attachment S – *Industry Operating Experience Report Submitted to INPO*

LIST OF APPENDICES

(Included as part of this report)
Appendix A – Investigation Charter
Appendix B – Hazard Barrier Target Analysis
Appendix C – Events & Causal Factor Chart
Appendix D – Fault Tree Analysis

CONFIDENTIAL

CRDR 2775015 Page 49 of 110

APPENDIX A – Investigation Charter

Fault on 1E-NAN-S06 Resulting in "B" Train LOP

To: Steve Schroeder, Significant Investigator

From: Mark Van Dop, Department Leader, Elect./I&C Design Engineering

Subject: Root Cause Investigation Charter
CRDR 2775015, Fault on 1E-NAN-S06 Resulting in "B" Train LOP

You are requested to form a team to investigate the root cause of the fault on 1E-NAN-S06 that occurred on February 6, 2005 which resulted in a "B" Train LOP and eventually required Unit 1 to shutdown. This investigation is to focus on the failure of the 13.8kV intermediate bus.

NOTE: CRDR 2775562 will evaluate the subsequent unit shutdown and CRDR 2775972 will address the impact of the loss of DC control power associated with 1E-NAN-S06.

You and the following team members are assigned to this investigation beginning on February 7, 2005 and until complete:

- Denny Custodio – Maintenance Engineering
- Prem Sahay – Design Engineering
- Steve Ruiz – Electrical Maintenance

You will conduct a formal root cause investigation per applicable CRDR procedures and the PVNGS Root Cause Investigation Manual. I expect a complete assessment of what happened, how it happened, and why. Your report should include root and contributing causes.

Please provide an interim report by February 18, 2005.

This scope and charter may be revised by our mutual agreement.

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APPENDIX B: Hazard- Barrier-Target Analysis

CRDR 2775015: SWITCHGEAR CUBICLE 1ENANS06J ELEC FAULT

Not Applicable to this Investigation

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APPENDIX C – Events & Causal Factors Chart

	32MT-9ZZ33	32MT-9ZZ91
1992		CRDR 9-2-0495 1ENANS06J Fault Cub Rear 8/22/1992
2001	Align & PDA Wipe verification → Install WO 2375294 1ENANS06J 8/13/2001	WO 2331224 1ENANS06 Swgr Inspect/Clean 4/8/2001 ← Megger, 100GΩ 100GΩ, 100GΩ
2002		WO 2484986 1ENANS06 Swgr Inspect/Clean 10//2002 ← No HC; Megger Acceptable
2004		WO 2611567 1ENANS06 Swgr Inspect/Clean 4/27/2004 ← Megger, 79GΩ 91GΩ, 74.5GΩ

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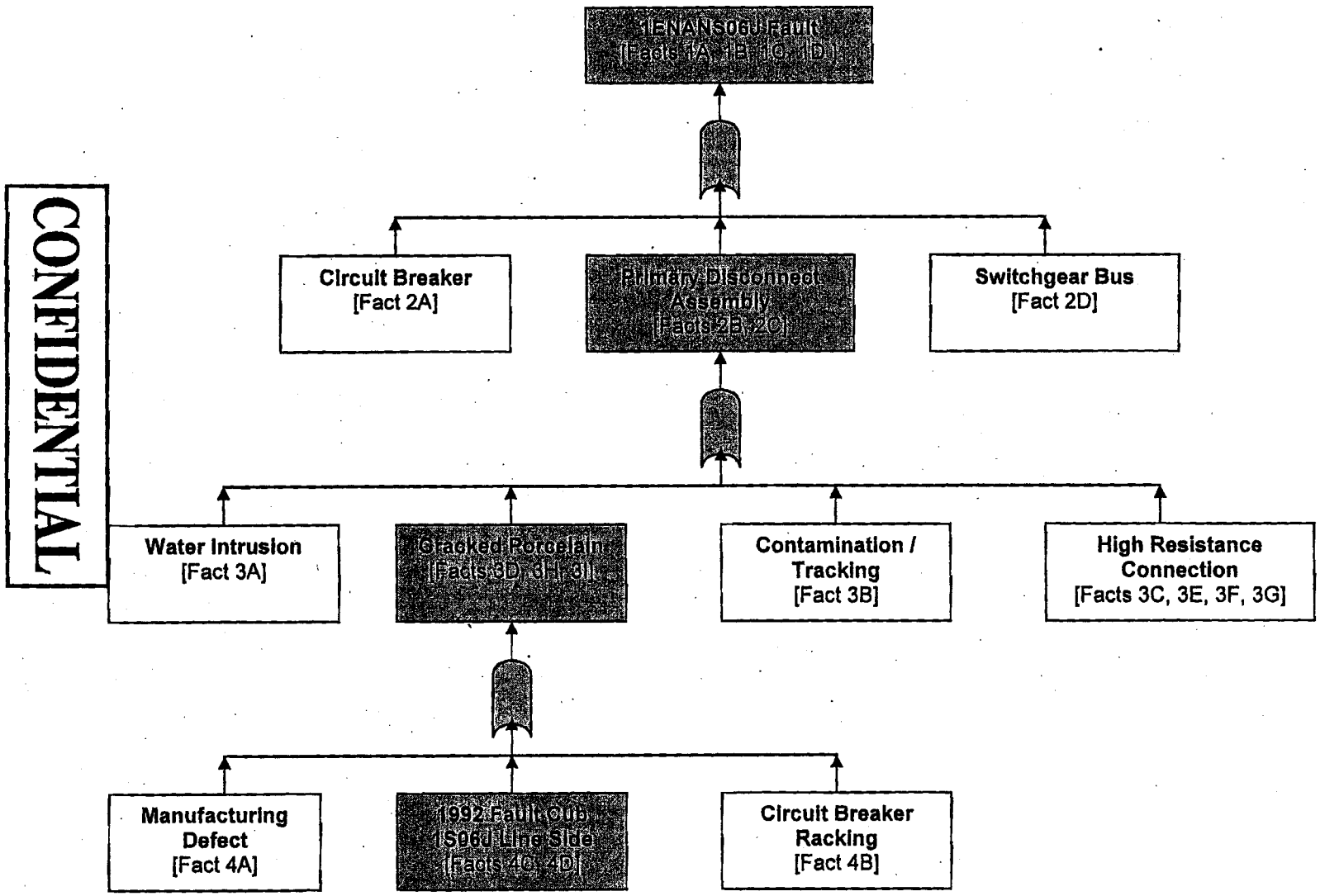
APPENDIX D – Fault Tree Analysis

Condition: Loss of 13.8 KV Power to 1ENANS04 and 1EPBBS04



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Fault Tree Facts

Level 1 - 1ENANS06J Fault

A. Digital fault recorder data: "C" Phase to Ground Fault (approximately .9 seconds); Three Phase to Ground Fault (approximately 1.4 seconds).
B. Door of switchgear cubicle 'J' blown open by the fault explosion.
C. Fault/Explosion/Fire/Smoke damage extensive within 'J' cubicle.
D. Cubicle condition in proximity the location of "C" phase bus PDA.

Level 2 - Circuit Breaker/Primary Disconnect Assembly (Rosette)/Switchgear Bus

A. No arc damage found below compartment containing bus primary disconnect assemblies. Inspection of circuit breaker confirmed no arc strikes to circuit breaker frame.
B. Bus PDA porcelain bottles and connection to breaker primary stabs destroyed.
C. Geometry of the bus compartment and the fault arc strike holes indicates 'C' phase fault initiation from the 'C' phase PDA porcelain bottle to the side and back walls adjacent to the lower back right corner of the bus PDA compartment.
D. No significant "C" phase bus bar damage.

Level 3 - Water Intrusion/Contamination-Tracking/High Resistance Connection/Cracked Porcelain

A. No evidence of water intrusion was found; no rain occurred just prior to or during event; no water intrusion was found due to rain during switchgear restoration/repair; and no condensation was found in "J" cubicle when walked down during rain 2/24/05.
B. Inspection of other line side primary disconnect assemblies (rosettes) in 1ENANS06 cubicles found reasonably clean conditions (low contamination to contribute to tracking) and no degraded conditions.
C. No evidence of overheating of the tape insulation on the 'C' phase PDA connection bar; tape insulation does not appear different than "A" and "B" phase.
D. Tape insulation on the 'C' phase PDA connection bar contains no electrical arc exit damage.
E. PDA fingers in the outdoor 13.8 KV switchgear are inspected and cleaned each refueling cycle as per maintenance procedure 32MT-9ZZ91.
F. Proper PDA finger and circuit breaker bushing contact is validated during circuit breaker alignment as per maintenance procedure 32MT-9ZZ33.
G. The load fed from circuit breaker 1ENANS06J is very low amperage; resistance would have to be very high to generate significant heat within the PDA.
H. Missing PDA fingers; 'C' phase initiation in combination with containment within PDA porcelain bottle.
I. Geometry of the PDA compartment, the PDA and the 'C' phase ground fault arc burn holes supports a fault path through the PDA porcelain bottle.

CONFIDENTIAL

CRDR 2775015 Page 54 of 110

Level 4 - Manufacturing Defect/Breaker Racking/1992 1ENANS06J Fault

A. Porcelain insulators are a very stable reliable component. It is very unlikely that a manufacturing defect would exhibit this many years after initial installation/inspection. No industry operating experience was discovered to indicate any manufacturing defects with primary disconnect assembly porcelain bottles.
B. Maintenance performs an extensive structured proceduralized alignment of circuit breakers in accordance with Appendix A "Breaker and Cubicle Alignment" of procedures 32MT-9ZZ33/4/5.
C. In 1992; a fault (CRDR 9-2-0495) occurred in the rear of switchgear cubicle 1ENANS06J. The fault magnitudes experienced would have been similar to the 2/6/2005 fault; however it was of a shorter duration since the fault was terminated by the 1ENANS06J circuit breaker. The electromagnetic forces exerted on the bus bars as a result of the three phase fault probably damaged the "C" phase bus PDA.
D. The through wall insulators bus bar insulators in the switchgear wall between cubicles 'J' and 'K' were found physically damaged (chipped, edges missing) either by the fault explosion (most likely) or by the electromagnetic forces exerted on the bus bars as a result of a three phase fault. The through wall bus bar insulators in the switchgear wall between cubicles 'J' and 'H' were not broken.

CRDR 2775015 Page 55 of 110

CONFIDENTIAL

ATTACHMENT 9

CRDR 2777226

UNIT 1 RCP 1B
1MRCEP01B

UPPER OIL SEAL
O-RING FAILURE

EVENT DATE: 2/16/2005
ERCFA Level I

Digitally signed by: Burge, Richard W(Z18026)
Date: 08/30/2005 20:24:00
Reason: I am the author of this document
Location: PVNGS

Prepared by: Rick Burge

RE

Digitally signed by: Berg, D. Lee (Z99751)
Date: 08/31/2005 07:12:30
Reason: I am approving this document
Location: PVNGS

Responsible Engineer Section Leader: Lee Berg

Digitally signed by: Landstrom, Carl E(Z98901)
Date: 08/31/2005 13:19:26
Reason: ERCFA Program Mgr Concurrence
Location: PVNGS

ERFCA PM: CarlLandstrom

CRDR 2777226 Page 25 of 48

CONFIDENTIAL

CRDR 2777226

TABLE OF CONTENTS

EXECUTIVE SUMMARY....3

EQUIPMENT DESCRIPTION....4

FAILURE DESCRIPTION....5

FAILURE EVALUATION....8

CONCLUSIONS / APPARENT CAUSE....12

TRANSPORTABILITY....13

ESCALATION REVIEW....14

CORRECTIVE ACTIONS....16

MAINTENANCE RULE CONSIDERATIONS....19

CRDR 2777226 Page 26 of 48

CONFIDENTIAL

UNIT 1 RCP 1B Thrust Bearing Upper Oil Seal Failure

EXECUTIVE SUMMARY

An O-ring installed in Unit 1 RCP 1B Thrust Bearing (TB) Upper oil seal during U1R11 was composed of an incorrect material that was incompatible with oil. As a result, the O-ring swelled over time and locked the rotating element of the seal onto the shaft.

When the RCP was started at the end of U1M12, the design shaft movement created a gap in the seal that resulted in excessive leakage of oil from the TB.

The seal was replaced with one verified to be composed of correct materials and the other three Unit 1 pumps were verified to not have a similar problem.

The swelled O-ring was traced to a batch of four, the other three being potentially installed in one Unit 3 RCP and two Unit 2 RCPs.

Of these, the Unit 3 RCP has been eliminated as a possibility.

The two Unit 2 RCPs with suspect O-rings were disassembled during U2R12 and the suspect O-rings confirmed to be installed. Both seals were replaced with new installations with O-rings verified to be of the correct material.

The last suspect O-ring has been shown to be installed in the Unit 1 RCP 2A Thrust Bearing lower seal. A review of the historical performance of this Thrust Bearing has shown this possibility to NOT be of immediate concern, including continued operation up to and entering in the upcoming outage.

Corrective actions have been initiated to replace the lower seal and O-rings in Unit 1 RCP 2A, and also to ensure the that new O- rings are tested for material as part of the normal procurement process.

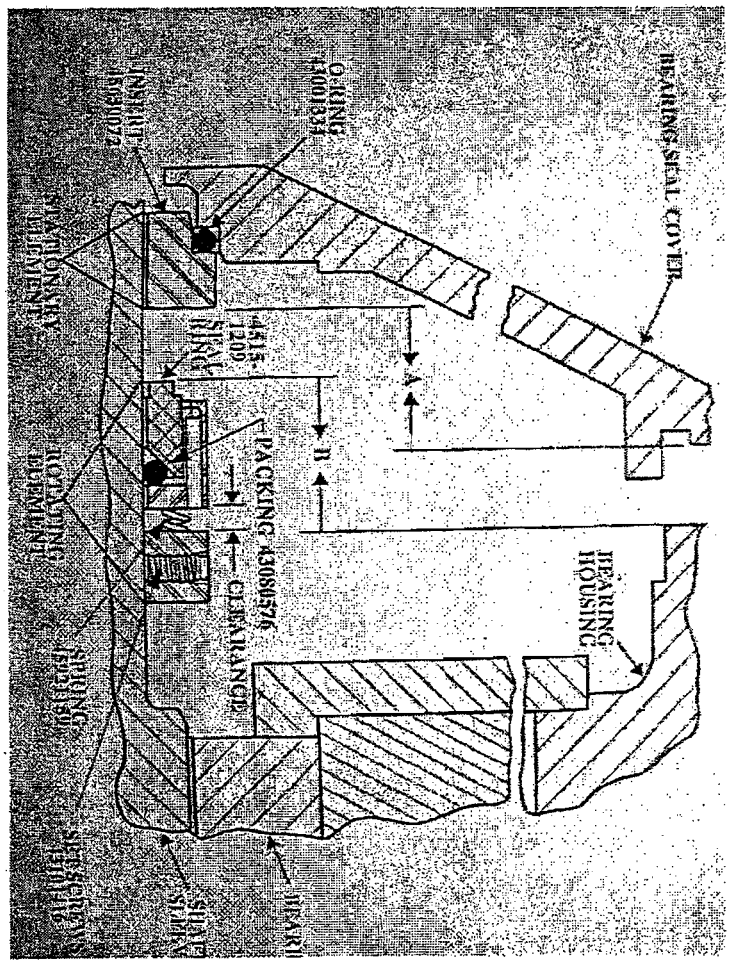
CRDR 2777226 Page 27 of 48

CONFIDENTIAL

EQUIPMENT DESCRIPTION

(A). Equipment Description / Function

Below is shown a diagram of a typical RCP upper oil seal, with the component parts indicated as shown.



From the functional aspect, the purpose of the applicable components is:

(1). Stationary Element, consisting of:

(1)(a). Insert (45630072): Provides a rigid, smooth surface for the rotating element to ride against. Composed of an alloy steel body, coated with ceramic for high temperature wear resistance.

(1)(b). O-ring (43001334): Seals the stationary element against the seal cover. Composed of Nitrile, a compound which is designed for use in oil without degradation.

CONFIDENTIAL

CRDR 2777226 Page 28 of 48

(2). Rotating Element, consisting of:

(2)(a). Seal Ring (4515-1209): Rigid Carbon ring, which provides a flat nose in contact with the stationary element. Material / geometry designed optimized to provide enough contact area to develop oil wedge, but not too much so as to generate excessive heat.

(2)(b). Packing (43080576): O-ring that seals the areas on the ID of the carbon and stationary rings from the pressurized oil in the cavity below. Composed of Nitrile, a compound which is designed for use in oil without degradation.

(2)(c). Springs (45921159): Provide upthrust force to keep the rotating element riding against the stationary element. A total of 16 springs, evenly spaced, are wedged between the stationary ring and the floating element (carrier). The clearance is adjusted via a spacer below the stationary ring (not shown) that rests on the shaft sleeve shoulder to provide solid support and maintain a constant preload via the spring compression. This clearance is set with the shaft assembly up against the upper pads (see below), which is the position for operation at NOP / NOT conditions.

(2)(d). Set Screws (42101416): A total of four screws keep the stationary ring from rotating on the shaft sleeve, in reaction to the shear forces developed at the rotating / stationary interface.

There is also an O-ring between the bearing seal cover (43001048, not shown) and the bearing housing that performs a static sealing function against the ~ 15 psi pressure that is developed on the upstream side of the seal by the oil pump internal to the TB.

FAILURE DESCRIPTION

(A). Event Description

During the recovery from the U1M12 SNOW outage, RCP 1B was started in accordance with normal Operations procedures for plant heatup. Local observation by the Maintenance Engineer of the vicinity of the Thrust Bearing (TB) Upper Oil seal showed excessive oil leakage (see Attachment 1 in attached media). The pump ran for approximately 3 minutes and was shutdown.

The situation was documented per this CRDR, and corrective actions were initiated per WO 2774138. The subsequent work performed replaced the upper oil seal, after which the RCP was successfully re-started on 2/16/05 with no upper oil seal problems noted. Also, informational testing of the other three RCPs in Unit 1 under the same conditions as RCP 1B was conducted to verify no similar occurrences.

CONFIDENTIAL

CRDR 2777226 Page 29 of 48

Per the Maintenance Rule Functional Failure (MRFF) evaluation attached to this CRDR, this condition is considered a MRFF as the RC system was unable to support its key safety function of trip initiator (TIN). Due to the oil leak, RCP 1B would eventually have to be shut down, which would initiate a plant trip.

(B). Estimated TB Leak Rate

An informational estimate of the average loss of oil from the RCP TB was made, and is included as Attachment 2 of attached media.

The rate of oil loss was estimated to be approximately 9 % / minute, which equates to approximately 13 gallons / minute. At this rate, the TB would have drained in approximately 20 minutes, assuming the leak rate stayed constant, and the RCP was not shut off.

(C). Previous Occurrences

There have been no previous occurrences of a TB leak of this magnitude in the past per the database currently available in SWMS. TB leakage at oil seals has been identified (e.g.: recent Unit 3 experience), but it has not been for the same reasons as this event.

(D). Original Installation

The RCP 1B upper oil seal assembly had been recently installed during the U1R11 refueling outage per WO 2609937, in conjunction with the TB Vent Mod (DIPC 2607758).

(E). Industry Operating Experience

The Palo Verde RCPs are unique to the Combustion Engineering (now Westinghouse) System 80 Design. The only similar RCPs are installed in the Korean Plants, but these units are not the same size, and the RCPs are slightly smaller. No information on these TBs appears to be available on the INPO database.

CRDR 2777226 Page 30 of 48

CONFIDENTIAL

Other OEs researched involving the wrong material supplied for O-rings found on the INPO database were as follows.

(A). This key words used to produce the above results were "wrong material". Of the 167 items under this category, only those noted involved O-rings. Most were associated with valves / valve actuators.

(1). OE14411 - Incorrect O-Ring Material was used for MOV's in Containment
Event Date:.....6/19/2002
Unit Name:.....Prairie Island Units 1 and 2.

(2). OE16454 - Incorrect O-Rings Installed on Turbine Control Valve Servo Dump Valves at Indian Point Unit 3
Event Date: 04/29/2003
INPO Change Date: 06/30/2003
Unit: 286, Indian Point 3 (Unit)

(B). A more specific search was made using key words "wrong O-ring material". Only three items were produced:

(1). 94~BRAIDWOOD 2~Valve operators
Abstract: **Fdwtr Cntmnt Isol Valvop~2FW009B~Failed to Open~Main Feedwater System-W~Degraded Train/Channel~Resulted in Unit Off-Line~Borg-Warner Corp.~38971*

(2). Calvert Cliffs 2 ~10/07/2004 9:50:00 AM~1004
Abstract: *10/07/2004 9:50:00 AM - No plant effect, from power operation. No generation capability was lost. A Haskel Inc. model AAD-2 (AAD-2), failure caused the event. Main Steam valves, dampers.*

(3). Brunswick 2 ~09/22/2000 3:40:00 AM~662
Abstract: *09/22/2000 3:40:00 AM - No plant effect, from power operation. No generation capability was lost. A Fisher Controls Co Inc model 471-16-80 (471-80), failure caused the event. Feedwater valves, dampers, 2-FW*

A similar search using "RCP Oil Seals O-rings", "RCP Thrust Bearing O-rings", and other such combinations produced no further information.

Thus, no IOE information is currently available for events involving the supplying of incorrect O-ring material in RCP Thrust Bearing Oil Seals.

CRDR 2777226 Page 31 of 48

CONFIDENTIAL

FAILURE EVALUATION

The following evaluation is intended to integrate the unique aspect of the RCP shaft lift phenomenon with the indicated failure mode to support the evidence found.

(A). Seal Operation relative to RCS Pressure

Theoretical Evaluation of Shaft Lift vs. RCS Pressure

Reference: SDOC N001-6.02-526-1, KSB Shaft Stress Analysis.

Figure 4a provides a summary of the forces acting on the rotating assembly for the cold condition (P = 200 psi, T = 68 F), and figure 4B provides the same for the hot condition (P = 2235 psi, T = 565 F). Both figures separate the forces into three categories:

--Axial forces due to system pressure
--Axial Hydraulic forces
--Weight

Since the hydraulic and weight forces are always acting down, then they can be combined. Likewise, since the pressure forces are always acting up, then they can be summed.

Results:
Cold: Fpress (up) = 15,720#. Fhyd+ W (down) = 68,993#. Net F (down) = 53,273 #, which explains why the **rotor rides on the lower pads in the cold state.**

Hot: Fpress (up) = 176,570#. Fhyd+ W (down) = 51,208#. Net F (up) = 125,362#, which explains why the **rotor rides on the upper pads in the hot state.**

The difference between riding on the upper and lower pads is ~ 0.030" (ref: 32MT-9RC24). This means that the upper oil seal will change by this amount when the shaft assembly changes from riding on one set of pads to the other.

Effective Area:

Since the pressure and the force due to pressure are known, an effective area can be estimated that the pressure forces act upon in each case:
Cold: A eff cold = Fp / Pc = 15,720 / 200 = 78.6 ~ 79 sq. inches.
Hot: A eff hot = Fh / Ph = 176,570/ 2235 = 79 sq. inches.
Therefore, Aeff = 79 sq. inches.

Now, using this area, what is the pressure necessary to just offset the average hydraulic + weight force?

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F ave(hyd + W) = (68,993 + 51,208) / 2 = 60,101#

So Poffset = F ave(hyd + W) / A eff = 60,101 / 79 = 760.8 ~ 761 psi.

SO, from this, the transition from riding on upper to lower pads would be expected to occur somewhere between 800 and 700 psi RCS pressure (during a cooldown).

Also, when the RCP is not running, the weights of the rotating assembly are acted on by system pressure. It can be estimated what pressure is needed to just balance these weights.

From VTM C490-00011 / VTD C490-0003, Table 1-5, the shipping weights of the rotating assembly can be estimated as:

W pump Shaft Assembly = 1500 #
W Drive Shaft Assembly = 2700 #
W Impeller = 1500 #
W Total = 5700 #

The RCS pressure to counterbalance this weight is:

P = W Total / A eff = 5700 / 79 = 72.2 ~ 72 psi

Since the minimum pressure required to operate RCPs is ~ 255 psi (ref: 40OP-9RC01 Rev 22, Appendix N, page 4, lowest curve), then **the shaft assembly will be raised up against the upper pads when the RCP is not running.**

Overall results:

(1). The RCP shaft assembly will ride against the upper pads when not running.

(2). When an RCP is started with RCS pressure < ~ 760 psi, the shaft assembly will ride on the lower pads. This will tend to open the upper oil seal by ~ 0.030". From field observations, the shaft drop occurs immediately upon RCP start.

(3). When an RCP is started with RCS pressure > ~ 760 psi, the shaft assembly will continue to ride on the upper pads, and will not drop. The upper oil seal will stay at the same compression as before the RCP start.

CRDR 2777226 Page 33 of 48

CONFIDENTIAL

(B). Evidence found per CMWO 2744138.

The referenced CMWO was generated to replace the upper oil seal per procedure 31MT-9RC24. Disassembly showed the following:

(1). The upper shaft packing O-ring had jammed the rotating element in place on the shaft, such that the element could not be moved with a reasonable applied external mechanical force.

(2). The springs that normally allow the rotating element to load the face against the stationary element were trapped by the jammed O-ring, such that they were non-functional.

(3).The shaft packing O-ring was removed as part of the seal replacement. This O-ring was inspected / informationally tested for material composition, and compared to a new O-ring of the same APN (4308-0576)..

(3)(a). **The O-ring removed from RCP 1B had material indicated to be EPDM** (Ethylene Propylene Rubber). **This material is NOT compatible with oil** (Ref: Parker O-ring Handbook, Catalog ORD 5700A/US).

(3)(b). **The new O-ring (APN 43080576) had material indicated to be Nitrile. This material IS compatible with oil** (Ref: Parker O-ring Handbook, Catalog ORD 5700A/US).

(3)(c). The O-ring removed from RCP 1B was found to be swollen relative to the new ring by an average of 16%, both in cross section and overall diameter (see Attachment 4 in attached media).

(C). Oil Lost from TB

It should be noted that approximately 39 gallons of oil was lost from the TB, based on the approximate run time and the estimated leak rate. This oil was verified to have been positively captured by the lube oil collection system (LOCS) as evidenced by local observation of the oil draining from the TB (see Attachment 3 in attached media). Oil was not spilled in any measurable amount in any areas of the pump bay.

The oil lost to the LOCS was left in the lube oil collection tank, as concurred with FP Engineer C. Foster via. E-mail (M.D.Powlikosky to C.Foster, dated 2/16/05, partially shown here):

CONFIDENTIAL

CRDR 2777226 Page 34 of 48

LEAVE OIL IN LOCTs

Talked with Cliff Foster about leaving the 30 gallons of oil in the LOCT. He agreed that we could leave this oil in the LOCT because:
a) The margin is 375 gallons, so we have plenty of margin left.
b) There is no current heavy oil leakage that would challenge this margin.
c) It is undesirable to disassemble these drain plugs and possibly induce oil leakage from the tank for very small volumes of oil.

(D). Oil refilled in Lift Tank (LT)

The estimate volume lost was later confirmed by the fact that approximately 35 gallons of new oil was required to re-fill the lift tank (LT) to the same approximate level as before the RCP start.

(E) Other possible failure modes

Stationary Element Failure

Other than the normal discoloration attributed to the heat generated by the rubbing of the rotating element, no anomalies were noted on the stationary element that would account for the gross leakage.

Other O-ring Failures

Both the Stationary element O-ring (45630072) and the seal cover O-ring (43001048) were inspected and found to be pliable, resilient, and in good condition, with no signs of swelling, pinching, or other anomalies.

Damaged Rotating Element

The running face of the rotating element was not chipped, gouged, cracked, or showing any other signs of problems which would account for the gross leakage. This can be seen per Attachment 4A in attached media.

The underside (slant face) of the seal showed signs of chafing as evidenced by a circumferential band of upset or missing material as shown in Attachment 5 in attached media. This was noted to be where the shaft packing O-ring contacts the rotating element, and is thought to be caused by the pressure generated by the swelled O-ring.

Loss of Spring Function

All springs were examined and found to be intact, resilient, and still providing proper function as evidenced by compressing the carrier several times by hand and observing full rebound to the maximum travel position with no binding or other signs of problems.

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Loss of seal preload

The spacer that sets the compression was found intact and solidly seated squarely on the shoulder of the shaft sleeve. Given this, and also since the springs were found with no problems, then the seal preload was as-left in U1R11, and no loss had occurred.

Loosening of the Set Screws

Upon initial disassembly, the setscrews were not found loose, as evidenced by the fact that they had to be loosened to remove the rotating seal assembly. Also, the loctite used to help ensure tightness was still evident on the threads of the setscrews after removal.

CONCLUSIONS / APPARENT CAUSE

(A). Postulated causes with refuting facts

All of the other postulated causes above have been rejected because of refuting facts noted.

(B). Direct Cause

The direct cause for the leak was the shaft packing O-ring being swelled, which was due to the O-ring being constructed of the incorrect material. The swelled O-ring would not allow the oil seal rotating assembly springs to perform their function because the rotating element was locked in place. There was no leakage before the RCP was started, because the RCP shaft assembly was in the upward position, against the upper pads. Since this is the shaft position in which the seal is initially set, then the seal performed its function. However, when the RCP was started with RCS pressure < ~ 760 psi, then the shaft assembly was pulled down ~ 0.030" to ride on the lower pads, but the rotating element stayed in its original position, effectively opening a ~ 0.030" gap between the rotating and stationary faces of the seal. Due to the internal oil pressure generated by the TB internal pump, oil was pumped out of this gap at the approximate leak rate noted.

(B). Apparent Cause

The apparent cause for the leak was as-supplied shaft packing O-ring material did not meet the correct specification.

CRDR 2777226 Page 36 of 48

CONFIDENTIAL

TRANSPORTABILITY

Per Attachment 6 in attached media, the shaft packing O-ring originally installed in U1 RCP 1B was one of four procured from a single vendor (Pioneer Equipment). The other three O-rings have preliminarily been traced to installations in Unit 2 and Unit 3 as noted in the attachment. It should also be noted that, per review of U2R11 Work Orders, the only RCP Thrust Bearings reworked were those of RCPs 1A and 2A (per the WOs noted in the attachment).

Immediate Transportability

Unit 3

According to Attachment 5, the installation of one of the suspect O-rings was performed in U3R10 in the RCP 1B Lower oil seal. No problems have been noted to date with the performance of this seal. However, as noted in Attachment 6A, the lower seal was NOT replaced by the referenced Work Order (2599237).

Additionally, as stated in Attachment 6A, the Unit 3 RCP 2B upper seal is suggested as a possible suspect O-ring. This seal was replaced during the U3M12 SNOW outage per WO 2796160, and the original O-ring found NOT to be swollen or otherwise suspect. This included testing that indicated the O-ring material to be correct (i.e.: Nitrile, not EPDM).

Also, the work order noted on Attachment 6 as being at loc 450 (WO 2669129) is confirmed in Attachment 6A as still being at loc 450.

Thus, from the above, it can be concluded that none of the suspect O-rings have been installed in Unit 3, and by the evidence noted, is considered **NOT transportable to Unit 3.**

Unit 2

The other two suspect O-rings were installed in the upper oil seals of RCPs 1A and 2A as noted.

Thus, in the absence of a positive identification of the material of these O-rings, this problem is considered to be **potentially transportable to Unit 2, RCPs 1A and 2A.**

Unit 2 RCP 1A

During the U2R12 Refueling outage, the upper oil seal in RCP 1A was replaced per WO 2669132. The suspect O-ring was indeed found to be swollen, and when tested indicated EPDM material. See Attachment 9 for an as-found illustration of this O-ring.

CONFIDENTIAL

CRDR 2777226 Page 37 of 48

Unit 2 RCP 2A

Also during the U2R12 Refueling outage, the upper oil seal in RCP 2A was replaced per WO 2669134. Similar to RCP 1A, the suspect O-ring was indeed found to be swollen, and when tested indicated EPDM material. See Attachment 10 for an as-found illustration of this O-ring.

Thus, since the two suspect O-rings have been removed and positively identified in terms of the incorrect material, then this problem is **not considered transportable to Unit 2, RCPs 1A and 2A.**

Unit 1

Along with the confirmed O-ring installed in Unit 1 RCP 1B, plus the two suspect O-rings in Unit 2, a total of one more of the suspect O-rings exists. This is based on the total of 4 cited in Attachment 6 - minus a total of 3 (two suspect in Unit 2 and one confirmed in Unit 1).

A document search was performed by tracing APNs / MRs / and Various Work Orders, with the result that the last suspect O-ring is thought to be installed in the Unit 1 RCP 2A LOWER oil seal.

A subsequent SWMS search confirms that this seal was replaced per WO 2559156 during U1R10. However, no mention is made of the material of this O-ring, as expected.

Thus, in the absence of a positive identification of the material of this O-ring, this problem is considered to be **potentially transportable to Unit 1, RCP 2A.**

<u>ESCALATION REVIEW</u>

As this is the first occurrence of this event due to the stated apparent cause, then this CRDR does not meet the criteria to be escalated to Significant status (i.e.: there has not been a second indeterminate cause determination on the same equipment within a three year window).

In general, the results of the MRFF evaluation were that the condition in this CRDR is a MRFF, but that the M-rule performance criteria were not exceeded.

Specifically, the results of the MRFF review were:

70DP-0MR01 R10 step 4.17 states that a MRFF is a failure of a SSC within the scope of the M-Rule that, if not corrected, could or did cause the affected system, structure, train or components to be unable to accomplish or support its Key Safety Function (KSF).

CONFIDENTIAL

CRDR 2777226 Page 38 of 48

This oil seal failure is considered a MRFF because of the possibility that RCP 1B could impact the RC KSF of Trip Initiator (TIN). With such an oil leak, RCP 1B would eventually have to be shut down which would initiate a plant trip.

(a). Is this condition a M-Rule Repeat Functional Failure (MRRFF)?

70DP-0MR01 R10 step 4.18 defines a MRRFF as a second or subsequent MRFF attributable to the same cause within 36 months. In the last 36 months, there have been no RC MRFFs on RCP oil seals. The only MRFF in the last 36 months on an RCP was CRDR 2627059 for Unit -3 RCP 2A main shaft seal # 3 failure on July 28, 2003. At this time, there is not direct correlation between these two failures that could be attributable to the
same cause. So, this is not a MRRFF.

(b). Does this MRFF cause M-Rule SSC Performance criteria (PC) to be exceeded?

No RC PC was exceeded as there is no specific PC for RCPs.
In general, RC System, Structures and Components (SSCs) that do not have specific PC are tracked under the Plant Level Performance Criteria (PLPC).
Procedure 70DP-0MR01 Rev 10 step 3.3.2.2.3 states that PLPC alone are generally adequate to monitor KSFs when the following criteria are met:

a) The KSF is low risk significant.

The KSF applicable to this CRDR condition is TIN with respect to forced circulation supplied by the RCPs. Procedure 70DP-0MR01 Rev 10, Appendix "F", page 51, 'KSF Identification' shows that the TIN KSF for the RC system is ranked as High Risk Significant. However, per PRA Study 13-NS-C025, Rev 03, RCPs and forced circulation is not defined in the component risk significant tables. Per conversation with PRA, the forced circulation aspect of the RCPs is not in the PRA model.

Also, as outlined in CRDR 2571275, the engineering basis for the current RC PC was developed using the low risk significant PC.

Hence, this KSF for this CRDR condition is deemed to be low risk. It should also be noted that:
--The KSFs are not standby functions
As outlined in CRDR 2571275, RC KSFs are not standby functions.
--Failure of the SSC to accomplish its KSF will have a direct effect on the PLPC (i.e. plant trip, etc)
--Loss of any RCP at power will result in a plant trip.

Thus, it is appropriate to evaluate this condition against the PLPC.

Per conversation with Ken Porter (PLPC system engineer), preliminary review of the

CONFIDENTIAL

CRDR 2777226 Page 39 of 48

Applicable Unit-1 SNOW indicates that the delay of having to rework the oil seal had no significant impact to the Unplanned Capacity Loss Factor. Any changes to this preliminary review that has any significant impact will be address by the PLPC system engineer.

(c).Is this condition an indicator of an M-Rule clearly declining trend?

A review of the RC MRFF evaluations from 1998 through 2005 does not document any such MRFFs or even any such failures of the RCP TB oil seals. Hence, this "single data point" is not considered to be an M-Rule clearly declining trend

Therefore, this CRDR does not require escalation review based on a review of the MRFF Escalation criteria.

CORECTIVE ACTIONS

Since the only remaining suspect O-ring has been shown to be installed in Unit 1, with none in Unit 2 or Unit 3, then the corrective actions below will be confined to only Unit 1.

Transportability Escalation Review / Short Term Corrective Actions

Since this installation was performed in U1R10 in the RCP 2A lower seal, and no significant problems have been noted in the performance of this Thrust Bearing, then this installation appears to not be a problem needing immediate attention.

As shown by monitoring of the indicated Thrust Bearing (TB) and Lift Tank (LT) levels, this TB has required pumping (i.e.: to restore TB level within the normal operating range) about every 5 – 6 days for the last ~ year (see Attachment 11). The pumping time interval has been essentially constant, with the TB / LT level slopes linear for the entire time.

This monitoring also shows that the oil leaking from the TB is essentially all going back to the LT, as evidenced by the "envelope" of the LT level traces being fairly flat line. Thus, there is not an Appendix R concern with this situation.

Thus, there does appear to be a slow, stable leak from the lower TB oil seal on Unit 1 RCP 2A, by monitoring indication.

Evidently, the seal is able to withstand the normal "exercise" inherent in the TB shaft lifting / dropping in response to RCS pressure changes (i.e.: the ~ 760 psi lift change threshold established earlier) without significant damage or seal degradation, again as evidenced by the fairly stable nature of the TB / LT level changes.

CONFIDENTIAL

CRDR 2777226 Page 40 of 48

For the near future, there is not expected to be any significant changes in the stability of the seal performance in terms of anticipated changes in the leakage characteristics, including the changes in RCS / RCP conditions when entering the upcoming refueling outage.

Thus, for the short term, no other concerns are warranted, and no other actions justified, and the immediate impact of the presence of a suspect O-ring in the lower TB seal of Unit 1 RCP 2A is deemed not to be adverse, as evidenced by the stable performance shown above.

Transportability Long Term Corrective Actions

Extent of Condition

As stated earlier, the potential adverse O-ring is limited to Unit 1 RCP 2A only. In terms of that TB, the condition is suspected to be limited to the lower seal only. Supporting evidence for this supposition is as follows.

Since there are two seals on a TB, leakage can be from either seal (upper or lower). Per past experience, the upper seal is usually the problem. This can be visually verified by observing the upper seal area with the RCP running, but this requires the observer to be present at the RCP, inside the biowall. This is not advisable during power operations due to the fairly large radiation dose considerations, unless absolutely necessary.

However, two opportunities have presented themselves to observe the Unit 1 RCP 2A TB Upper oil seal at NOP / NOT Mode 3 conditions during the present operating cycle.

During the U1 SNOW Outage of 2/08/05, a boric acid walkdown was performed per WO 2775073. In conjunction with this walkdown, the RCPs were inspected. Attachment 7 shows the RCP 2A TB Upper seal at this time. **This seal does NOT appear to have developed an oil leak** – relative to similar seals that have shown similar pump up intervals.

Another opportunity to inspect this seal occurred with the Unit 1 SNOW Outage of 3/18/05, in conjunction with the boric acid walkdown performed per WO 2782864. Attachment 8 shows the upper seal at this time, and once again, **there does not appear to be a typical upper oil seal leak.**

Thus, since by documentation review the adverse O-ring has been shown to be installed in the lower oil seal of Unit 1 RCP 2A, and by visual evidence of the absence of a credible leak from this TB upper oil seal, then it can be reasonably concluded that the leak is occurring on the lower oil seal of this RCP.

CRDR 2777226 Page 41 of 48

CONFIDENTIAL

In terms of other O-rings from the same supplier, a search was made to determine the nature and extent of items supplied.

The following table was generated manually by looking at the supplier's MLIS assigned number to see what P.O.s were sent to them. The orders were then examined to determine the APNs bought and if they were soft parts. Then a stock status check was made to see where they were issued (WO, DCID) and the quanity currently on hand. Most of the items found were used only at WRF and are not included in the table.

ITEM	APN	DCID	WO	Date Issued	PO	OH
O RING, SEAL 4 1/4IN 4 5/8IN 3/16IN NEOPRENE FOR BEARING HOUSING ADAPTER AMMONIA TRANSFER PUMP	43000599	3MSCNP10B 2MSCNP02A	2527754 2699754	06/15/05 06/10/04	500258736(2) 11/18/02	2
SEAL, OIL, OUTBOARD, CENTRIFUGAL PUMP, BUNA RUBBER TYPICAL PUMP S/N 786B938.	43010395	2MCHNP08A	2630180	01/16/04	500242570(1) 04/23/01	1
SEAL, GREASE HSG. FOR GOULDS PUMP MODEL 3171	00061579	1MCHNM02A	914608	03/01/00	500230189(1) 03/01/00	0
SEAL, LABYRWTH M GRP, FOR GOULDS PUMP MODEL 3171	00061581	2MCHNM02A	914608	03/01/00	500230189(1) 03/01/00	0
GASKET, GLAND, FOR GOULD PUMP MODEL 3196ST SIZE 1X1-1/2X6 S/N 786B938 COMPRESSED ARAMID FIBER WITH EPDM RUBBER BINDER	43094177	3NLRNP09A 2MCHNP09A 2MCHNP08A	2505298, 2496354 2630180	06/03/02, 06/10/02 01/16/04	500217434(4) 10/29/98	2
GASKET, FOR HPSI MECHANICAL SEAL, EPT. ITEM G OF DWG 2D-152304R1, NON-ASBESTOS ONLY.	43093662	2MSIAP02, 1MSIBP02, 3MSIBP02, 2MSIBP02	2420413, 2456333, 2607645, 2724489	02/26/02, 09/19/02, 08/25/04, 02/22/05	500284158(10) 03/02/05	13
GASKET, CASE F/ PUMPS MOD 3196 ST MER GPC, S/N C719C239-1&2 AND C719C243, B/M#351 NON ASBESTOS FIBER	43091021	2MCHNP09A 2MCHNP08A	2496354, 2630180	06/10/02, 01/16/04	500282540(2) 01/11/05	0

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Since none of the applications above involve an oil environment, then there would be no significant consequences of EPDM material in these applications, since this material is specifically made for non-oil applications.

Thus, the aspect of potential impact of other elastomers being of incorrect material from the subject supplier installed in the plant does not appear to be of significant concern.

Specific Action:
Obviously, the lower TB oil seal must be replaced during the U1R12 refueling outage. CMWO 2821360 has been generated to perform this replacement. This work must be performed to remove any suspicion of the potential adverse effects of the incorrect O-ring material on the future operation of this RCP.

General Action:
In the more general sense, it would be most beneficial to ensure the TB Seal O-rings were composed of the correct material before they are installed, and preferably at the receipt inspection stage of the procurement process.

Therefore, a method should be developed to inspect O-rings for both the rotating (APN 4308-00576) and stationary elements (APN 4300-1334) of the TB oil seals.

CRAI 2821417 has been generated for unit 9727 (Procurement Engineering) to develop this method. Priority 3.
No further actions are deemed necessary, and no other concerns warranted at this time.

MAINTENANCE RULE CONSIDERATIONS

As stated earlier, the O-ring failure did result in a MRFF, however the M-rule performance criteria were not exceeded.

Additionally, no new Maintenance Rule (a)(1) Goal needs to be established, due to the following conditions NOT being established:

(1). An established performance trigger was NOT reached due to the failure.

As was detailed earlier:

Does this MRFF cause M-Rule SSC Performance criteria (PC) to be exceeded?

No RC PC was exceeded as there is no specific PC for RCPs.
In general, RC System, Structures and Components (SSCs) that do not have specific PC are tracked under the Plant Level Performance Criteria (PLPC).
Procedure 70DP-0MR01 Rev 10 step 3.3.2.2.3 states that PLPC alone are generally adequate to monitor KSEs when the following criteria are met:

CONFIDENTIAL

CRDR 2777226 Page 43 of 48

a) The KSF is low risk significant.

The KSF applicable to this CRDR condition is TIN with respect to forced circulation supplied by the RCPs. Procedure 70DP-0MR01 Rev 10, Appendix "F", page 51, 'KSF Identification' shows that the TIN KSF for the RC system is ranked as High Risk Significant. However, per PRA Study 13-NS-C025, Rev 03, RCPs and forced circulation is not defined in the component risk significant tables. Per conversation with PRA, the forced circulation aspect of the RCPs is not in the PRA model.

Also, as outlined in CRDR 2571275, the engineering basis for the current RC PC was developed using the low risk significant PC.

Hence, this KSF for this CRDR condition is deemed to be low risk. It should also be noted that:
--The KSFs are not standby functions
As outlined in CRDR 2571275, RC KSFs are not standby functions.
--Failure of the SSC to accomplish its KSF will have a direct effect on the PLPC (i.e. plant trip, etc)
--Loss of any RCP at power will result in a plant trip.
Thus, it is appropriate to evaluate this condition against the PLPC.

Per conversation with Ken Porter (PLPC system engineer), preliminary review of the Applicable Unit-1 SNOW indicates that the delay of having to rework the oil seal had no significant impact to the Unplanned Capacity Loss Factor. Any changes to this preliminary review that has any significant impact will be address by the PLPC system engineer.

(2). Failures indicate a clearly declining trend.
Again, as was detailed earlier:
Is this condition an indicator of an M-Rule clearly declining trend?
A review of the RC MRFF evaluations from 1998 through 2005 does not document any such MRFFs or even any such failures of the RCP TB oil seals. Hence, this "single data point" is not considered to be an M-Rule clearly declining trend

(3). Multiple or repetitive failures are identified.
Is this condition a M-Rule Repeat Functional Failure (MRRFF)?
70DP-0MR01 R10 step 4.18 defines a MRRFF as a second or subsequent MRFF attributable to the same cause within 36 months. In the last 36 months, there have been no RC MRFFs on RCP oil seals. The only MRFF in the last 36 months on an RCP was CRDR 2627059 for Unit -3 RCP 2A main shaft seal # 3 failure on July 28, 2003. At this time, there is direct correlation between these two failures that could be attributable to the same cause. So, this is not a MRRFF.

Thus, all Maintenance Rule impacts are clearly understood, and no further actions are warranted for the applicable problem described in this CRDR.

CONFIDENTIAL

CRDR 2777226 Page 44 of 48

Maintenance Rule Functional Failure Review

Is this Condition a Maintenance Rule Functional Failure?	☐ No	☒ Yes	☐ Unknown

If yes:

Is this condition a repeat functional failure?	☒ No	☐ Yes	☐ Unknown
Does this failure cause a M-Rule SSC performance criteria to be exceeded?	☒ No	☐ Yes	☐ Unknown
Is this condition an indicator of a clearly declining trend?	☒ No	☐ Yes	☐ Unknown

Comments

CRDR condition 277726 is a MRFF. See attached media for details on above questions. MDP 03-03-05

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General Guidance for MRFF Determinations

Definitions:

Maintenance Rule Functional Failure (MRFF) is the failure of an SSC within the scope of the Maintenance Rule that, if not corrected, could or did cause the affected system, train or component to be unable to accomplish or support its key safety function(s). Failures occurring during post maintenance testing are not considered MRFFs if they occur prior to returning the SSC to service and are caused by the maintenance for which the post maintenance testing is performed. An MRFF of low risk significant SSCs monitored at the plant level occurs only when plant level performance criteria is effected or an unplanned safety system actuation results (i.e., when the failure results in a plant trip, unplanned capacity loss or safety system actuation).

Support SSC: A system, subsystem, or component which provides support required by supported SSC(s) to perform their Maintenance Rule Key Safety Function(s). Essential Cooling Water (EW) is considered a support SSC for Essential Chilled Water (EC) and Shutdown Cooling (SDC).

Supported SSC: A system, subsystem, or component that depends upon one or more support SSCs to perform its Maintenance Rule Key Safety Function(s). The HPSI Pump is supported by the Essential Room Cooler, which is supplied by Essential Chilled Water (EC). Therefore the HPSI Pump is considered an SSC supported by EC.

General Rules for MRFF Determinations

I. General Rule for LRS SSCs Monitored at The Plant Level

1. For normally operating low risk significant key safety functions monitored at the plant level an MRFF occurs only when a component, train or system failure causes a plant trip, unplanned capacity loss or safety system actuation

II. General Rules for Post Maintenance Testing and Troubleshooting Activities

2. SSC failures detected during post maintenance retest prior to declaring the equipment available for service will not be counted as a maintenance rule functional failure unless the failure is unrelated to the maintenance performed.
3. Following an MRFF, all demands that are placed on the SSC as part of the troubleshooting and verification of corrective maintenance following the MRFF should be considered invalid (no demand and no failure) regardless of their success or failure. Normal accounting of SSC demands should resume upon the final retest of the SSC, which will be counted as a demand.

III. General Rules for Trips or Malfunctions of Equipment Bypassed in Emergency Mode

4. Spurious operation of a trip that would be bypassed while the SSC was performing its key safety function will not be counted as a MRFF providing the bypass feature is periodically verified functional.
5. A malfunction of equipment that prevents the successful completion of a test will not be counted as an MRFF provided that the equipment is not used by the SSC for the fulfillment of its key safety function.

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IV. General Rules for Human Performance Errors by Operations, Maintenance and Others

6. Human performance errors (such as valve mispositioning events) can result in Maintenance Rule Functional Failures even when there is no damage to, malfunction of, or degraded condition of the effected SSC.
   - An operator error made during support of a maintenance activity (i.e., corrective, preventative, predictive or testing) that unexpectedly caused an SSC to be incapable of accomplishing the key safety function(s) for which it was included in the Scope of the Maintenance Rule would typically be considered an MRFF.
   - Any error made during routine operations resulting in a latent failure of a Maintenance Rule SSC is typically considered an MRFF. A latent failure is a condition that is not detected and corrected prior to declaring the SSC available for service and that could (or does) cause a failure of the key safety function(s).
   - Minor equipment problems or operating errors will not be considered MRFFs provided the following criteria are satisfied: 1) the problem is detected and corrected during the evolution; 2) the problem is diagnosed and corrected without corrective maintenance (e.g., turn a switch or reset a breaker); and 3) these actions can be completed within the time limits assumed by the safety analysis and PRA.

V. General Rules for Support and Supported SSCs

7. Typically, a Maintenance Rule Functional Failure (MRFF) of a support SSC will not be counted as an MRFF of the supported SSC for Maintenance Rule reliability monitoring purposes even if the failure renders the supported SSC unable to perform its Maintenance Rule key safety function(s).

> Note: see rule 8 for an exception applicable to outage situations. See rule 9 and the applicable Maintenance Rule System Performance Criteria/Scoping Basis information in the Maintenance Rule Performance Criteria Database for exceptions related to combining systems for monitoring purposes.

8. The risk ranking and monitoring criteria for support systems was established based on "at power" system functions, therefore some support systems for outage related key safety functions may not be independently monitored during outage periods. When this occurs, an SSC failure resulting in the loss of a key safety function that is high risk significant only during outage periods may need to be considered an MRFF of the supported system even when the failure occurs within the formal boundary of a support system.
9. Support components such as supply breakers, relays and other components (e.g., the turbine driven AF pump steam admission valves) designed to supply energy, an actuation signal or cooling for a single supported SSC (i.e., the support component supports only one SSC not multiple SSCs) are considered to be within the scope of the Maintenance Rule SSC they support unless otherwise documented in the applicable system basis documents. Therefore, any failures of these components resulting in the inability of the supported SSC to perform its Maintenance Rule Key

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Safety Function(s) will be counted as an MRFF of the supported SSC, but will not be counted as an MRFF of the support system. See Rules 10 and 11 for additional guidance regarding MRFF determinations for these types of components.

10. When there are redundant support components designed to supply energy, an actuation signal or cooling for a single supported SSC the failure of either support SSC should be counted as an MRFF, unless a documented evaluation or special accounting rule justifies an alternate approach. This justification should consider whether either the PRA or the plant Safety Analysis Report take credit for the redundant support SSC.

VII General Rule for Redundant SSCs within a Redundant Train

11. Special accounting rules should be developed and documented to address failures of redundant components within a single train that are both capable of independently supporting a key safety function (e.g., two check valves in a single line). Unless the PRA or plant Safety Analysis specifically takes credit for such redundancy, the special accounting rule can stipulate that the failure of only one of the redundant components need not be counted as an MRFF.

CRDR 2777226 Page 48 of 48

CONFIDENTIAL

ATTACHMENT 10

PALO VERDE

CRDR NUMBER: **2782680**

EMERGENCY DIESEL GENERATOR 1A FAILURE TO ATTAIN RATED VOLTAGE/FREQUENCY, REV. 0

EVENT DATE: MARCH 17, 2005

Approval Signatures

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(and Investigation Director) (Sign & date)

Senior Manager: Carl Churchman — 10/12/05
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Significant Root Cause Investigation Report

CRDR 2782680: EMERGENCY DIESEL GENERATOR 1A FAILURE TO ATTAIN RATED VOLTAGE/FREQUENCY

Table of Contents

EXECUTIVE SUMMARY 3
DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY 4
DESCRIPTION OF EVENT, FAILURE, OR CONDITION 7
FAILURE MODE INVESTIGATION 8
SAFETY SIGNIFICANCE 14
CONCLUSIONS (DIRECT, ROOT, AND CONTRIBUTING CAUSES) 15
OTHER ISSUES 17
OPERATING EXPERIENCE SUMMARY 18
CORRECTIVE ACTIONS 21
SEQUENCE OF EVENTS 22
TRANSPORTABILITY 23
MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE 24
ROOT CAUSE ANALYSIS METHODS 26
LIST OF DOCUMENTS REVIEWED 26
LIST OF PEOPLE CONTACTED 26
LIST OF ATTACHMENTS 27
LIST OF APPENDICES 27
APPENDIX A – Investigation Charter 28
APPENDIX B - Block Diagram - System Operation during a Test Mode Start 29
APPENDIX C – Events & Causal Factors Chart 32
APPENDIX D – Fault Tree Analysis 35
APPENDIX E - Vendor Test as Received (TAR) for EDG 1B governor actuator 37
APPENDIX F - Lube Oil Sample Results from all six (6) EDGs 54

CONFIDENTIAL

Notice: This is a significant Condition Report Investigation report prepared in accordance with applicable Palo Verde Nuclear Generating Station procedures. It is a self-critical evaluation of events, activities, and processes intended to fully understand and correct a significant condition adverse to quality per 10CFR50, Appendix B. The consequences of the significant adverse condition, if any, are described in the report. Unless otherwise stated, PVNGS was at all times operated safely and in compliance with its operating licenses.

CRDR 2782680 Page 50 of 112

EXECUTIVE SUMMARY

On March 17, 2005, a manual unloaded exception test mode start from the control room for the Emergency Diesel Generator (EDG) 1A was attempted as required for retest following a planned out-of-service maintenance outage. The area 4 auxiliary operator (AO) reported that both visually and audibly the start appeared normal but the engine never accelerated past 100 rpm as indicated on the local engine speed indicator. A walk down of the engine room and a review of valve lineups was performed by the AO following the engine failed start attempt with no discrepancies found.

Troubleshooting focused on the governor actuator, fuel oil delivery, pneumatic systems, and the maintenance work that was just completed during the planned maintenance outage. During troubleshooting, Mechanical Maintenance found very little resistance on the output shaft of the governor actuator when exercising the fuel racks/linkage. This was abnormal based on experience with other governor actuators - the residual hydraulic oil pressure and friction caused by sliding internal parts normally require considerable effort to rotate the output shaft. A small inconsequential leak was found on the fuel control cylinder (original manufacturers' name - "Bimba"). No other abnormal conditions were found.

The governor actuator and Bimba were replaced with refurbished spares, and the diesel was successfully started. A governor lube oil sample was taken, the lube oil drained, and the actuator was shipped to the vendor, Engine Systems Incorporated (ESI), for Root Cause. The oil sample subsequently was found with very high levels of water (5159 ppm vs. an upper limit of 1500 ppm). Normal water content is in the 100 – 200 ppm range with new oil required to be less than 500 ppm.

ESI performed a Test As Received (TAR) on the governor actuator which was successful with the actuator building up hydraulic pressure to the specified value. An internal inspection, however, revealed rust in the oil seal retainer area, on the base, and on the accumulator springs. The conclusion on the TAR was that the foreign material should not have contributed to the failure to start event, however, this was contrary to the many other documents including the Woodward Technical Manual and Operating Experience (OEs) relating to oil contamination and failure of governor actuators.

Due to the root cause methodologies used herein and the preponderance of evidence, the direct cause was oil contamination inside the governor actuator. The presence of rust in the actuator lube oil most likely resulted in particles being lodged in the internal oil pump check valves or any of the pistons or other internal areas with close tolerances. Ultimately this caused the actuator output shaft to become loose/limp and starve the engine of fuel when the actuator could not pull the racks open.

The three (3) most probable root causes of water introduction into the actuator lube oil sump are:

1. Water introduced at Woodward during the refurbishment of the governor and never completely drained. (there is precedence stated in OEs of contamination of internals at the Woodward facility),
2. Governor stored in the PVNGS warehouse drained of oil for 9 months creating prime conditions for rust formation (i.e. water, air, and warm ambient conditions), and/or
3. Water may also have been introduced during an oil change in April 2004, but this was deemed a lesser probability based on a walk down of the oil change PM with no obvious discrepancies found.

Regardless, water introduction into the lube oil is regarded as an isolated event as there have been no other instances of water introduction causing rust at Palo Verde or in the related OEs reviewed.

Corrective actions have been assigned. Two Priority 2 actions have been completed to prevent recurrence.

• RT 245877 was generated to add oil to the governors when they are received in the warehouse from the vendor in order to minimize the possibility of rust formation. This action provides an added benefit as Woodward stated that there is an unlimited shelf life with governor actuators stored with oil in a controlled environment.

• The second action has also been completed – vendors were changed in Fall of 2000 from Woodward to ESI and there have been no instances of water introduction noted with the several governor actuators that have been refurbished by ESI since the Fall of 2000.

Transportability was evaluated and found to not be an issue; the recent lube oil samples of governor lube oil showed water content in the range of 104 – 240 ppm. WMs have been written to obtain more recent lube oil samples - oil samples on EDG 2A (8/24/05), 3B (9/7/05), 1B (9/15/05), 1A (9/21/05), and 3A (9/28/05) were found with normal water content and all other parameters in the normal range.

CONFIDENTIAL

CRDR 2782680 Page 51 of 112

DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY

The diesel generator system is a class 1E standby generation system comprised of two completely independent and redundant diesel generator units that are each rated for 5500 kW continuous output and 6050 kW output for 2 hours out of 24 hours.

The diesel generator system provides a standby source of AC power for the two trains of engineered safety features (ESF) equipment (4.16KV AC class 1E buses) for safe plant shutdown and decay heat removal under all conditions including the design bases accident in the event of the loss of preferred (off-site) power.

The diesel generator can attain full load speed and be able to accept sequenced load within 10 seconds following a start signal. A governor maintains diesel generator speed below the 110% of full load speed trip set point and frequency of 60Hz + 1.2 Hz when operating under any load. The diesel engine is designed to operate during and after a safe shutdown earthquake.

The diesel engine is a 20 cylinder V-type turbocharged engine designed to drive the 5500kW generator. The engine has a fabricated steel base, which includes an area for mounting the generator and outboard bearing. The section under the engine serves as a sump for the lubrication sub-system. The center frame supports an under hung steel crankshaft in tri-metal split shell bearings. Pistons are connected to the crankshaft by main and articulating connecting rods with the flywheel and generator shaft bolted to the crankshaft. A chain driven sprocket on the aft end of the crankshaft drives the governors and camshafts. A link driven sprocket and hub drive the oil, fuel, and water pumps at the forward end of the engine.

Each diesel generator unit has its own independent and redundant auxiliary support system which include the;

- Fuel oil sub-system
- Engine cooling water sub-system
- Air starting sub-system
- Engine lubrication sub-system
- Air intake and exhaust sub-system

DESCRIPTION OF HYDRAULIC ACTUATOR AND PRINCIPALS OF OPERATION

The EGB 50-PLS hydraulic actuator consists of three distinct but interconnected sections: (1) an electric governor section; (2) a mechanical governor section and (3) a hydraulic amplifier section which amplifies the force output of the other two sections. (Note: for purposes of this report, the terms of governor actuator and actuator are used interchangeably to describe the hydraulic actuator that failed during this event). The three sections are interconnected through the loading piston. The loading piston position determines the actuator output shaft position. Either the electric or mechanical governor can control the position of the loading piston.

During starting and steady state conditions, the Palo Verde EDGs are controlled by whichever portion of the actuator (electrical or mechanical governor) has the lowest set point. The electric governor is set to control speed at the normal running speed of 600 rpm. The speed inputs to the electric governor are provided by a Woodward 2301PLS load and speed sensing control unit (the electronic governor). In order to prevent the governors from fighting for control, the mechanical governor speed set point is 608 rpm.

CONFIDENTIAL

CRDR 2782680 Page 52 of 112

The 2301 control unit does not receive 120 VAC power when the diesel is shutdown. It is only after the engine reaches 178 rpm, when the generator field flashes, that AC power is provided to the 2301 control unit and hence to the electric governor. There is a delay of approximately 3 to 4 seconds between field flash and the build up of sufficient voltage to allow the electric governor to assume control.

When the engine is started, it is supplied full fuel by the opening of the fuel racks and the reverse acting governor going to maximum. The result is that the engine rapidly accelerates toward 600 rpm. The speed regulating governor can not react quickly enough to catch and hold the engine, which overshoots the governor set point and RPM reaches around 630, before the governor can assume control and pull back engine speed to 600 rpm.

The EGB 50-PLS actuator contains two separate hydraulic circuits. There is one circuit controlled by either the electric and mechanical ballhead sub-governors and one section containing the hydraulic amplifier. As the engine is started, oil pressure is built up in the hydraulic amplifier section and the mechanical and electrical sub-governors (see Figure 1).

The increasing oil pressure forces the accumulator pistons up, opposing the downward force of the accumulator springs. When the pistons move up sufficiently, one piston uncovers a bypass hole through which excess oil is returned to the sump and thus oil pressure is regulated and an oil reservoir is created.

As the oil pressure continues to build, it acts upon the relay servo piston and the relay valve plunger. The servo piston is connected to the actuator terminal (output) shaft through the terminal lever. Since engine speed is below both the mechanical and electrical governor set points, the output nut moves to a full fuel position (up-reverse acting) which allows the output shaft to rotate to the maximum fuel position.

As the engine accelerates past 600 rpm, the electric and mechanical sub-governors begin to interact to engine speed. The mechanical governor pilot valve plunger is held in a downward position by the speeder spring. Due to centrifugal force, the engine speed causes the governor flyweights to extend and exert an upward force on the speeder spring. Whenever these two forces are unbalanced, movement of the pilot valve plunger occurs. This movement of the pilot valve plunger displaces the buffer piston which then raises or lowers the mechanical governor power piston. Movement of the power piston causes movement of the loading piston. The loading piston movement is translated to the terminal shaft vial the intermediate lever, the relay valve plunger and the relay servo piston. Above 608 rpm, the upward force of the flyweights is greater than the force of the speeder spring; this moves the pilot valve plunger upward. This movement uncovers the sump port and relieves pressure from the buffer piston which moves away from the power piston causing it to move downward. The power piston downward movement causes downward movement of the floating lever loading piston and the relay valve plunger (amplifier section) which ports oil to the relay servo piston and thus moves the terminal shaft to the minimum fuel position.

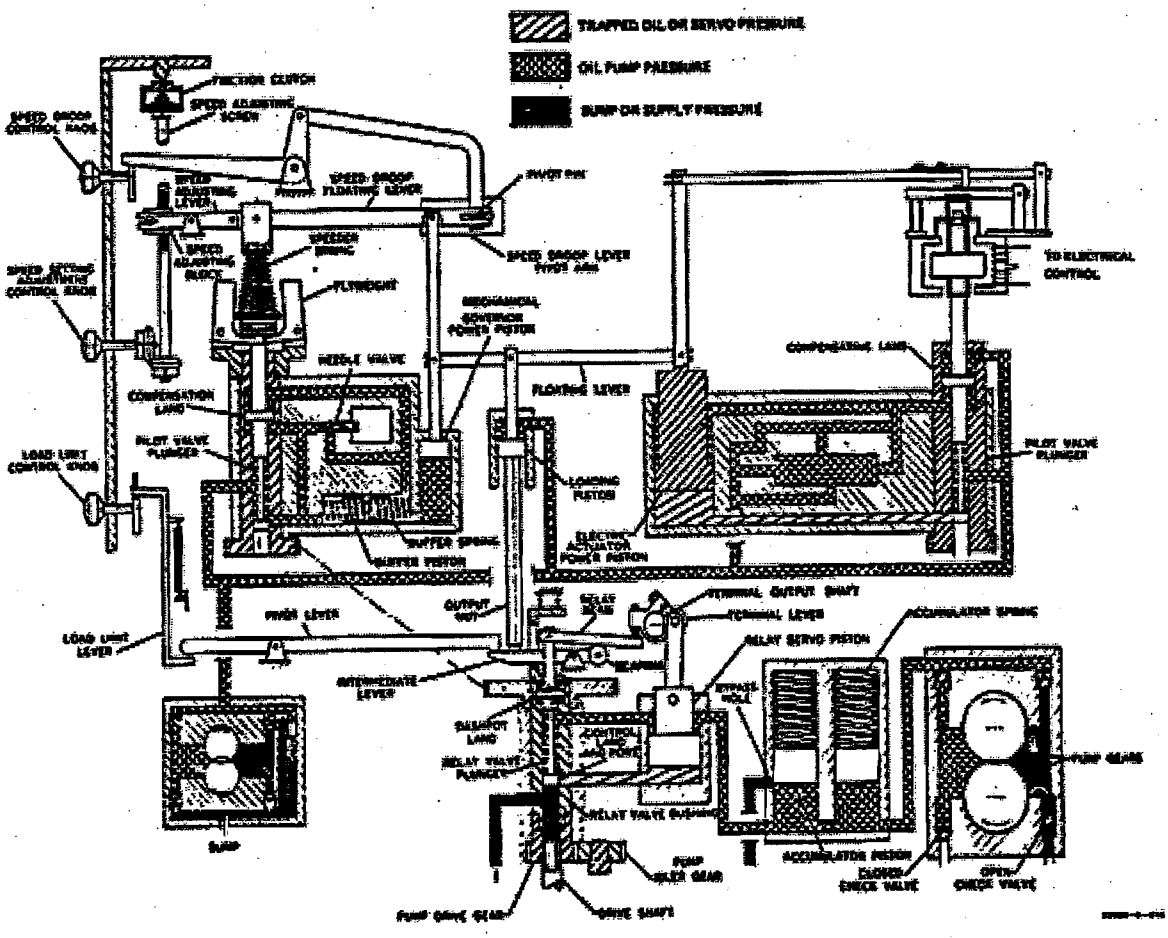
The voltage in the 2301-PLS speed sensing unit (electronic governor) has now built sufficiently that the electrical governor gains control. The electrical governor works similarly to the mechanical governor with the exception that its pilot valve plunger is position and controlled by a two-coil polarized solenoid, a permanent magnet, a centering spring and a restoring spring. Movement of the pilot valve plunger causes movement of the electric actuator power piston. The power piston then positions the loading piston via the floating lever, which in turn positions the relay valve plunger through the various linkages (intermediate lever and relay beam).

CONFIDENTIAL

CRDR 2782680 Page 53 of 112

As the engine speed decreases to the electrical governor set point, the electrical forces on the coil and the spring force balance. This centers the electrical pilot valve plunger which covers the internal ports. With the pilot valve plunger centered, no oil, other than leakage make-up, flows to or from the electrical actuator power piston. With the electrical governor controlling, pressure oil is continually directed to the underside of the mechanical governor servo piston which is held up against its stop. The governor actuator maintains equilibrium (maintains engine rpm) by the interaction between the three sections of the governor and the loading piston.

Figure 1



CONFIDENTIAL

CRDR 2782680 Page 54 of 112

DESCRIPTION OF EVENT, FAILURE, OR CONDITION

On March 17, 2005, a manual unloaded exception test mode start from the control room for the Unit 1 Diesel Generator A was attempted as required for retest following maintenance under the following WO's 2708746, 2764878, 2698842, 2698879, 2698970, 2766153, 2689160, 2749679, and 2708746. The following alarms were received in the control room approximately 15 seconds later: 03:12:16 - DG A Lo Priority TRBL, 03:12:18 - DG A Status Trip, 03:12:18 - DG A Hi Priority TRBL. The following alarms annunciated locally at DGA-B01: Window 08A - Incomplete Sequence (High Priority Shutdown), Window 1C - DG Bypassed or Inoperable, and Windows 04C and 05C - Starting Air Receiver A and B Malfunction.

The area 4 AO reported that both visually and audibly the start appeared normal but the engine never accelerated past 100 rpm as indicated on the local engine control panel. A area walk down was performed by the AO along with a review of Appendix A lineups of 40OP-9DG01, which check the support subsystems of Diesel Generator A for the Fuel Oil and Starting Air with no discrepancies found. This was in an attempt to determine an initial cause for the failure. Engineering was notified of the failure and CRDR 2782680 was generated for cause determination.

Engineering and Maintenance began troubleshooting of the fuel oil, governing, and control systems of the 1A Diesel Generator. Troubleshooting consisted of exercising fuel metering rods for fuel injection pumps, inspecting governor/fuel rack fittings, exercising the fuel control cylinder ("Bimba" – original manufacturers' name), and manually exercising the terminal shaft on the governor actuator. Troubleshooting concluded that the light resistance of the governor terminal shaft was abnormal (governor internal hydraulic pressure and friction from sliding parts in governor should cause heavy resistance to movement of the terminal shaft). It was decided to replace the governor actuator and also the Bimba cylinder based on a small air leak on the shaft end of the Bimba.

The governor and Bimba were subsequently replaced. A shutdown of Unit 1 was performed based on a Probabilistic Risk Analysis (PRA) and Technical Specifications (TS) restrictions on the retest requirements for a governor actuator. During the unit shutdown (mode 5), a retest was performed with the EDG 1A performing per the retest plan (all parameters normal). A successful surveillance test was performed on March 19, 2005 with EDG 1A subsequently declared operable.

CRDR 2782680 Page 55 of 112

CONFIDENTIAL

FAILURE MODE INVESTIGATION

The Failure Mode Investigation includes a Sequence of Events, Events and Causal Factors Chart, and Fault Tree modules to aid in determining the Direct, Root, and Contributing causes of the EDG 1A failure to accelerate past 100 rpm and a subsequent "Incomplete Sequence" alarm/shutdown. In order to determine the causes and the corrective actions for the failure, the following Failure Mode Investigation plan was implemented by the Investigation Team.

The Sequence of Events (SOE), module was first undertaken to determine what events transpired just prior, during, and after the event. The SOE was taken from the Unit logs, troubleshooting plan, and the subsequent Engineering and vendor analysis of data. SOE was used to indicate facts to support the Event and Causal Factors Chart. The following are the events, documents reviewed, and discussions that were undertaken by the Investigation Team to arrive at the cause(s) of the EDG 1A failure.

- EDG 1A governor actuator, serial number 1524051, was removed from EDG 3A for normal refurbishment during U3R8 (April 2000) and sent to Woodward Governor Company (the last Palo Verde actuator that was rebuilt by Woodward).

- EDG 1A actuator was rebuilt in June 2000 and shipped back to Palo Verde in July 2000. It should be noted that the Test As Received (TAR) reported that the Jacket Water Cooler was degraded, appeared to be leaking (along with o-rings). The cooler tube and o-rings were replaced during refurbishment but there was no mention of any rust discovered.

- Governor actuator was installed on EDG 1A during U1R9 (April 2001).

- Failure event on March 17, 2005, when the 1A EDG failed to accelerate past 100 rpm and the subsequent "Incomplete Sequence" alarm/shutdown received.

- Troubleshooting and subsequently declaring the EDG 1A operable involved:

  - Exercising the individual fuel metering rods for the engine fuel injection pumps – *no binding found*
  - Inspecting the fuel control cylinder, Bimba, to fuel rack fittings for tightness – *all fittings tight*
  - Inspecting the governor actuator to Bimba fittings for tightness – *all fittings tight*
  - Pressurizing the reset (starting) air header that extends and contracts (exercising) the Bimba cylinder several times. This PM task also checks for leaks (small inconsequential leak noted from the Bimba on the shaft end) – *otherwise Bimba extends/contracts properly and no other leaks found*
  - Manually exercising the governor actuator output terminal shaft. *Light resistance was found which is abnormal taking into account residual governor actuator hydraulic pressure and friction from internal sliding surfaces*
  - Governor actuator and Bimba cylinder are replaced
  - Maintenance retest and subsequent monthly ST successful

- EDG 1A governor [illegible] prior to shipping governor to vendor, ESI, for [illegible]

CONFIDENTIAL

CRDR 2782680 Page 56 of 112

- EDG 1A governor actuator tested at ESI with PVNGS Mechanical Maintenance Engineer (A. Fernandez) present. Actuator was found to be operating properly (developed oil pressure per specification). The conclusion from the vendor was that the rust found on internal parts should not have affected the operation of the governor. See Attachment B and Appendix E for Mechanical Maintenance Engineer witness report and ESI TAR-report, respectively.

- Lube oil sample was tested at the on-site lube oil lab. The testing found 5159 ppm of water (previous sample on 4/19/04 contained 104 ppm. Upper range is 1500 ppm per 37DP-9MP04) and viscosity of 12.6 centistokes at 100 deg. C (slightly lower than recommended range of 13.7 – 15.5 cS). See Attachment C for the EDG 1A sample results and Appendix F for sample results from the other diesel generators.

- Lube Oil Predictive Engineer was requested to analyze the lab results of the EDG 1A lube oil sample. Report states that "*small amount of debris can affect the performance of a hydraulic system to include causing abrasive damage, interfering with sliding within close tolerance surfaces and plugging small openings*". See Attachment D for the Lube Oil Engineer report.

- Reviewed lube oil operating experience (OE). OE contains many examples/statements and resultant problems related to emulsified water and the relationship with lubricating systems. *Noteworthy is that of the five (5) factors that demonstrate the magnitude of harmful effects of water on lubricating oil, this event indicated that 4 out of the 5 were present (the fifth one was unknown)*. See Attachment E for the full evaluation of lubricating oil OE.

- Review of the fragnet/schedule of the work performed on EDG 1A during the scheduled 12 week on-line outage on 3/16/05 was performed by Engineering. The planned work during this outage was performed by EMS, I&C and RAMS personnel and consisted of the following work:

ON-LINE MAINTENANCE WORK PERFORMED JUST PRIOR TO FAILURE

ELECTRICAL MAINTENANCE WORK

The only work mechanism (WM) performed by EMS that could have affected the manual start of EDG 1A was WM #2764878. This WM provided work instruction to replace the Metal Oxide Varistors (MOVs) across the 135 VDC coils of the EDG starting air (JDGAUV-3 (20SR-2), -5 (20SL-1), -7 (20SL-2), -15 (20SR-1)), emergency fuel oil (JDGAUV-9 (20FO-1), -11 (20FO-2)) and the test mode engine shutdown solenoids (JDGNUV-13 (20SD)).

STARTING AIR SOLENOIDS

There are a total of four (4) engine starting air solenoids (JDGAUV-3 (20SR-2), -5 (20SL-1), -7 (20SL-2), -15 (20SR-1)). With both EDG air receivers fully charged (250 PSI) and available (true in this case), only one (1) of the four (4) starting solenoids would have to operate to successfully start the engine. The AO in the engine control room at the time of the engine start reported that it rolled up to approximately 100 RPM on starting air but that engine combustion did not appeared to occur.

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Review of the plant Digital Fault Recorder (DFR) records for this same start, also showed that the engine never reached the field flash set point of 178 RPM (no generator

CRDR 2782680 Page 57 of 112

voltage/frequency buildup). In addition, during an engine start the EDG "Starting Air Solenoid/System Malfunction" local annunciator alarm will occur if any of the starting air solenoids fail to operate properly. This particular alarm did not occur during the failure of EDG 1A to manually start properly.

CONCLUSION
Therefore, it is concluded that all four of the starting air solenoids worked properly during the failure of the engine on a start to properly attain rated voltage/frequency.

EMERGENCY FUEL OIL SOLENOIDS
The engine has two (2) emergency fuel oil solenoids (JDGAUV-9 (20FO-1), -11 (20FO-2)) that function to prevent closure of the fuel racks if an engine test mode only trip occurs during emergency EDG operations. The other function of these two solenoids is to maintain the fuel racks open during the five (5) minute cool down cycles that automatically occur following manual shutdown of an engine. The EDG 1A failure to reach rated voltage/frequency was a test-mode only start that would not have energized the emergency fuel oil solenoids. A later successful completion of a cool down cycle for the engine showed that each of the individual fuel oil solenoids were operating properly following replacement of the MOVs across their DC coils.

CONCLUSION
Therefore, it is concluded that the emergency fuel oil solenoids had no effect on the engine failure on a start to properly attain rated voltage/frequency.

TEST MODE ENGINE SHUTDOWN SOLENOID
The engine shutdown solenoid (JDGNUV-13 (20SD)) functions to vent the pneumatic engine trip header in the event of a test mode only high priority trip/alarm. The loss of this solenoid would cause the fuel racks to close and result in an engine shutdown. During EDG emergency mode operations, the emergency fuel oil solenoids (1 out of 2) prevent the closing of the engine fuel racks due to a test mode only trip or upon a failure of the engine shutdown. If the engine shutdown solenoid failed to operate properly (energize and block the air vent path), the fuel racks would have remained closed resulting in a loss of combustion during the start due to no fuel being available to the engine cylinders. During the follow-up troubleshooting after the EDG 1A failure to properly start, the integrity/function of the engine shutdown solenoid was verified. This included energizing its 135 VDC coil and verifying that the solenoid valve operated. The coil lead terminations were also checked for tightness along with the newly installed MOV and all were found to be installed correctly.

CONCLUSION
Therefore, since all coil lead terminations were checked for tightness and the solenoid did energize, the loss of the engine shutdown solenoid was ruled out as a possible cause for the failure of EDG 1A to successfully start in the test mode and reach rated voltage/frequency.

The remaining 12-week outage work performed by EMS were inspections of the engine control cabinets/generator brushes and a calibration of the EDG metering loops (VAC, HZ, AMPS, WATTS, VARS, FIELD AMPS/VOLTS) by PR&C. No connection from this work to the engine failure to reach rated voltage/frequency was found.

CONFIDENTIAL

CRDR 2782680 Page 58 of 112

I&C MAINTENANCE WORK

A review of the work performed on EDG 1A by I&C personnel during the on-line outage again found only one (1) WM with any possible impact on EDG manual start capability. WM #2708746 was performed by I&C to inspect/clean/rebuild/lubricate the four (4) pneumatic valves (JDGNUV-243 (PC-8), -245 (USY-9), -247 (USCV-9) & -249 (PC-12)) on the engine that function as a control loop for the engine fuel control cylinder (JDGBSV-241 (USC-7)). The fuel control cylinder extends to close the engine fuel racks and collapses to open them.

On an EDG "A" startup, pneumatic control valve JDGNUV-245 (USY-9) opens to pressurize fuel control valve JDGNUV-247 USCV-9), which closes to vent air from JDGNUV-243 (PC-8) causing the fuel control cylinder JDGBSV-241 (USC-7) to collapse admitting full fuel oil to the engine. Pneumatic valve JDGNUV-249 (PC-12) locks out diesel generator "A" Turbocharger Low Lube Oil pressure trip valve JDGNPV-257 (PEV-18) until engine startup is complete. When starting air is cancelled JDGNUV-249 reopens to allow a vent path for JDGNPV-257 (PEV-18) in the event of a "Turbocharger Low Lube Oil Pressure" test mode only trip/alarm.

If any one of the four (4) pneumatic valves that were worked on under WM #2708746 failed to operate correctly, the end result would be that the engine fuel racks would fail to open properly as required for combustion to occur during an engine test mode start. After this particular PM task (RT #060552) is completed on these four (4) pneumatic valves, the PM specified retest requires that a pneumatic jumper be installed to simulate an actual engine start and verify that the fuel control pneumatic loop works properly to immediately collapse the fuel control cylinder. This retest was performed successfully as documented in the WM. During troubleshooting for the EDG 1A fail to properly manual start, the PM task retest was again successfully performed several times to show that the pneumatic valves for fuel control were working properly after maintenance.

In the event of an EDG emergency mode start, the 135 VDC emergency fuel oil solenoids (JDGAUV-9 (20FO-1), -11 (20FO-2)) energize to block control air to the non-spring side of the fuel control cylinder. This action allows for the spring internal to the fuel control cylinder to expand and collapse the cylinder to the full fuel position in the event that any of the non-class pneumatic control valves (JDGNUV-243 (PC-8), -245 (USY-9), -247 USCV-9) & -249 (PC-12)) fail to function properly.

I&C also replaced the power supplies for the EDG local annunciator panel and also replaced a Moore booster relay (JDGAPY007) that converts engine inlet jacket water pressure to an equivalent pneumatic signal for a gauge on the local engine control panel. No connection from this work to the engine failed start was found.

CONCLUSION

Therefore, the malfunction of one of the pneumatic valves in the test-mode only fuel control loop was determined to not be a likely cause for EDG 1A failure to reach rated voltage/frequency following an engine start.

MECHANICAL MAINTENANCE WORK

The only work performed by RAMS during this on-line outage was to replace the zinc anodes in the spray pond water side of the fuel oil heat exchanger under WM 2766153.

CONFIDENTIAL

CRDR 2782680 Page 59 of 112

CONCLUSION

This work would not have introduced any air in the fuel system that could have resulted in the failure to have combustion during the attempted start of the engine.

CONCLUSION OF ON-LINE MAINTENANCE WORK PERFORMED JUST PRIOR TO FAILURE

It is concluded that none of the work performed during the preceding planned out-of-service maintenance outage could have affected the failure of the EDG 1A to start and reach rated voltage/frequency.

Additional documents reviewed and investigation plan of the Significant Investigation Team follows:

- Reviewed Woodward Governor Technical Manual, for description and operation of the Woodward EGB 50-PLS Governor (see "Description of Equipment, Process, or Activity" for summary of review). It is stated in the manual that "*oil contamination is the major cause of actuator troubles*".... See page 5 of 34 in the VTM C628-001, VTD W290-00003 (Reference 1).

- Reviewed Woodward Governor Technical Manual section "Oils for Hydraulic Controls". In Section 5 of VTM C628-001, VTD W290-00009-2 it states that "*Particles of dirt and water in the oil are the greatest causes of governor or actuator failures*".... See Reference 2.

- Discussed operation of governor actuator with vendor, ESI.

- Reviewed MPR Associates (Cooper-Bessemer Owners Group Managers) report # 2249 on governor troubleshooting and experience. This OE related to the governor actuator is contained in the Operating Experience Summary section of this report.

- Discussed the packing and shipping level of the EDG 50-PLS as received from ESI (this particular governor, serial number 1524051, was rebuilt by Woodward Governor Company – not by ESI). The governors that are rebuilt by ESI are shipped per Level B with desiccant and a plastic wrap to prevent moisture from entering. It is not known the condition or shipping level (requirement is Level C) of this governor when it was received in July 2000 from Woodward Governor Company. It would have been shipped drained as Department of Transportation requires equipment to be drained of oil for shipment.

- Walked down the Palo Verde warehouse and determined that the warehouse is Level B storage. Temperature must be between 40 and 140 deg. F, and our warehouse meets those criteria.

- Warehouse walk down determined that a recent governor actuator that was refurbished by ESI and shipped back to Palo Verde in June 2005 was unwrapped and drained of oil and stored on a pallet on the floor of the warehouse. This is consistent with the warehouse policy during the receipt inspection of governor actuators to unwrap equipment to check for damage, cleanliness, and verification of nameplate information. Purchase Order 500282709 for the governor actuator was reviewed and there were no special requirements for storage (i.e. no special temperature or humidity limits, requirements for re-wrapping governor, or use of desiccant).

CONFIDENTIAL

CRDR 2782680 Page 60 of 112

- Reviewed RM 2609713 (RM for changing and sampling oil for the speed regulating and overspeed governors). Section 4.2.3 states that the method of changing the oil is the feed and bleed method (add oil at the same time and about the same rate as draining the oil) to prevent air from entering the actuator. Approximately 2 quarts are drained (while adding oil to the actuator) into a container, mixed and then poured into a 250ml sample bottle. The bottle is then placed in the LO Lab storage bin to be taken to the lab for testing.

- A walk down was performed with Mechanical Maintenance of RM 2609713 for changing and sampling lube oil for the governor actuators. The following information was gathered during the walkdown.

  - Barrels of oil are transferred from the warehouse and stored in the service building. The barrels are transferred from the service building to the oil storage C-van (Level B storage) next to the service building only when needed. Oil barrels are not left outside exposed to the weather – *water intrusion into the barrels is unlikely at this stage.*
  - The barrels are fitted with hand cranked pumps that extend into the barrels and can draw oil from the bottom of the barrel. Current maintenance practice is to position the pump suction 1-2" above the bottom of the barrel until the oil is nearly depleted. The barrels are then tipped up to one side and the remaining oil is pumped out – *this does not appear to be a potential source of excess water as a sample was taken from a tipped up barrel and the water level was at 273 ppm water (less than the upper limit of 500 ppm for new oil per PCP 2646821).*
  - The tops of the barrels are cleaned off prior to inserting the hand cranked pump – *this indicates good FME and water introduction protection practices.*
  - The pumps are provided with an in-line filter (NapaGold (or Wix Filters) #51453) with 32 micron filter element – *this filter is effective for larger particulates but is ineffective for smaller particles.*
  - Some of the oil is transferred from the service building C-van into separate 5 and 1 gallon secondary storage containers and stored in the Diesel Shop or the C-van that is used for outages. These containers are used frequently for changing oil in governors or topping off the governor site glasses – *no evidence was found of poor secondary container oil storage or transfer techniques during the walk down.*
  - Actual oil change procedure and techniques were discussed with Mechanical Maintenance – *no discrepancies or possible procedure violations (e.g. per RM 2609713) were noted during the discussions.*
  - In conclusion, there were no procedure discrepancies or water/debris intrusion vulnerabilities that were apparent during the walk down. *Governor actuator oil change and topping off techniques remain a possible source of water and debris introduction, as evidenced by the low water content in the 4/2204 oil change (104 ppm) vs. 5159 ppm after the event, and the lack of positive control of the secondary oil storage bottles. However there is no proof/evidence that this actually happened in the EDG 1A governor failure.*

- WMs were written to obtain more recent lube oil samples – oil samples on EDG 2A (8/24/05), 3B (9/7/05), 1B (9/15/05), 1A (9/21/05), and 3A (9/28/05) were found with normal water content and all other parameters in the normal range.

CONFIDENTIAL

CRDR 2782680 Page 61 of 112

SAFETY SIGNIFICANCE

This evaluation considered the Safety Significance of the event due to the effects a loss of governor control. EDG 1A was in a planned maintenance outage and inoperable at the time. The Technical Specification out-of-service time of 72 hours was not challenged by the failure and subsequent replacement of the mechanical governor/actuator and fuel control cylinder. The unit, however, was shut down due to Technical Specification limitations on the modes required for the retest of the replaced governor and the risk of the evolutions. The risk of shutting down without EDG 1A was not significantly higher than the risk associated with the original 72 hour limiting condition for operation (LCO).

No other onsite EDGs have exhibited any degraded conditions, i.e. slow starts, voltage/frequency oscillations at start-up or at rated speed, or lube oil contamination in the most recent samples of governor lube oil. Both trains of preferred off site power were available as well as the redundant Unit 1 train of safety-related on-site AC power. This is an analyzed condition and previously found to be acceptable. For these reasons, the safety significance is low.

CRDR 2782680 Page 62 of 112

CONFIDENTIAL

CONCLUSIONS (DIRECT CAUSE OR FAILURE MECHANISM, ROOT, AND CONTRIBUTING CAUSES)

Direct Cause

The direct cause of the EDG 1A governor failure and subsequent "Incomplete Sequence" was oil contamination of the lube oil in the governor actuator which resulted in abnormal operation.

Supporting Facts

- The lube oil sample taken on 3/29/2005 was analyzed and found to contain 5,159 parts per million (ppm) of emulsified water. Moderate sediment (identified as sand/dirt with metallics) and slightly low viscosity was also found. See lube oil sample 29201 test report in Attachment C.
- 5159 ppm of water is very high compared to previous samples taken on this particular EDG and the other EDGs. See Appendix F
- Rust was found in the governor actuator during inspection and testing at ESI. See Attachment B and Appendix C.
- Woodward Governor Company Technical Manuals VTM C628-001, VTDs W290-00003 & 00009-2 both state that oil contamination and particles of dirt and water in the oil are the greatest/major cause of governor or actuator failure. See Reference 1 and 2.
- Lubrication oil OE review determined that the water in the actuator lube oil demonstrates four out of the five factors indicating a higher magnitude of harmful effects of water to the equipment. See Attachment E.

Root Cause # 1

No root cause could be found for this event. However, there are three (3) most probable root causes determined by sufficient evidence using prescribed root cause methodologies. Rigorous evaluation of the event and the absence of some facts preclude labeling the conclusions as the ROOT CAUSE because of the remote possibility that another cause may exist. The causes will be considered MOST PROBABLE ROOT CAUSES.

There are numerous scenarios that could have introduced water into the governor actuator. These are listed below in order of probability (highest probability ones listed first); with the first three considered the Most Probable Root Causes:

1. Water introduced during the oil fill to begin Test As Received (TAR) and not fully drained at Woodward Governor Company when the unit was refurbished in June 2000. *Not able to be validated or verified, however this is a probable cause taking into consideration previous operating experience involving Palo Verde (EDG 1B on 10/20/2002, CRDR 2562611) and Byron (see OE section) that demonstrates that contaminates may have been introduced at the vendor facility – Woodward Governor Company.*
2. Rust forming during governor actuator being stored in the warehouse drained of lube oil for approximately 9 months prior to installation in EDG 1A during 1R9. *This is a probable cause as any water left in the actuator during the refurbishment and draining of oil at Woodward combined with addition of air and warm ambient temperatures during the 9 months of storage could lead to rust formation in the internals of the actuator. Moisture may*

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CRDR 2782680 Page 63 of 112

have also been introduced during cool down and heat up of the actuator during storage, but this is not considered to be a major contributor to water as 2 ½ teaspoons (the calculated amount of water due to 5159 ppm water in a sump of 2 ½ quarts) would have to be drawn into governor actuator.

3. Water introduced during oil change in April 2004. *Walk down did not indicate any possible source of water or lack of proper FME techniques in changing oil, however this remains a probable cause considering the low water content at the oil change on 4/19/2004 (104 ppm vs. 5159 ppm after the event).*
4. Jacket water leaking past governor cooler o-rings. *Possible, but vendor performs a Test As Received on governor actuators which test for o-ring degradation and no leak was reported. Also inspection of o-rings showed no pitting, cuts, or sign of distortion - like new condition.*
5. Water introduced during addition of oil when oil in sight glass was low ("topping off"). *Walk down did not indicate any possible source of water or lack of technique in adding oil.*
6. Condensation at the engine. *Not likely since no other governor actuator has seen the large spike in water in the oil with identical operating/ambient conditions.*
7. Water introduced during initial oil addition in April 2001 and/or during oil change in 2004 due to water being present in oil storage barrels located in the C-van at the service building. *Walk down revealed no indication of water contamination in the room. Draw-off is from about 2" from the bottom of the barrel which should preclude drawing water into secondary oil container. Also an additional test was performed with a near empty barrel tipped up and the resultant sample showed low water content.*
8. Water contained in oil barrels from the oil vendor. *Receipt inspection documentation reviewed and interview with Lube Oil Lab Team Leader indicated that the specified maximum water level is 500 ppm (lower than our 5159 ppm). Lube Oil Lab Team Leader stated that they never have tested and found water out of specification in the oil barrels received from the oil vendor.*
9. Water introduced during transport of governor either to vendor or back from vendor in 2000. *No evidence of this due to the short time frame involved in shipping the actuator (3-4 days).*
10. Leak in the governor actuator cooler tube (i.e. hole in the tube). *This was discounted by the vendor in a cooler test on 7-22-05. See Attachment F for cooler test report.*

Supporting Facts

- Based on the above, the most probable root causes are:
  1. Water introduced during the refurbishment of governor at Woodward Governor Company and not fully drained following refurbishment.
  2. Rust forming due to long term storage of refurbished governor actuator in warehouse drained of oil.
  3. Water introduced during oil change in April 2004.

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CRDR 2782680 Page 64 of 112

OTHER ISSUES/LESSONS LEARNED

Another issue characterized as a lesson learned that should have been considered during the troubleshooting phase is the use of repeat starts of the diesel generator to gather additional information for further troubleshooting and root cause determination. Since it was determined early in troubleshooting that the governor actuator was suspect, no additional starts of the engine was requested prior to removing and replacing the actuator. No Engineering Troubleshooting Action Plan was developed for this event because it was believed by plant personnel that is was evident what the suspect equipment was (i.e. governor actuator).

Additional engine starts (at least one) would have enabled Engineering, Maintenance, and Operations personnel to be placed around the engine to detect any abnormal or unexpected engine condition. This may have aided in troubleshooting and root cause determination.

Engineering and Maintenance have discussed this issue and has determined that in future troubleshooting, Operations will be asked to start the diesel generator in the same configuration (i.e. test mode or emergency mode start) and personnel will be placed around the engine to determine any abnormal conditions.

This is deemed a Lessons Learned issue for the DG System Team.

CRDR 2782680 Page 65 of 112

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ATTACHMENT 11

Rev. 0

PALO VERDE

CRDR Number: **2825485**

Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup

Event Date: **August 26, 2005**

Approval Signatures

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Significant Root Cause Investigation Report

CRDR 2825485: *Reactor Trip on Steam Generator High Level Following Transition from Auxiliary to Main Feedwater during Unit 1 Startup*

Table of Contents

EXECUTIVE SUMMARY 3
DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY 4
DESCRIPTION OF EVENT, FAILURE, OR CONDITION 4
COMPLIANCE WITH PROCEDURE & EXPECTATIONS 5
SAFETY SIGNIFICANCE 8
CONCLUSIONS (DIRECT CAUSE, ROOT, AND CONTRIBUTING CAUSES) 8
OTHER ISSUES 12
OPERATING EXPERIENCE SUMMARY 13
CORRECTIVE ACTIONS 14
SEQUENCE OF EVENTS 16
TRANSPORTABILITY 16
MAINTENANCE RULE GOAL / FUNCTIONAL FAILURE 17
ROOT CAUSE ANALYSIS METHODS 17
LIST OF DOCUMENTS REVIEWED 17
LIST OF PEOPLE CONTACTED 17
LIST OF ATTACHMENTS 18
LIST OF APPENDICES 18
APPENDIX A – Investigation Charter 19
APPENDIX C: Hazard- Barrier-Target Analysis 20
APPENDIX C – Human Performance Analysis 24
APPENDIX D – Events & Causal Factors Chart 29
APPENDIX E – Analysis of DFWCS Performance 30

Notice: This is a significant Condition Report Disposition Request (CRDR) root cause investigation report prepared in accordance with applicable Palo Verde Nuclear Generating Station procedures. It is a self-critical evaluation of events, activities, and processes intended to fully understand and correct a significant condition adverse to quality per 10CFR50, Appendix B. The consequences of the significant adverse condition, if any, are described in the report. Unless otherwise stated, PVNGS was at all times operated safely and in compliance with its operating licenses.

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EXECUTIVE SUMMARY

The Unit 1 reactor tripped during a plant startup at 1824 hours on 08/26/2005. Main Feedwater had been placed into service and the digital control had been placed into automatic. Uncomfortable with system performance, the secondary control room operator (SO) attempted to restore levels. After several attempts to adjust levels in both manual and automatic, excessive feed rate increased steam generator water level to near trip setpoint before feed was secured. As the cooler water expanded, high steam generator level setpoint was reached resulting in an engineered safety features (ESF) actuation of main steam isolation system (MSIS) and Reactor Trip at 91.5% narrow range (NR) level.

This investigation was chartered to determine the facts and causes of the human performance and process issues that permitted the overfeeding of Steam Generators that resulted in a Unit 1 Reactor Trip on high SG level and MSIS actuation on 8/26/05. The investigation determined the Reactor Trip was caused by a combination of individual and team human performance deficiencies and inadequate resolution of identified digital feedwater control system (DFWCS) issues.

The Direct Causes were individual and crew failures to implement expected requirements and good practices prescribed by their training and delineated in procedures.

Root Cause # 1: Consistent standards of performance by Unit 1 Operations Crew C were not sufficiently anchored.

Root Cause # 2: Feedwater control system performance issues at low power levels have not been effectively resolved since the digital upgrade. This has led to acceptance of operational strategies to cope with system instability at low power levels.

Contributing Cause # 1: Procedures 40DP-9FT01 & (2), *Feedwater Pump Turbine A(B)*, are not sufficiently human factored for all users, making them susceptible to performance error and resultant system perturbations.

Contributing Cause # 2: Common belief existed among licensed operators that the DFWCS can not reliably control SG level well at low power. This belief was not based on actual performance data and led to acceptance of the condition and mitigating strategies.

Contributing Cause # 3: Training was not commensurate with the unidentified difficulty of putting the DFWCS into auto operation given the current procedure detail and system design. This has resulted in mis-operation of DFWCS components while in single element control.

Corrective actions have been initiated to correct all causes identified.

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DESCRIPTION OF EQUIPMENT, PROCESS, OR ACTIVITY

DFWCS Single Element Control Functional Description

The Digital Feedwater Control System (DFWCS) is designed to provide automatic steam generator water level control from the time a main feedwater pump is placed into service at about 2% reactor power. In this low power mode the FWCS is in a Single Element Control Mode and uses Steam Generator (SG) narrow range level as the measurement for the developing the controller error relative to an Operator specified setpoint. To assist the level controller with anticipating load changes and the resulting shrink and swell of SG level, an output bias is added to the controller output processed from an impulse module signal developed from the Steam Bypass Master Controller Demand output and/or the Turbine Load Index output. To understand the responsiveness of the Single Element Control tuning, it is important to understand the impact of cold feedwater on the SG and that the controller is tuned adaptively from feedwater temperature. For a typical startup with feedwater temperature around 100°F, the responsiveness of the FWCS is tuned to be very slow. This is to compensate for the impact of the cold feedwater on the RCS and the amount of time it will take before the water will heat up and increase the SG level. As power is increased to about 11% and the main turbine is placed on line, feedwater temperature has increased to approximately 250°F and the tuning settings have become more responsive. At 14% reactor power, the FWCS shifts to Three Element Control.

To facilitate the Operators interface with the system, two methods of operating the system are provided. The Operator may chose from a graphical interface using a mouse for selecting and operating system features or the Operator may use an older style Auto/Manual Station interface. Both interfaces operate in parallel and reflect changes made on the other interface. Each interface however does provide a slightly different set of human factors to deal with. Additionally a feature for providing a smooth transfer without system perturbation between valve controllers and the master controller is available by placing both valve controllers in manual. This places the master controller in the tracking mode until a valve is placed into auto. When the valve is shifted from manual to auto, the master controller will come out of tracking into manual with the exact setting to control the valve at its existing position, thereby executing a smooth transfer without system perturbation. This method of transferring to auto is not used in procedures today. The procedures today attempt to do this transfer by manually matching the controller outputs. Procedures 40OP-9FT01, *Feedwater Pump Turbine A,* and 40OP-9FT02, *Feedwater Pump Turbine B,* provide the current guidance.

DESCRIPTION OF EVENT, FAILURE, OR CONDITION

Following the transition from auxiliary feed to main feed in Unit 1 on 08/26/05, automatic steam generator feedwater level control was not smoothly established. (See sequence of events and events & causal factors charting sections of this report for the detailed chronology of events.) The initial attempt at transfer to auto per step 4.3.13 of 40OP-9FT01, *Feedwater Pump Turbine A,* resulted in a no feed condition. Recognizing this was not the proper result of this step, the secondary control room operator (SO) returned to manual valve control briefly to re-establish feedflow and again attempted to establish automatic control. The result of the second evolution was an underfeed condition that set a trend of gradually lowering SG levels. Uncomfortable with being lower than the 30 to 40% narrow range level band prescribed by the procedure, several increases to the level setpoint were made in an attempt to restore sufficient feedflow to restore SG levels within band. Uncomfortable with the continuing slow SG level decrease, the SO again returned to manual valve control to increase feedflow until SG level was observed to be increasing. The DFWCS was again briefly returned to automatic operation when it appeared to the SO to be underfeeding again. After a setpoint adjustment in manual, the DFWCS was again returned to automatic operation where the level rapidly increased to about 76% NR level, when the DFWCS was taken to manual and valve setpoint reduced and then closed. The resultant expansion as the

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feedwater temperature increased from about 100°F to nearly 565°F caused the level to swell to the main steam isolation signal (MSIS) setpoint of 91.5% NR level initiating a reactor trip. The investigation has determined this event occurred because personnel failed to implement expected requirements and good practices prescribed by their training and delineated in procedures. The following section identifies the specific procedural requirements and policies that were not properly implemented.

COMPLIANCE WITH PROCEDURE & EXPECTATIONS

Recently, site-wide attention has been given to procedural adherence and compliance with written expectations at Palo Verde and is being addressed through the corrective action program. This investigation identified the following procedural and departmental practices non-compliances:

Issue	***Requirement of Procedure Step***
Step 4.3.13 of procedure 40OP-9FT01, *Feedwater Pump Turbine A*, performed incorrectly resulting in the downcomer control valve stroking closed when placed in Automatic. This affected the control system response resulting in a longer delay in restoring level to the desired setpoint and contributed to the operators decision to make subsequent manual adjustments. *For the valve to remain as-is when placed in Automatic the Demand and the Output of the Downcomer controller must be equal.* *In this Unit 1 event the downcomer valve initially went closed when placed in Auto, which is indicates the Demand value was less than the Output value. If the Operator selects Demand on either Downcomer or Master controller, indication will change showing matched Demand/Output, however, Demand will quickly return to the previous value when the button is released. On 08/25/05 in Unit2, misperformance of this step this resulted in an overfeed condition which was corrected by the crew before trip setpoints were reached. The overfed in Unit2 was most probably caused by matching Master to Downcomer outputs. This sets up a five fold increase in feed flow.* *When placing the downcomer controller in Auto the valve will go to the position the Demand calls for. If the output and Demand are equal the valve will remain in the as-is position.*	**Procedure 40OP-9FT01, *Feedwater Pump Turbine A,*** 4.3.13 Transfer SG 1 level control to Auto by performing **ALL** of the following. ___ 1. Manually adjust SGN-FIC-1111, SG 1 Feedwater Master until the "Demand" and the "Output" setpoints on SGN-FIK-1113, SG 1 Downcomer Valve Control are approximately equal. ___ 2. **WHEN** SGN-FIK-1113, SG 1 Downcomer Valve Control "Demand" and the "Output" setpoints are approximately equal, **THEN** place SGN-FIK-1113, SG 1 Downcomer Valve Control in Auto. ___ 3. Adjust the manual output on SGN-FIC-1111, SG 1 Feedwater Master as necessary to maintain steam generator levels 30 to 40% NR. ___ 4. **WHEN** SG 1 level is stable and between 30 and 40%, **THEN** perform **BOTH** of the following: ___ Adjust SGN-FIC-1111, SG 1 Feedwater Master Auto setpoint to approximate actual steam generator level. ___ Place SGN-FIC-1111, SG 1 Feedwater Master in Auto. ___ 5. Slowly adjust SGN-FIC-1111, SG 1 Feedwater Master Auto setpoint to 35% NR.
FWCS Process Trouble alarmed when the Control Operator placed the DFWCS into Manual. The Alarm was not (or not effectively) communicated to the CRS. The CRS stated he was not aware that the SO had placed the controller into Manual.	**OPD 1, *Operations Department Practices* - Alarm Management Standards - Unexpected Alarm** Expected alarms are communicated to the CRS. • The communication may be as simple as "expected alarm". Unexpected alarms are communicated to the CRS.

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Issue	*Requirement of Procedure Step*
The SO placed the DFWCS in Manual in an attempt to restore level to the desired band (30-40%) and failed to inform the CRS or the crew. The TRO stated that he did not inform the CRS that Steam Bypass control valves were closing (due to lowering RCS temperatures and subsequent SG pressure) The TRO manually closed and reopened valve 1004 and in an attempt to keep flows balanced as directed by the CRS. The Reactivity RO stated he had informed the SO that he was feeding excessively and didn't recall informing the CRS. The CRS (and STA) became aware of the plant status when the RO reported he had lost Pressurizer Heaters	**40DP-9OP02, *Conduct of Shift Operations*** **12.0 MANUAL OVERRIDE OF AUTOMATIC SYSTEMS** 12.5 Concurrence shall be obtained from the CRS prior to placing any automatic controller in manual or returning any controller to automatic. 12.6 All Control Room personnel shall be informed of the status of the controller and changes in their expected actions in the event of a plant transient with the automatic controller in manual. 12.9 Frequently monitor automatic controllers which are in manual mode, particularly during transient conditions. Of particular importance are controllers on the FWCS, SBCS, and PPCS systems.
Peer Checks were not conducted when the SO placed the Downcomer and Master Controllers into Automatic.	**OPD 1, *Operations Department Practices* - Shift Turnover and Briefings** Pre-job briefs are conducted prior to performing all evolutions. Irretrievable actions and establishment of appropriate peer checks are determined during these briefs. **OPD 1, *Operations Department Practices* –Verification Practices** The pre-evolution brief or tailboard will be used to identify any irretrievable actions and establish appropriate peer checks. Peer checks should be used when performing evolutions that could result in • A unit trip or reduction of generation • A change in the reactivity condition of the core • An inadvertent automatic system or component actuation • A change, from the Control Room, in the configuration of the electric plant. • A change to the operation status of equipment required by the "Shutdown Risk Assessment" during plant outages. • The above list is not all-inclusive. There may be other evolutions, dependant upon plant conditions, where additional peer checking may be appropriate. This determination can be made by the CRS or licensed operator. ***Palo Verde Expectation and Standards Preventing Events* - Peer Checking Expectation** Peer-checking will be used when performing steps or actions that are irreversible. The peer checker must always assume the performer is about to make a mistake.
The CRS (and STA) did not become aware of the plant status until the RO reported he had lost Pressurizer Heaters. The STA was conducting shift turnover activities with the on-coming STA. The CRS had been peer checking the CEA withdrawals at the onset of the overfeeding and cooldown (see peer checks below)	**OPD 1, *Operations Department Practices* - Control Room Monitoring Standards** Operators are alert and attentive to control board indications and alarms. Board indications are monitored frequently. Prompt actions are taken to determine the cause of operating abnormalities and associated corrective actions. Early problem detection is provided by an emphasis on attentive monitoring, issue investigation, and trending of plant status.

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Issue	*Requirement of Procedure Step*
Although the CRS was following expectations by providing Peer Checks of the Reactivity Operator, and the CRS and RO withdrawing CEAs were monitoring RCS temperature, they were not fully aware of the magnitude of changes the SO and TRO were making to main feed flow and Steam Bypass, this was primarily because communications were less than adequate and secondary side changes are not immediately seen in primary side parameters. CRS did not maintain awareness of other control room activities and alarms during this time period.	**40DP-9OP02, *Conduct of Shift Operations*,** states: Reactivity maneuvers shall be conducted with the highest levels of control and monitoring. Reactivity Management expectations are contained in Operations Department Practices (ODP-01). **ODP-01, *Operations Department Practices* – Reactivity Management,** The CRS ensures the performance of peer checks for all reactivity manipulations. • The CRS will provide direct oversight of all manual CEA manipulations. A designated SRO may provide the required CRS oversight and verification during specific evolutions, such as reactor startup, swapover and CEA testing. **OPD 1, *Operations Department Practices* - Command and Control Standards** The CRS provides supervisory oversight for all activities and evolutions conducted in the control room. Command and control includes provisions of: • Approval and oversight of all reactivity changes • Monitoring members of the control room staff
The Secondary Operator (SO), after placing the DFWCS in automatic, returned to manual when the downcomer closed indicating he knew the valve closure was not the desired state. The SO failed to exercise STOP WHEN UNSURE by continuing to attempt Automatic operation. He also failed to inform the CRS of the condition.	***Palo Verde Expectations and Standards Preventing Events* – Questioning Attitude/Stop When Unsure** Use a questioning attitude when information received does not seem consistent with our knowledge and training or when things "don't seem right". Stop if you have a feeling something is not right.
Failure to provide adequate log entries or record log entries.	**40DP-9OP22, *Operations Logkeeping*,** **3.2 SM/CRS Logging Responsibilities** 3.2.1 Information entered in the Control Room log by the SM/CRS shall include, but is not limited to, the following: • Entering or exiting all Technical Specification Conditions should be recorded by an SM/CRS or STA in Autolog's LCO Log. Details about the entry shall be added in the subsequent Master log window that automatically pops up after the LCO Log entry. There are many complexities of how LCO ACTIONS can be entered and exited. LCO entries should be managed using Appendix A as a standard. • Entering and exiting all Part 72 Certificate of Compliance Technical Specifications as delineated in Appendix A (Dry Cask Storage Operations). • Commencement and completion of loading of Vertical Concrete Casks (VCC#_____). • Scheduled major equipment status changes 3.2.2 Information entered in the Unit log by the SM/CRS shall include, but is not limited to, the following: • Incapacitation of Licensed individuals • Personnel injuries requiring off-site medical attention • Emergency Plan implementation • Operability Determinations • Notifications to government agencies, or Vice President or above • Significant changes in radiological conditions • The Shift Manager/Control Room Supervisor will evaluate significant issues that require Operator action to resolve. • Chemistry Action Levels which adversely impact power generation • Major transients or critical evolutions • Emergent or unscheduled major equipment status changes • Entry into RED RMALs (Risk Management Action Levels). • Exit from RED RMALs (Risk Management Action Levels). • Mode changes

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SAFETY SIGNIFICANCE

There was no nuclear safety impact from this event. However the unplanned trip did challenge reactor protection systems. Although the MSIS was initiated at 91.5% NR level as designed, the impact to secondary equipment was minimized due to the low steaming rate following the cold feedwater and closure of the SBCVs prior to trip. Reactor power increase due to the cold feedwater effect on the core was fully evaluated. All plant performance and safety system evaluations required by 90DP-0IP06, *Reactor Trip*, were completed prior to the PRB meeting that recommended plant restart on 08/27/05. The completed Standard Trip Evaluations can be found in SWMS attached media as **Attachment C** for this CRDR. These evaluations include the following:

- Plant Transient Review Assessment
- Safety Limit Review Evaluation
- Plant Performance Evaluation
- Plant Protection System Response Evaluation
- Control System Response Evaluation
- Nuclear Safety Assessment

CONCLUSIONS (DIRECT CAUSE, ROOT, AND CONTRIBUTING CAUSES)

Direct Cause #1

The assigned dayshift licensed operator for Steam Generator feedwater control failed to request CRS concurrence when placing the digital feedwater control system in manual when level was lower than desired under automatic control. This communication failure isolated the individual from supervisory oversight and the crew's ability to assess the overall plant condition. Subsequently, feedwater flow was increased by operator action at a rate in excess of the rate required to compensate for the steaming rate at that power level and resulted in a high steam generator level and subsequent MSIS and reactor trip.

Supporting Facts

- FWCS Process Alarm (SFYS2) alarmed when the control system was placed in manual the first time. Subsequent alarm did not occur due the previous alarm not being acknowledged and cleared from the FWCS alarm screen. This alarm was not communicated to the CRS.
- The SO placed the DFWCS in manual at 1815 and at 1819. The SO returned the controllers to Automatic with level at 22% Narrow Range (NR) and flow reduced from 800,000 to 90,000 lbs mass/hr. Approximately 1 minute later, with level at 26% NR, the controller was shifted to Manual again. *(Actual flow required was about 80,000 lbs mass/hr).* Flow increased to 1E+6 and the controller returned to Automatic. With the controller in Automatic, flow remained high. The CRS stated he believed the control system was in Automatic during this timeframe (He was unaware of the manual manipulations). (System data and interviews)
- With the DFWCS in manual the second time flow was increased to 1E+6 lbs mass/hr. This is more than five times the flow necessary to maintain Steam Generator level at 3% power.
- The initial direction the CRS gave to the SO, in an attempt to restore SG level, was to "match feed flow with steam flow". Steam flow at 3% power is unreliable.

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- At 56% NR The SO placed the controller in manual and began closing the downcomer valve. When level reached approximately 82% the downcomer valve was fully closed.
- The SG level continued to increase due to the heating and expansion (swell) of the cold feedwater addition up to the trip setpoint of 91%.

Direct Cause #2

Crew members failed to provide the team support needed to ensure individual errors are promptly identified and corrected.

Supporting Facts

- A FWCS Process Alarm annunciated when the SO place the controller in Automatic. The alarm was not communicated to the CRS by the Control Operator manipulating the controls or any other crew member.
- The reactivity RO stated he didn't recall informing the CRS that Reactor Coolant temperatures were dropping. His communication of the condition was directed to the Control Operator controlling feedwater.
- The TRO stated he didn't recall informing the CRS when SBCVs began closing (a result of the overcooling due to excessive feed). (Interviews)
- One crew member said he could not recall a control room pre-job brief to place the main feedwater pumps in service and into automatic single element control. (Interviews)
- Peer checks were not mandated by the CRS and were not performed when placing the DFWCS into automatic.
- The pre-job brief for this evolution did not include details such as Peer Checking requirements and that the evolution would include placing the control system into Automatic. Operations Department Policy for the conduct of pre-job briefs states that pre-evolution brief or tailboard will be used to identify any irretrievable actions and establish appropriate peer checks.
- Not all crew members were aware of plant status. The TRO and STA stated they were not aware that their shift would be placing the DFWCS into Automatic.

Root Cause # 1

Consistent standards of performance by Unit 1 Operations Crew C were not sufficiently anchored.

Supporting Facts

- See Supporting Facts for Direct Cause #1 & 2 above for pre-job brief and communication inadequacies.
- See section on Compliance with Procedure & Expectations for specific shortfalls.

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Root Cause # 2

Feedwater control system performance issues at low power levels have not been effectively resolved since the digital upgrade. This has led to acceptance of operational strategies to cope with perceived system instability at low power levels.

Note that Effective Problem Resolution *as identified in Root Cause #2 extends throughout the Palo Verde organization as previously identified in the NRC PI&R cross-cutting issue. The Priority 2 Site-wide actions taken to address this are being taken under Significant CRDR 2780286.*

Supporting Facts

- DFWCS operational problems identified on CRDRs have not identified the cause of the inconsistent performance. (See Operating Experience section and Appendix E)
- The response of the single element control has been "de-tuned" to the maximum level based on engineering judgment. This was to prevent overfeeding due to the swell of cold (100 °F) feedwater during heatup to operating temperature (565 °F). (Interviews and CRDR evaluations)
- Performance analyzed over the past two years of placing DFWCS into automatic single element control revealed that 6 of 15 (40%) startups/power ascensions exhibited unstable and/or transient feed flow conditions. (See Appendix E)
- Procedures. 40DP-9FT01(2), Feedwater Pump Turbine A(B), were revised in 2004 an attempt to improve performance of this evolution, however, performance since implementation has resulted in one Unit trip and two additional unstable/transient feedwater conditions. (See Appendix E and Contributing Cause #1 below)

Contributing Cause # 1:

Procedures 40DP-9FT01 & (2), *Feedwater Pump Turbine A (B)*, are not sufficiently human factored for all users, making them susceptible to performance error and resultant system perturbations.

Supporting Facts

- 40DP-9-FT01, *Feedwater Pump Turbine*, is technically correct. Performing the associated steps correctly, as written, will result in a smooth transfer to auto without changing downcomer valve position when placed into automatic. (This was confirmed through Simulator walkthrough and 60% of recent startups analyzed in Appendix E.)
- The procedure does not include information to alert the operator of the digital input memory (wind-up) processing characteristics of the master controller which may affect stability under certain conditions.
- Incorrect performance of the steps to place the controllers into automatic results in the downcomer valve changing position (either open or closed). This results in additional time for level to reach the desired setpoint sometimes requiring operator intervention.
- Simulator instructor recalls operators informally reported some difficulty with step 4.3.13 during training on the procedure change. (Interview following event.)
- Two licensed operators were observed performing procedure step 4.3.13 incorrectly in the simulator (Identified during simulator walkthroughs conducted after the event.)

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- Prior to the Unit trip, when the downcomer controller was placed in Auto (twice) the downcomer valve went closed. This condition can only be reproduced by not matching the demand and output values on the downcomer controllers.
- The Unit 2 startup/power ascension that occurred the day before the Unit 1 trip resulted in the downcomer valve going open when the controller was placed in auto. The individual who performed this task reproduced the same response in the simulator. When asked to reproduce the actions, the individual incorrectly set the master controller output to equal the output of the downcomer controller. The Demand on the downcomer controller was not equal to the output.

Contributing Cause # 2:

Common belief existed among licensed operators that the DFWCS can not reliably control SG level well at low power. This belief was not based on reviewing actual performance data and led to acceptance of the condition and mitigating strategies.

Supporting Facts

- Many licensed operators believed the DFWCS was not reliable in maintaining stable feedwater levels when at low power levels. (Interviews)
- Reliance on individual experience and unconfirmed anecdotal accounts influenced operator opinion of low power DFWCS stability. This was not an isolated, single occurrence, but rather a common mindset (culture) regarding expected system performance at low power levels. (Interviews)
- Past evaluations of system performance have not resulted in actions (procedure or training) to address how the system is operated. (See CRDR and OE review section. *Note that CRDR 2760186 evaluation addressed stability and SBCV but had no CRAIs.*)
- Actual performance data shows that most of the time (~60% - See Appendix E) the DFWCS operates well at low power.
- Actual performance data shows that often (~40% - See Appendix E) the DFWCS operates experiences significant level perturbations at low power causing Operators to manual system control.

(Once manual control is taken during level perturbation and then returned to auto, the digital memory (wind-up) influences system operation usually resulting in multiple shifts from auto to manual until the system becomes more responsive with increased feedwater temperature at higher Rx power.)

Contributing Cause # 3:

Training was not commensurate with the difficulty of putting the DFWCS into auto operation given the current procedure detail and system design. This has resulted in mis-operation of DFWCS components while in single element control.

Supporting Facts

- Licensed Operator Continuing Training (LOCT) does not typically train this evolution. (Interviews) This evolution is not required training identified by the job task analysis.
- There is no current job performance measure (JPM) for this task in LOCT.

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- Performance issues associated with this evolution have not been forwarded to training for analysis. (Interviews) (*PI&R related: Site-wide actions taken to address this are being taken under Significant CRDR 2780286*)
- Training was conducted in 2004 on the procedure change to 40DP-9FT01(2), Feedwater Pump Turbine A(B). Since the training was conducted there have been at least five instances where SG levels were difficult to control (See Appendix E). In at least two of these cases (8/25 & 8/26/05) misoperation of the DFWCS caused the level instability, one of which resulted in reactor trip and MSIS. (*PI&R related: Site-wide actions taken to address this are being taken under Significant CRDR 2780286*)
- Following the training in 2004 for transferring from manual to auto DFWCS, no formal feedback was provided noting procedure ambiguity of step 4.3.13. Anecdotal instructor recollection is that Operators had concerns with the wording. (See Appendix E)
- Many operators were not aware of the impact SBCV demand had on the DFWCS performance. (Interviews following event)
- The training conducted in 2004 was provided in the simulator was to the entire crew with only one crew member actually performing the task.

OTHER ISSUES

Steam Flow Indication

WM 2825487 was worked to evaluate why the SG1 steam flow indication was on scale. The transmitters were found to be reading high within their tolerance band. At low power, steam flow is not a valid indicator and for that reason is not used by the FWCS for controlling SG level. CRDR 2825593 has been initiated to further evaluate this indication concern.

Log Keeping

During the course of this investigation the team noted that the Unit/Control Room logs did not contain entries for completed operational evolutions/steps. This was also true for the Unit 2 event which occurred the previous day.

Unit 2 Reactor Power Increase With CEA Withdrawal during FWCS Instability

While reviewing Adverse CRDR 2825635 (Unit 2 FWCS response requiring operator intervention) it was discovered that during the power ascension the operating crew continued reactivity addition using CEAs while experiencing difficulty establishing automatic feed water control. The FWCS was being transferred into automatic using 40OP-9FT01, Feedwater Pump Turbine A. Following the shift to automatic on the Master Controller, flow increased at a rate resulting in increasing Steam Generator levels, lowering RCS temperature, and increasing reactor power. The excessive flow was believed by the crew to be due to the slow system response. As a result, the crew allowed continued automatic FWCS operation and continued the pre-planned power ascension by withdrawing CEAs to raise reactor power and RCS temperature. The crew also believed that the power increase would improve the conditions necessary to stabilize the FWCS response.

Although there was no direct negative consequence as a result of the crew's actions, increasing reactor power under these conditions was not consistent with conservative operating principles expected by Operation's management. Operations Department Practice (ODP 1, rev. 2) for Reactivity Management states; "CEAs will not be manually withdrawn in an attempt to restore primary system temperature changes during an unplanned transient".

CRDR 2830078 was initiated and classified for apparent cause evaluation per 90DP-0IP10, Condition Reporting. The expected outcome of this evaluation is that measures will be taken to address the cause(s) permitting reactor power to be increased during system instability so that this does not again occur at Palo Verde. Adverse CRDR 2825635 was closed to this Significant CRDR for cause determination.

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OPERATING EXPERIENCE SUMMARY

Industry Operating Experience

Many examples of difficulties controlling SG levels are documented in industry operating experience. A synopsis of representative events and lessons learned can be found in the following documents:

- INPO SEN 210
- INPO SER 9-95
- INPO SOER 84-4
- *Full text and additional Industry Operating Experience Found in* ***SWMS Attachment I***

A common theme noted during these reviews was the importance of management monitoring of personnel to ensure procedures are being implemented as expected to avoid the overfilling effect of cold feedwater expansion on SG level.

PVNGS Operating Experience

Appendix E identifies recent Palo Verde experience with DFWCS operation:

The following CRDRs were selected for review due to their similarity to this event:

CRDR # ***Classified as***	***Description***	***Due*** ***Status***
2825635 apparent cause	Feed water control system (FWCS) response at lower power levels in automatic is unacceptable and required operator intervention to prevent loss of steam generator control during the U2 08/25/05 startup. Engineering needs to review system response and any recent changes to the system to determine why constant operator assistance is required to maintain steam generator levels. CRDR initiated 08/27/05. *This CRDR was closed to this significant investigation.*	09/27/05 Evaluate
2815878 adverse	The digital feedwater control systems and associated control valves in each Unit present the Operator with added challenges during shutdowns and low power operations. Often requiring the operator to take the downcomers to manual and/or fast close the economizer valves to prevent overfeeding. This CRDR has been generated at managements request to provide a vehicle for engineering to evaluate these generic issues on a site wide basis. *Initiated 07/14/05.*	08/14/05 Evaluate **Overdue**
2760186 adverse	Large SG level oscillations occurred in the 6 to 12% power range during startup in U3 on 12/08/04. Manual Control taken and dedicated operator stationed. *Evaluation referenced DCR.* ***No actions taken to improve operator control.***	01/08/05 Turnover
2754796 adverse	Inappropriate gain applied to controller for DFWCS. Impact of change from Rx power to FW temp not fully evaluated for impact over range of operations. *Evaluation references DMWO.* ***No actions taken to compensate for condition.***	11/17/05 Working

Operating Experience Review Conclusions

Palo Verde has had several opportunities to correct identified weaknesses in DFWCS performance identified during review of both external OE and Palo Verde events. This event demonstrates that these efforts have generally been narrowly focused on DFWCS system instability and sluggish control at low power and have not been successful at consistently ensuring successful system operation (CC#1, 2, 3). Although discussed in an evaluation, No CRAIs were initiated to change procedures or training. The training provided independent of the corrective action program was not fully effective in sustaining a high level of task performance as evidenced by this event (CC#3). Standards of Conduct were not sufficiently instilled in the Unit 1 Crew C (RC#1). Acceptance of inconsistent DFWCS system performance at low power was common among operators (RC# 2).

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CORRECTIVE ACTIONS

Completed or in place (e.g., immediate, remedial, or interim)

Cause	Action Description	Completed
DC#1&2 *Immediate*	Operation's management removed affected personnel from shift duties until preliminary investigation determined extent of performance deficiencies.	08/27/05
DC#1&2 *Remedial*	Operation's management coached those personnel removed from shift on personal accountability to ensure compliance with Operations Departments Principles and procedures prior to resumption of shift duties.	08/27/05
DC#1&2 *Interim*	Just-in-time training (JITT) was conducted for the licensed Operator placing the first Main Feed Pump in service including placing the DFWCS into automatic prior to the Unit 1 power ascension above 3%.	08/27/05
DC#1&2 *Interim*	The Management Review Team (MRT) met to review the preliminary findings and direct investigation resources in accordance with 90DP-0IP06, *Reactor Trip*. At second the MRT, the Standard Evaluations (*SWMS Attachment C*) required per the Reactor Trip procedure were reviewed and direct cause of human performance failure to request permission to take the DFWCS to manual from auto was identified. Directly following the MRT, the Plant Review Board (PRB) convened to review the Standard Evaluation and voted to recommend Unit 1 restart.	08/27/05

Required to Prevent Recurrence (CRDR Priority 2)

Cause	CRAI #	Action Description	Owner	Date Due
RC#1	2834520	Operation's management will discuss with the involved licensed Operators and their supervisors their shared accountability in ensuring compliance with Operations Departments Principles and procedures. Specific departures from expected behaviors will be identified. Individual responsibility for each other's success will be clarified. Expectations for both individual and team accountability will be reinforced.	T. Radtke M. McGhee	11/18/05
RC#1	2834523	Operation's management will evaluate crew performance and composition to ensure optimal matching of personal strengths necessary to sustain a culture committed to improving performance within the License and Operation's Departmental Practices and implementing procedures. If necessary, a crew performance improvement plan should be successfully completed or consideration for crew re-alignment should be made.	T. Radtke M. McGhee	01/20/06
RC#2	***Note that Effective Problem Resolution*** *as identified in Root Cause #2 extends throughout the Palo Verde organization as previously identified in the NRC PI&R cross-cutting issue. The Priority 2 Site-wide actions taken to address this are being taken under Significant CRDR 2780286.*			

Corrective Actions (CRDR Priority 3)

RC#2 (DFWCS Performance at Low Power)	2834525	Engineering will modify DFWCS for all three Units to improve SG level control under single element control at low power. This should include consideration of the incorporating following improvements discussed during this investigation: • Tune the system for slightly more responsiveness at low power • Remove or modify the distracting steam flow display until in a more reliable range (~14%) • Remove or modify the anticipatory SBCV/TLI demand bias input to single element control at low power. • Develop a DFWCS display graph showing actual feedwater flow versus anticipated flow as Rx power increases from about 2 to14%. Visual alarm (flashing or color) could be included when flow deviates from operating band. *This action may be milestoned.*	D. Smyers G.Anderson	01/20/06
DC#1&2 RC#2 Interim	2834526	Just-in-time (JITT) shall be **developed** for placing the first Main Feed Pump in service including placing the DFWCS into automatic. This should include lessons learned from the 08/26/05 Unit 1 trip.	J. Wood T. Stahler	10/29/05
DC#1&2 RC#2 Interim	2834528	Just-in-time (JITT) shall be **conducted** for placing the first Main Feed Pump in service including placing the DFWCS into automatic prior to the performance of any Unit power ascension above 3%. This requirement shall remain in place until corrective actions for training and procedures are completed.	J. Taylor J. Wood	11/18/05

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CC#1	2834529	Revise procedures 40DP-9FT01 & (2), *Feedwater Pump Turbine A(B)*, to human factor for all licensed operators when transferring from manual to auto SG level control. The following changes should be **evaluated** for inclusion: 1. Create separate steps for Auto/Manual Station control and Trackball control of the DFWCS to include applicable terminology for each. 2. Include caution describing impact of SBCV and SG blowdown on DFWCS. 3. Identify criteria for system stability prior to transfer to auto control (e.g, level +/- 5% for 20-30 minutes with steady SBCV demand and no SG blowdown. 4. Revise **If, Then** step for unsuccessful transfer to auto and add guidance for restoring DFWCS system to auto operation following auto to manual transition. Currently there is no success path identified. 5. Add step to record feed rate while in stable manual control. Add additional step to ensure that feed rate is approximately matched once in auto control. 6. Evaluate expanding acceptable SG NR level, once in stable auto control to 15 to 45% (from current 30-40%) to prevent unnecessary transfer to manual. Engineering and LOCT should assist Operations in providing input to this revision. Simulator validation of changes should be validated to ensure unintended issues are not created by the revision.	J. Taylor N. Henry	01/20/06
CC#1 & CC#2	2834532	Revise procedure 40OP-9ZZ04, *Plant Startup Mode 2 to Mode 1*, by adding an Attachment for guidance when transferring from manual to automatic feedwater control to include DFWCS operating experience and system control inputs. This should include a chart showing expected range of required feed rate to Rx power	N. Henry	12/30/05
CC#2 & CC#3	2834535	Using the systematic approach to training, LOCT will train licensed operators on the specific task of transferring the DFWCS from manual to auto per procedures 40DP-9FT01 & (2), *Feedwater Pump Turbine A(B)* to ensure all licensed Operators can successfully perform this task. *This action may be milestoned to accommodate training cycle scheduling.*	J. Woods	01/20/06
Other Actions (CRDR Priority 4)				
RC#2	2834538	Evaluate changing setpoint for SG High Level override from current value of 88% to a lower value that will prevent SG overfeeding and resultant MSIS during low power operations.	D. Smyers G.Anderson	01/20/06
CC#2 & CC#3	2834539	Using the systematic approach to training, Licensed Operator Training will analyze the initial and continuing training needs for licensed operators for the task of transferring the DFWCS from manual to auto per procedures 40DP-9FT01 & (2), *Feedwater Pump Turbine A(B)*.	J. Woods	01/20/06
Effectiveness Review Actions (CRDR Priority 4)				
CC#2 & CC#3	2834540	LOCT will evaluate the training given to licensed Operators for transferring the DFWCS from manual to auto. Results will be forwarded to Operations and Systems Engineering for evaluation to help determine effectiveness of corrective actions.	J. Woods	05//30/06
RC#1	2834541	Operations Management will review the effectiveness of the corrective action to prevent recurrence, CRAI's 2834520 & 2834523. This review will document that the action is being implemented as intended. This will include Operations review of Training's evaluation results to determine the effectiveness of training. Additionally, an assessment of conformance with procedural expectations for Conduct of Operations should provide the assurance necessary to preclude repetition. Action closure shall include a conclusion statement, which clearly states the action(s) was or was not effective in preventing recurrence. Ref. 90DP-0IP10 section 3.13.1 and Appendix E, Section 1.8.	M. McGhee	05//30/06
RC#2	N/A	No specific action is required for System Engineering to review the effectiveness of the corrective action, CRAI 2834525. Under the Maintenance Rule, the DFWCS Engineer evaluation of DFWCS performance during startups will provide the assurance necessary to preclude repetition of a MSIS as well as ensure stable level control in auto. System performance will be reviewed by the system team and documented in the system health reports.	N/A	N/A

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ATTACHMENT 12

CRDR NUMBER: 2824258

TITLE: U-2 3.0.3 SHUTDOWN DUE TO CPC SOFTWARE

EVENT DATE: 8/22/05

Prepared By: Al Fluegge
(Lead Investigator)

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Significant Root Cause Investigation Report

CRDR 2824258: U-2 3.0.3 Shutdown due to CPC Software

Table of Contents

EXECUTIVE SUMMARY 3
DESCRIPTION OF ACTIVITY 4
DESCRIPTION OF EVENT 4
SAFETY SIGNIFICANCE 5
DIRECT CAUSE, ROOT CAUSE AND CONCLUSION 7
OPERATING EXPERIENCE SUMMARY 9
CORRECTIVE ACTIONS 11
SEQUENCE OF EVENTS 12
TRANSPORTABILITY 15
MAINTENANCE RULE 16
ROOT CAUSE ANALYSIS METHODS 16
LICENSEE EVENT REPORT 16
LIST OF DOCUMENTS REVIEWED 16
LIST OF PEOPLE CONTACTED 18
LIST OF ATTACHMENTS 18

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EXECUTIVE SUMMARY

In the fall 2003 Unit 2 steam generator replacement outage (U2R11), Palo Verde installed the Common Q Core Protection Calculator System (CPCS) with revision 5.0 software. Units 1 and 3 are scheduled to be upgraded to the Common Q CPCS in fall 2005 and fall 2007 respectively. On 3/24/04, Palo Verde made purchase request 478696 to Westinghouse for various enhancements to the Common Q CPCS. During the 2005 Unit 2 spring outage (U2R12) OCS personnel installed software revision 6.1 in the CPCS. The software revision included requests made by Palo Verde and other changes made by the vendor. A total of 52 software change requests (SCR) were incorporated by Westinghouse into the 6.1 revision software. OCS engineering completed the in-service verification for this software revision on 5/15/05.

On 5/18/05, after notification by KOPEC (Korea Power Engineering Company), Westinghouse issued report # 05-139-W008 in-house to address an issue Korea had identified while testing revision 6 software. Westinghouse identified the issue as the CPCS 6.1 software release was inconsistent with the system requirements specification. The specification required an auxiliary trip when both channels for a process input indicate an error (failure) and software release 6.1 would not generate this trip. The issue report asked the question "Does this issue potentially represent a condition adverse to nuclear safety pursuant to Westinghouse procedures". The question was initially addressed as "I don't know". On 5/26/05 a Westinghouse Issue Review Meeting decided it was not a nuclear safety concern. On 8/8/05, a Westinghouse engineer performing the apparent cause analysis for the issue determined the condition did represent a nuclear safety concern.

At approximately 0900 on 8/22/05, during a weekly phone call, a Westinghouse engineer informed the Palo Verde OCS section leader of the CPCS software issue. The section leader discussed the issue with the OCS department leader, an OCS engineer, OCS planner and a nuclear fuel analysis engineer and then performed a test in the shop and confirmed the problem. The OCS section leader informed the Unit 2 shift manager at 1300 on 8/22/05 of the issue. The shift manager discussed the issue with the OCS section leader, site shift manger, shift technical advisor (STA) and the unit department leader (UDL). The SM made the decision to enter technical specification LCO 3.0.3 at 1326 and shutdown the plant due to the CPCS software not supporting technical bases 3.3.1 which states "Those detectable channel failures resulting in a loss of protective function and channel inoperability will result in a CPC Fail indication and associated Low DNBR and High LPD trips". Plant shutdown commenced at 1605 on 8/22/05 and LCO 3.0.3 was exited at 1750 when the unit entered mode 3.

The direct cause of the Unit 2 CPCS software issue was a 2002 revision of the software requirements specification led to an inconsistency with the system requirements specification.

The root cause of the software requirement specification (SRS) not being consistent with the system requirement specification (SysRS) was no formal communication plan existed with the internal Westinghouse "downstream" users of reactor trip. The Westinghouse Reactor Protection and Monitoring Systems group did not communicate with the Transient Analysis and Setpoint group to discuss the trip functions when setting the software for the trip function during CPCS development.

The root cause of untimely notification of PVNGS was Westinghouse procedures did not require justification from the Issue Review Meeting team for changing the answer to the question "Does this issue potentially represent a condition adverse to nuclear safety pursuant to Westinghouse procedures" from "I don't know" to "no". Because the assessment was answered "no", the Regulatory and Compliance & Plant Licensing group did not start an evaluation to determine if the issue represented a Substantial safety Hazard.

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DESCRIPTION OF ACTIVITY

80DP-0CC01 (Rev. 10), *Control of Software and Data for Digital Process Control and Monitoring Systems*, establishes the administrative controls pertaining to software quality assurance and configuration management for digital process control and monitoring system software, data, firmware that requires version control, and associated software development systems commensurate with their importance to nuclear safety and overall plant operations. The procedure describes 4 software integrity levels (SIL) with level 1 being the highest level. The higher the required software integrity, the more rigorous are the requirements for software design engineering, verification and validation, and documentation, and the more restrictive the design constraints and practices. Step 3.4 states CPC software is SIL 1.

81DP-0CC05, Design and Technical Document Control, step 3.4.1 allows for external design organizations (EDOs) to provide services for quality related activities provided all services have been performed under a design control program meeting Reg. Guide 1.64. Step 3.4.1.3 states the responsible engineer (PVNGS engineer) may perform a technical review on a sample basis at the discretion of the responsible leader if the EDO is on the APS approved vendor list with an approved QA program to provide engineering design services on quality related activities. In this case Westinghouse was the approved EDO with an approved QA program providing core protection calculator replacement services per purchase order 500238695. See attachment 9, Tool for Common Q CPC Project Documents, listing various documents in the design and testing process that demonstrates the rigor suggested by 80DP-0CC01 for software that is SIL1. PVNGS OSC engineers reviewed and approved various Westinghouse documents during the design and implementation phase making comments before approval demonstrating sample technical reviews as suggested by step 3.4.1.3 of 81DP-0CC05. See Attachment 14, for samples of OCS (Operations Computer Systems) engineers' review of CPCS documents and comments during the CPCS replacement project.

Description of Event

PVNGS Unit 2 installed the Common Q Core Protection Calculator System (CPCS) in U2R11, performed in the fall of 2003. Westinghouse was contracted per purchase order 500238695 to provide hardware and software for the CPC replacement project. The software was contracted to retain the same functionality as the previous CPC software. On 2/5/02, Westinghouse issued revision 1 to the Software Requirements Specification (SRS) that introduced a technical discrepancy between it and the System Requirement Specification (SysRS). The change to the SRS resulted in a different functionality then the original CPC/CEAC system in regard to generating an auxiliary trip when both input modules are good and the input sensor is failed, which the SysRS was still in agreement with. The discrepancy was called out in the Westinghouse Requirement Traceability Matrix (RTM) and as an open item in the Verification and Validation (V & V) report but the items were closed without resolution on 10/4/02. They were, however, disposition "use as is" since they were defined as not affecting safe operations.

During May of 2005, KOPEC (Korea Power Engineering Company) identified an error in the software while performing final testing for installation of the CPCS in their plants. KOPEC notified Westinghouse and engineers generated Issue Report #05-138-W008 (attachment 4) on 5/18/05. The issue report described the problem as the SysRS states that when both channels for a process input indicate an error (failure) they generate an auxiliary trip. CPCS software was not consistent with the SysRS in that it would not generate an auxiliary trip in this condition. A question on the issue

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report asks "Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures". The answer can be "yes", "no" and "I don't know". Initially a Westinghouse engineer answered this question "I don't know". On 5/26/05, a Westinghouse Issue Review Meeting reviewed Issue Report 05-138-W008 and answers "no" without justification to the Question "Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures". Because the assessment of the issue was marked "no", the Westinghouse Regulatory Compliance and Plant Licensing group did not start an evaluation to determine if this issue represented a Substantial Safety Hazard. On 7/12/05, the evaluation of commitment .02 (attachment 17) of Issue Report 05-0138-W008 identified the issue as the CPCS software was not consistent with the System Requirements Specification. An email was sent to the Westinghouse manager of Regulatory Compliance and Plant Licensing group to initiate an investigation on whether the issue had safety significance. The manager was on vacation and upon return assumed the issue had been processed during his absence but it had not been. A Westinghouse engineer completed an apparent cause analysis of the issue identified on Issue Report 05-0138-W008 and concluded the issue did potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures. On 8/9/05 the issue was assigned to Regulatory Compliance and Plant Licensing group to evaluate if the issue represented a nuclear safety concern. During a weekly phone call on 8/22/05 a Westinghouse engineer described Issue report 05-0138-W008 to the PVNGS OCS section leader and he asked for an email describing the problem.

After obtaining the email on the morning of 8/22/05 (see attachment 5) the OCS section leader discussed the issue with OCS department leader, OCS software engineer, OCS planner and nuclear fuels analysis engineer. A test performed on the OCS CPCS single channel development system confirmed the problem with the CPCS software. At 1300, the section leader notified the Unit 2 shift manager. The SM discussed the issue with OSC engineering, CRS, STA, UDL and the STA section leader. The SM reviewed LCO bases B 3.3.1 and declared all 4 CPCs inoperable and entered LCO 3.0.3. The SM made the decision to enter technical specification LCO 3.0.3 at 1326 and shutdown due to the CPCS software not supporting technical bases 3.3.1 which states "Those detectable channel failures resulting in a loss of protective function and channel inoperability will result in a CPC Fail indication and associated Low DNBR and High LPD trips". Plant shutdown commenced at 1605 on 8/22/05 and LCO 3.0.3 was exited at 1750 when the unit entered mode 3.

Safety Significance

See attachment 12, Westinghouse Safety Significance Evaluation, for full write-up. The lead investigator discussed the Westinghouse evaluation with the Probability/Risk assessment section leader and he agreed with the vendor conclusion.

The Common Q based Core Protection Calculator System (CPCS) is installed in Palo Verde Unit 2 and scheduled to be installed in Unit 1 the fall of 2005 and in Unit 3 the fall of 2007. The CPCS generates trip and pre-trip signals on Low Departure from Nucleate Boiling Ratio (Low DNBR) and High Local Power Density (High LPD), as well as CEA Withdrawal Prohibit (CWP) signals to the PPS, in the form of binary (contact) inputs. The PPS shall use these and other inputs to automatically actuate a Reactor Trip whenever the monitored processes violate predefined limits in at least two of the four redundant PPS channels. The CPCS consists of four channels of equipment (Channels A, B, C, & D). The four channels of equipment are located inside the Auxiliary Protective Cabinet where the channels are physically separated and isolated from each other. Each CPCS channel provides contact outputs to its respective PPS channel. The CPCS obtains process inputs (8 per channel) via the analog input module, AI685. The following input parameters are processed in each CPCS channel:

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- 2 Cold Leg Temperatures
- 2 Hot Leg Temperatures
- 1 Pressurizer Pressure
- 3 Ex-core Neutron Flux Detectors

Each input parameter is read by two separate analog input modules in a channel. One of the two redundant analog input modules is normally selected. If the normally selected module indicates a failure, the software will select the alternative module.

It was discovered that the 6.1 version of the Common Q based CPCS software is not consistent with the system requirements regarding the system response to analog input module errors. When the redundant analog input modules within a safety channel both indicate an error, simultaneously; the CPCS uses the last known good value. However, the system requirements state that a channel trip should also be initiated for this event.

Input errors are indicated by the AI685 analog input module and read by the software. A failed input sensor would be the most likely cause for both of the redundant input modules to indicate errors simultaneously because the two redundant input modules within a safety channel are connected to a single sensor. A similar scenario would occur if both analog input modules simultaneously failed. In both cases the result would be a failure of the channel without initiating a trip signal. If this problem occurred coincident with an unsafe plant condition, the other three safety channels would still provide protective action. The incorrect response by the software is only associated with a hardware failure (AI685 module failure or sensor failure). Since the initiating event for the incorrect software response is a hardware failure, this problem occurs as a result of a localized failure in one of four channels. The AI685 analog input modules, together with all other Common Q hardware modules, have been qualified to show that they are not subject to common cause failure. During the safety system design process, potential sources of common cause failure are identified and addressed by a combination of measures. First, the equipment is designed to withstand extremes of environment, power supply variation and electromagnetic disturbance. Qualification testing is performed on equipment of the same type as used for the installed system to demonstrate that the design is capable of withstanding the extremes of environment assumed in the design process. Then, when the equipment is installed in the plant, physical separation principles are followed, using both distance and barriers, to limit the potential for faults in one portion of the system from propagating to other redundant portions. Also, interconnections between redundant portions are made via fiber optic cables to prevent electrical fault propagation. Power is provided through separate, uninterruptible power sources.

Palo Verde Unit 2 CPCS provides the reactor trip functions for Low DNBR and High LPD. The CPCS is implemented in four redundant divisions. AI685 analog input module failures, i.e., input or card failures, are detected within the module. This results in the setting of error terminal outputs that are read by the software. The software then actuates contact output signals in the affected channel to CPC Operator's Module Alarms and Plant Annunciators. If one AI685 analog input module fails within a channel, then a CPC Trouble contact output is set. If a process input sensor fails or if both AI685 analog input modules simultaneously fail, then the CPC Sensor Failure contact output is also set, even though the trip outputs in the affected channel will not be set. Therefore, this is a detectable failure. Plant Technical Specifications mandate that the failed channel be placed in bypass or trip within one hour. PVNGS alarm response procedure 42AL-2RK5A directs compliance with LCO 3.3.1. For a CPC sensor failure (alarm window 5A13B). The CPCS safety function will continue to be provided by the other three safety channels.

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Conclusion

This problem occurs as a result of a localized failure in one of four channels. The problem can only occur coincident with a process sensor input failure or a failure of the analog input hardware that provides the interface between the sensors and the CPCS processor module. Also, there is no common cause failure mode that would render both (2 per channel) AI685 analog input modules inoperable in multiple channels. Therefore, the failure of the channel to trip is isolated to one of four redundant safety channels, and this failure will be indicated to the operations staff.

Direct Cause

The direct cause of the Unit 2 CPCS software issue was inconsistency between the system requirements specification and the software requirements specification.

Facts:

- Westinghouse VCAR report VC-WAP5-05-034 (see attachment 13) states the inconsistency between the SysRS and the SRS/SDD (software design document) existed since revision 1 of these documents, which were issued in early 2002.
- Open Item 74.110 in the APS requirements and Design Implementation and Test Phase appendix of the Verification and Validation report (SDOC JN1000-A00061-3 approved by Westinghouse on 7/8/03) states "SRS (software requirements specification) 4.9.1 does not appear to implement an auxiliary trip for both primary and redundant AI input channels failed as required in Note 1 of SysRS Table 3.1.1.1.7-1. See RTM 445.24". The resolution was closed on 10/4/02 with no apparent actions but did say depending on circumstance that redundant input failures would cause an auxiliary trip.
- System Requirements Specification (SDOC JN1000-A00015-Rev. 0) step 3.1.1.1.3.13.8 states "Failure or removal of an analog input module in the CPC processor subrack will cause the CPC channel to use the redundant analog input module. A Channel Trouble alarm and associated annunciation will be generated, but the CPC channel shall remain operable. If both redundant analog input modules fail, a CPC Fail condition shall be generated, resulting in alarm, annunciation, and opening of the Low DNBR and High LPD trip contacts. Refer to Table 3.1.1.1.7-1".
- System Requirements Specification table 3.1.1.1.7-1 states for channel failures on both the primary and backup modules a DNBR/LPD auxiliary trip and CPC sensor failure digital output will actuate. Note 1 to the table adds "For CPC analog Input Module channel errors on one or more inputs when the parameter is in range, Channel Trouble annunciation will occur to identify the error. The CPC channel will use the last valid sensor value prior to the failure in its calculations. This is analogous to CEAC behavior on rate of change failure, where the failure mode leads to a clearly erroneous reading. In order that the CPC "fail Safe", a new auxiliary trip will be added on I/O errors when both the primary and backup sources are unavailable (Pump inputs are not redundant, therefore the loss of the single input will be treated. as if both the primary and backup sources are unavailable)".
- Westinghouse VCAR report VC-WAP5-05-034 states for initiating event #1 that the CPCS Software Requirements Specification (revision 1) did not include the auxiliary trip if the same sensor on both modules was determined to be bad.

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Root Cause #1

Root cause for the software requirement specification not being consistent with the system requirements specification:

> There was no formal communication plan with the internal Westinghouse "downstream" users of reactor trip (i.e., the Westinghouse Reactor Protection and Monitoring Systems group did not communicate with the Westinghouse Transient Analysis and Setpoint group to discuss the trip functions when setting the software for the trip function).

Facts:

- See Attachment C (5 Why Trees) to VCAR NO. VC-WAPS-05-034 (attachment 13)

Root Cause #2

Root cause for vendor (Westinghouse) delay in notification of PVNGS.

> There was no specification guidance for the Westinghouse Issue review Meetings discussions regarding issue reports except in WEC 14.4. Justification for changing the question "Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse Policy/Procedure WEC-21.0 or WEC-22.2" from "I don't know" to "No" is not required by procedure or guidelines.

Facts:

- See Attachment C (5 Why Trees) to VCAR NO. VC-WAPS-05-034 (attachment 13)

CONCLUSION

81DP-0CC05, Design and Technical Document Control, allowed for an external design organization (EDO) to design and develop the Common Q Core Protection Calculator System (CPCS). Westinghouse, the EDO, was on the APS approved vendor list with an approved QA program. PVNGS OSC engineers reviewed and approved various Westinghouse documents during the design and implementation phase making comments before approval demonstrating sample technical reviews as suggested by step 3.4.1.3 of 81DP-0CC05.

In the initial release of the CPC software to APS (installed from December 2003 to May 2005), the channel trip would have occurred on an "out of range" signal which was subsequently removed in a later release of the software (installed from May 2005 to August 2005). The initial release would still provide a channel trip on a sensor input failure, but it would not always be a direct auxiliary trip. It was an indirect trip, caused by the actual parameter value, going out of range, provided as an input to the DNBR and LPD calculations. In most cases a value of DNBR or LPD would be calculated resulting in a DNBR or LPD pre-trip and trip. Supplier document JN1000-A00086-1 (see controlled documents), Unit Test Report for One Channel for the Core Protection Calculator System (CPCS) for Common Q, page 242 of 260 shows Westinghouse engineers checking off that they observed a DNBR/LPD [illegible] process connectors were removed for an input sensor. This was the test for the initial release of CPC software to verify the implementation of the SysRS requirement by removing the process connector from the analog input cards (in effect, severing the field sensor from the AI card). The subsequent software change in May 2005 removed

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the functionality of the channel to trip in these certain "out or range" cases such that PVNGS no longer had the indirect (calculated) trip an no auxiliary trip on an out of range signal because the change now used the last good value.

The investigation team concludes PVNGS OCS engineers provided reasonable review of Westinghouse documents for the Common Q CPCS in accordance with 81DP-0CC05.

The delay in notification of PVNGS of the potential CPCS software issue is internal to Westinghouse and will be tracked by VCAR #VC-WAP5-05-034.

A licensing document change will be issued to review removing or amending the guidance in technical specification bases 3.3.1 concerning CPCS input channel failures.

OPERATING EXPERIENCE SUMMARY

PVNGS Operating Experience

2005	Westinghouse is currently on the PVNGS "Noteworthy Performance Quality Issues List" with NUPIC (Nuclear Procurement Issues Committee) as the owner to improve supplier performance.
6/8/04	Significant CRDR 2714809: Vendor notified PVNGS engineering that an erroneous profile correction factor was causing a non-conservative indication bias in the Ultrasonic Flow meters they supplied. This led to reactor power exceeding licensed thermal power. Root Cause: Weakness in the design verification test (DVT). Corrective actions: PVNGS engineering will develop more thorough and independent verification of UFM prior to restoration or updating to a new system.
2/29/04	Significant CRDR 2685303: Unit 2 shutdown due to SG tube leak Cause: Human error on the part of the person(s) assembling the packaging for the Unit 2 SG1 tube bundles at the tube manufacturer's (Sandvik) facility. Less than adequate transportability review by the fabricator (Ansaldo) and follow-up by APS for a prior nonconformance report identifying a similar incident. Corrective Actions: Leaking tube plugged other tubes inspected. PVNGS generated a VCAR to improve packaging process. APS will establish a formal review process for nonconformance reports generated at the tubing manufacturer's and steam generator fabricator's facilities.
4/4/03	OSRC recommends documentation of validation and verification testing results for CPC-CEAC replacement project Cause: CRDR was a recommendation Corrective actions: SDOC JN1000-A00061 and JN1000-A00062 documents validation and verification for the Common Q CPCS software. SDOC JN1000-A00086 documents satisfactory completion of the factory acceptance test (FAT). SDOC JN1000-A00092 documents satisfactory completion of the hardware (FAT).
7/1/98	Significant CRDR 380145: Unit 3 entered LCO 3.0.3 (later retracted) and commenced a plant shutdown due to declaring all 4 CPCs inoperable. The CPCs

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were declared inoperable due to discovery that the LPD trips may not initiate when 21 kw/ft was exceeded. The ex-core instrument system restricted the output during a surveillance test and prevented a LPD pre-trip. The shutdown was halted after applicable surveillance testing was completed satisfactorily.

Root Cause: Impact review process did not determine an extremely obtuse impact.

Corrective Actions: Revised surveillance test procedures.

Industry Operating Experience

9/8/02 Beaver Valley Unit 2 (OE 14871): Error in assumptions used in vendor software leads to thermal power from the Leading Edge Flow Meter indicating high.

Cause: Assumptions in the vendor software

Corrective action: Upgraded the software

12/12/00 Grand Gulf Nuclear Station (OE 11707): Vendor software would not activate all emergency pagers.

Cause: Limitations of the vendor's software.

Corrective Actions: ERO pagers placed into two groups. Annual group page test.

6/28/00 Donald C. Cook (OE 11614): Technical Specification 3.0.3 Shutdown Initiated Due to inoperable Individual Rod Position Indicators (IRPI) and Deviation Monitor Alarm Inoperable Due to Software Error.

Cause: Human performance error led to a non-conservative decision with the IRPIs. The root cause of the failure of the rod monitor alarm was a non-conservative error in the plant process computer software.

Corrective Actions: Adjusted IRPIs and corrected software error. Training was given to reinforce conservative decision making.

5/21/00 Millstone Unit 2 (OE 11035): Fault in software corrupts parameters in electronic dosimeters.

Cause: Error in software provided by vendor

Corrective Actions: New dosimeters issued and the vendor was contacted to investigate cause. The vendor provided software to correct the problem.

10/22/97 Susquehanna (LER 97-024-00): Inboard Isolation Valves for the Drywell and Suppression Chamber Purge System were not single Failure Proof causing technical specification 3.0.3 entry.

Cause: Most Likely Cause was human error on the part of the original designers.

Corrective actions: Administrative control of valves and review of design.

9/6/06 Beaver Valley Power Station 1 & 2: Design problems with firmware/software cause several events with the Control Room Bottled Air Pressurization System resulting in entrance to technical specification 3.0.3.

Cause: Firmware/software design problems

Corrective Actions: Vendor is checking on problem with the software.

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Operating Experience Review Conclusions

Actions associated with deficiencies found in vendor products are frequently related to training, validation and verification practices. Westinghouse is taking actions related to these actions as identified in VCAR #VC-WAP5-05-034 along with actions related to internal communications. PVNGS will perform a corrective action verification per 64DP-0QQ08 step 3.4 for actions associated with VCAR #VC-WAP5-05-034.

CORRECTIVE ACTIONS

Completed Actions (immediate and interim)

Cause	*Action Description*	*Completed*
NA	Unit 2 shutdown to mode 3	8/22/05
RC #1	CPCS software release 6.3 installed in Unit 2 CPCs. DI 2824743 installed DFWO 2824397 (see related work)	8/25/05
NA	PVNGS Issues vendor corrective action report (VCAR) VC-WAP5-05-034 to Westinghouse for software issue related to release 6.1 software to the Common Q CPC/CEACs in Unit 2.	9/1/05

Corrective actions to prevent recurrence are internal to Westinghouse and documented in VCAR # VC-WAP5-05-034 (attachment 13). PVNGS has corrected the software problem with issuance of CPCS software release 6.3. Unit 1 and Unit 3 will have current software revisions when the CPCS is installed (extent of condition). Extents of cause actions are internal to Westinghouse.

Other Actions (CRDR Priority 3)

RC #1 And RC #2	2847231	PVNGS Nuclear Assurance department will perform a corrective action verification per 64DP-0QQ08 step 3.4 for actions associated with VCAR #VC-WAP5-05-034	F. Jabali	1/22/06

Other Actions (CRDR Priority 4)

NA	2847228	Issue LDCR for review removing or amending the guidance in technical specification bases 3.3.1 concerning CPCS input channel failures	F. Swirbul	1/22/06
RC #1 And RC #2	2847466	PVNGS Nuclear Assurance department will review VCARs and CRDRs to determine if Westinghouse corrective actions have resolved software and problem notification issues.	F. Jabali	11/1/06

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SEQUENCE OF EVENTS

Date /Time	Source of Data	Data
5/26/00	SDOC JN1000-A00003 (Rev. 0) Available on SWMS	Westinghouse approves revision 1 to the Software Program Manual (CECES195). PVNGS OCS engineers complete review on 10/1/02 (this is PVNGS revision 0)
1/10/02	Westinghouse Issue report #05-138-W008 See attachment 4	Westinghouse generates System Requirements Specification (SysRS) ICE30158 (Rev 1).
2/5/02	Westinghouse Root Cause Analysis Report (see attachment 13)	Westinghouse generates revision 1 to the Software Requirements (SRS) which introduces the discrepancy between the SysRS and the SRS requirements specifications.
2/18/02	Westinghouse Issue report #05-138-W008 See attachment 4	Westinghouse Software Design Phase (SDD) revision 1 (ICE30107) is first revision to inhibit a trip signal if both process input channels are failed. If both input channels are failed and the A1 modules are OK, then the last good value is used and a trip form UPDATE is not initiated.
4/22/02 & 10/1/02	SDOC JN1000-A00025 (Rev. 0) Available on SWMS	PVNGS OCS engineers complete review of Westinghouse Software Design Phase (SDD) revision 1 (ICE30107).
11/6/02	SDOC JN1000-A00015 (Rev.0) Available on SWMS	PVNGS OCS engineers review and approve for first time the System Requirements Specification (SysRS) for the CPCS for Common Q. This is Westinghouse document ICE30158 revision 2.
11/6/02	SDOC JN1000-A00016 (Rev.0) Available on SWMS	PVNGS OCS engineers review and approve for first time the Software Requirements Specification (SRS) for the CPCS for Common Q. This is Westinghouse document ICE3233 revision 2.
6/17/03 & 6/20/03	SDOC JN1000-A00061 (Rev.2) Available on SWMS	PVNGS OCS engineers review and approve Verification and Validation (V & V) Report Draft for the Core Protection Calculator System (CPCS) for Common Q. This is Westinghouse document ICE3700E (Rev.00)
6/17/03 & 6/18/03	SDOC JN1000-A00049 (Rev.1) Available on SWMS	PVNGS OCS engineers review Unit Test procedure for One Channel for the CPCS for Common Q (Westinghouse document ICE35483 (rev.1)
6/30/03	SDOC JN1000-A00086 (Rev.1) See controlled documents	Westinghouse completes Unit Test report for One Channel for the CPCS for Common Q. Westinghouse document ICE37150 (Rev.0). The test removed the process connectors for both inputs and observed that there was a DNBR/LPD auxiliary trip.

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11/13/03 & 11/14/03	SDOC JN1000-A00086 (Rev.1) See controlled documents	PVNGS engineers review and approve Unit Test Report for One Channel for the Core Protection Calculator System (CPCS) for Common Q. Westinghouse document ICE37150 (Rev.0). The test removed the process connectors for both inputs and observed that there was a DNBR/LPD auxiliary trip.
November 2003	DMWO 223535 See related work	Unit 2 installs Common Q CPC/CEACs in Unit 2.
3/24/04	Interview with OCS section leader	PVNGS generates Purchase request (PR) 478696 for various CPCS software enhancements for the Common Q CPC/CEACs.
4/8/04	Change Order #4 to Contract #500238695 See attachment 2	CPC/CEAC change order sent to Westinghouse for software release 6.0.
11/12/04	SWMS SDOC JN1000-A00757 (Rev. 0) See controlled documents	Westinghouse commences testing of CPC software release 6.0 which includes the 6.1 release.
11/15/04-11/18/04	Interview with OCS section leader	OCS personnel go to Westinghouse to observe factory acceptance testing on Unit 3 CPC software which includes software release 6.1.
12/1/04	SWMS SDOC JN1000-A00757 (Rev. 0) See controlled documents	Westinghouse approves completed Single Channel Test report for Software release 6.0 to the Common Q Core Protection Calculator System which includes testing for revision 6.1.
12/6/04	SDOC JN1000-A00088 (Rev. 2) Available on SWMS	Westinghouse completes Input Sweep Test Report for the Common Q CPC for release 6.0 CPCS software.
12/8/04	E-mail See attachment 3	PVNGS meeting to discuss changes and identify impacts on new CPC software revision.
12/17/04	SDOC JN1000-A00758 (Rev. 0) See controlled documents	Westinghouse approves Verification and Validation Report for Software release 6.1
2/11/05	SWMS SDOC JN1000-A00757 (Rev. 0) See controlled documents	PVNGS OCS engineers complete review for approval of the CPCS Single Channel Test report for Software release 6.1
4/2/05	DI 2759185 See controlled documents	DI 2759185 authorized to be worked. Installs software release 6.1 in Unit 2 CPCs. DVT (design validation test) is performed on each CPC channel for software release 6.1 per appendix "C" of DI 2759185. CPC channel functional tests are performed under STWO 2712185, 2712186, 2712183 and 2712184 (see related work) per 77ST-9SB17 (Rev.2).

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5/15/05	DI 2759185 See controlled documents	Completed loading 6.1 software releases in all 4 Unit 2 CPCs. In-service Verification/Operations acceptance of software release 6.1. The software release included software release 6.2 which just include APS display changes.
5/18/05	Westinghouse Issue report #05-138-W008 See attachment 4 and Westinghouse Root Cause Analysis Report (see attachment 13)	Westinghouse submits Issue Report #05-138-W008 within their house after notification by KOPEC. The problem is the CPCS System Requirements Specification states that when both channels for a process input indicate an error (failure) they generate an aux trip. Engineers initially think the system requirements specification is in error not the software. A question on the issue report asks "Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures". Initially a Westinghouse engineer answered this question "I don't know".
5/26/05	Westinghouse Root Cause Analysis Report (see attachment 13)	Westinghouse Issue Review Meeting reviews Issue Report 05-138-W008 and answers "no" without justification to the Question ""Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures". Because the assessment of the issue was marked "no", the Westinghouse Regulatory Compliance and Plant Licensing group did not start an evaluation to determine if this issue represented a Substantial Safety Hazard.
7/12/05	Westinghouse Root Cause Analysis Report (see attachment 13)	Commitment .02 of Issue report 05-138-W008 identifies the issue as being with the CPCS software.
7/13/05	Westinghouse Root Cause Analysis Report (see attachment 13)	Due to the conclusion of commitment .02 an e-mail is sent to Regulatory Compliance and Plant Licensing group to initiate an investigation on whether the issue had safety significance. The manager of Compliance and Plant Licensing had started vacation and upon return did not investigate the issue further due to assuming the issue had been process during his absence, which it had not been.
8/8/05	Westinghouse Issue report #05-138-W008 See attachment 4	Westinghouse engineer performing ACA (apparent cause analysis) answers "yes"' to the question ""Does this issue potentially represent a condition adverse to nuclear safety pursuant to the requirements of Westinghouse policy and procedures".
8/22/05 0858	Interview and Email See attachment 5	Fred Swirbul (OCS section leader) contacted by phone from Westinghouse about issue with release software 6.1 to CPCS during weekly phone call. Fred requests E-mail on the issue.
8/22/05 0900-1300	Interview	OCS engineering section leader discussed issue with OCS department leader, OCS software engineer, OCS planner and nuclear fuels analysis engineer. Test is performed in shop that confirms issue with software.
8/22/05 ≈1300	Interview and Unit 2 Operations Log (see attachment 6)	OCS section leader informs Unit 2 shift manager of issue with unit 2CPC software. The SM discusses issue with OSC engineering, CRS, STA, UDL and STA section leader. SM reviews LCO bases B 3.3.1 and declares all 4 CPCs inoperable and enters LCO 3.0.3
8/22/05 1326	Unit 2 Operations Log (see attachment 6)	Unit 2 entered LCO 3.0.3 and declared all CPC channels inoperable when notified by OCS engineering section leader of software issue identified in Westinghouse Issue report #05-138-W008
8/22/05 1430	Unit 2 Operations Log (attachment 6), MRT notes (attachment 8) and CRDR 2824498 (see related work)	MRT (management review team) agrees with SM conclusion that Unit 2 CPCs are inoperable and Units 1 and 3 are not affected.

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8/22/05 1605	Unit 2 Operations Log (see attachment 6)	Commenced Unit 2 shutdown
8/22/05 1710	Unit 2 Operations Log (see attachment 6) and ENS Worksheet #41939 see attachment 7	Initiated 4 hour ENS (#41939) phone call to NRC.
8/22/05 1750	Unit 2 Operations Log (See attachment 6)	Unit 2 exited LCO 3.0.3. Unit 2 shutdown in mode 3.
8/24/05	SDOC JN1000-A00016 (Rev.3) See Controlled Documents	PVNGS OCS engineers review and approve Westinghouse Software requirements Specification for the Common Q CPC/S. Westinghouse document ICE3233 (Rev. 7)
8/25/05	SDOC JN1000-A00758 (Rev.1) See Controlled Documents	PVNGS OCS engineers review and approve Westinghouse Verification and Validation Report for Software release 6.3. Westinghouse document WNAVR00187CVER2 (Rev.0)
8/25/05	DI 2824743 See related work	CPC software release 6.3 installed in Unit 2 CPCs. DI 2824743 installed DFWO 2824397 (see related work)
9/1/05	Letter 302-02084-FHJ/DMC (VCAR VC-WAPS-05-034) See attachment 11	PVNGS Issues vendor corrective action report (VCAR) VC-WAP5-05-034 to Westinghouse for software issue related to release 6.1 software to the Common Q CPC/CEACs in Unit 2.

TRANSPORTABILITY

EXTENT OF CONDITION

The condition is transportable to the Common Q Core Protection Calculator System. Unit 2 presently is the only unit with the Common Q CPCS and software release 6.3 was installed per DI 2824743 in all 4 channels on 8/25/05 correcting the condition. The Common Q CPCS is scheduled to be installed in the upcoming U1R12 outage and will be installed with revision 6.3 software or greater. The Common Q CPCS is scheduled to be installed in the Unit 3 2007 fall outage (U3R13) and will be installed with the current software revision at the time.

Extent of Cause

The extent of cause is internal to Westinghouse organizations. See VCAR # VC-WAP5-05-034 for actions taken by Westinghouse.

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MAINTENANCE RULE

The software related issue with Unit 2 CPCs was not a maintenance rule functional failure as determined by the responsible engineer. See attachment 10, Maintenance Rule Evaluation.

ROOT CAUSE ANALYSIS METHODS

See VCAR # VC-WAP5-05-034, attachment 13 and Hazard-Barrier- Target Analysis (attachment 17.

LICENSEE EVENT REPORT

See attachment 15.

LIST OF DOCUMENTS REVIEWED

- 90DP-0IP10 (Rev. 22), *Condition Reporting*
- PVNGS Root Cause Investigation Manual (Rev. 3)
- 42AL-2RK5A (Rev.31), *B05A Alarm responses*
- 77DP-9ZZ01 (Rev. 1), *NSSS Software Changes*
- 80DP-0CC01 (Rev. 10), *Control of Software and Data for Digital Process Control and Monitoring Systems*
- 81DP-0EE10 (Rev. 11), *Plant Modifications*
- 81DP-0CC05 (Rev. 27), *Design and Technical Document Control*
- 81DP-0DC16 (Rev.15), *Engineering Document Change (EDC)*
- 93DP-0LC07 (Rev. 7), *10CFR 50.59 and 72.48 Screenings and Evaluations*
- 93DP-0LC07 (Rev. 8), *10CFR 50.59 and 72.48 Screenings and Evaluations*
- PVNGS Technical Specifications and Bases
- 10CFR21
- 10CFR50.36 Technical Specifications
- NRC Regulatory Guide 1.152, Criteria for Digital Computers in Safety Systems of Nuclear Power Plants
- NRC Regulatory Guide 1.33, *Quality Assurance Program Requirements (Operation)*
- NRC Regulatory Guide 1.168, *Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants*
- NRC Regulatory Guide 1.169, *Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants*
- NRC Regulatory Guide 1.170, Software Test Documentation for Digital Computer Software Used In Safety Systems of Nuclear power Plants
- NRC Regulatory Guide 1.172, *Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants*
- NRC Regulatory Guide 1.64, *Quality Assurance Requirements for the Design of Nuclear Power Plants*
- INPO Software Controls for Plant Computers
- UFSAR 7.2, *Reactor Protection System*
- UFSAR 17.2G, *Control of Computer Software and Data*
- Procurement Change Order #4 to CPC/CEAC Contract #500238695
- DBM for Common Core Protection Calculator System/Core Operating Limit supervisory System (Rev 0)
- Vendor Corrective Action Report (VCAR) # VC-WAP5-05-034

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- Nuclear Assurance Engineering Evaluation Report (ER) # 05-0165
- DMWO 223535
- DIWO 2759185
- DMWO 2605767
- SDOC JN1000-A00003 (Rev. 0), Software Program Manual for Common Q Systems
- SDOC JN1000-A00003 (Rev. 1), Software Program Manual for Common Q Systems
- SDOC JN1000-A00015 (Rev. 0)- System Requirements Specification (SyRS) for the Core Protection Calculator System (CPCS) for Common Q
- SDOC JN1000-A00016 (Rev. 0 and 3)- Software Requirements Specification (SRS) for the Core Protection Calculator System (CPCS) for Common Q
- SDOC JN1000-A00049 (Rev. 2), Unit Test Procedure for One Channel for the CPCS for Common Q (7/14/03)
- SDOC JN1000-A00061 (Rev. 3), Verification and Validation (V &V) Report for the Core Protection Calculator System (CPCS) for Common Q
- SDOC JN1000-A00063 (Rev. 0), Final Requirements Trace Matrix (RTM) for the Core Protection Calculator System (CPCS) for Common Q
- SDOC JN1000-A00086 (Rev.1), Unit Test Report for One Channel for the Core Protection Calculator System (CPCS) for Common Q
- SDOC JN1000-A00088 (Rev. 2), Input Sweep Test Report for the Common Q CPC
- SDOC JN1000-A00109 (Rev.3)-Software Release Memo for Common Q based Core Protection Calculator System (CPCS). Incorporate EDC 2005-00098
- SDOC JN1000-A00109 (Rev. 5)-Software Release Memo for Common Q based Core Protection Calculator System (CPCS). Incorporate EDC 2005-00466
- SDOC JN1000-A00117 (Rev. 4)-Common Q Core Protection Calculator System (CPCS) Advant AC160 and OM/MTP Node Box Software Media. Incorporate EDC 2004-00345
- SDOC JN1000-A00765 (Rev. 0) - Common Q Core Protection Calculator System (CPCS) QNX Patch Software Media. Incorporate EDC 2005-00098
- SDOC JN1000-A00757 (Rev. 0)-CPCS Single channel Test Report for Software Release 6.0
- SDOC JN1000-A00758 (Rev. 0 and 1)-CPCS Verification and Validation Report for Software Release 6.1
- SDOC N001-1303-01773 (Rev. 2), CPC Prot Algorithm Software Change Procedure
- EDC 2004-00345
- EDC 2005-00098
- EDC 2005-00466
- Purchase Order 500238695
- Change Order #4 to CPC/CEAC Contract #500238695
- 10CFR50.59 Screening/Evaluation Log Number S-03-0044 (Rev. 0 and Rev.1)
- 10CFR50.59 Screening/Evaluation Log Number S-03-0237 (Rev.0)
- Unit 2 Control Logs from 8-22-05 (Used CORA)
- IEEE Std 1012-1986, *Standard for Software Verification and Validation Plans*
- IEEE Std 7-4.3.2-1993, *Standard Criteria for Digital Computers in Safety systems of Nuclear Power Generating stations*
- IEEE Std 1059-1993, *IEEE Guide for Software Verification and Validation Plans*
- IEEE Std 829-1998, *IEEE Standard for Software Test Documentation*

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LIST OF PEOPLE CONTACTED

Fred Swirbul-OCS Engineering SectionLeader	John Glover-Procurement Engineering Section Leader
Dan Marks-Compliance Section Leader	Bob Pickwoad-OCS Senior Engineer
James McCarthy-Procurement Engineering Senior Technician	John Wade-Reactor Engineering Consulting Engineer
Steve McKinney-Site Shift Manager	Linda Johnson-OCS Senior Engineer
Mike Sanchez-U2 Shift Manager	John Aronson- U2 Shift Technical Advisor
Jill Monahan-Westinghouse Root Cause Team Leader	Jim Compass-System Engineering Contract Services-Westinghouse
Wendy Wynn- OCS System Design Engineer	Ray Buzard-Regulatory Affairs Senior Consultant
Michele M. DeWitt-Westinghouse Repair Replacement and Automation Services Vice President	David K. Rohm-Westinghouse Quality Programs and Supplier Qualification Manager
Tom Weber-Licensing Section Leader	Ron Raisanen-Nuclear Assurance Engineer
Jerry Sowers-Probability/Risk Assessment Section Leader	Don Whitehead-OCS Senior Engineer
Fawaz Jabali-Nuclear Assurance Audits Section Leader	

List of Attachments

Attachment 1: Investigation Charter
Attachment 2: Change Order #4 to CPC/CEAC Contract #500238695
Attachment 3: E-Mail for PVNGS meeting on CPC Software change
Attachment 4: Westinghouse Issue Report #05-138-W008
Attachment 5: 8-22 E-mail on CPC Software Issue
Attachment 6: U2 Logs taken from CORA using Date and entry
Attachment 7: ENS Worksheet
Attachment 8: MRT Notes
Attachment 9: Tool for Common Q CPC Project Documents
Attachment 10: Maintenance Rule Evaluation
Attachment 11: VCAR VC-WAPS-05-034
Attachment 12: Westinghouse Safety Significance Evaluation
Attachment 13: VCAR No. VC-WAP5-05-034 Report
Attachment 14: OCS review of CPCS Documents (samples)
Attachment 15: Licensee Event Report 2005-004-00
Attachment 16: Hazard-Barrier- Target Analysis
Attachment 17: Commitment .02 of Westinghouse Issue Report #05-0138-W008

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ATTACHMENT 13

CRDR 2835132 Investigation Charter

Date: November 21, 2005
To: Don Kissinger (Lead Investigator)
From: Carl Churchman, Director of Engineering

Background:

The NRC challenged the design adequacy of the PVNGS emergency core cooling system (ECCS). The specific concern involves the potential for air entrainment in the ECCS suction lines during the transfer of pump suction from the refueling water tank (RWT) to the containment sumps following a recirculation actuation signal (RAS).

In the injection mode, ECCS suction is taken from the RWT. Upon receipt of a low water signal in the RWT (i.e., a RAS), the isolation valves for the containment sump suction line begin to open so ECCS suction can transfer to the containment sump. The suction isolation valves from the RWT do not automatically close and due to the elevation difference between the RWT and containment sump, water would continue to draw down from the RWT until such time that the elevation head is balanced between the two respective columns of water. This would uncover the RWT vortex breaker and suction pipe inlet. The concern is that during the draw-down period, the reduced water level in the RWT could result in vortex formation and air entrainment in the suction pipe with the resultant possibility of gas binding of the ECCS pumps.

PVNGS Units 2 and 3 entered Technical Specification action 3.0.3 and were shut down when the NRC concern could not be immediately addressed (Unit 1 was in a refueling outage). Subsequent analysis by PVNGS and Westinghouse adequately demonstrated operability of the ECCS and the units were restarted, but the inability of PVNGS to provide a timely response to the NRC question resulted in a manual trip of two reactors with concomitant plant transients, increased risk and economic harm.

Scope:

You will conduct an investigation to determine the direct, root and contributing cause(s) of the design basis issue that resulted in the Technical Specification required shutdown. Where warranted, corrective actions will be established, clearly defined and assigned to appropriate individuals and organizations. Your investigation will also include measures to identify additional similar issues that may exist at PVNGS (i.e., extent of condition) and will include measures to identify other plant equipment, processes, or human performance issues that may be adversely affected by the root cause(s) (i.e., extent of cause). Corrective actions will be identified and assigned to address weaknesses identified during the extent of condition and extent of cause reviews.

In addition, your investigation will address possible "missed opportunities" to identify and correct this problem at an earlier time and will include an evaluation of how design basis and licensing basis information is communicated to and used by Operations in the operability determination process. Any organizational weaknesses revealed by your investigation will be identified in your final report.

Team:

Don Kissinger (Lead Investigator)
To Be Named (Engineering)
To Be named (STA)
To Be named (NAO)

Digitally signed by: Churchman, Carl D (Z24020)
Date: 11/22/2005 07:14:25
Reason: I am approving this document
Location: PVNGS

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ATTACHMENT 14

AREVA

PRESSURIZER HEATER FAILURES AT PALO VERDE AND WATERFORD ROOT CAUSE INVESTIGATION REPORT

October 4, 2005

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FANP PROPRIETARY

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Investigation Team Leader: J.P. Bartleman 10/4/05
J.P. Bartleman, Manager, Corrective Action Program

Approved: H.B. Prasse 10-4-05
H.B. Prasse, Manager, Operations Support Nuclear Parts Center

Approved: J.P. Bartleman for
D.E. Matthews, Supervisor Component Engineering (CR&R) per telecon

Approved: S.P. Hellman 10/4/05
S.P. Hellman, Vice President Nuclear Parts Center

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TABLE OF CONTENTS

EXECUTIVE SUMARY ---------- 2

I. DESCRIPTION OF EVENTS ---------- 5
I.A. Heater Failures ---------- 5
I.B. Background ---------- 5

II. ROOT CAUSE INVESTIGATION RESULTS /FINDINGS ---------- 7
II.A Palo Verde Heater Failures ---------- 7
II.B Waterford Heater Failures ---------- 12
II.C Other FANP/Thermocoax Heater Failures/Non Conformances ---------- 17
II.D Pressurizer Heater Receptacle Evaluation ---------- 17
II.E Thermocoax Design Non Conformance to FANP Specification ---------- 22

III. CONCLUSIONS ---------- 24

IV. ROOT AND CONTRIBUTING CAUSES AND CAUSAL FACTORS ---------- 25

V. CORRECTIVE/PREVENTIVE AND RECOMMENDED ACTIONS ---------- 26

CRDR 2809138 Page 64 of 89

CONFIDENTIAL

EXECUTIVE SUMMARY

A. Problem Statement/Description of Event

Pressurizer Heaters designed and fabricated by FANP/Thermocoax are prematurely failing. Nine Pressurizer heaters manufactured for Palo Verde and six for Waterford failed soon after being placed in service and the utilities replaced the FANP/Themocoax heaters with heaters manufactured by other suppliers. Additionally, three SONGS heaters are inoperable and have been removed from service.

B. Scope of Investigation included but was not limited to:

- A failure analysis of the failed Palo Verde and Waterford heaters at an independent laboratory
- Observation and review of fabrication activities at Thermocoax
- A review of design, fabrication, condition reports and other documentation associated with the heaters recently manufactured for Palo Verde 3, Waterford 3, SONGS 3 and St. Lucie 1 replacement pressurizer.
- Interviews with key personnel (Customers, Thermocoax and FANP)
- Review designs/design differences between failed heaters and heaters that are operating successfully.
- Review of heater operating conditions (electrical, mechanical and thermal).
- Other causes, events and causal factors that could lead to premature pressurizer heater failures.

C. Direct Causes for the failures

1. Due to a deviation to the FANP design, a "warm zone" was created that placed a heated portion of both the Palo Verde and Waterford heaters in the pressurizer sleeves, which generated sufficient heat to prematurely fail the heaters. For three of four Palo Verde heaters that were examined, the heater failures occurred in the warm zone located in the sleeve area.
2. The Waterford heater fault was found in the receptacles and was due to a breakdown of receptacle materials due to overheating. The primary sources for the heat were conductive heating from the high temperature generated by a heated portion of the heater being located in the pressurizer sleeve and self-heating from normal current flow through the copper conductors in the receptacle.
3. The direct cause for the inoperative SONGS heaters is not known since a failed heater is not available for destructive examination. However, testing at Thermocoax and FANP analysis of the heater receptacle temperatures indicates that receptacle temperature limits for the SONGS heaters may be challenged by self-heating due to current flow through the conductors when added to the expected heater operating and environmental conditions.

D. Root Causes

Inadequate Design/Design Control:

1. The Thermocoax design/design review process was not adequately implemented and did not identify the non-compliance with the FANP design requirements.
2. The design/design review process did not identify the elevated receptacle operating temperatures for the SONGS and Waterford Heaters.

E. Potential Cause for Premature Failure

The receptacle design, fabrication process and material may not complement each other to provide long-term heater reliability. Cracks and/or voids were found in the receptacle potting materials that could reduce the dielectric strength of the organic insulating materials and under adverse circumstances lead to premature heater failure.

F. Contributing Causes/Casual Factors

1. Thermocoax significantly underestimated the power in the warm zone and did not evaluate the effect the warm zone could have on pressurizer heater operation.
2. The US heater project was considered by Thermocoax as a modification of existing products rather than a new product requiring a more extensive design review process.
3. The schedule for design and fabrication was aggressive and may have contributed to an error likely environment.
4. Inadequate design review by FANP. The FANP Design Review Board did not include a representative or presentation by the heater element assembly designer, Thermocoax.
5. Aging/operability testing was not performed to simulate actual operating conditions and to verify heater reliability through the design life of the heater.

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CRDR 2809138 Page 62 of 89

G. Corrective, Preventive and Recommended Actions (See Section V of the report for details)

1. The design deviation that resulted in the heater overheating in the pressurizer sleeve has been identified and corrected. Pressurizer heaters are being replaced as requested by the customers.
2. Changes to the receptacle design and/or fabrication process are being implemented to reduce receptacle temperatures, eliminate voids and cracks in the potting materials and improve heater reliability.
3. Thermocoax and FANP are taking actions to address the failure to fabricate the heaters in accordance with the FANP design requirements.
   a. Thermocoax is reviewing existing FANP documents to ensure there are no other design changes that have not been reported, treat new FANP products as First of a Kind to implement more rigorous design requirements and controls, use of a comparison matrix and prototype inspection/testing to verify implementation of the FANP design requirements, train/retrain personnel on design requirements and management expectations regarding design control, and the additional detailed actions listed in section V of this report.
   b. FANP has expanded requirements for reviewing Thermocoax drawings prior to fabrication.
   c. FANP is evaluating the design review process and taking appropriate actions to improve the process, including implementing required procedure/process changes, briefing personnel associated with the heater fabrication and other FANP design organizations on lessons learned from this event.
4. Testing and analysis continue to validate the effectiveness of actions taken to ensure heater reliability. For example:
   a. FANP is testing new heaters for St. Lucie at the AREVA GmbH Technical Center Multi-functional Thermal-Hydraulic Test Loop - KATHY in Karlstein, Germany to challenge the survivability of heaters under adverse conditions and demonstrate long-term heater reliability.
   b. The Root Cause Team identified additional testing to be performed under controlled conditions to determine the actual effects to a heater operated with the heated portion of the heater installed in a pressurizer nozzle in an attempt to validate the failure mode. Additionally, aging testing (thermal and radiation) to assess long term heater reliability.
   c. Testing on follow-on contracts will be performed on an as required basis depending on St. Lucie test results and other on-going testing and analysis.
   d. Thermocoax has fabricated and tested a SONGS Unit 3 heater test specimen under controlled/simulated conditions to determine actual receptacle temperatures.
5. The required customer and 10CFR part 21 notifications have been completed regarding the pressurizer heater failures and pressurizer overheating.

H. Significance of the Event

1. FANP classified this event as a defect in accordance with 10CFR Part 21. Palo Verde and Waterford removed the heaters from service, evaluated the condition and determined that there was no adverse impact to pressurizer materials from the elevated temperatures in the sleeves.
2. The pressurizer heater failure was a significant impact to the applicable customers, requiring heaters to be replaced, outage delays and significant time and effort to evaluate the degradation of the vessel materials caused by the overheating in the pressurizer sleeve area.
3. This event resulted in significant customer dissatisfaction, a loss of confidence in FANP products and a significant commercial impact to FANP, Thermocoax and our customers.
4. SONGS heaters were fabricated in accordance with the FANP design requirements and did not have a warm zone located in the pressurizer sleeve.

I. Extent of Conditions

The deviation to the FANP design was also identified in the heaters fabricated for the St. Lucie Unit 1 replacement pressurizer and the receptacle problems appear to exist or potentially exist in all FANP/Thermocoax heaters previously provided to US customers.

CRDR 2809138 Page 63 of 89

CONFIDENTIAL

I. DESCRIPTION OF EVENTS

A. Heater Failures

The following FANP condition reports identify premature failure of pressurizer heaters provided to Palo Verde and Waterford and deviations to the FANP design requirements.

1. CR 2005-2307 identifies that six FANP pressurizer heaters with Thermocoax internals supplied to Waterford Unit 3 failed during the initial pressurizer heat up subsequent to installation. These heaters shorted to ground. Additionally, a visual inspection of the heaters revealed that the epoxy insulation material had ejected from the receptacles of two heaters and there was indication that receptacle sealing material had dripped from some of the other failed heaters.

2. CR 2005-2342 identifies five FANP pressurizer heaters in the backup heater banks with Thermocoax internals failed during restart of Palo Verde Unit 3 in June 2005. These heaters were installed during the fall of 2004 and had operated without problem until the plant was restarted from a mid-cycle outage. Additionally, four heaters in the proportional banks (cycling heaters to maintain pressure) had failed within three months from startup after the replacement in the fall of 2004. These heaters were shorted to ground and the heater elements indicated an open circuit.

3. CR 2005-2653 identifies that the pressurizer heaters fabricated by Thermocoax for Palo Verde Unit 3 and Waterford Unit 3 pressurizers were not in compliance with the FANP design drawings. The preliminary investigation into the premature pressurizer heater failures identified that the heated zones of the heaters had been extended into the cold area identified in the FANP design drawing without FANP's knowledge or authorization. This change in design resulted in a portion of the heated area being located in the pressurizer sleeve and this caused subsequent overheating of the heaters and pressurizer. Additionally, the pressurizer heaters fabricated for St. Lucie replacement pressurizer were not fabricated to the drawing requirements and have the same potential for premature failure.

B. Background:

1. Pressurizer Heater Description

Pressurizer heaters are used to control pressurizer saturation temperature, which in turn controls RCS pressure. Electric resistance water immersion type heaters are individually mounted at the bottom of the pressurizer (see Figure 1) and the number of heaters varies from 30 to ~120 depending on NSSS design. The heaters are powered and controlled in groups or banks, including proportional heaters that cycle to maintain pressure during steady state operation and backup heaters that come on full time to increase pressure during plant start up and restore pressure during plant transients.

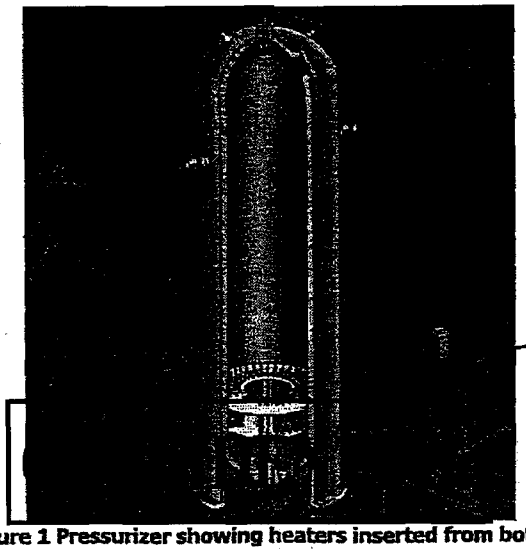

Figure 1 Pressurizer showing heaters inserted from bottom

CRDR 2809138 Page 65 of 89

The heater element assembly includes the heating elements swaged in a stainless steel sheath, an end plug and a receptacle. The heating element consists of a cold section with Copper conductors and a heated section with resistive Nickel Chromium (NiCr) conductors. In the cold end, the copper conductors are surrounded by MgO insulation in a stainless steel sheath. The cold section of the heating elements (figure 2.a.) is placed in a Monel core. In the heated (coiled) end (see figure 2.b.), resistive NiCr conductors surrounded by MgO insulation in a stainless steel sheath are wrapped (coiled) around a copper mandrel to obtain the required power (heat) concentration. The heating elements are inserted into a stainless steel outer sheath and swaged to provide good mechanical, electrical and thermal properties. The heater receptacle or connector is the connection point to provide electric power to the heater. The copper conductors enclosed in the inner sheath enter the receptacle where the end of the sheath is sealed with Resin 353 ND, and the receptacle is filled with insulating material (e.g., epoxy) to protect and isolate the electrical connections, improve the dielectric strength and homogenize the temperature inside the receptacle.

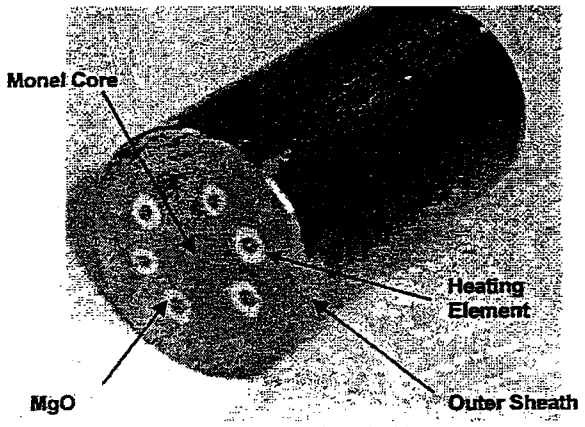

Figure 2.a - Cold end of heater

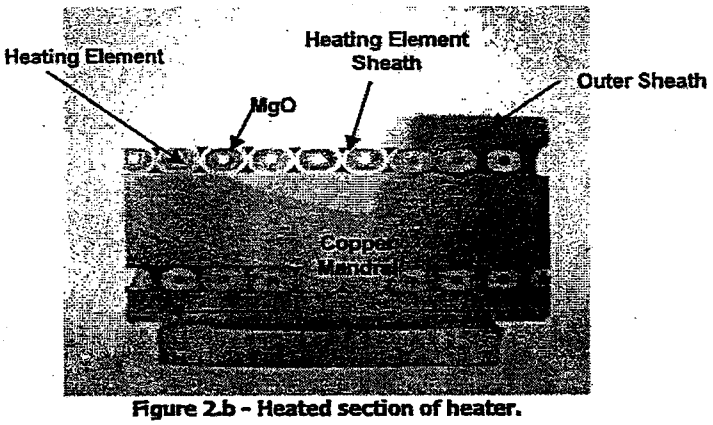

Figure 2.b - Heated section of heater.

2. FANP – Thermocoax

Thermocoax has supplied heaters to the French Navy and commercial nuclear reactor plants throughout the world with the exception of North America for approximately 30 years. Over 4000 heaters have been supplied with very good operational performance. In March 2003, FANP teamed with Thermocoax to develop pressurizer heaters for the US Market. FANP/Thermocoax heaters were designed and installed in SONGS Unit 3 and Palo Verde Unit 3 in the fall of 2004 and in Waterford Unit 3 in the spring of 2005.

3. QA Requirements:

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The pressure boundary is fabricated to ASME Code requirements and the heaters are NPT stamped. FANP provides the pressure boundary material/parts, performs the ASME Code welding and NDE, final hydrostatic testing and applies the NPT Stamp. FANP's audited and approved supplier, Thermocoax is

CRDR 2809138 Page 66 of 89

responsible for the design and fabrication of the quality-related heating element assembly, heater assembly (with the exception of ASME Code welding and NDE) and performs the final safety related heat treatment.

II. ROOT CAUSE INVESTIGATION RESULTS/FINDINGS

A. Palo Verde Unit 3 Heater Failures

The Palo Verde heaters are single phase, 480 volt, 52.5 KW (nominal) heaters with a tubular conductor that is filled with magnesium oxide (MgO).

1. Proportional Heaters

Within approximately three months after placing the FANP pressurizer heaters in Palo Verde Unit 3 in operation the customer experienced failure of four proportional heaters. Although not conclusive, at the time of the event the initial Thermocoax analysis (Thermocoax Report HI01ER30) identified that cyclic stresses imposed by the heater control system could contribute to a failure at the connection point (junction) for the heater hot - cold conductors. Furthermore, Thermocoax concluded that the tubular design of the Palo Verde heating elements made them more susceptible to the cycling stresses. As a result Palo Verde took the proportional heaters out of service and used an alternative pressure control method. At the time (February 2005) there were no operational concerns with the backup heaters. The FANP review of this report concluded that the report did not provide sufficient information to show that the stresses generated by the analyzed heater cycling under normal operating conditions were sufficient to cause the heater failures.

2. Backup heaters

Following a mid-cycle outage (June 2005) five backup heaters failed during the subsequent startup. Palo Verde terminated the startup, removed the FANP/Thermocoax heaters from service and replaced them with heaters from other suppliers.

3. Design non conformance

The replacement pressurizer heaters provided to Palo Verde were not fabricated in accordance with the FANP design drawing. The FANP design required a cold section that contains the low resistance copper conductors, which conduct the heating element current from the receptacle to the heated zone that contains the resistive heat producing coiled NiCr heating element. Thermocoax, without informing FANP or revising the design drawing, moved the hot – cold junction (connection point of the copper conductor to the NiCr heating element) from the coiled portion of the heating element in the heated section of the heater (see figure 2.b.) by extending a straight section of the NiCr heating element into the larger diameter cold section of the heater (see figure 2.a). This relocation of the heating element junction created a warm zone in the Palo Verde heater as shown in figure 3.a and 3.b. Several inches of the warm zone were located within the pressurizer heater sleeve and the power (heat) generated in this area was calculated to be between 29 and 108 watts/cm depending on the exact length and number of conductors (two or four). FANP calculation 32-50767316 concluded that the water within the small gap between the heater and the heater sleeve would boil off during heater operation reducing heat removal from this section of the heater and estimated that the heater sheath surface temperatures would be elevated within the heater sleeve and could exceed 1800 degrees F in localized areas. Normal operating temperature for the heater sheath surface is expected to at or near the pressurizer operating of 653 degrees F.

CRDR 2809138 Page 67 of 89

CONFIDENTIAL

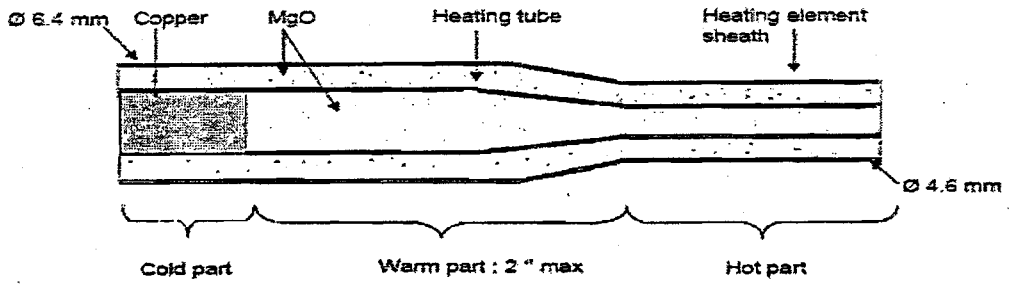


Figure 3.a. – Palo Verde heating element schematic showing hot (heated) section, cold section and warm section created by extending the heating element into the cold part. Note that the total length of the warm zone was estimated to be up to 8.2" due to the staggering of the four (4) "warm sections" within the heater."

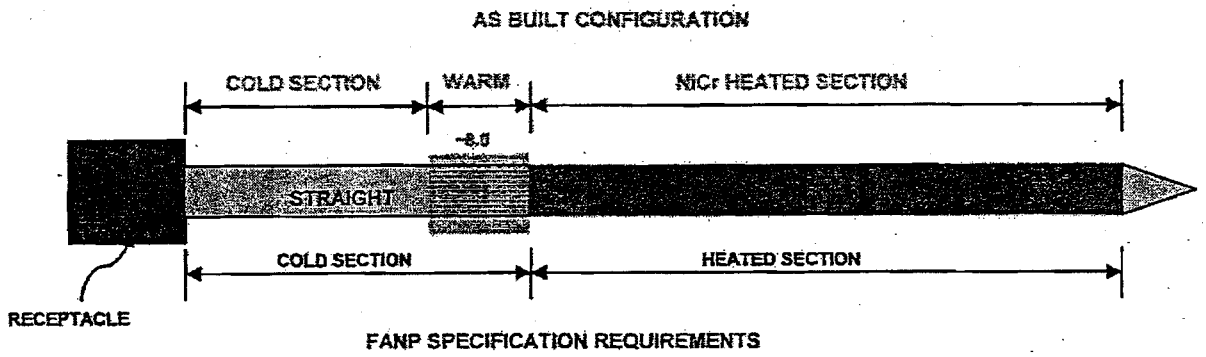


Figure 3.b – Palo Verde heater schematic showing the FANP specification dimensional requirement (bottom) and the as built by Thermocoax hot (heated) section, cold section and warm section created by extending the heater element.

4. Failure Analysis of Palo Verde heaters

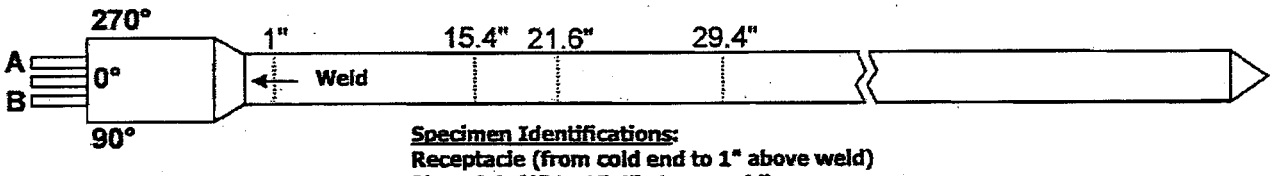
A Failure Analysis was performed on Palo Verde heaters by an independent laboratory (BWXT) in accordance with a test plan prepared by the Framatome ANP Nuclear Parts Center and approved by the Root Cause Team and APS. An unused heater (Palo Verde S/N 25) was used as a comparison standard and a test piece to demonstrate disassembly and examination processes prior to destructively examining the failed heaters. Visual inspections, dimensional measurements, radiography, and electrical measurements were taken on the failed heaters with the results documented in the test plan. Three of four Palo Verde heaters examined experienced failures of the NiCr conductor(s) in the "warm" region of the heaters at approximately the same elevation above the toe of the receptacle weld. The results are as follows:

a. Proportional heaters (S/Ns 30 and 32) were sectioned (figure 4.a shows the sectioning of S/N 30) according to the test plan to establish/confirm the fault area. As each section was cut, electrical measurements were taken to locate the fault. For both heaters the electrical faults (open circuits and grounded heating elements) were found in the warm zone of the heaters. Radiographs revealed failed heating element(s) in both heaters within the warm zone (19 – 20 inches from the toe of the receptacle weld). Destructive examination was performed on the subsection of the heaters warm zones identified in the radiographs as containing a failed heating element (~2.75 inches in length). These areas have been sectioned and examined both optically and with the scanning electron microscope (SEM) with photomicrographs taken to document the observed conditions. The examination identified significant degradation (see figures 4.b - 4.f) confirming the conditions identified on the radiographs. The observed heating element failure locations within the warm zone are near the peak temperature area identified in FANP calculation 32-6067316. It appeared that temperatures in this region approached the melting point of the Ni-Cr heating element (~2300° F) and caused ground faults across the heating element and the surrounding stainless steel sheath.

CONFIDENTIAL

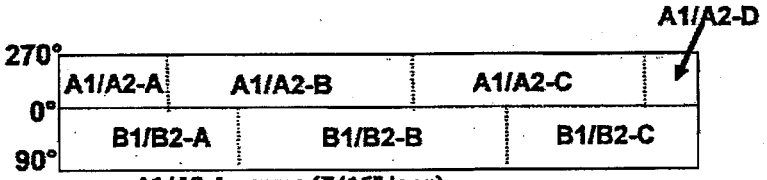
CRDR 2809138 Page 68 of 89

Palo Verde S/N 30 Sectioning Diagrams



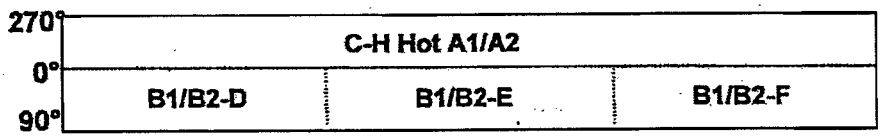
Specimen Identifications:
Receptacle (from cold end to 1" above weld)
Piece C-R (1" to 15.4" above weld)
Piece C-H Cold (15.4" to 21.6" above weld)
Piece C-H Hot (21.6" to 29.4" above weld)
Heated End (29.4" above weld to hot end)

Further sectioning of piece C-H Cold:



A1/A2-A - spare (7/16" long)
A1/A2-B - met sample (2-3/4" long)
A1/A2-C - met sample (2-3/4" long)
A1/A2-D - spare (5/16" long)
B1/B2-A - spare (1-1/2" long)
B1/B2-B - met sample (2-3/4" long)
B1/B2-C - spare (2-1/16" long)

Further sectioning of piece C-H Hot:



C-H Hot A1/A2 - spare (7-3/4" long)
B1/B2-D - met sample (2-1/2" long)
B1/B2-E - met sample (2-5/8" long)
B1/B2-F - met sample (2-5/8" long)

Figure 4.a: Sectioning diagrams for PV030. Cold end oriented to left in each diagram. Not to scale.

Photographs of PV030 Conductor B-1 and B-2 Faulted Areas

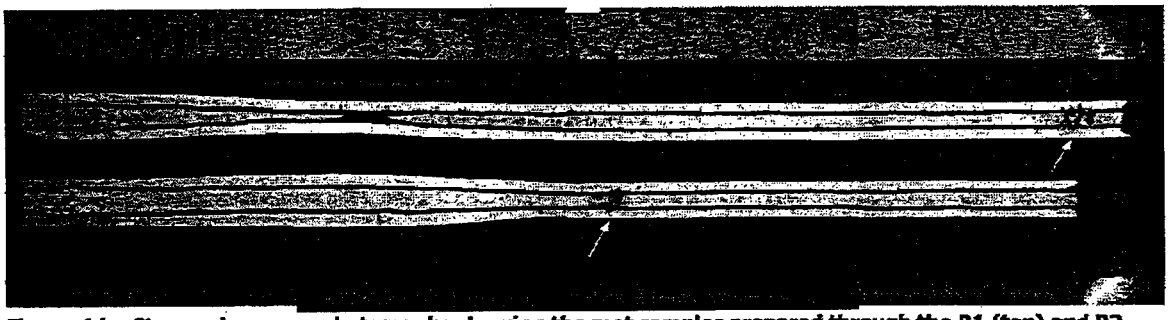


Figure 4.b: Stereomicroscope photographs showing the met samples prepared through the B1 (top) and B2 conductors of the transition region of PV030 piece C-H Cold.

CONFIDENTIAL

CRDR 2809138 Page 69 of 89

Figure 4.c: PV030 B1 wire damage

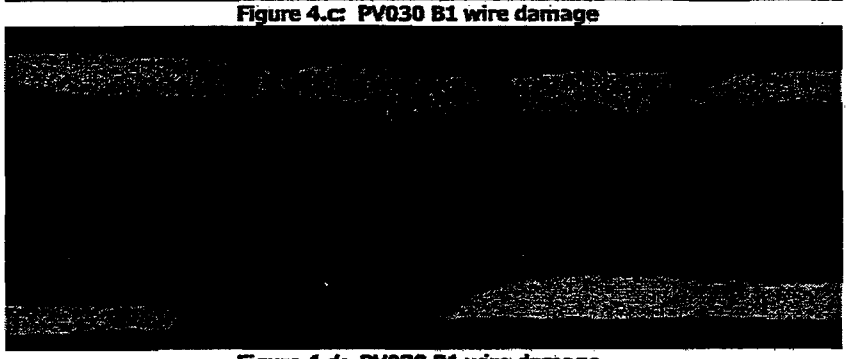


Figure 4.d: PV030 B1 wire damage

Figure 4.e: PV030 B2 wire damage

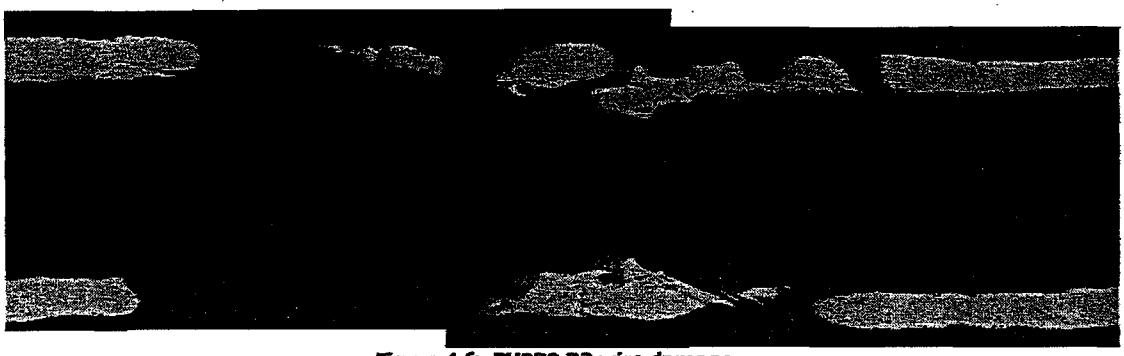


Figure 4.f: PV030 B2 wire damage

b. The five backup heaters that failed were in operation for approximately six months and failed quickly when energized to support a startup from a cold plant condition following a mid-cycle outage. Backup heater S/N 31 was sectioned to isolate the failure location. Electrical measurements revealed a B2 conductor open circuit and ground in the 14 inch Grid (warm) section between 15.4 and 29.4 inches from the toe of the receptacle weld that was similar to the failures in S/N 030 and S/N 032.

CONFIDENTIAL

CRDR 2809138 Page 70 of 89

c. Backup heater S/N 34 was sectioned and the electrical failure was identified to be in the receptacle (see figure 5.1 and 5.2), with a measured B-to-ground resistance of 25,000 Ω between a copper conductor and its sheath. When the epoxy was removed from around the conductor (see figure 5.3) the resistance to ground increased to ~2 MΩ and the cause for the 25,000 Ω ground fault could not be determined, but indicated that a conductive substance was removed with the epoxy.

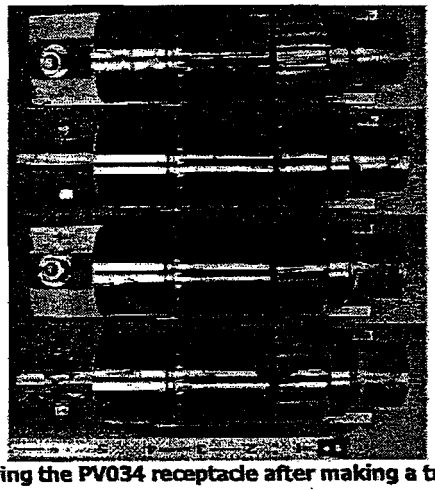


Figure 5.1: Macro photographs showing the PV034 receptacle after making a transverse section 1.5" below the receptacle weld.

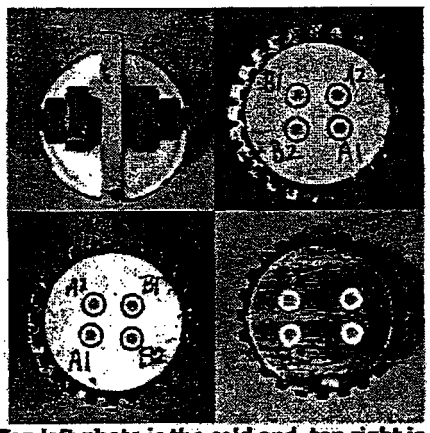


Figure 5.2: PV034 receptacle faces. Top left photo is the cold end, top right is the cold side of the laboratory cut face, lower left is the hot side of the laboratory cut face, and lower right is the hot end of the receptacle (1" above the weld).

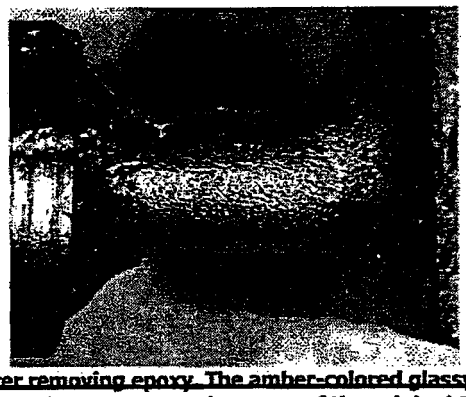


Figure 5.3: PV034 B1 conductor after removing epoxy. The amber-colored glassy material (believed to be Resin 353 ND) was present at the end of the sheath, but was not the cause of the original 25 KΩ ground fault.

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1. The remaining portion of Palo Verde heater S/N 34 was checked electrically and found to be satisfactory. However, the OD surface oxide appeared to be similar to PV 030 and 032 and there were indications of heat tinting and MgO cracking in the transition region indicating overheating.

CRDR 2809138 Page 71 of 89

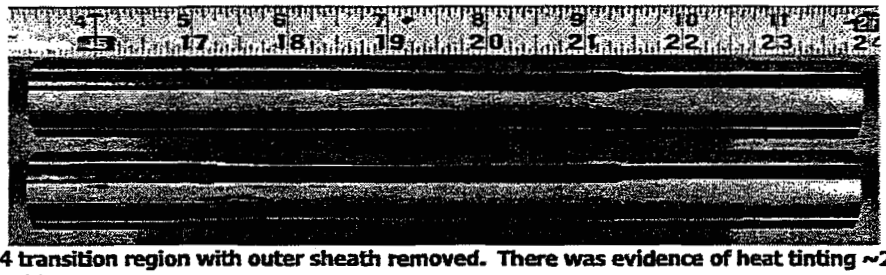

Figure 6: PV034 transition region with outer sheath removed. There was evidence of heat tinting ~20"-21" above the receptacle weld.

B. Waterford Heater Failures

The Waterford heaters are three phase – wye configuration, 480 volt, 52.5 KW (nominal) heaters with a solid conductor (see figure 17).

1. Heater Failure During Initial Startup after being Installed

The Waterford heaters failed soon after placing them in operation to support plant start up. The first heater failed approximately 5 1/2 hours after being energized, the second at 26 1/2 hours, the third at 46 hours and the remainder within a few days. The visual inspections of the heaters revealed that the epoxy insulation material had ejected from the receptacles of two heaters and there was indication that receptacle sealing material had dripped from some of the other failed heaters (Figures 10.a-10.d). Additionally, the inspections identified significantly higher temperatures than expected with up to 400 degrees F external contact temperatures on the receptacles. Figure 7 shows the Thermography data provided by Waterford.

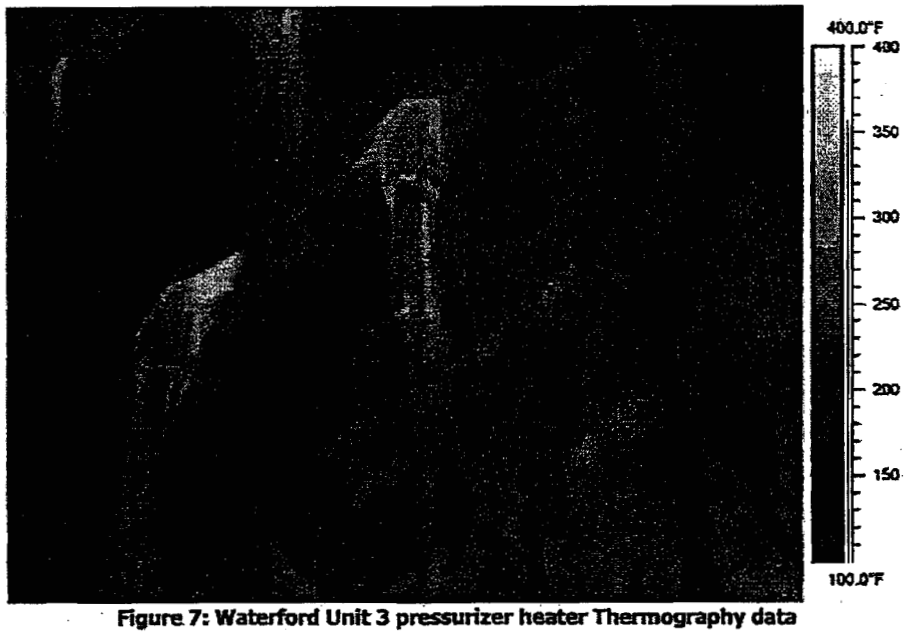

Figure 7: Waterford Unit 3 pressurizer heater Thermography data

2. Waterford heater design non conformance

Similar to the Palo Verde heaters, the Waterford heaters were not fabricated in accordance with the FANP design requirements and FANP was not aware of this design deviation. In this instance the "warm section" was estimated to be up to 6.7 inches into the cold section of the heater. The warm zone resulted in a heated section of the heater being located within the pressurizer heater sleeve for a significant length, dependent upon the heater sleeve location. The power (heat) generated in this area was calculated to be between 50 to 164 watts/cm depending on the exact length of the NiCr

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and number of conductors. FANP calculations concluded that the water within the small gap between the heater and the heater sleeve would boil off during heater operation reducing heat removal from this section of the heater and estimated that the heater sheath surface temperatures would be elevated within the heater sleeve and could exceed 1800 degrees F in localized areas. Normal operating temperature for the heater sheath surface is expected to be at or near pressurizer operating temperature of 653 degrees F.

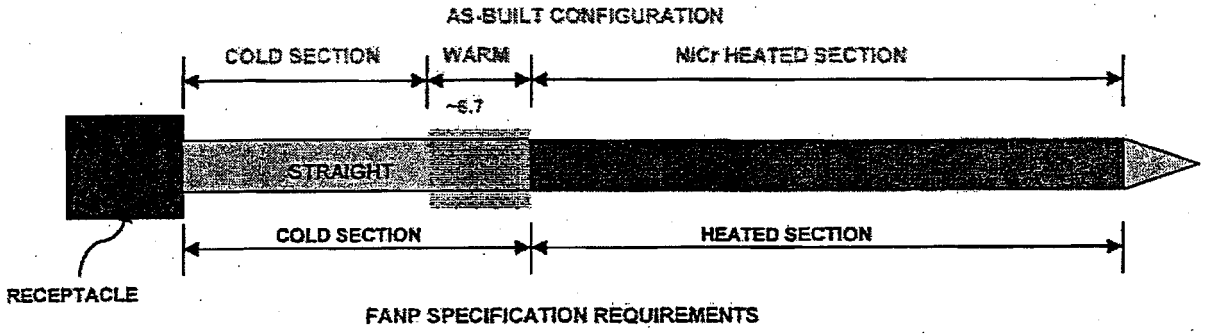


Figure 8: Differences between As-Built and FANP Requirements

3. Waterford Heater Failure Analysis

A Failure Analysis was also performed on Waterford heaters by BWXT in accordance with a test plan prepared by the Nuclear Parts Center and approved by the Root Cause Team and provided to Waterford for their information. Two intact heaters (W029 and W0032), portions of a 3rd heater (W028), and a receptacle from a 4th heater (W0003) from Waterford Unit 3 were examined by BWXT. Visual, electrical and destructive examinations and sectioning performed to identify the location and cause for the failures in accordance with the Waterford Pressurizer Heater Test Plan 03-5068054, which revealed the following:

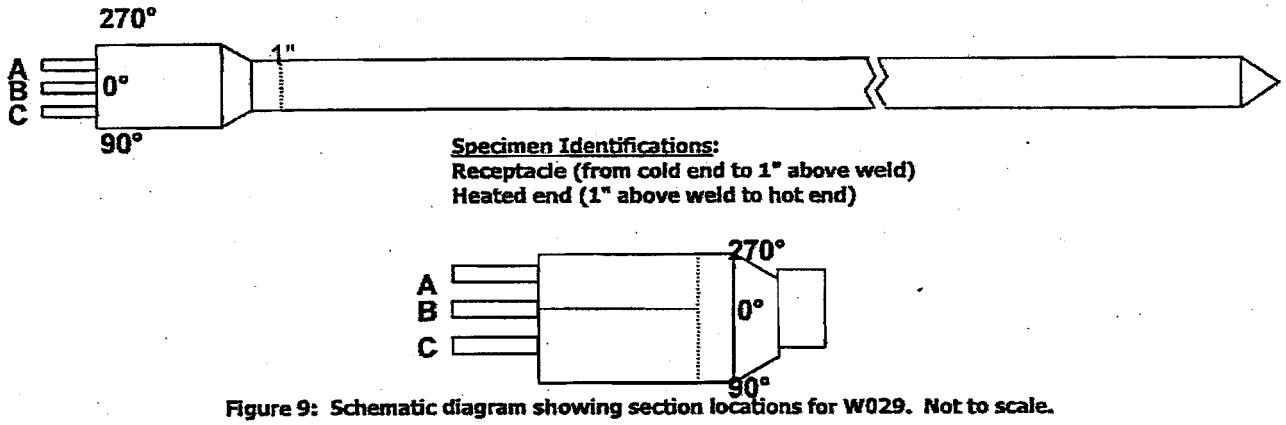


Figure 9: Schematic diagram showing section locations for W029. Not to scale.

a. The Waterford heater faults were located in the heater receptacles and there were indications of receptacle overheating. (See Figures 10.a – 10.d)

CRDR 2809138 Page 73 of 89

CONFIDENTIAL

Figure 10a: Macro photographs showing "dripping" of the white Silastic material W029 receptacle end

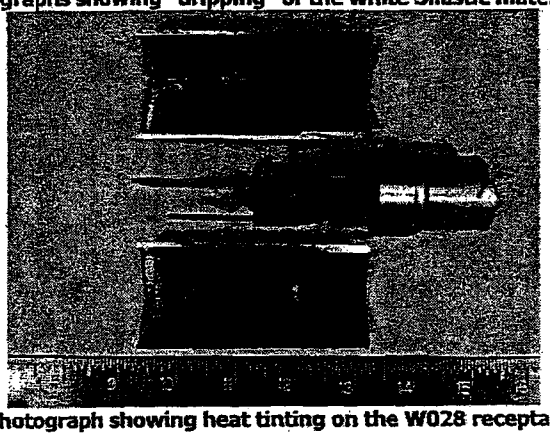


Figure 10.b: Macro photograph showing heat tinting on the W028 receptacle sheath ID surface

b. The epoxy material (see figure 10.c.) had been ejected from two receptacles (W0003 and W028). In both instances the ceramic material (DW30) was missing with only residual deposits found during EDS analysis to indicate that the ceramic material had been in the receptacle prior to the epoxy being ejected.

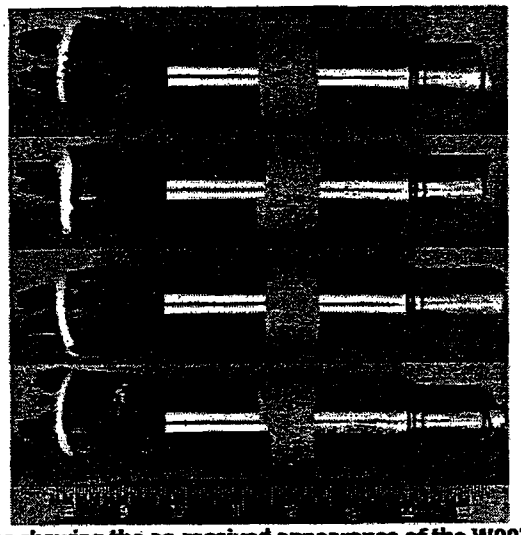


Figure 10.c: Macro photographs showing the as-received appearance of the W003 receptacle in 90° increments. The epoxy material was ejected from the receptacle during service.

CRDR 2809138 Page 74 of 89

CONFIDENTIAL

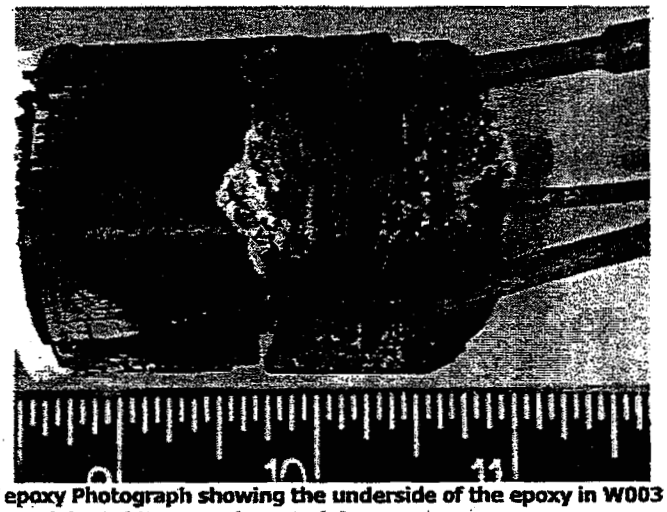


Figure 10.d: Underside of epoxy Photograph showing the underside of the epoxy in W003 receptacle. There appeared to be very little remaining white ceramic material.

c. The electrical checks of Waterford heater S/N 29 identified a conductor A to ground resistance of 1.7 Ω, B-to-ground and C-to-ground resistances at 9.7 Ω. Destructive examination of the receptacle found a black carbonaceous conductive material bridging the gap between the conductor A and the heater element sheath (see figure 11). The carbonaceous material is from overheating and breakdown of the epoxy or fast resin used to seal the conductor sheath.

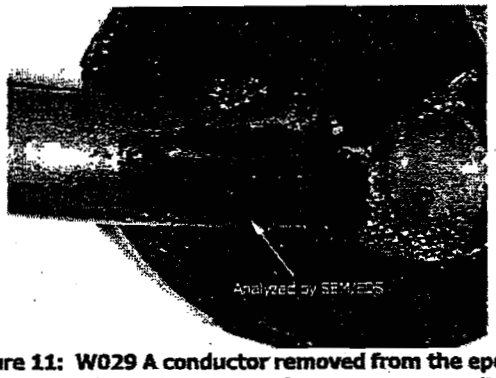
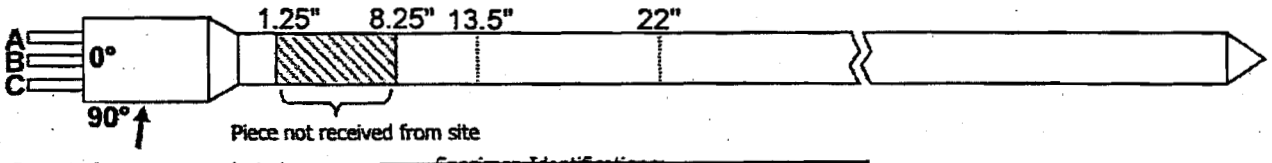


Figure 11: W029 A conductor removed from the epoxy.
The sooty black material present on the end of the conductor was responsible for the ~2Ω ground fault.

d. A band of discoloration (green oxide), was present on W028 (see figure 13) between 16 and 19 inches above the toe of the receptacle weld in the apparent transition area that was inside the pressurizer nozzle. Destructive analysis of the warm section of this heater, which had significantly less operating time than the Palo Verde heaters found no discoloration on the conductor sheaths or enlarged grain size on the conductors that appears to be the result of elevated temperature.

W028 Heater Sectioning

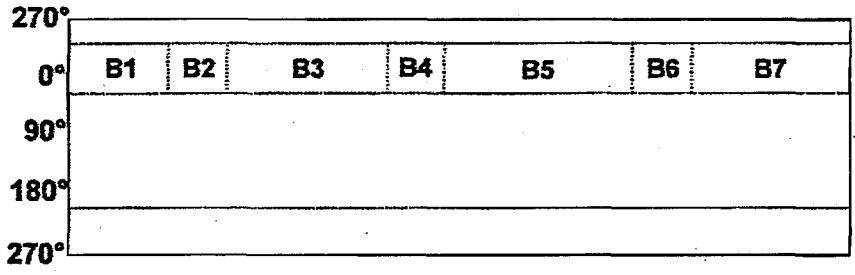


Specimen Identifications:
Receptacle (from cold end to 1.25" above weld)
Piece W028-A (1.25" to 8.25" above weld)
Piece W028-B (13.5" to 22" above weld)
Piece W028-C (22" above weld to hot end)

CONFIDENTIAL

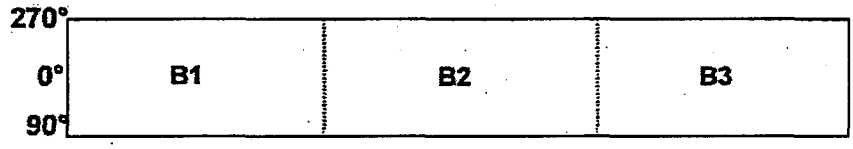
CRDR 2809138 Page 75 of 89

Further sectioning of piece W028-B outer sheath



B1 - spare (1" long)
B2 - met below green (0.5" long)
B3 - spare (1.4" long)
B4 - met within green (0.5" long)
B5 - spare (2.3" long)
B6 - met above green (0.5" long)
B7 - spare (2" long)

Further sectioning of piece W028-B conductors



B1 - met of B & CN conductors (3" long)
B2 - met of A & CN conductors (3" long)
B3 - met of B & CN conductors (2.5" long)

Further sectioning of receptacle

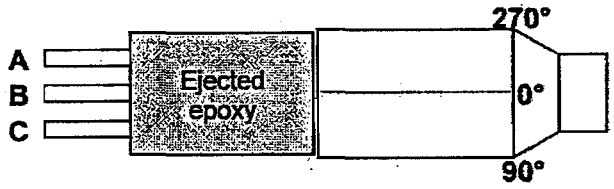


Figure 13: Sectioning diagrams for W028. Cold end is oriented to the left in all diagrams. Not to scale.

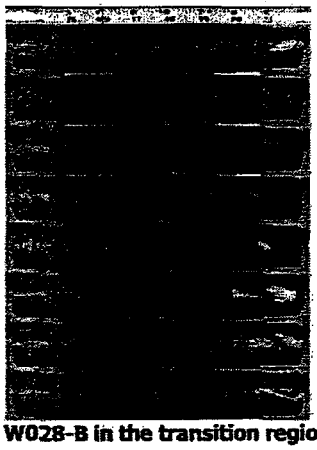


Figure 13: Macro photographs taken of piece W028-B in the transition region. A band of green oxide was present ~16"-19" above the receptacle weld.

CONFIDENTIAL

CRDR 2809138 Page 76 of 89

C. Other FANP/Thermocoax Pressurizer Heater Failures/Non Conformances

1. SONGS Unit 3 Pressurizer Heaters

There are three heaters that were installed in the SONGS Unit 3 pressurizer during the fall of 2004 that are not operational. The root cause team has limited data on the SONGS heater failures and the investigation team was not able to conclusively identify why the heaters are not operational. However, an unused SONGS heater was sectioned to confirm that these heaters were fabricated to the FANP design requirements and the available information from SONGS appears to indicate that the heater failures are in the receptacles. See Section II.D.6 below for discussion on additional testing and analysis associated with the SONGS receptacle development for the SONGS 2 heaters.

2. St. Lucie 1 Pressurizer Heaters

The St. Lucie pressurizer heaters were not fabricated in accordance with the FANP design requirements and FANP was not aware of this design deviation. These heaters have been rejected by FANP and new heaters are being fabricated for installation in the St. Lucie replacement pressurizer.

D. Pressurizer Heater Receptacle Evaluation

Figures 14.a – 14.d are photographs of the Palo Verde S/N 034 receptacle shown to illustrate receptacle construction.

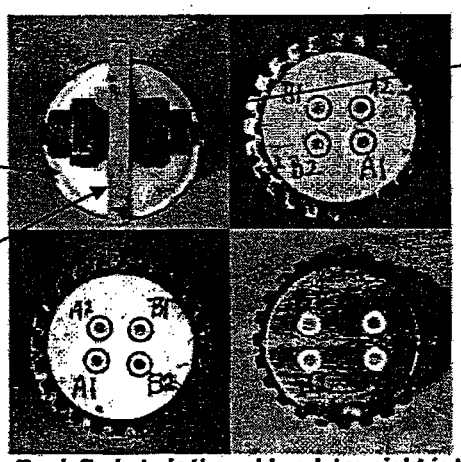


Figure 14.a: PV034 receptacle faces. Top left photo is the cold end, top right is the cold side of the laboratory cut face, lower left is the hot side of the laboratory cut face, and lower right is the hot end of the receptacle (1" above the weld).

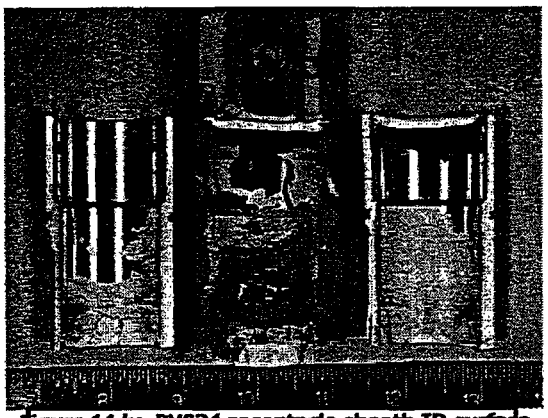


Figure 14.b: PV034 receptacle sheath ID surface

CONFIDENTIAL

CRDR 2809138 Page 77 of 89

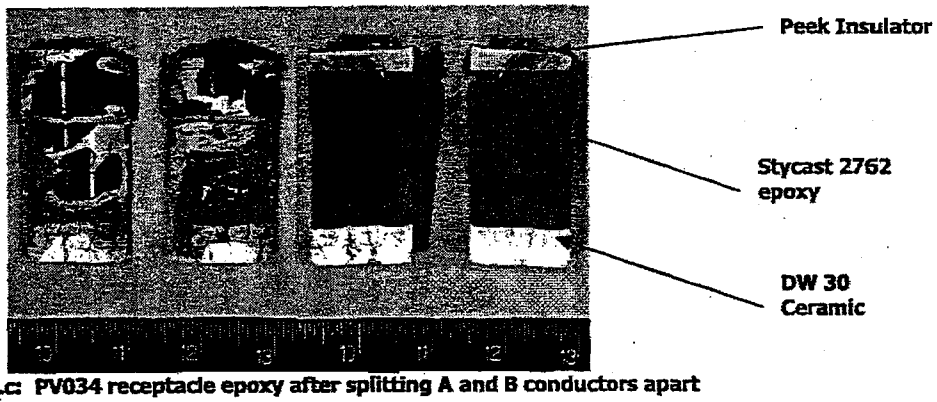


Figure 14.c: PV034 receptacle epoxy after splitting A and B conductors apart

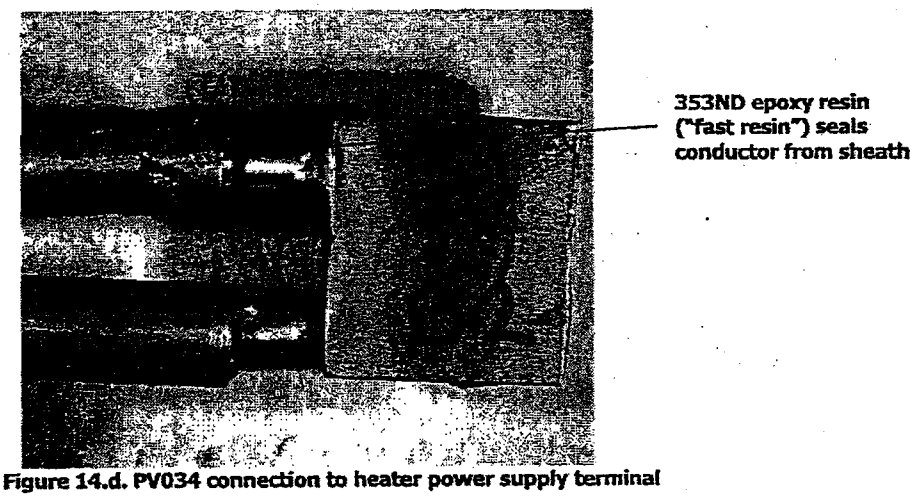


Figure 14.d. PV034 connection to heater power supply terminal

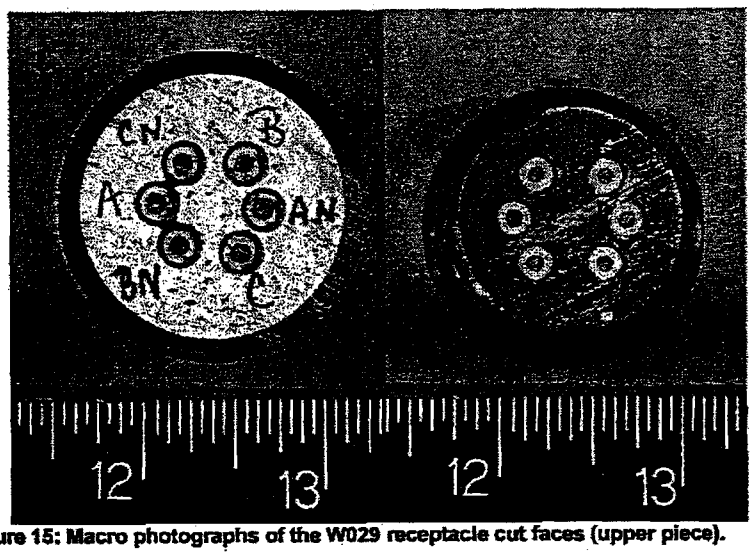


Figure 15: Macro photographs of the W029 receptacle cut faces (upper piece).

1. As discussed in Section II.B above, the Waterford heaters failed due to overheating in the receptacle. Evidence of overheating in the receptacles included actual temperatures taken at the receptacles, heat tinting on the ID surface of the receptacle sheath (figure 10.b.) and Silastic "dripping" (figure 10.a.). In two cases (W008 and W028), the epoxy resin was ejected from the receptacle (figure 10.c) end and the ceramic material was missing. A EDS analysis of residual deposits indicated ceramic material was originally present in both of these receptacles prior to the ejection of the potting material.

CONFIDENTIAL

CRDR 2809138 Page 78 of 89

2. An inspection of heater receptacles from failed heaters and unused heaters (SONGS and St. Lucie) identified cracks and/or voids in the stycast epoxy fill. In some instances these cracks/voids were filled with Silastic silicone rubber.

3. The Thermocoax Receptacle Failure Root Cause Report (HI110R009) requested by the Root Cause Investigation Team identified the following causes that may have contributed to the receptacle failure:

   a. The maximum continuous operating temperatures for the organic materials close to the heating element (see figures 14.a & 14.c) in the receptacle are:

      - 353ND (fast resin): 225° C/437° F (intermittent 325° C/667° F)
      - Epoxy Stycast 2762:230° C/446° F (intermittent 260° C/500° F)
      - Silastic RTV 734: 230° C/446° F

      The temperature measurements provided by Waterford in the range of 400° F at the top of the receptacle is near the maximum continuous operating temperatures for the epoxy. The Thermocoax theoretical analysis of epoxy behavior at high temperatures shows that epoxy resins can degrade and form carbon, which is the material found on the W0029 conductor that was attributed to the low resistance to ground.

   b. The cracking observed most likely occurred during the curing process. Cracks that do not get filled with Silastic 734 RTV will reduce the dielectric strength of the receptacle if they are located between the naked conductors or a naked conductor to ground. Additionally, uncured Silastic has a low viscosity and cures with the air moisture. If the Silastic is trapped inside the cracks and/or not exposed to air it will take a long time to cure, which could explain the dripping observed from the Waterford receptacles. Additionally, cracks can propagate due to the repetitive thermal stresses associated with heater operation.

   c. Voids located near conductors can reduce the dielectric strength of the receptacle. Voids can be created in the receptacle potting process due to:

      - Air being entrapped inside the epoxy due to poor degassing or too energetic epoxy catalyst mixing.
      - Presence of an obstruction in the receptacle that traps air in the receptacle.
      - Curing process that is too fast and prevents air from escaping during the gelation process.

4. The failure analysis (X-ray inspections and destructive examinations) did not identify the cause for the 25KΩ resistance reading fault between a copper conductor and its sheath in the receptacle in the Palo Verde (PV034) heater or indications of high temperature. X-Ray results for Waterford heater No. 29 receptacle A-conductor (figure 16), which contained a ~ 2 Ω ground, revealed that the conductor was properly centered in its sheath and did not identify the ground path. Destructive examination of the receptacle found a black carbonaceous conductive material bridging the gap between the conductor A and the heater element sheath (see figure 11).

[redacted]

Figure 16a: X-ray image of W029 A conductor

CONFIDENTIAL

CRDR 2809138 Page 79 of 89

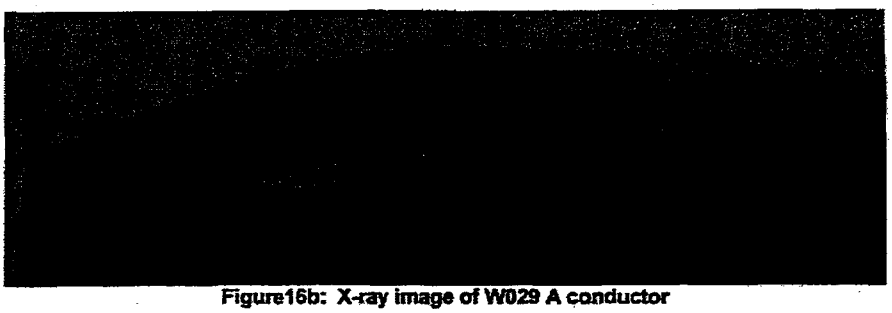


Figure16b: X-ray image of W029 A conductor

Figure 15: X-ray images of the A conductor in W029. The same area is shown in both images; the voltage was lower in Figure 4.3.7b to highlight lower density material. The cause of the ground fault could not be determined.

5. FANP performed calculations(FANP Doc. No. 12-9002608) to analyze receptacle temperatures for Waterford (figure 15) heater receptacles. The calculation was performed using HEATING7, a multi-dimensional, general purpose heat transfer code written in FORTAN 77 that can do either steady state or transient analysis, in one, two or three dimensions, in Cartesian, cylindrical or spherical coordinates. The model used to determine the receptacle temperature was an expansion of the model previously used to analyze the overheating that occurred in the Waterford pressurizer nozzles due to the heater warm zones and included the input due to self-heating from current flow through the receptacle conductors. The calculation results are a worst case scenario since the worst case warm zone heat was used and 5% was added to self-heating values. Additionally, the receptacle self-heating input calculation (12-9002488) used the epoxy stycast maximum temperature limit of 446°F to determine the temperature correction factor for the heat input (1.5 watts/cm).

   The actual temperature obtained on the outside of the receptacles prior to removing the heaters from operation was approximately 400°F with the pressurizer at approximately 435°F. The maximum calculated temperature in the Waterford heater receptacle potting material was 543.8°F. The calculation inputs included the conductive heat from the "warm zone" located in the nozzle, an ambient temperature of 120°F, pressurizer fluid temperature at 653°F and 1.5 watts/cm self-heating due to current flow through the conductors (see wiring schematic–figure 17).

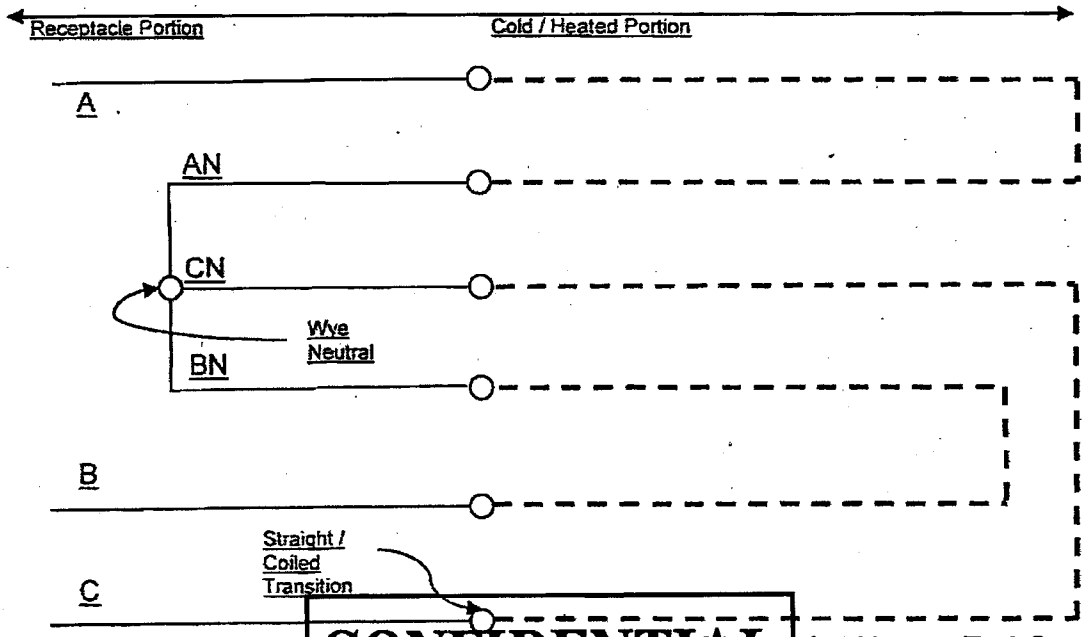


Figure 17: Schematic wiring diagram showing the 3-conductor arrangement of the Waterford-3 heaters. The A, B, and C conductors are joined together at the neutral within the heater receptacle.

CONFIDENTIAL

CRDR 2809138 Page 80 of 89

6. Thermocoax Testing of SONGS receptacles (Thermocoax draft report HI 03LR067) – The following is the result of testing performed by Thermocoax on the new receptacle design for SONGS 2 and the receptacle for the installed heaters in SONGS 3. The purpose of the test was to show the reduction in receptacle temperatures due to the new design of the SONGS 2 heater and the addition of DW30 in the receptacle between the seal braze and the stycast and a heat sink. Although this test does not completely simulate the conditions of an installed heater (e.g. does not include the embedded WYE connection point in the receptacle and the effect of conductive heat transfer to the receptacle from the heated portion of the heater), the test data identifies that temperatures in the receptacles were approaching the material temperature limits due to self-heating with a temperature of 350 °C (662°F) 6.7 inches from the pressurizer and that improvement in the design is needed to improve the temperature margins between actual temperatures and the temperature limits of the receptacle materials.

Comparison of Testing of SONGS 2 and 3 Receptacles

AREA	SONGS 2 W/O HEAT SINK	SONGS 3 W/O HEAT SINK	SONGS 2 W/HEAT SINK	SONGS 3 W/HEAT SINK
Receptacle Seal Braze	156°C (313F)	142°C (288F)	116°C (241F)	104°C (219F)
Middle of the Stycast layer	126°C (259F)	137°C (279F)	104°C (219F)	102°C (216F)
Epoxy Resin	103°C (217F)	128°C (262F)	91°C (196F)	99°C (210F)

Temperature under 60A with heating source at 350°C (662F) located 6.7" from the receptacle with and without heat sink, RT = 25°C (77F).

COMPARISON	SONGS 2 W/O HEAT SINK	SONGS 3 W/O HEAT SINK
Receptacle Seal Braze	191°C (376F)	177°C (351F)
Stycast	161°C (322F)	177°C (351F)
Epoxy Resin	139°C (282F)	163°C (325F)

Temperature estimates under 60A with heating source at 350°C located 6.7" from the receptacle with and without heat sink, RT = 60°C (140F).

FANP calculation Doc. No. 12-9002608 also analyzed the receptacle temperatures for SONGS heater receptacles using HEATING7. The model for calculating the SONGS receptacle temperature was developed from the Waterford model by removing the warm zone input and modifying the applicable dimensions. Using the Waterford model and adding 5% to the heat input resulted in a worse case scenario and calculated temperatures that are somewhat higher than the test temperatures. Additionally, the receptacle self-heating input calculation (12-9002488) used the epoxy stycast maximum temperature limit of 446°F to determine the temperature correction factor for the resistance of the copper conductors in determining the heat input (1.5 watts/cm).

The maximum calculated temperature for the receptacle materials was 492.7°F. The calculation inputs included conductive heating from the heated portion of the heater, ambient temperature of 120F, pressurizer fluid temperature of approximately 653°F and self-heating due to the current flow through the receptacle (calculated to be ~1.5w/cm).

CONFIDENTIAL

7. The receptacle design for the US heaters is significantly different from the design for the EdF heaters. For example, the US heaters have connection points for the two heating elements in the single phase

CRDR 2809138 Page 81 of 89

Palo Verde heater and the WYE connection points for the three – phase heaters that could provide a barrier to the epoxy fill of the receptacles. The EDF receptacles are longer, with a smaller diameter, include a heat sink and the single phase (two conductors) connection points are joined to the pigtails deep in the receptacle and the internal barriers to the epoxy fill are minimal.

E. Thermocoax Design Non Conformance to FANP Specification

The quality related heating element assembly is designed by Thermocoax to meet the FANP design requirements shown in the applicable design drawings and product specifications. The root cause team review of the Thermocoax design process and process controls identified:

1. The Thermocoax design and design review process appeared to be adequate for new products based on a review by the Root Cause and Audit Team visit to Thermocoax in July 2005. However, the heaters designed for the US Plants were not considered to be new products and did not receive the same level of design development/review as a new product.

   The design/design verification process for the US heaters included the comparison with existing proven products provided to European plants and fabrication of prototype heaters based on these previous designs with design changes developed by Thermocoax to meet the applicable FANP specifications for the US heaters. For example, Thermocoax document HI100R045 (FANP 03-5039757), "Three-Phase Pressurizer Heaters 50 KW – 480 VAC" estimated the life of the proposed pressurizer heater design and compares the results to the requirements of the FANP specification for the SONGS heaters. Included in this report was a comparison of the three phase heater characteristics to the French pressurizer heater for which Thermocoax has a finite element analysis and a large good experience at French and other utilities. The SONGS prototype heaters were fabricated tested and modifications made as required to meet the specification requirements prior to starting fabrication of production heaters. The same process was used for subsequent US heater designs. For example, Thermocoax procedure HI70CR007 (FANP 38-5046696) for developing the receptacle for the Palo Verde heater based the single phase heater design on the SONGS design with changes made to the heating element to accommodate the higher currents expected in the single phase design. Additionally, testing was performed on the receptacles (connectors) to verify that the temperature limits would not be exceeded and to verify that the heaters met the design requirements. Note: For Palo Verde, as part of the receptacle design review/prototype testing process the decision was made to use two heating elements rather than one and add fins to the receptacle to reduce receptacle temperature.

2. Thermocoax considered that moving the hot/cold junction into the cold section of the heater by extending straight sections of the heating element(s) into the larger diameter heating element cold section was an enhancement to improve heater life. Thermocoax Corrective Action Sheet HI110P009 reported the investigation of the few heater failures reported by EdF revealed the probable cause to be an electrical breakdown at the heating element cold-to-hot junction where the inner electrical field is at its maximum, the temperature is high and there was a concentration of mechanical and thermal stresses. Thermocoax moved the hot-cold junction into the larger cold section of the heater to elongate the junction, reduce the electrical field and associated mechanical and thermal stresses to improve heater reliability. This design was in use at some power plants for more than eight years without any known problems. Thermocoax did not thoroughly evaluate the effect of this change for the US heaters, significantly under estimated the power in the warm zone, did not evaluate the effect the warm zone could have on pressurizer heater operation and did not inform FANP of the change. The Thermocoax experience was with a Monel wire guide with only two conductors. The Waterford three phase heaters have six conductors and the Palo Verde heater has two heater elements with four conductors in the Monel guide. Therefore, the power generated in this area is two to three times greater than Thermocoax's prior experience.

CONFIDENTIAL

3. The Thermocoax heating element design documents did not specifically identify the hot-cold junctions and were not revised when the hot-cold transition was moved to the previously cold section

CRDR 2809138 Page 82 of 89

of the heater. Thermocoax considered this transition area to be a "warm zone" and the heated zone was considered the "real hot" coiled portion of the heater. Therefore, the design documents presented to FANP for approval were consistent with the FANP design requirements and did not identify the straight portion of the heating element extending into the cold area of the heaters. The Thermocoax fabrication documents did recognize the extension of the heating element into the cold zone, but these documents were not provided to FANP for review. The FANP product specifications and design drawings for all pressurizer heaters required FANP approval of any change to the length and/or design of the hot and cold sections of the heater. The root cause team concluded that if this change had been presented to FANP there was a high probability that the impact of extending the heated portion of the heater element into the heater cold section would have been identified and the design change would not have been approved.

4. The FANP and Thermocoax design documents did not specifically address the heater installation parameters associated with the pressurizer. The FANP design documents identified specific lengths for the cold and heated sections of the heater required to meet the installation requirements, but did not identify the portion of the heater that would be installed in the pressurizer. The root cause team reviewed the need to provide the specific pressurizer installation requirements and concluded that including specific non deviation lengths of the heaters and sections on the FANP design drawing were sufficient and that providing Thermocoax pressurizer design drawings to show heater location could cause confusion. Furthermore, the investigation team did identify that in some instances the heater installation requirements were provided to Thermocoax (e.g., email dated October 29, 2004 from FANP to Thermocoax that clearly addressed the pressurizer interface for some heater applications including Waterford), but there was no apparent action by Thermocoax to evaluate the heater design against these installation requirements.

5. The investigation identified that the FANP and Thermocoax understanding of the heated section of the heater was not consistent. As noted II.E. 3, Themocoax considered that the heated section was the "real hot" coiled section of the heater and that the transition zone was a "warm zone" not shown on the design drawings. The FANP and Thermocoax design drawings/specifications only recognized a hot and cold section for the heaters. FANP revised the product specification for the St. Lucie heaters (06-4001355) and will do so for subsequent specifications to clearly define the cold section, heated section and the transition zone.

6. The Product Specifications identified requirements for design life (typically 10,000 hours @full-capacity with 5000 on-off cycles of 20,000 hours @ ½ power with 10,000 proportionally controlled power cycles consisting of +50% and -40% from the half power level). However, the actual proportional heater cycles, power input and cycling times were not included in the customer or FANP Design Specification and requests for cycling times found that the actual cycling time information did not appear to be readily available.

7. The schedule was aggressive for the US heater development and fabrication and may have created an error likely environment. Thermocoax reported that new product development normally takes approximately one year. The time allotted to design and fabricate heaters subsequent to the initial US market development for SONGS was two - three months for Palo Verde, four months for Waterford and five months for St. Lucie. Moreover, the schedule pressure for fabrication was exacerbated by the requirements for multiple cross-oceanic shipments. Although there were no specific findings during the investigation that directly associated time/schedule pressure to the inadequate design/design control or to fabrication errors, the interviews with FANP project personnel and Thermocoax management revealed that they considered the fabrication schedules for some contracts was aggressive.

8. The Thermocoax inspection and testing requirements included in the heater fabrication process documents was adequate. However, the method used to perform the final power testing showed the hotter coiled section of the heating element, but did not show the warm zone (no bubbles forming around the warm section of the heater) due to the heater being fully immersed in running water.

CONFIDENTIAL

CRDR 2809138 Page 83 of 89

FANP provided additional requirements that were incorporated into Thermocoax fabrication procedures to clarify heating element measuring, positioning and documentation requirements.

9. The heater design/development testing did not include aging tests or tests to simulate plant operations (including proportional heater cycling) to verify long term operability of the heaters.

10. Although the Thermocoax order entry process included a review of the FANP design documents, Thermocoax did not develop a detailed comparison document to show that all the FANP technical requirements were being met by the design. However, as noted in I.E.2 above, it is not apparent that Thermocoax would have identified the straight extension of the heating element as a significant design difference.

11. In September 2004, a FANP Design Review Board (DRB) reviewed the change from GE/Watlow pressurizer heater designs at Palo Verde, TMI, Oconee and St. Lucie (DRB report 80-5050153). (The Waterford heater was not addressed during the DRB.) The Design Review Board concluded that the replacement Thermocoax heater was a suitable replacement for function and physical interfaces, but identified concerns with the temperature sensitivity of the receptacle materials and the effectiveness of heat removal from the receptacle. The DRB issued action items associated with the receptacle design concerns, but there was no documentation of action item completion. Subsequently the DRB chairman provided documentation to show completion of assigned actions.

    There were no Thermocoax or customer (including customers would have added value regarding plant conditions and heater operations) participants in the DRB. Since Thermocoax designed the heating element and receptacle portion of the heater, Thermocoax should have presented the heating element and receptacle design to the DRB.

III. CONCLUSIONS

1. The pressurizer heaters fabricated for Palo Verde, Waterford and St. Lucie were not fabricated to the FANP design requirements.

2. The power (heat) generated by the heated portion of the heater being located in the pressurizer sleeve as the result of the non conforming design was sufficient to damage the heaters and a direct cause for premature failure of three of four Palo Verde pressurizer heaters examined during the failure analysis. The failure analysis/root cause investigation was not able to validate the direct cause for the low resistance reading to ground on the fourth Palo Verde heater failure, but consider that the low resistance was likely due to the same type conductive material found in the Waterford 029 receptacle (see section II.B.3.c of the report).

3. The stresses associated with the cycling of the Palo Verde proportional heaters combined with the elevated temperatures in the area where the failures occurred could have contributed to the proportional heaters failures. However, FANP evaluation of the Thermocoax stress analysis report (H101ER030) of the cycling heaters found no evidence to indicate that cycling stresses under design conditions will lead to heater failure.

4. The direct cause for the Waterford heater failure was due to overheating in the receptacles. The FANP thermal analysis of the Waterford heater performance identified that the receptacle material calculated temperatures due to self-heating from the current flow through the conductors and the heat conducted to the receptacle due to the high temperatures generated in the pressurizer nozzles exceeded the receptacle potting materials temperature limits.

5. A problem with the receptacle design, fabrication process and/or materials contributes to premature failure of the heaters. Furthermore, the thermal analysis to determine the temperatures in the SONGS heaters also showed the potting material temperature limits were challenged by the heater operating conditions, which is contributing to the premature failure of the SONGS heaters

CONFIDENTIAL

CRDR 2809138 Page 84 of 89

6. The aggressive schedule for designing and fabricating the heaters was a causal factor that may have contributed to the receptacle as built conditions. The schedule pressure was exacerbated by the requirements for multiple cross-oceanic shipments.

7. The significant increase in the heater power and the new receptacle design was a significant change from Thermocoax's existing products. The design reviews did not completely recognize the significance of the design and/or performance challenges.

8. The temperatures that were generated in the Palo Verde and Waterford pressurizers/pressurizer sleeves exceeded the design temperature limits.

IV. ROOT AND CONTRIBUTING CAUSES AND CAUSAL FACTORS

Root Cause No. 1

Inadequate Design/Design Control:

- The Thermocoax design/design review process was not adequately implemented and did not identify the non-compliance with the FANP design requirements.

- The design process/design review process did not identify the elevated receptacle operating temperatures for the SONGS and Waterford Heaters

Corrective/Preventive Action Number: 2

Contributing Causes/Causal Factors Associated with Root Cause No. 1

1. Thermocoax significantly under estimated the power in the warm zone and did not evaluate the effect the warm zone could have on pressurizer heater operation.

   Corrective/Preventive Action Number: 1, 2, 3 and 4

2. The US heater project was considered by Thermocoax as a modification of an existing product rather than a new product requiring a more extensive design process.

   Corrective/Preventive Action Number: 2

3. Although there was no direct evidence that time/schedule pressure contributed to the inadequate design/design control or fabrication errors, the aggressive schedule resulted in an error-likely environment.

   Corrective/Preventive Action Number: 2

4. The FANP Design Review Board was not adequate. Thermocoax, the heating element designer did not present the design to the board for review or participate in this independent design review process. Additionally, the root cause team concluded that customer participation would have added value to the independent design review process to assure that plant operating conditions and requirements were adequately addressed in the design.

   Corrective/Preventive Action Number: 5 and 6

Potential Cause for Failure

The receptacle design, fabrication process and material did not complement each other to provide long term heater reliability. The root cause team concluded that there was a problem with receptacle design, material selection and/or fabrication process that result in cracks and/or voids in the receptacle potting

CONFIDENTIAL

CRDR 2809138 Page 85 of 89

materials that could reduce the dielectric strength of the organic insulating materials and under adverse circumstances lead to premature heater failure.

Corrective/Preventive Action Number: 1, 2, 3 and 4

Other Contributing Causes:

5. Time/schedule pressure also created an error likely environment during fabrication.

   Corrective/Preventive Action Numbers: 2, 6 and 8

6. The heater power testing/test setup was not adequate to identify that significant heat was being produced in the warm section of the heater.

   Corrective/Preventive Action Number: 1

7. The use of tubular conductors in the Palo Verde heaters increased the susceptibility of the Palo Verde Proportional heaters to the cycling stresses.

   Corrective/Preventive Action Number: 1,

8. Aging/operability testing was not performed to verify heater reliability through the design life of the heater.

   Corrective/Preventive Action Number: 1, 3 and 4

V. CORRECTIVE/PREVENTIVE AND RECOMMENDED ACTIONS

1. Actions being taken by Thermocoax with FANP support and approval to address the heater failures includes:

   a. Thermocoax has performed and is performing extensive receptacle testing and analysis to identify the cause for the receptacle failures. The results of the testing and analysis are being provided to FANP, the Root Cause team and are being made available to the customer for information / review.

   b. Based on the findings of receptacle testing and analysis, Thermocoax with FANP approval and in most instances customer review has taken or is taking remedial actions to develop and test new and replacement heaters to prevent receptacle and other foreseeable heater problems.

   c. X-rays are being performed on 25% of the St. Lucie 1 heater receptacles to confirm that there are no cracks or voids. If cracks or voids are found the condition will be corrected and the number of heaters to be X-rayed will be increased to confirm acceptability. The root cause team recommends that FANP continue to require receptacle X-rays during future contracts until a confidence level is obtain to justify discontinuing this requirement.

   d. When practical, tubular conductors will not be used in the design of heaters for the US market.

2. Thermocoax is taking the following actions to address non compliance with the FANP design requirements:

   a. All new Framatome projects will be considered as new products requiring compliance with the Thermocoax new product design procedures and processes including completing a design compliance matrix to determine and verify compliance with the Framatome heater specification and drawing. A compliance matrix will also be created to review the designs for existing projects. Compliance matrixes will be submitted to FANP for approval and the prototype heater will be used to verify compliance with the compliance matrix.

CONFIDENTIAL

CRDR 2809138 Page 86 of 89

b. The design drawings for new products and the drawings for existing products being replaced will be up dated to show the location of the transition zone (hot- cold junction).

c. Management will reinforce expectations regarding design and design change control and ensure personnel are not unduly subjected to time/schedule pressure.

d. Training will be conducted as applicable for managers, supervisors and employees associated with the engineering and fabrication of FANP heaters to review as a minimum:

- This event
- Design and design change control requirements
- Management expectations for establishing and complying with rigid control of designs
- Applicable changes implemented to assure reliable heater design, production and testing.
- 10CFR Part 21 requirements
- Expectations for all employees to identify problems, concerns and error likely situations such as time/schedule pressure

3. The following actions are being taken by FANP to prevent premature failure of heaters:

a. FANP is testing new and redesigned heaters (e.g. St. Lucie) at the AREVA GmbH Technical Center Multi-functional Thermal-Hydraulic Test Loop - KATHY in Karlstein, Germany to demonstrate long-term heater reliability and to challenge the survivability of a heater under adverse conditions. The root cause team recommends that FANP/Thermocoax continue to perform testing to verify long-term reliability for future heater designs until the actions taken to address the causes for the heater failures are proven to be effective.

b. FANP has expanded requirements for reviewing Thermocoax drawings to include those drawings that depict internals from four-inches from the receptacle weld to the end of the end plug.

4. Additional testing under controlled conditions will be performed to determine the actual effects to a heater operated with the heated portion of the heater installed in a pressurizer nozzle to validate the failure mode and aging testing (thermal and radiation) to assess long term heater reliability.

5. FANP Nuclear Engineering Business Unit (procedure owner) and Component Repair and Replacement will be requested to review the DRB procedure (Administrative Instruction 0405-22) to determine if additional direction is required to assure participation of the supplier providing a design.

6. FANP will utilize the root cause report to brief personnel associated with the heater design, procurement and fabrication on lessons learned from this event. The lessons learned from this event also have been or will be rolled out to other applicable FANP design organizations to make them aware of the need for effective control of designs provided by suppliers.

7. The required customer and 10CFR part 21 notifications have been completed regarding the pressurizer heater failures and pressurizer/pressurizer nozzle overheating.

8. FANP/Thermocoax to minimize or mitigate the impact from aggressive scheduling to prevent the creation of an error likely situation.

VI. Root Cause Team Members

Jim Bartleman	Manager Corrective Action Program	Team Leader
Greg Kane	Consultant (6/14-17)	Plant Operations, Human Performance, Independent Validation of Process
William Bruce	Electrical Engineer IV	Electrical Design
Ben Grambau	Manager, Material & Structural Analysis	Materials
Nissen Burnstein	Advisor Engineer, Electrical Systems	Heater Testing

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CRDR 2809138 Page 87 of 89

AREVA

November 3, 2005
JPB-05-006

Mr. Carl Churchman
Director of Engineering
Arizona Public Service
P.O. Box 52304
Phoenix, AZ 85072-2034

Dear Mr. Churchman:

The attached information is provided to supplement the FANP Root Cause Report on the Unit 3 pressurizer failures that was previously provided to you.

Please contact me if you have further questions. You can reach me at 434-832-3947 (work), 434-841-2406 (cell), or at jim.bartleman@framatome-anp.com.

Sincerely,

James P. Bartleman
Manager, Corrective Action Program

cc: S.P. Hellman
T.A. Werner

Attachment

CRDR 2809138 Page 88 of 89

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AREVA

PRESSURIZER HEATER FAILURES AT PALO VERDE AND WATERFORD
ROOT CAUSE INVESTIGATION REPORT - PALO VERDE SUPPLEMENT DATED NOVEMBER 3, 2005

The FANP Root Cause Investigation, which included a Failure Analysis by an independent test laboratory, concluded that there was no compromise in the safety related function (i.e. the integrity of the pressure boundary) of the FANP/Thermocoax heaters that were installed in the Palo Verde Unit 3 pressurizer. The Failure Analysis that included visual, electrical, non destructive and destructive examination of four failed Palo Verde heaters (two proportional and two backup) revealed that there was no degradation of the heater pressure boundary. Moreover, FANP has reviewed the data submitted from the Operations Log of 5/31 to 6/02 and has concluded that the heaters which failed during startup were fully functional when heat up began. Therefore, FANP concludes that the backup heaters were capable of performing their pressure control function from the time Palo Verde resumed power operation in the Fall 2004 outage until the May 05 mid-cycle outage. The following summarizes the overall sequence of events:

- Palo Verde installed 36 Framatome ANP supplied heaters during a scheduled refueling outage in the fall of 2004. The plant resumed power operation in December 2004.
- Four (4) proportional heaters failed within approximately 3 months of operation, December 04 - February 05. These heaters cycle continuously to maintain pressurizer pressure. In February 05, Palo Verde chose to de-energize the proportional heaters and operate with backup heaters only.
- Backup heaters were in operation continuously without failure for approximately 6 months, December 04 - May 05. Additional backup heaters were in operation as necessary for equalizing boron within the primary system. The backup heaters are not subject to the cycling control scheme; backup heaters are simply on or off.
- Palo Verde shutdown for a mid-cycle outage in May 05. Five (5) backup heaters failed within approximately 5 days when energized during startup from the cold plant condition.

The fact that five backup heaters failed in approximately five days, after numerous backup heaters operated continuously or as necessary for six months without failure, appears to indicate that the heat up (after the cold plant condition) process beginning in May 05, in addition to the stresses and high temperatures associated with the "warm zone" being located in the pressurizer nozzle, contributed to the backup heater failure.

Investigation Team Leader: J.P. Bartleman 11/3/05
J.P. Bartleman, Manager, Corrective Action Program - QA

Approved: K.B. Price for HBP 11/3/05
H.B. Prasse, Manager, Operations Support - NPC

Approved: D.E. Matthews 11/3/05
D.E. Matthews, Supervisor Component Engineering - CR&R

Approved: J.J. Cuvelier for SP Hellman 11/3/05
S.P. Hellman, Vice President Nuclear Parts Center

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ATTACHMENT 15

Review of Palo Verde 2005 Outages

Disallowance of Replacement Power Costs For Imprudent Forced Outages For the Period of April through December 2005 (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Claimed Replacement Power Costs For Imprudent Forced Outages (3) ($ x 1,000) (d)	Recommended Disallowance of Replacement Power Costs For Imprudent Forced Outages (4) ($ x 1,000) (e)
	May	[redacted]	[redacted]	[redacted]
1	Unit 1			
2	Unit 2			
3	Unit 3			
	June			
4	Unit 1			
5	Unit 2			
6	Unit 3			
	July			
7	Unit 1			
8	Unit 2			
9	Unit 3			
	August			
10	Unit 1			
11	Unit 2			
12	Unit 3			
	October			
13	Unit 1			
14	Unit 2			
15	Unit 3			
	December			
16	Unit 1			
17	Unit 2			
18	Unit 3			
19	TOTAL	56,922	16,604	14,944

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.

(2) Amounts are prior to the 90/10 sharing allocation and net of avoided nuclear fuel costs.

(3) Amount in column (d) is the portion in column (c) related to imprudence.

(4) Amounts in column (e) are equal to 90% of amounts in column (d).

Review of Palo Verde 2005 Outages

Replacement Power Costs For Imprudent Forced Outages For the Period Prior to PSA Implementation (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Claimed Replacement Power Costs For Imprudent Forced Outages (3) ($ x 1,000) (d)
	February	[redacted]	[redacted]
1	Unit 1		
2	Unit 2		
3	Unit 3		
	March		
4	Unit 1		
5	Unit 2		
6	Unit 3		
7	TOTAL	5,380	1,325

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.

(2) Amounts are net of avoided nuclear fuel costs.

(3) Amount in column (d) is the portion in column (c) related to imprudence.

Review of Palo Verde 2005 Outages

Replacement Power Costs For Forced Outages Not Caused by Imprudence (1)

Line No. (a)	Month/Unit (b)	APS' Total Replacement Power Cost Claim For All Forced Outages (2) ($ x 1,000) (c)	Portion Of APS' Replacement Power Costs For Forced Outages Due To Faulty Equipment (3) (d)	Portion Of APS' Replacement Power Costs For All Other Forced Outages Not Caused by Imprudence (3) (e)
	February	[redacted]	[redacted]	[redacted]
1	Unit 1			
2	Unit 2			
3	Unit 3			
	March			
4	Unit 1			
5	Unit 2			
6	Unit 3			
	May			
7	Unit 1			
8	Unit 2			
9	Unit 3			
	June			
10	Unit 1			
11	Unit 2			
12	Unit 3			
	July			
13	Unit 1			
14	Unit 2			
15	Unit 3			
	August			
16	Unit 1			
17	Unit 2			
18	Unit 3			
	October			
19	Unit 1			
20	Unit 2			
21	Unit 3			
	December			
22	Unit 1			
23	Unit 2			
24	Unit 3			
25	TOTAL	62,302	20,597	23,776

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential responses APS07309 & APS07310 to ACC Staff RFI 1.7. Excluded months are those months in which no forced outages occurred.

(2) Amounts are net of avoided nuclear fuel costs.

(3) Amount in column (d) is the portion in column (c) related to faulty equipment forced outages.

(4) Amount in column (e) is the portion in column (c) not related to forced outages due to imprudence or faulty equipment

ATTACHMENT 16

Review Of Palo Verde 2005 Outages

Estimated Impact On Off-System Sales Margins Due to Imprudent Forced Outages

Line No. (a)	Month/Unit (b)	Palo Verde Generation Loss Due To Imprudent Forced Outages (1) (c)	Estimated Reduced Margins From Off-System Sales Due To Imprudent Outages (2) (d)	Recommended Disallowance Due To Reduced Margins From Off-System Sales (4) (e)
1	February - Unit 1	[redacted]	[redacted]	
2	March - Unit 1			
3	Subtotal - Pre-PSA (3)	23,882 MWH	$298,286	
4	May - Unit 3	[redacted]	[redacted]	[redacted]
5	June - Unit 3			
6	August - Unit 1			
7	August - Unit 2			
8	October - Unit 2			
9	October - Unit 3			
10	Subtotal - Post-PSA (3)	187,098 MWH	$2,336,854	$2,103,169
11	Total For 2005	210,980 MWH	$2,635,140	$2,103,169

Notes: (1) Source: Docket No. E-01345A-05-0526, APSC confidential response APS07310 to ACC Staff RFI 1.7. Amounts for August - Unit 1 and October - Unit 3 are the portion of the total MWH related to imprudence.
(2) Lost outage generation times average margin per MWh on off-system sales for April through December, or $12.49 per MWh.
(3) PSA became effective on April 1, 2005.
(4) Amounts in column (e) are equal to 90% of amounts in column (d).

ATTACHMENT 17

Review Of Palo Verde 2005 Outages

Adjustment to APS Interest On Fuel Under-Recovery Balances
Due To Imprudent Outages

Line No.	Month	Imprudent Palo Verde Outage Replacement Power Cost Disallowance	Adjustment For Lost Opportunity Sales Due To Palo Verde Outages	Total Disallowed Power Cost And Lost Opportunity Sales	Interest Adjustment
(a)	(b)	(c)	(d)	(e)	(f)
1	April 2005	$0	$0	$0	$0
2	May	$0	$0	$0	$0
3	June	$0	$0	$0	$0
4	July	$0	$0	$0	$0
5	August	$1,134,000	$186,949	$1,320,949	$0
6	September	$0	$0	$0	$3,071
7	October	$13,810,000	$1,916,220	$15,726,220	$3,078
8	November	$0	$0	$0	$39,649
9	December	$0	$0	$0	$39,741
10	Subtotal -	$14,944,000	$2,103,169	$17,047,169	$85,539
11	January 2006				$39,834
12	February				$39,926
13	March				$40,019
14	April				$40,112
15	May				$40,205
16	June				$40,299
17	Subtotal (2) -				$240,395
18	Total	$14,944,000	$2,103,169	$17,047,169	$325,934

Notes: (1) Source: APSC response APS08093 to ACC Staff RFI 7.1, Attachment 15 and Attachment 16. This document is APS' Power Supply Adjustor Report.

(2) Since APS will continue to earn interest on the fuel cost under-recovery in 2006 the interest reduction adjustment must continue after 2005.

ATTACHMENT 18

Review Of Palo Verde 2005 Outages

Summary Of Cost Disallowances For Imprudent Outages
For the Period of April through December 2005

Line No.	Month	Replacement Power Cost Disallowance	Margin Adjustment For Lost Opportunity Sales	Interest Adjustment	Total Recommended Disallowance
(a)	(b)	(c)	(d)	(e)	(f)
1	April 2005	[redacted]	[redacted]	0	0
2	May	[redacted]	[redacted]	0	0
3	June	[redacted]	[redacted]	0	0
4	July	[redacted]	[redacted]	0	0
5	August	[redacted]	[redacted]	0	1,320,949
6	September	[redacted]	[redacted]	3,071	3,071
7	October	[redacted]	[redacted]	3,078	15,729,298
8	November	[redacted]	[redacted]	39,649	39,649
9	December	[redacted]	[redacted]	39,741	39,741
10	2005 Subtotal	$14,944,000	$2,103,169	$85,539	$17,132,708
11	January 2006			39,834	39,834
12	February			39,926	39,926
13	March			40,019	40,019
14	April			40,112	40,112
15	May			40,205	40,205
16	June			40,299	40,299
17	2006 Subtotal			$240,395	$240,395
18	Disallowance for Imprudent Outages	$14,944,000	$2,103,169	$325,934	$17,373,103

Notes: (1) Source: Column (c) = Attachment 15, Column (d) = Attachment 16, Column (e) = Attachment 17.

Review Of Palo Verde 2005 Outages

Summary Of Cost Impacts For Imprudent Outages For the Period Prior to PSA Implementation

Line No. (a)	Month (b)	Replacement Power Cost Disallowance (c)	Margin Adjustment For Lost Opportunity Sales (d)	Total Cost Impact (e)
1	January 2005	[redacted]	[redacted]	$0
2	February			0
3	March			1,623,286
4	Cost Impact for Imprudent Outages			$1,623,286

Notes: (1) Source: Column (c) = Attachment 15, Column (d) = Attachment 16.