APS

A subsidiary of Pinnacle West Capital Corporation

Palo Verde Nuclear Generating Station

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102-05989-DCM/GAM
April 14, 2009

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN 50-528, 50-529, and 50-530
Supplement 1 to License Renewal Application

By letter no. 102-05937, dated December 11, 2008, Arizona Public Service Company (APS) submitted a license renewal application (LRA) for PVNGS Units 1, 2, and 3. By letter dated February 13, 2009, the NRC notified APS of a deficiency in the PVNGS LRA regarding missing valve fatigue analysis information, and requested that APS inform the staff of plans for resolving the deficiency and supplementing the LRA. By letter no. 102-05965, dated February 25, 2009, APS committed to submit a supplement to the PVNGS LRA to include the valve fatigue analysis information no later than April 15, 2009.

In the original LRA submittal, APS reported being unable to recover a fatigue analysis for a limited number of ASME III Class 1 valves and committed to recovering them prior to the period of extended operation. The ASME fatigue analyses are now in place and confirm that these components will continue to operate safely throughout the current license, as well as through the period of extended operation.

Enclosed are PVNGS Units 1, 2, and 3 LRA Supplement 1 replacement pages and insertion instructions. These supplement pages contain the following changes to resolve the deficiency identified in the February 13, 2009, NRC letter to APS:

Sections 4.3.2.6 and A3.2.1.6, and Tables 4.1-1, 4.3-9, and A4-1, Commitment No. 44

Table 4.3-9 has been updated to reflect completion of the commitment to include previously-missing valve fatigue analysis results for the time-limited aging analyses required by 10 CFR 54.21(c)(1). In addition, discussions describing the

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commitment to obtain this information have been updated in Table 4.1-1, Sections 4.3.2.6 and A3.2.1.6, and Table A4-1.

APS is taking this opportunity to update the LRA, as described below, to reflect completed commitments, make minor corrections and enhancements, and clarify information previously provided.

- Table 3.1.2-1

  Corrected the Aging Management Program (AMP) Section number reference for Component Type RV ICI Nozzle in Table 3.1.2-1 (page 3.1-46) from B2.1.22 to B2.1.21.

- Figure 4.5-2

  Extended the Regulatory Guide 1.35.1 Predicted Prestress graph values to 60 years.

- Section 4.5

  Aligned the 10 CFR 54.21(c)(1) discussion in the "Summary Description" to be consistent with the "Disposition" in this section.

- Sections A1.5 and B2.1.5, and Table A4-1, Commitment No. 7

  Updated to reflect completion of the commitment to revise the PVNGS Alloy 600 Management Program Plan to incorporate the applicable examination requirements of ASME Code Case N-729-1 (Reactor Vessel Head Inspections), subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6).

- Sections A1.12 and B2.1.12, and Table A4-1, Commitment No. 14

  Updated to reflect completion of the commitment to enhance procedures to inspect the halon discharge pipe header for mechanical damage, corrosion and loss of material.

- Sections A1.13 and B2.1.13, and Table A4-1, Commitment No. 15

Updated to reflect completion of the commitment to enhance procedures to state trending requirements.

- Sections A1.34 and B2.1.34, and Table A4-1, Commitment No. 36

  Updated to reflect completion of the commitments to revise the PVNGS Alloy 600 Management Program Plan to (1) add Alloy 600 steam generator components, including tube sheet cladding and portions of the primary nozzle cladding, and (2) incorporate the applicable examination requirements of ASME Code Case N-729-1 (Reactor Vessel Head Inspections), subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6) and ASME Code Case N-722 (reactor coolant pressure boundary visual Inspections) subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4).

- Appendix E, Environmental Report, Sections D3.1 and D.11

  Provided an expanded description of the basis for the population projections.

- Appendix E, Environmental Report, Sections 4.20, D6.2, D6.8, and D6.13

  Enhanced the description of the basis for the estimated cost considerations and added emphasis that SAMAs 6, 17, and 23 are being considered for implementation regardless of their costs.

- Appendix E, Environmental Report, Sections 2.14, 3.6, 4.0, 4.2, 4.3, 4.4, 4.9, 4.11, 4.22, 7.2, 7.4, 9.1, and Attachment D

  Additional post-submittal reviews identified certain citations in the Environmental Report reference lists that required corrections.

Should you have questions regarding this submittal or if additional information is needed, please contact Angela K. Krainik, License Renewal Department Leader, at 623-393-5045.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 4/14/09
(Date)

Sincerely,

B.C. Mim

DCM/SAB/GAM

Enclosure: Replacement Pages and Insertion Instructions, Supplement 1 to License Renewal Application, Palo Verde Nuclear Generating Station Units 1, 2, and 3

cc:	E. E. Collins Jr.	NRC Region IV Regional Administrator
	J. R. Hall	NRC NRR Project Manager
	R. I. Treadway	NRC Senior Resident Inspector
	B. E. Holian	NRC License Renewal Director
	J. G. Rowley	NRC License Renewal Project Manager
	L. M. Regner	NRC License Renewal Environmental Project Manager
	A. V. Godwin	Arizona Radiation Regulatory Agency (ARRA)
	T. Morales	Arizona Radiation Regulatory Agency (ARRA)

Enclosure

Replacement Pages and Insertion Instructions, Supplement 1 to License Renewal Application, Palo Verde Nuclear Generating Station Units 1, 2, and 3

Insertion Instructions
Supplement 1 to License Renewal Application,
Palo Verde Nuclear Generating Station Units 1, 2, and 3

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4.3-52 / 4.3-53	4.3-52 / 4.3-53
4.3-54/4.3-55	4.3-54/4.3-55
****	4.3-55a/4.3-55b
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Insertion Instructions
Supplement 1 to License Renewal Application,
Palo Verde Nuclear Generating Station Units 1, 2, and 3

Appendix E
Environmental Report

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LICENSE RENEWAL APPLICATION

PALO VERDE NUCLEAR GENERATING STATION
UNIT 1, UNIT 2, AND UNIT 3

Facility Operating License Nos.
NPF- 41, NPF- 51, and NPF-74

Supplement 1
April 10, 2009

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Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RV ICI Nozzle	PB	Nickel Alloys	Reactor Coolant (Int)	Loss of material	Water Chemistry (B2.1.2)	IV.A2-14	3.1.1.83	A
RV ICI Nozzle	PB	Nickel Alloys	Reactor Coolant (Int)	Cracking	Nickel Alloy Aging Management (B2.1.34), ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) for Class 1 components, Water Chemistry (B2.1.2), and Comply with applicable NRC Orders and FSAR Commitment (B2.1.21)	IV.A2-19	3.1.1.31	E, 1
RV ICI Nozzle	PB	Nickel Alloys	Reactor Coolant (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	IV.A2-21	3.1.1.09	A
RV Nozzle Safe Ends and Welds	PB	Carbon Steel with Stainless Steel Cladding	Borated Water Leakage (Ext)	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2-13	3.1.1.58	A
RV Nozzle Safe Ends and Welds	PB	Carbon Steel with Stainless Steel Cladding	Reactor Coolant (Int)	Loss of material	Water Chemistry (B2.1.2)	IV.A2-14	3.1.1.83	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System – Summary of Aging Management Evaluation – Reactor Vessel and Internals (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Vol. 2 Item	Table 1 Item	Notes
RV Nozzle Safe Ends and Welds	PB	Carbon Steel with Stainless Steel Cladding	Reactor Coolant (Int)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD for Class 1 components (B2.1.1) and Water Chemistry (B2.1.2)	IV.A2-15	3.1.1.69	A
RV Nozzle Safe Ends and Welds	PB	Carbon Steel with Stainless Steel Cladding	Reactor Coolant (Int)	Loss of fracture toughness	Reactor Vessel Surveillance (B2.1.15)	IV.A2-17	3.1.1.18	C
RV Nozzle Safe Ends and Welds	PB	Carbon Steel with Stainless Steel Cladding	Reactor Coolant (Int)	Cumulative fatigue damage	Time-Limited Aging Analysis evaluated for the period of extended operation	IV.A2-21	3.1.1.09	A
RV Nozzles	PB	Carbon Steel with Stainless Steel Cladding	Borated Water Leakage (Ext)	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2-13	3.1.1.58	A
RV Nozzles	PB	Carbon Steel with Stainless Steel Cladding	Reactor Coolant (Int)	Loss of material	Water Chemistry (B2.1.2)	IV.A2-14	3.1.1.83	A

4.1.3 Summary of Results

Sections 4.2 through 4.7 of this report list and describe six general categories of TLAAs. They are listed in Table 4.1-1. They are presented in the order in which they appear in Sections 4.2 through 4.7 of the NUREG-1800 *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants* (the SRP).

Standard Review Plan Tables 4.1-2 and 4.1-3 list examples of analyses that could be TLAAs, depending on the applicant's current licensing basis (CLB). Table 4.1-2 summarizes the results of the PVNGS review of the analyses identified in SRP Tables 4.1-2 and 4.1-3.

Table 4.1-1 - List of TLAAs

TLAA Category	Description	Disposition Category[1]	Report Section
1.	Reactor Vessel Neutron Embrittlement Analysis	NA	4.2
	Neutron Fluence, Upper Shelf Energy and Adjusted Reference Temperature (Fluence, USE, and ART)	i, iii	4.2.1
	Pressurized Thermal Shock (PTS)	i	4.2.2
	Pressure-Temperature (P-T) Limits	i	4.2.3
	Low Temperature Overpressure Protection (LTOP)	i	4.2.4
2.	Metal Fatigue Analysis	NA	4.3
	Fatigue Aging Management Program	NA	4.3.1
	ASME III Class 1 Fatigue Analysis of Vessels, Piping, and Components	NA	4.3.2
	Reactor Pressure Vessel, Nozzles, Head, and Studs	ii, iii	4.3.2.1
	Control Element Drive Mechanism (CEDM) Nozzle Pressure Housings	i	4.3.2.2
	Reactor Coolant Pump Pressure Boundary Components	iii	4.3.2.3
	Pressurizer and Pressurizer Nozzles	iii	4.3.2.4

Table 4.1-1 - List of TLAAs

TLAA Category	Description	Disposition Category[1]	Report Section
	Steam Generator ASME III Class 1, Class 2 Secondary Side, and Feedwater Nozzle Fatigue Analyses	i, iii	4.3.2.5
	ASME III Class 1 Valves	i, iii	4.3.2.6
	ASME III Class 1 Piping and Piping Nozzles	iii	4.3.2.7
	Absence of Supplemental Fatigue Analysis TLAAs in Response to Bulletin 88-08 for Intermittent Thermal Cycles due to Thermal-Cycle-Driven Interface Valve Leaks and Similar Cyclic Phenomena	Included under 4.3.2.7	4.3.2.8
	Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification	iii	4.3.2.9
	Class 1 Fatigue Analyses of Class 2 Regenerative and Letdown Heat Exchangers	iii	4.3.2.10
	Class 1 Fatigue Analyses of Class 2 HPSI and LPSI Safety Injection Safeguard Pumps for Design Thermal Cycles	i	4.3.2.11
	Class 1 Analysis of Class 2 Main Steam Safety Valves	i	4.3.2.12
	Absence of TLAAs in Evaluations of Effects of Vibration on the Unit 1 Train A Shutdown Cooling System Suction Line Fatigue Analysis, and of Vibration Limits Established for its Isolation Valve Actuator	NA	4.3.2.13
	High Energy Line Break Postulation Based on Fatigue Cumulative Usage Factor	iii	4.3.2.14
	Absence of TLAAs in Fatigue Crack Growth Assessments and Fracture Mechanics Stability Analyses for the Leak-Before-Break (LBB) Elimination of Dynamic Effects of Primary Loop Piping Failures	NA	4.3.2.15

Table 4.1-1 - List of TLAAs

TLAA Category	Description	Disposition Category[1]	Report Section
	Fatigue and Cycle-Based TLAAs of ASME III Subsection NG Reactor Pressure Vessel Internals	iii	4.3.3
	Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190)	i, iii	4.3.4
	Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in ANSI B31.1 and ASME III Class 2 and 3 Piping	i, ii	4.3.5
3.	Environmental Qualification (EQ) of Electric Equipment	iii	4.4
4.	Concrete Containment Tendon Prestress	ii, iii	4.5
5.	Containment Liner Plate, Equipment Hatch and Personnel Air Locks, Penetrations, and Polar Crane Brackets	NA	4.6
	Absence of a TLAA for Containment Liner Plate, Polar Crane Bracket, Equipment Hatch, Air Lock, and Containment Penetration Design (Except Main Steam, Main Feedwater, and Recirculation Sump Suction Penetrations)	NA	4.6.1
	Design Cycles for the Main Steam and Main Feedwater Penetrations	i	4.6.2
	Design Cycles for the Recirculation Sump Suction Line Penetrations	i	4.6.3
6.	Plant-specific Time-Limited Aging Analysis	NA	4.7
	Load Cycle Limits of Cranes, Lifts, and Fuel Handling Equipment Designed to CMAA-70	i	4.7.1
	Absence of TLAAs for Metal Corrosion Allowances and Corrosion Effects	NA	4.7.2
	Inservice Flaw Growth Analyses that Demonstrate Structural Stability for 40 Years	Included in 4.3.2.4 and 4.7.4	4.7.3

Table 4.1-1 - List of TLAAs

TLAA Category	Description	Disposition Category[1]	Report Section
	Fatigue Crack Growth and Fracture Mechanics Stability Analyses of Half-Nozzle Repairs to Alloy 600 Material in Reactor Coolant Hot Legs; Absence of a TLAA for Supporting Corrosion Analyses	iii	4.7.4
	Absence of a TLAA in Corrosion Analyses of Pressurizer Ferritic Materials Exposed to Reactor Coolant by Half-Nozzle Repairs of Pressurizer Heater Sleeve Alloy 600 Nozzles	NA	4.7.5
	Absence of a TLAA for Reactor Vessel Underclad Cracking Analyses	NA	4.7.6
	Absence of a TLAA for a Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis	NA	4.7.7
	Building Absolute or Differential Heave or Settlement, including Possible Effects of Changes in a Perched Groundwater Lens	i, iii	4.7.8
Exemption List	Absence of TLAAs Supporting 10 CFR 50.12 Exemptions	NA	4.8

[1] i - 10 CFR 54.21(c)(1)(i) – Validation: Demonstration that "The analyses remain valid for the period of extended operation,"
ii - 10 CFR 54.21(c)(1)(ii) – Revision: Demonstration that "The analyses have been projected to the end of the period of extended operation," or
iii - 10 CFR 54.21(c)(1)(iii) – Aging Management: Demonstration that "The effects of aging on the intended function(s) will be adequately managed for the period of extended operation."
NA - Not Applicable – Section heading or no TLAA, disposition categories are not applicable

Disposition: Validation, 10 CFR 54.21(c)(1)(i); and Aging Management, 10 CFR 54.21(c)(1)(iii)

Validation, Units 1 and 3

The fatigue analyses of the Unit 1 and 3 replacement steam generators are for a period sufficient to cover their installed life, to the end of the period of extended operation, and therefore will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Aging Management, Unit 2

The fatigue analyses of the Unit 2 replacement steam generators are for a period sufficient to cover all but about two years of their expected 42-year installed life, including the period of extended operation. The Metal Fatigue of Reactor Coolant Pressure Boundary program will track events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits will permit completion of corrective actions before the design basis number of events is exceeded, and before the cumulative usage factor exceeds the code limit of 1.0. Effects of fatigue in the Unit 2 replacement steam generator pressure boundaries with Class 1 analyses will thereby be managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

The Metal Fatigue of Reactor Coolant Pressure Boundary program is described in Section 4.3.1; and is summarized in Appendix B, Section B3.1. See Table 4.3-4 for details of the program, and Section 4.3.1.5 for a description of its action limits and corrective actions.

4.3.2.6 ASME III Class 1 Valves

Summary Description

PVNGS Class 1 valves (power-operated relief, pressurizer safety, control, motor- and air-operated, manual, check, and solenoid) are designed to ASME III, Subsection NB, 1974 Edition with multiple addenda, the 1977 Edition with Winter 1977 addendum, and the 1989 Edition no addenda [UFSAR Table 5.2-1]. ASME Section III requires a fatigue analysis only for Class 1 valves with inlets greater than four inches nominal. At PVNGS, specifications for some Class 1 valves with inlets four inches or less also require a fatigue analysis.

Analysis

Code Fatigue Analyses

Fatigue analyses or evaluations were performed for the valves listed in the following table:

Table 4.3-9- Summary of PVNGS Class 1 Valve Fatigue Analyses

Valve, Specification, and Analysis Descriptions	Calculated Design Basis Ops N_A for NB-3545.3 Normal Duty(1)	Maximum Design Basis CUF I_t for NB-3550 Cyclic Loads(1)
1/2/3JSIAUV0651 and 1/2/3JSIBUV0652 Borg-Warner Model 77850/77850-1, 16" Shutdown Cooling Suction Isolation Valve Reanalysis Valve UV-651 was relocated closer to the RCS hot leg in all three Units because of line vibration issues in Unit 1, and reanalyzed. See Section 4.3.2.13. The reanalysis included the UV-652 valves.	NA(2)	0.702 (Crotch)(3)
1/2/3JSICUV0653, and 1/2/3JSIDUV0654 Borg-Warner Model 77850/77850-1 16" Shutdown Cooling Suction Containment Isolation Valves. The Borg Warner valves meet the normal duty fatigue requirements of Articles NB-3522, NB-3545, and NB-3550 for cyclic loading conditions.	> 2,000	0.194
1/2/3JSIAUV0634/644 and 1/2/3JSIBUV0614/624 Borg-Warner Model 77840, 14" Safety Injection Tank Injection Discharge Isolation Gate Valves. The Borg Warner valves meet the normal duty fatigue requirements of Articles NB-3522, NB-3545, and NB-3550 for cyclic loading conditions.	> 2,000	0.204
1/2/3PSIEV215/217/225/227/235/237/245/247 Borg-Warner Model 77810, 14" Safety Injection Tank Injection Discharge Check Valves. The Borg Warner valves meet the normal duty fatigue requirements of Articles NB-3522, NB-3545, and NB-3550 for cyclic loading conditions.	> 2,000	0.15 - 0.661(4)
1/2/3/PSIEV540/541/542/543 Borg-Warner Model 77790-1, 12" HPSI and LPSI Header Injection Discharge Check Valves. The Borg Warner valves meet the normal duty fatigue requirements of Articles NB-3522, NB-3545, and NB-3550 for cyclic loading conditions identified.	> 2,000	0.141 - 0.625(4)

Table 4.3-9- Summary of PVNGS Class 1 Valve Fatigue Analyses

Valve, Specification, and Analysis Descriptions	Calculated Design Basis Ops N_A for NB-3545.3 Normal Duty[1]	Maximum Design Basis CUF I_t for NB-3550 Cyclic Loads[1]
3JCHAHV0205 and 3JCHBHV0203 Valcor Model V526-5631-9, 2" Isolation Valves between the Unit 3 Regenerative Heat Exchanger and Auxiliary Spray Line A fatigue analysis of the crotch of the body used Subparagraph NB-3545.3 for the section in thermal cycles when the temperature change rate is 100 °F/hr. Pipe and seismic load stresses are treated as cyclic loads in the fatigue analysis.	10,000	0.151 (Crotch)
1/2/3JRCEPSV0200/201/202/203 Dresser Model 6-31709NAX-1-XNC045 Pressurizer Pressure Safety Valves (6" Inlet)	$> 10^6$	< 0.002[5]
1/2/3JCHEPDV0240 FisherModel 667-DBQ/ 50B0617/ 54A6460, 2" Isolation Valves for the Charging Line This analysis used Subparagraph NB-3545.3, "Fatigue Requirements," 1983	6,000	0.7656 (Valve Body)
1,2,3JSIBPSV0169 and 1,2,3JSIAPSV0469 Crosby Model JMAK-3/4X1, ¾" Safety Injection Line Thermal Relief Valves The analysis confirms that these valves will withstand the specified number of each of three thermal transients from the valve specification as reported in UFSAR 5.2.2.4.4.2.	> 2,000	0.075 (Valve Body Inlet)[6]

1 N_A and I_t were calculated for the design basis number of loading events applicable to the component that were originally intended to encompass a 40-year design life.

2 The fatigue evaluations of the valve components are performed in accordance with ASME Code, Section III, Subparagraph NB-3222.4, hence a calculated NA for NB-3545.3 normal duty operations is not applicable.

3 "Crotch" is a critical section of the valve body between the body and neck as defined in NB-3545.2-1. Fatigue stresses of this region are required to be calculated under the rules of ASME III, Subarticle NB-3545 and NB-3550.

4 A range of 40-year CUF has been calculated. The lower value was arrived at by conservative interpretation of the Code regarding combination of cycles that exceed 100 °F/hr. whereas the lower value takes consideration of the actual ramp of 116 °F/hr rate.

5 The CUF is not explicitly calculated in the Design Report, but the CUF presented here is derived from the statement in the Design Report that the allowable number of cycles from the ASME Code analysis is greater than 10^6, compared to the specification allowable value of 2,000 cycles (CUF = $2{,}000/>10^6 < 0.002$).

6 Highest CUF calculated for the three analyzed locations; the inlet nozzle, valve inlet and valve outlet.

For the valves modeled with an NB-3545.3 normal duty operating cycle evaluation, the allowed NB-3545.3 N_A normal duty operations is much greater than the required minimum of 2000 cycles. The calculated cumulative usage factors I_t for NB-3550 cyclic loads are less than the code limit of 1.0.

Effect of Combustion Engineering Infobulletin 88-09 "Nonconservative Calculation of Cumulative Fatigue Usage"

The CE Owner's Group review of Combustion Engineering Infobulletin 88-09 did not identify any effects on the fatigue analyses of Class 1 valves.

Disposition: Validation, 10 CFR 54.21(c)(1)(i); and Aging Management, 10 CFR 54.21(c)(1)(iii)

Validation - Valves with large margin

The calculated worst-case usage factors for the 16" Shutdown Cooling Suction Containment Isolation Valves, the 14" Safety Injection Tank Injection Discharge Isolation Gate Valves, the 14" Safety Injection Tank Injection Discharge Check Valves, the 12" HPSI/LPSI check valves, the ¾" Safety Injection Line Thermal Relief Valves, the pressurizer safety valves, and the 2" isolation valves for the auxiliary spray indicate that the designs have large margins, and therefore that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design lifetimes. The design of these valves for fatigue effects is therefore valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Aging Management - Shutdown Cooling Suction Isolation Valve, and Charging Line Isolation

The calculated worst-case usage factor in these valves is 0.7656. However, fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The Metal Fatigue of Reactor Coolant Pressure Boundary program will track events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits will permit completion of corrective actions before the design basis number of events is exceeded. The charging line isolation valves are subject to similar but less-severe cyclic effects than the charging nozzles, whose fatigue usage is tracked by the stress-based method. The shutdown cooling suction isolation valve is the limiting location on the shutdown cooling line, and will be tracked by the cycle-based fatigue method. Effects of fatigue in Class 1 valve pressure boundaries will thereby be managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

The Metal Fatigue of Reactor Coolant Pressure Boundary program is described in Section 4.3.1; and is summarized in Appendix B, Section B3.1. See Table 4.3-4 for details of the program, and Section 4.3.1.5 for a description of its action limits and corrective actions.

4.3.2.7 ASME III Class 1 Piping and Piping Nozzles

Summary Description

Class 1 reactor coolant main loop piping designed and supplied by Combustion Engineering is designed to ASME III, Subsection NB, 1974 edition with addenda through Summer 1974. The main loop piping fatigue analysis was performed to the 1974 edition with addenda through Summer 1974. The fatigue analyses of piping outside the main loop used the 1974

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EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Excess conservatism in thermal life analysis may be reduced by reevaluating material activation energy, to justify a higher value that would support extended life at elevated temperature. Similar methods of reducing excess conservatism in the component service conditions and material properties used in prior aging evaluations may be used for radiation and cyclical aging. The PVNGS EQ-PM provides detailed directions for use of these Arrhenius and Arrhenius-based methods, including the basis for activation energies, examples of specific cases, and activation energies for specific materials.

Acceptance Criteria and Corrective Actions: If qualification cannot be extended by reanalysis, the component is refurbished or replaced prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is, sufficient time is available to refurbish, replace or requalify the component if reanalysis is unsuccessful).

Disposition: Aging Management, 10 CFR 54.21(c)(1)(iii)

The existing EQ program will be continued for the period of extended operation. Continuing the existing EQ program ensures that the aging effects will be managed and that the EQ components will continue to perform their intended functions for the period of extended operation. Aging effects addressed by the EQ program will thereby be managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

The Environmental Qualification (EQ) of Electrical Components program is summarized in Appendix B, Section B3.2.

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

Summary Description

The PVNGS containment is a prestressed concrete, hemispherical-dome-on-a-cylinder structure with a steel membrane liner. Post-tensioned tendons compress the concrete and permit the structure to withstand design basis accident internal pressures.

The steel tendons, in tension, relax with time; and the concrete structure, which the tendons hold in compression, both creeps and shrinks with time. Therefore, to ensure the integrity of the containment pressure boundary under design basis accident loads, an inspection program confirms that the tendon prestress remains within design limits throughout the life of the plant.

The original design predictions of loss of prestress are TLAAs. Regression analyses of surveillance data that predict the future performance of the post-tensioning system to the end of design life support revision and aging management of the tendon design per 10 CFR 54.21(c)(1)(ii) and (iii), as described in NUREG-1800 and NUREG-1801.

Post-Tensioning System

The PVNGS post-tensioning system consists of two tendon groups in each unit:

- 90 vertical, inverted-U-shaped tendons, extending up through the basemat, through the full height of the cylindrical walls, in two subgroups that cross at right angles over the dome.
- 150 horizontal circumferential (hoop) tendons, in two subgroups, at intervals from the basemat to about the 45-degree elevation of the dome. There are 120 cylinder (wall) tendons and 30 dome hoop tendons.

The vertical inverted-U tendons are anchored through the bottom of the basemat. The basemat is conventionally-reinforced concrete. The horizontal hoop tendons are anchored at three exterior buttresses, 120 degrees apart. Each hoop tendon extends 240 degrees around the containment building, passing under an intervening buttress. The tendons are not bonded to the concrete but were inserted in tendon ducts, after concrete cure, and tensioned in the prescribed sequence.

Each tendon consists of up to 186, ¼ - inch high-strength steel wires with cold-formed button heads on each end bearing on a stressing anchorhead. The total tendon load is then carried by a shim stack to steel bearing plates embedded in the structure. The tendons are twisted approximately 1 turn every 20 feet.

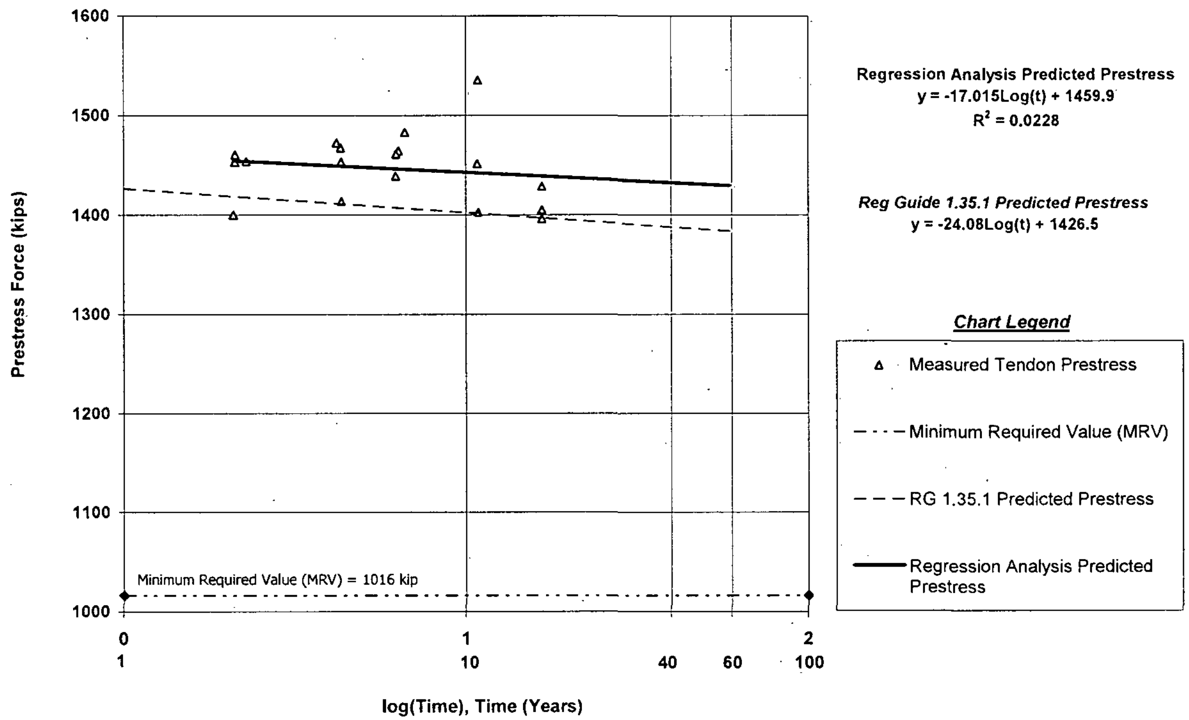

Figure 4.5-2: Regression Analysis of Unit 1 Vertical Tendon Lift-off Data Through the 15-Year Surveillance; With Reg Guide 1.35.1 Predicted Prestress
(See Notes)

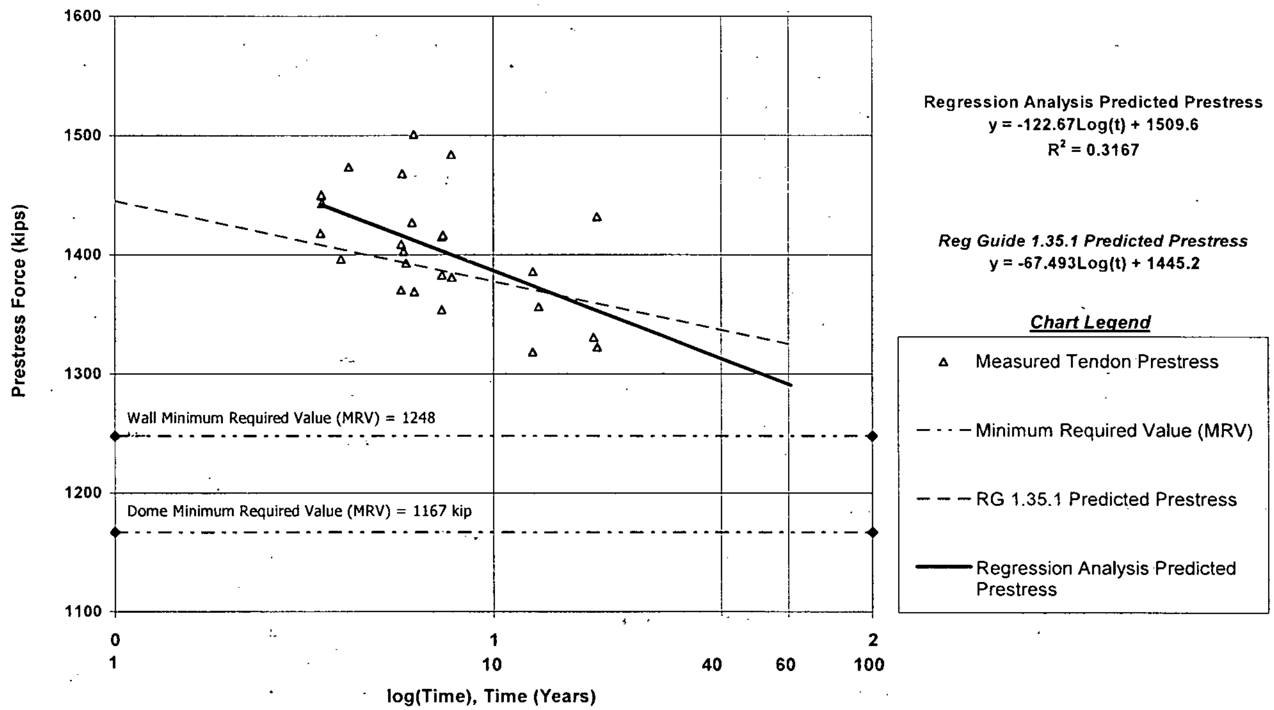

Figure 4.5-3: Regression Analysis of Unit 3 Horizontal Tendon Lift-off Data Through the 15-Year Surveillance; With Reg Guide 1.35.1 Predicted Prestress
(See Notes)

secondary water systems. The Water Chemistry program is based upon the guidelines of EPRI 1002884, "*PWR Primary Water Chemistry Guidelines*", Volumes 1 and 2, and EPRI 1008224, "*PWR Secondary Water Chemistry Guidelines*".

The effectiveness of the program is verified under the One-Time Inspection program (A1.16).

Prior to the period of extended operation, plant procedures will be enhanced to address sampling of effluents from new secondary system cation resins for purgeable and non-purgeable Organic Carbon.

A1.3 REACTOR HEAD CLOSURE STUDS

The Reactor Head Closure Studs program manages reactor vessel stud, nut and washer cracking and loss of material. The Reactor Head Closure Studs program includes periodic visual, surface, and volumetric examinations of reactor vessel flange stud hole threads, reactor head closure studs, nuts, and washers and performs visual inspection of the reactor vessel flange closure during primary system leakage tests. The program implements ASME Section XI code, Subsection IWB, 2001 Edition through the 2003 addenda.

A1.4 BORIC ACID CORROSION

The Boric Acid Corrosion program manages loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective actions. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, "*Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*". Additionally, the program includes examinations conducted during ISI pressure tests performed in accordance with ASME Section XI requirements. The program addresses recent operating experience noted in NRC Regulatory Issue Summary 2003-13, "*NRC Review of Responses to Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity*" (which includes NRC Bulletin 2002-01, 2002-02, and NRC Order EA-03-009) and NRC Bulletin 2003-02, "*Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity*".

A1.5 NICKEL-ALLOY PENETRATION NOZZLES WELDED TO THE UPPER REACTOR VESSEL CLOSURE HEADS OF PRESSURIZED WATER REACTORS

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking (PWSCC) and loss of material due to boric acid wastage in nickel-alloy pressure vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. The term "primary water stress corrosion cracking" applies to the nozzles and J-welds and "Wastage" applies to the reactor closure head. The aging management for the aging effect of wastage is addressed in Boric Acid Corrosion program (A1.4). This program was developed in response to NRC Order EA-03-009. ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6) has superseded the requirements of NRC Order EA-03-009.

Detection of cracking is accomplished through implementation of a combination of bare metal visual examination (external surface of head) and surface and volumetric examination (underside of head) techniques. Reactor Pressure Vessel Head bare metal visual examinations, surface examinations, and volumetric examinations are performed consistent with the ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6).

A1.6 FLOW-ACCELERATED CORROSION

The Flow-Accelerated Corrosion (FAC) program manages wall thinning due to FAC on the internal surfaces of carbon or low alloy steel piping, elbows, reducers, expanders, and valve bodies which contain high energy fluids (both single phase and two phases).

The objectives of the FAC program are achieved by (a) identifying system components susceptible to FAC, (b) an analysis using a predictive code such as CHECWORKS to determine critical locations for inspection and evaluation, (c) providing guidance of follow-up inspections, (d) repairing or replacing components, as determined by the guidance provided by the program, and (e) continual evaluation and incorporation of the latest technologies, industry and plant in-house operating experience.

Procedures and methods used by the FAC program are consistent with APS commitments to NRC Bulletin 87-01, "*Thinning of Pipe Wall in Nuclear Power Plants*", and NRC Generic Letter 89-08, "*Erosion/Corrosion-Induced Pipe Wall Thinning*".

Prior to the period of extended operation, the program procedure will be enhanced to clarify the guidance for susceptible small-bore piping components and to verify the trace chromium content of the carbon steel pipe replacement.

A1.7 BOLTING INTEGRITY

The Bolting Integrity program manages cracking, loss of material, and loss of preload for pressure retaining bolting and ASME component support bolting. The program includes and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors manage aging. Periodic testing of the diesel-driven fire pumps ensures that there is no loss of function due to aging of diesel fuel supply lines. Drop tests are performed on 10 percent of fire dampers on an 18 month basis to manage aging. Visual inspections manage aging of fire-rated doors every 18 months to verify the integrity of door surfaces and for clearances to detect aging of the fire doors. A visual inspection and function test of the halon and CO_2 fire suppression systems every 18 months manages aging. Ten percent of each type of penetration seal is visually inspected at least once every 18 months. Fire barrier walls, ceilings, and floors including coatings and wraps are visually inspected at least once every 18 months.

Prior to the period of extended operation, the following enhancements will be implemented:

- Procedures will be enhanced to state trending requirements for the diesel-driven fire pump and to include visual inspection of the fuel supply line to detect degradation.
- Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the CO_2 system discharge nozzles.
- Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors.

A1.13 FIRE WATER SYSTEM

The Fire Water System program manages loss of material for water-based fire protection systems. Periodic hydrant inspections, fire main flushing, sprinkler inspections, and flow tests are performed considering applicable National Fire Protection Association (NFPA) codes and standards. The fire water system pressure is continuously monitored such that loss of system pressure is immediately detected and corrective actions are initiated. The Fire Water System program conducts an air or water flow test through each open head spray/sprinkler head to verify that each open head spray/sprinkler nozzle is unobstructed. Visual inspections of the fire protection system exposed to water, evaluating wall thickness to identify evidence of loss of material due to corrosion, are covered by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (A1.22). The Buried Piping and Tanks Inspection program (A1.18) is credited with the management of aging effects on the external surface of buried fire water system piping.

Prior to the period of extended operation, the following enhancements will be implemented:

- Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM).

- Procedures will be enhanced to be consistent with the current code of record or NFPA 25 2002 Edition.
- Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner.
- Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4.
- Procedures will be enhanced so that the PVNGS Quality Assurance programs will apply to Fire Protection SSCs that are within the scope of license renewal that are also part of the boundary of the WRF (Water Reclamation Facility).

A1.14 FUEL OIL CHEMISTRY

The Fuel Oil Chemistry program manages loss of material on the internal surface of components in the emergency diesel generator (EDG) fuel oil storage and transfer system, diesel fire pump fuel oil system, and station blackout generator (SBOG) system. The program includes (a) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM Standards, (b) periodic draining of water from fuel oil tanks, (c) visual inspection of internal surfaces during periodic draining and cleaning, (d) ultrasonic wall thickness measurements from external surfaces of fuel oil tanks if there are indications of reduced cross sectional thickness found during the visual inspection, (e) inspection of new fuel oil before it is introduced into the storage tanks, and (f) one-time inspections of a representative sample of components in systems that contain fuel oil by the One-Time Inspection program.

The effectiveness of the program is verified under the One-Time Inspection program (A1.16).

Prior to the period of extended operation:

Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks.

Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage tanks, and SBOG skid fuel tanks.

Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil

A1.34 NICKEL ALLOY AGING MANAGEMENT PROGRAM

The Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all plant locations that contain Alloy 600, with the exception of steam generator tubing (aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (A1.8)) and reactor vessel internals (aging management of reactor vessel internals is addressed in Reactor Coolant System Supplement (A1.21)). Aging management requirements for Alloy 600 penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (A1.5) are included in this program. This program includes Alloy 600 reactor coolant pressure boundary locations in the reactor coolant system (RCS) and ESF systems.

The Alloy 600 aging management program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at PVNGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB, ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4), and EPRI Report 1010087 (MRP-139) issued under NEI 03-08 protocol. Mitigation techniques are implemented when appropriate to preemptively remove conditions that contribute to primary water stress corrosion cracking. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw. Mitigation and repair/replace activities are consistent with those detailed in EPRI Report 1010087 (MRP-139). The inspection plan of Alloy 690 replacement is also included in this program.

A1.35 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the effects of loosening of bolted external connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. As part of the PVNGS predictive maintenance program, infrared thermography testing is being performed on non-EQ electrical cable connections, associated with active and passive components within the scope of license renewal. A representative sample will be tested at least once prior to the period of extended operation using infrared thermography to confirm that there are no aging effects requiring management during the period of extended operation. The selected sample is based upon application (medium and low voltage), circuit loading, and environment.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.36 METAL ENCLOSED BUS

The Metal Enclosed Bus (MEB) program manages the effects of loose connections, embrittlement, cracking, melting, swelling, or discoloration of insulation, loss of material of bus enclosure assemblies, hardening of boots and gaskets, and cracking of internal bus supports to ensure that metal-enclosed buses within the scope of license renewal. Internal portions of MEBs are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation is inspected for signs of embrittlement, cracking, melting, swelling, hardening or discoloration, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. The bus enclosure assemblies are inspected for loss of material due to corrosion and hardening of boots and gaskets. Samples of the accessible bolted connections on the internal bus work are checked for loose connections by measuring connection resistance.

The Metal Enclosed Bus program is a new program and will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

Although the steam generator tubes have a Class 1 fatigue analysis, the calculated usage factor is zero, and the safety determination for integrity of steam generator tubes now depends on managing aging effects by a periodic inspection program rather than on the fatigue analysis. The code fatigue analysis of the tubes is therefore not a TLAA.

The fatigue analyses of the Unit 1 and 3 replacement steam generators are for a period sufficient to cover their installed life, and remain valid for the period of extended operation.

The fatigue analyses of the Unit 2 replacement steam generators are for a period sufficient to cover all but about two years of their expected 42-year installed life, including the period of extended operation. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 will track events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded, and before the ASME code cumulative fatigue usage limit of 1.0 is reached.

A3.2.1.6 ASME Section III Class 1 Valves

PVNGS Class 1 valves are designed to ASME Section III, Subsection NB, 1974 Edition with multiple addenda, the 1977 Edition with Winter 1977 addendum, and the 1989 Edition no addendum. ASME Section III requires a fatigue analysis only for Class 1 valves with inlets greater than four inches nominal. At PVNGS, specifications for some Class 1 valves with inlets four inches or less also require a fatigue analysis.

For the valve models with an NB-3545.3 normal duty operating cycle evaluation, the allowed NB-3545.3 N_A normal duty operations far exceed those expected to occur.

The calculated worst-case usage factors for the 16" Shutdown Cooling Suction Containment Isolation Valves, the 14" Safety Injection Tank Injection Discharge Isolation Gate Valves, the 14" Safety Injection Tank Injection Discharge Check Valves, the 12" HPSI/LPSI check valves, the ¾" Safety Injection Line Thermal Relief Valves, the pressurizer safety valves, the pressurizer relief valves, and the 2" isolation valves for the auxiliary spray indicate that the designs have large margins, and therefore that the pressure boundaries would withstand fatigue effects for at least 1.5 times the original design lifetimes. The design of these valves for fatigue effects is therefore valid for the period of extended operation.

The calculated worst-case usage factors for the Unit 1, Class 1 Shutdown Cooling Suction Isolation Valve, and Charging Line Isolation Valves exceed 0.7. However, fatigue usage factors in these valves do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events. The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 tracks events to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded. The charging line isolation valves are subject to similar but less-severe cyclic events than the charging nozzles, whose fatigue usage is tracked by the stress-based method. The shutdown cooling suction isolation valve is the limiting location on the shutdown cooling line which will be tracked by the cycle-based fatigue method.

A3.2.1.7 ASME Section III Class 1 Piping and Piping Nozzles

Class 1 reactor coolant main-loop piping supplied by Combustion Engineering is designed to ASME Section III, Subsection NB, 1974 edition with addenda through Summer 1974. The main loop piping fatigue analysis was performed to the 1974 edition with addenda through Summer 1974. The fatigue analyses of piping outside the main loop used the 1974 edition with addenda through Winter 1975 or the 1977 edition with addenda through Summer 1979. These analyses have been updated from time to time to incorporate redefinitions of loads and design basis events, operating changes, power rerate, steam generator replacement, and minor modifications.

See Section A3.2.1.8 for fatigue in the pressurizer surge lines.

The CVCS charging nozzles, the pressurizer surge line hot leg nozzle, and the surge line elbows are the limiting components for fatigue in the Class 1 charging lines and surge line. These locations are subject to stress-based fatigue monitoring under the PVNGS fatigue management program.

The charging nozzle safe ends, the safety injection nozzle forging knuckle and safe ends, and the shutdown cooling line long-radius elbow are evaluated for effects of the reactor coolant environment on fatigue behavior of these materials, consistent with NUREG/CR-6260. See Section A3.2.3.

With the exception of the CVCS charging lines and nozzles and the pressurizer surge lines and nozzles; fatigue usage factors in Class 1 piping and nozzles do not depend on effects that are time-dependent at steady-state conditions, but depend only on effects of operational, abnormal, and upset transient events.

The Metal Fatigue of Reactor Coolant Pressure Boundary program described in Section A2.1 counts significant transient events and thermal cycles, and tracks usage factors in the bounding set of sample locations to ensure that appropriate reevaluation or other corrective action is initiated if an action limit is reached. Action limits permit completion of corrective actions before the design basis number of events is exceeded and before the ASME code cumulative fatigue usage limit of 1.0 is reached.

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
7	Existing Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program is credited for license renewal, AND Prior to December 31, 2008, the PVNGS Alloy 600 Management Program Plan will be revised to incorporate the applicable examination requirements of ASME Code Case N-729-1 (Reactor Vessel Head Inspections), subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6). (RCTSAI 3246894) **(Completed)**	A1.5 B2.1.5 Nickel-Alloy Penetration Nozzles Welded to The Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Ongoing
8	Existing Flow-Accelerated Corrosion program is credited for license renewal, AND Prior to the period of extended operation, the program procedure will be enhanced to clarify the guidance for susceptible small-bore piping components and to verify the trace chromium content of the carbon steel pipe replacement. (RCTSAI 3246895)	A1.6 B2.1.6 Flow-Accelerated Corrosion	Prior to the period of extended operation[1].
9	Existing Bolting Integrity program is credited for license renewal. (RCTSAI 3246896)	A1.7 B2.1.7 Bolting Integrity	Ongoing
10	Existing Steam Generator Tube Integrity program is credited for license renewal. (RCTSAI 3246897)	A1.8 B2.1.8 Steam Generator Tube Integrity	Ongoing
11	Existing Open-Cycle Cooling Water System program is credited for license renewal, AND Prior to the period of extended operation, the program will be enhanced to clarify guidance in the conduct of heat exchanger and piping inspections using NDE techniques and related acceptance criteria. (RCTSAI 3246898)	A1.9 B2.1.9 Open-Cycle Cooling Water System	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
12	Existing Closed-Cycle Cooling Water System program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to incorporate the guidance of EPRI TR-107396 with respect to water chemistry control for frequency of sampling and analysis, normal operating limits, action level concentrations, and times for implementing corrective actions upon attainment of action levels. (RCTSAI 3246899)	A1.10 B2.1.10 Closed-Cycle Cooling Water System	Prior to the period of extended operation[1].
13	Existing Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to inspect for loss of material due to corrosion or rail wear. (RCTSAI 3246900)	A1.11 B2.1.11 Inspection Of Overhead Heavy Load And Light Load (Related To Refueling) Handling Systems	Prior to the period of extended operation[1].
14	Existing Fire Protection program is credited for license renewal, AND Prior to the period of extended operation, the following enhancements will be implemented: • Procedures will be enhanced to state trending requirements for the diesel-driven fire pump and to include visual inspection of the fuel supply line to detect degradation. • Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the halon discharge pipe header **(Completed)** and the CO_2 system discharge nozzles. • Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors. (RCTSAI 3246901)	A1.12 B2.1.12 Fire Protection	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
15	Existing Fire Water System program is credited for license renewal, AND Prior to the period of extended operation, the following enhancements will be implemented: • Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM). • Procedures will be enhanced to be consistent with the current code of record or NFPA 25 2002 Edition. • Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner. • Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4. • Procedures will be enhanced to state trending requirements. **(Completed)** • Procedures will be enhanced so that the PVNGS Quality Assurance programs will apply to Fire Protection SSCs that are within the scope of license renewal that are also part of the boundary of the WRF (Water Reclamation Facility). (RCTSAI 3246902)	A1.13 B2.1.13 Fire Water System	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
16	Existing Fuel Oil Chemistry program is credited for license renewal, AND Prior to the period of extended operation: • Procedures will be enhanced to extend the scope of the program to include the SBOG fuel oil storage tank and SBOG skid fuel tanks. • Procedures will be enhanced to include ten-year periodic draining, cleaning, and inspections on the diesel-driven fire pump day tanks, the SBOG fuel oil storage tanks, and SBOG skid fuel tanks. • Ultrasonic testing (UT) or pulsed eddy current (PEC) thickness examination will be conducted to detect corrosion-related wall thinning if degradation is found during the visual inspections and once on the tank bottoms for the EDG fuel oil storage tanks, EDG fuel oil day tanks, diesel-driven fire pump day tanks, and SBOG fuel oil storage tanks. The onetime UT or PEC examination on the tank bottoms will be performed before the period of extended operation. (RCTSAI 3246903)	A1.14 B2.1.14 Fuel Oil Chemistry	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
35	Existing RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to specify that the essential spray ponds inspections include concrete below the water level. (RCTSAI 3246928)	A1.33 B2.1.33 RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants	Prior to the period of extended operation[1].
36	Existing Nickel Alloy Aging Management Program is credited for license renewal, AND Prior to the period of extended operation, the PVNGS Alloy 600 Management Program Plan will be enhanced to add Alloy 600 steam generator components, including tube sheet cladding and portions of the primary nozzle cladding (RCTSAI 3246929) **(Completed)**, AND In addition, prior to December 31, 2008, the PVNGS Alloy 600 Management Program Plan will be revised to incorporate the applicable examination requirements of ASME Code Case N-729-1 (Reactor Vessel Head Inspections), subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6) and ASME Code Case N-722 (RCPB Visual Inspections) subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4). (RCTSAI 3260208) **(Completed)**	A1.34 B2.1.34 Nickel Alloy Aging Management Program	Ongoing
37	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246930 [U1]; 3247228 [U2]; 3247231 [U3])	A1.35 B2.1.35 Electrical Cable Connections Not Subject To 10 CFR 50.49 environmental qualification requirements	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
38	The Metal Enclosed Bus program is a new program and will be completed before the period of extended operation and once every 10 years thereafter. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program. (RCTSAIs 3246932 [U1]; 3247220 [U2]; 3247221 [U3])	A1.36 B2.1.36 Metal Enclosed Bus	Prior to the period of extended operation and once every 10 years thereafter.
39	(1) The existing Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to provide guidelines and requirements for tracking both transient cycle counts and fatigue usage of fatigue-sensitive, safety related components, using the FatiguePro® software, to maintain the fatigue usage of components within the cumulative usage factor limit of 1.0 established by Section III Subsection NB of the ASME Boiler and Pressure Vessel Code. The enhanced program will include tracking of cumulative usage, counting of transient cycles, manual recording of selected transients, and review of FatiguePro® data. (2) Prior to the period of extended operation, the following enhancements will be implemented: • The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to include (1) additional Class 1 locations with high calculated cumulative usage factors, (2) Class 1 components for which transfer functions have been developed for stress-based monitoring, and (3) Class 2 portions of the steam generators with a Class 1 analysis and high calculated cumulative usage factors. • The Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced with additional cycle count and fatigue usage action limits, and with appropriate corrective actions to be invoked if a component approaches a cycle count action limit or a fatigue usage action limit. Action limits permit completion of corrective actions before the design limits are exceeded. (RCTSAI 3246934)	A2.1 B3.1 Metal Fatigue of Reactor Coolant Pressure Boundary A3.2 Metal Fatigue Analysis	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
40	Maintaining qualification through the extended license renewal period requires that existing EQ evaluations (EEQDFs) be re-evaluated. (RCTSAI 3246935)	A2.2 B3.2 Environmental Qualification (EQ) Of Electrical Components	Prior to the period of extended operation[1].
41	Existing Concrete Containment Tendon Prestress program is credited for license renewal, AND The program will be enhanced to continue to compare regression analysis trend lines of the individual lift-off values of tendons surveyed to date, in each of the vertical and hoop tendon groups, with the MRV and PLL for each tendon group, to the end of the licensed operating period, and to take appropriate corrective actions if future values indicated by the regression analysis trend line drop below the PLL or MRV. The regression analyses will be updated for tendons of the affected unit and for a combined data set of all three units following each inspection of an individual unit. Prior to the period of extended operation, procedures will be enhanced to require an update of the regression analysis for each tendon group of each unit, and of the joint regression of data from all three units, after every tendon surveillance. The documents will invoke and describe regression analysis methods used to construct the lift-off trend lines, including the use of individual tendon data in accordance with Information Notice (IN) 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The Tendon Integrity test procedure will be revised to extend the list of surveillance tendons to include random samples for the year 45 and 55 surveillances. (RCTSAI 3246937)	A2.3 B3.3 Concrete Containment Tendon Prestress 4.5 Concrete Containment Tendon Prestress	Prior to the period of extended operation[1].

Table A4-1 License Renewal Commitments

Item No.	Commitment	LRA Section	Implementation Schedule
42	APS will confirm the RCS Pressure-Temperature limits basis for 54 EFPY prior to operation beyond 32 EFPY and will update documents in accordance with the provisions of 10 CFR 50.59. (RCTSAI 3246939)	A3.1.3 Pressure-Temperature Limits	Prior to operation beyond 32 EFPY[1].
43	The segment of the Unit 2 head vent line with wall thickness reduced by the removal of indications will be replaced when the vessel head is replaced, and its fatigue analysis will be revised. The repair and the revised fatigue analysis will demonstrate an adequate fatigue life, projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). This is a commitment for license renewal. (RCTSAI 3246941)	4.3.2.1 A3.2.1.1 Reactor Pressure Vessel, Nozzles, Head, and Studs	Prior to the period of extended operation[1].
44	During the review process APS identified a number of ASME III Class 1 valves greater than four inches nominal inlet that might require a fatigue analysis, but for which the analysis was not immediately retrievable. Efforts are ongoing to confirm the need for and if necessary to obtain these analyses. APS will recover and evaluate the fatigue analysis for each of the remaining ASME III Class 1 valves greater than four inches nominal inlet, for which a fatigue analysis is also otherwise required, before the end of the current licensed operating period. Each of these analyses will be validated or revised for the period of extended operation, or fatigue in the valve will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program. (RCTSAI 3253459)	4.3.2.6 A3.2.1.6 ASME Section III Class 1 Valves	**Completed.**

B2.1.5 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors

Program Description

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program manages cracking due to primary water stress corrosion cracking (PWSCC) and loss of material due to boric acid wastage in nickel-alloy pressure vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds. The program for Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (Upper Head Nickel Alloy AMP) was developed by PVNGS to respond to NRC Order EA-03-009. ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6), has superseded the requirements of NRC Order EA-03-009. The aging management for the aging effect of loss of material of the upper vessel head due to wastage is also included in the Boric Acid Corrosion program (B2.1.4).

Detection of cracking (including cracking induced by PWSCC) is accomplished through implementation of a combination of bare metal visual examination (external surface of the RPV closure head) surface and volumetric examinations (underside of RPV head) techniques. Underside of RPV head examinations include volumetric examination of the control element drive mechanism penetration tube walls, surface examination of the inner diameter of the penetrations, and surface examination of the J-groove weld. Examinations are consistent with ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6). Visual examinations are performed by VT-2 certified personnel.

The Alloy 600 Management Program Plan maintains the integrity and operability for all nickel alloy components at PVNGS.

NUREG-1801 Consistency

The Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program is an existing program that is consistent with NUREG-1801, Section XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors".

Exceptions to NUREG-1801

None

Enhancements

None.

Operating Experience

Inspections completed to date have indicated no evidence of PWSCC in the vessel head penetration nozzles with the exception of vent line indications on Unit 2 which were repaired by machining and subsequently weld overlayed during refueling outage U2R13. Reactor vessel head replacements for all three PVNGS Units are scheduled from year 2009 to year 2010.

The following is a summary of information that has been provided to the NRC concerning inspections per the requirements of NRC Order EA-03-009:

PVNGS UNIT 1 - REFUELING 12 (U1R12) ending in December, 2005

A visual examination of the bare-metal surface of the reactor head found no evidence of boron or corrosion. No cleaning of the RPV head was necessary during U1R12. Additionally, a boric acid walkdown was performed for the U1R12 refueling outage. Potential boric acid leak sites from pressure retaining components above the RPV head were examined. No leaks or evidence of leakage was found.

Ninety seven control element drive mechanism penetrations had nondestructive exams performed. Eighty four were acceptable with no detectable defects and thirteen had additional examinations performed as a result of the initial examinations. The additional examinations performed on the thirteen penetrations were acceptable with no detectable defects found.

In preparation for modifying the head vent nozzle in Unit 1 to remove the flow-restricting orifice, the vent penetration J-weld and orifice J-weld were examined with manual eddy current testing techniques. Upon removal of the orifice, a surface examination (eddy current) of the J-groove weld and inside nozzle surface was performed as required. The head vent nozzles at PVNGS do not protrude below the surface of the RPV head and, as a result, there is no material below the J-groove weld to be examined. Although two areas of reduced wall dimension were noted, the results of the examinations were acceptable with no detectable defects. The head vent orifice was relocated to a downstream flange.

PVNGS UNIT 2 - REFUELING 13 (U2R13) ending in November, 2006

B2.1.12 Fire Protection

Program Description

The Fire Protection program manages loss of material for fire rated doors, fire dampers, diesel-driven fire pumps, and the CO_2 and halon fire suppression systems, cracking, spalling, and loss of material for fire barrier walls, ceilings, and floors, and hardness and shrinkage due to weathering of fire barrier penetration seals. Periodic visual inspections of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated floors are performed to ensure that they can perform their intended function.

The Fire Protection program manages aging by a visual inspection on ten percent of each type of penetration seal at least once every 18 months. This sample set method ensures that each penetration seal is inspected at least once every 15 years.

The Fire Protection program manages aging by a visual inspection every 18 months of the fire barrier walls, ceilings, and floors, including coating and wraps of Thermo-lag enclosures, examining for any signs of aging such as cracking, spalling, and loss of material.

The Fire Protection program manages aging by drop testing on ten percent of all accessible fire dampers on an 18 month basis.

The Fire Protection program manages aging by performing visual inspections every 18 months on fire-rated doors to verify the integrity of door surfaces and for clearances to detect aging of the fire doors prior to the loss of intended function.

The diesel-driven fire pumps are under observation during performance tests such as flow tests, start/run tests for detecting any aging of the fuel supply line. The fuel oil supply line is also managed by the Fuel Oil Chemistry program (B2.1.14) and External Surface Monitoring Program (B2.1.20).

A visual inspection and function test of the halon and CO_2 fire suppression systems is performed every 18 months.

NUREG-1801 Consistency

The Fire Protection program is an existing program that, following enhancement, will be consistent with exception to NUREG-1801, Section XI.M26, "Fire Protection".

Exceptions to NUREG-1801

Program Elements Affected

Parameters Monitored or Inspected - Element 3 and Detection of Aging Effects – Element 4

NUREG-1801 recommends a visual inspection and function test of the halon and CO_2 systems every six months. The PVNGS procedures for visual inspections and function testing of the halon and CO_2 fire suppression systems are performed every 18 months per Technical Requirements Manual Surveillance Requirement (TSR) 3.11.106.4 and 3.11.103.4, respectively. This procedural function test would identify any mechanical damage of the halon and CO_2 fire suppression system that prevents the system from performing its intended function. The 18 month frequency is considered sufficient to ensure system availability and operability based on station operating history that indicates no loss of intended function due to aging. A review of the past ten years of operating experience and corrective action documentation has shown no degradation or loss of intended function between test intervals.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Parameters Monitored or Inspected – Element 3, Detection of Aging Effects – Element 4, Monitoring and Trending –Element 5, and Acceptance Criteria – Element 6

Procedures will be enhanced to state trending requirements for the diesel-driven fire pump and to include visual inspection of the fuel supply line to detect degradation.

Procedures will be enhanced to inspect for mechanical damage, corrosion and loss of material of the CO_2 system discharge nozzles.

Procedures will be enhanced to state the qualification requirements for inspecting penetration seals, fire rated doors, fire barrier walls, ceilings and floors.

Operating Experience

Plant operating experience indicates that there have been instances of Thermo-Lag degradation and cracking. These portions of affected Thermo-Lag envelopes have been reworked according to PVNGS specification. PVNGS has also experienced door skin cracks. These have been weld repaired according to specification.

During May of 2005, a fire protection audit was performed by members of APS and other industry representatives. The audit team observed current conditions and installations of the CO_2 and halon suppression systems during walk-downs of selected fire zones. All systems were found in good condition. Multiple walkdowns per unit were conducted to examine the current condition of existing fire barriers in the Unit 1 control building, the Unit 2

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

Preventive Actions - Element 2 and Acceptance Criteria – Element 6

Specific procedures will be enhanced to include review and approval requirements under the Nuclear Administrative Technical Manual (NATM).

Parameters Monitored or Inspected – Element 3

Procedures will be enhanced to be consistent with the current code of record or NFPA 25, 2002 Edition.

Detection of Aging Effects – Element 4

Procedures will be enhanced to field service test a representative sample or replace sprinklers prior to 50 years in service and test thereafter every 10 years to ensure that signs of degradation are detected in a timely manner.

Procedures will be enhanced to be consistent with NFPA 25 Section 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4.

Corrective Actions – Element 7

Procedures will be enhanced so that the PVNGS Quality Assurance programs will apply to Fire Protection SSCs that are within the scope of license renewal that are also part of the boundary of the WRF (Water Reclamation Facility).

Operating Experience

NaOH and NaSO3 are added to the fire water system and sampled periodically. Based on analyses of corrosion coupons, the corrosion rate has been 0.3 mils/yr thus indicating successful corrosion control measures.

There has been some at-grade evidence of buried piping leakage observed. Remote field eddy current testing was performed on about 7,721 feet of 12-inch pipe covering the fire water main loop. Test results indicated that there were several sections of pipe that had localized degradation in excess of the minimum wall thickness of 40% of nominal wall thickness. Validation was then performed by excavating and removing two spools, and corrosion related pitting was confirmed. PVNGS replaced portions of the North and South Loop piping with epoxy lined reinforced fiberglass. Replacement of approximately 6,000 feet of pipe on the North Loop was completed during September of 2001. Approximately 4,500 feet of pipe on the South Loop was completed during July of 2006. Some of this degradation was attributed to coating holidays caused by improper backfilling and lack of cathodic protection attention during early plant operation.

The flushes of the deluge system, fire hydrants, and underground fire water loops have identified little or no debris in the lines, and there have been no indications that the SSCs would not be able to perform their intended function.

A review of the past ten years of corrective action documents showed no signs of gasket degradation or fire hose degradation due to inspection intervals of 18 months and three years, respectively.

Conclusion

The continued implementation of the Fire Water System program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B2.1.34 Nickel Alloy Aging Management Program

Program Description

The plant-specific Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking in all reactor coolant pressure boundary locations that contain Alloy 600, with the exception of steam generator tubing and reactor vessel internals. Aging management of steam generator tubing is performed by the Steam Generator Tubing Integrity program (B2.1.8). Aging management of reactor vessel internals is addressed in Reactor Coolant System Supplement (B2.1.21). Aging management requirements for nickel alloy penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (B2.1.5) are included in this program. This program includes Alloy 600 reactor coolant pressure boundary locations in the reactor coolant system (RCS) and ESF systems. The term Alloy 600 is used throughout this program to represent Nickel Alloy 600 material and Nickel Alloy 82/182 weld metal. Non-Alloy 600 nickel components (e.g., welds made of Alloy 52/152) are subject to the ASME Section XI Inservice Inspection program (B2.1.1) requirements as indicated in the Program Plan.

The plant-specific Nickel Alloy Aging Management Program uses inspections, mitigation techniques, repair/replace activities and monitoring of operating experience to manage the aging of Alloy 600 at PVNGS. Detection of indications is accomplished through a variety of examinations consistent with ASME Section XI Subsections IWB, ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6), ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4), and EPRI Report 1010087 (MRP-139) issued under NEI 03-08 protocol. The official review and incorporation of practices of EPRI Report 1010087 (MRP-139) is not currently complete and the implementation schedule, per EPRI Report 1010087 (MRP-139), is defined in the Program Plan. Mitigation techniques are implemented when appropriate to preemptively remove conditions that contribute to PWSCC. Repair/replacement activities are performed to proactively remove or overlay Alloy 600 material, or as a corrective measure in response to an unacceptable flaw. Mitigation and repair/replace activities are partially complete with those detailed in EPRI Report 1010087 (MRP-139). Historical operating experience was reviewed and operating experience is continually monitored to provide improvements and modifications to the Alloy 600 Program as needed.

Aging Management Program Elements

The results of an evaluation of each element against the 10 elements described in Appendix A of NUREG-1800, "*Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*" are provided below.

Scope of Program – Element 1

With the exception of steam generator tubing, which is managed by the Steam Generator Tube Integrity Aging Management program (B2.1.8), and reactor vessel internals, all Alloy 600 reactor coolant pressure boundary locations in plant systems are included in the scope of this program. This program includes reactor coolant system (RCS) and ESF system locations. Aging management requirements for Alloy 600 penetration nozzles welded to the upper reactor vessel closure head noted in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Aging Management program (B2.1.5) are included in this program. The term Alloy 600 will be used throughout this program to represent Nickel Alloy 600 material and Nickel Alloy 82/182 weld metal.

The PVNGS Alloy 600 aging management program identifies the following Alloy 600 locations including dissimilar metal (DM) welds:

- RPV Upper Head Penetrations / 97 CEDMs', 1 Head Vent
- Bottom Mounted Instrument Nozzles (BMI) / 61 Incore Instrumentation Penetrations
- Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material
- RCS Piping Instrument Nozzles / 12 Cold Leg instrument nozzles per unit (SB-166 material), 8 RCP instrument nozzles per unit (SB-166 material), 8 Unit 2 Hot Leg pressure instrument nozzles (82/182) welds

The pressurizer (PZR) instrument nozzles and heater sleeves have been replaced with Alloy 690 material.

With exception of 8 Unit 2 Hot Leg pressure instrument nozzles, the RCS Hot Leg instrument nozzles also have been replaced with Alloy 690 material.

Steam Generator tube sheet cladding and nozzle dam retaining ring Alloy 600 cladding are not reactor coolant pressure boundary components and are not included in the Nickel Alloy Aging Management Program.

A full structural weld overlay (FSWO) with Alloy 690 was completed for the following Hot Leg and Pressurizer locations. The Hot Leg and Pressurizer welds are no longer considered to be composed of Alloy 600, since they are completely encased in Alloy 690.

- Pressurizer Spray
- Pressurizer Safeties
- Pressurizer Surge Line (Hot Leg and Pressurizer side)
- Shutdown Cooling 1 & 2 (Unit 3 FSWO spring 2009 outage)

The dissimilar metal butt-welds which are addressed in this program are those greater than or equal to 1" NPS in locations operating at cold leg temperature or higher. The Alloy 600 material locations at lower than cold leg temperatures are not subject to increased augmented inspections/replacements at this time because of the lower PWSCC susceptibility at lower service temperatures.

The PVNGS Alloy 600 aging management program identifies the following RCS dissimilar metal butt welds:

- Safety Injection 1A 14" dia
- Safety Injection 1B 14" dia
- Safety Injection 2A 14" dia
- Safety Injection 2B 14" dia
- PZR Spray 1A 3" dia
- PZR Spray 1B 3" dia
- Drain Line 1A 2" dia
- Drain Line 1B 2" dia
- Drain Line 2A 2" dia
- Letdown Line 2" dia
- Charging Line 2" dia

Preventive Actions – Element 2

The plant-specific Nickel Alloy Aging Management Program includes many potential mitigation strategies that remove one or more of the three conditions that control primary water stress corrosion cracking (susceptible material, tensile stress field, supporting environment). Mitigation activities that have been successfully performed for at least one US PWR plant include weld overlays, replacement of Alloy 600 (as a pre-planned activity), and mechanical stress improvement process (MSIP). Weld overlays are being implemented for more susceptible DM welds and those with inspectability issues. This method provides structural reinforcement at the (potentially) flawed location, such that adequate load-carrying capability is provided by the overlay. MSIP is a mechanical process that places the component surface in contact with the primary water in a compressive state, thereby removing the tensile stresses needed for initiation of PWSCC.

The considerations used in the PVNGS program include selecting a mitigation strategy, options for the most cost effective management specific to each category of components and the optimal course of action. All aspects of this plan comply with industry and regulatory guidance for inspections and repairs.

The PVNGS program includes the recommended mitigation strategies for all of the Alloy 600 components at PVNGS. Specific mitigation strategies will be determined by plant-specific and industry operating experience and may include the following:

<u>Component / Mitigation Strategy / Planned Replacements</u>

<u>Reactor Pressure Vessel (RPV) – Upper Head Penetrations</u>

- RPV Upper Head Penetrations / None / RVH replacements scheduled 2009-2010

<u>Reactor Pressure Vessel (PRV) – Bottom Mounted Instrument (BMI) Nozzles</u>

- Bottom Mounted Instrument Nozzles (BMI) / Cold leg zinc injection, half-nozzle repair to be developed / None planned

<u>Pressurizer Nozzles</u>

- Pressurizer instrument nozzles (7 each unit) / None / Complete (replaced with Alloy 690 material)
- Pressurizer heater sleeves / None / Complete (replaced with Alloy 690 material)
- Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material / None / Complete (nozzles replaced with Alloy 690 material)

<u>Dissimilar Metal Welds</u>

- PZR Spray / Structural Weld Overlay / weld overlays implemented
- PZR Safeties / Structural Weld Overlay / weld overlays implemented Surge Line (HL and PZR Side) / Structural weld Overlay or MSIP / weld overlays implemented
- Pressurizer Surge Line (HL and PZR Side) / Structural weld Overlay or MSIP / weld overlays implemented
- PZR Spray 1A and 1B / Structural weld Overlay or MSIP / None
- Shutdown Cooling 1 and 2 / Structural weld, Overlay or MSIP / weld overlays implemented Unit 1 and Unit 2. Unit 3 planned Spring 2009
- Safety Injection lines / None / None
- Drain Line 1A and 1B / None / None

- Drain Line 2A / None / None
- Letdown Line / None / None
- Charging Line / None / None

RCS Piping Instrument Nozzles

- 27 Hot Legs (each unit) / None / Complete (replaced or plugged with Alloy 690 material)
- 8 Unit 2 Hot Leg pressure instrument nozzles (82/182 welds) / None / None planned
- 12 Cold Legs (each unit) / Cold leg zinc injection, half-nozzle repair to be developed / None planned
- 8 RCP Instrument Taps (each unit) / None / None planned

The Water Chemistry program (B2.1.2) provides preventive actions for monitoring and control of the supporting environment for PWSCC. Primary water chemistry changes such as zinc addition is being evaluated to improve resistance to PWSCC for locations that are not being replaced or mitigated by other means.

Parameters Monitored/Inspected – Element 3

The Nickel Alloy Aging Management Program monitors for cracking due to PWSCC. Loss of material due to boric acid wastage is also used as an indication of cracking due to PWSCC. Visual exams are used to detect evidence of leakage from reactor coolant pressure boundary components due to cracking and/or discontinuities and imperfections on the surface of the component. Surface examinations indicate the presence of surface discontinuities. Volumetric examination indicates the presence of cracking/discontinuities throughout the volume of material.

Detection of Aging Effects – Element 4

The Nickel Alloy Aging Management Program utilizes various visual, surface and volumetric inspection and examination techniques for early detection of PWSCC in Alloy 600 components.

Three types of visual exams are used:

1) VT-2 Exams which are conducted to detect evidence of leakage from pressure retaining components,

2) Bare Metal Visual (BMV) Exams which are similar to VT-2 exams but require removal of insulation to allow direct access to the metal surface,

3) Visual Exams which are conducted to assess the general condition of non-pressure boundary components.

Surface Exams are used to indicate the presence of surface discontinuities and are conducted by liquid penetrant or eddy current methods. Volumetric Exams indicate the presence of discontinuities throughout the volume of material and are conducted by radiographic, ultrasonic, or eddy current methods, or a combination.

The Palo Verde Nickel Alloy Program Plan provides visual, surface, and volumetric examinations to support the Nickel Alloy AMP. The following examinations are identified by the Palo Verde Nickel Alloy AMP for Alloy 600 locations. Inspections are for all units unless a unit specific inspection is indicated.

Component / Current Examinations

Reactor Pressure Vessel (RPV) – Upper Head Penetrations

- Requirement: ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6)
  Examination: BMV, surface and Volumetric (UT)

Reactor Pressure Vessel (RPV) - Bottom Mounted Instrument (BMI) Nozzles

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: BMV

Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: BMV

Dissimilar Metal Welds

- Requirement: EPRI Report 1010087 (MRP-139) and ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: see below

- PZR Spray 1A and 1B / BMV

- Safety Injection lines / BMV, Volumetric

- Drain Line 1A and 1B / BMV

- Drain Line 2A / BMV

- Letdown Line / BMV

- Charging Line / BMV

<u>RCS Piping Instrument Nozzles</u>

- Requirement: ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through (4)
  Examination: see below.

- 12 Cold Legs with SB-166 material (each unit) / BMV

- 8 RCP instrument taps (4 per pump each unit) / BMV

- 8 Unit 2 Hot Leg pressure instrument nozzles (82/182 welds) / BMV

<u>RPV Upper Head Penetrations</u>

BMV examinations are implemented consistent with the requirements of Table 1 item B4.10 in ASME Code Case N-729-1, subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through (6). Surface and volumetric examinations are implemented consistent with ASME Code Case Table 1, Item Number B4.20 for reactor vessel upper head components composed of Alloy 600/82/182 material. 10 CFR 50.55a(g)(6)(ii)(D) requires volumetric and/or surface examination of essentially 100% of the required volume or equivalent surfaces of the nozzle tube. Inspection frequency and susceptibility to crack initiation are determined by ASME Code Case N-729-1 Table 1 and section 2400.

<u>RPV BMI Nozzles, Unit 1 Pressurizer Instrument Nozzles, RCS Dissimilar Metal Welds, and RCS Piping Instrument Nozzles</u>

BMV examinations for the following reactor coolant pressure boundary components are implemented consistent with noted items of Table 1 ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4).

- RPV BMI Nozzles – item B15.80

- Unit 1 Pressurizer Instrument Nozzles – item B15.180

- RCS Piping Instrument Nozzles – item B15.200 (Hot Leg) and B15.205 (Cold Leg)

- RCS Piping Dissimilar Metal Welds – item B15.215 (Cold Leg)

Note: Examination frequencies are identified in Element 5.

Monitoring and Trending – Element 5

The following examination frequencies are identified by the Nickel Alloy Aging Management Program for Alloy 600 locations. The examination frequencies are specified by the requirements noted in element 4. Examinations are for all units unless a unit specific examination is indicated.

a) Reactor Pressure Vessel (RPV) Upper Head Penetrations:

1) An Above Head Bare Metal Visual Examination of each RPVH every refueling outage

2) Under Head NDE Examination of each RPVH penetration every refueling outage.

Reactor Vessel Head replacements for all three PVNGS Units are scheduled from year 2009 to year 2010.

b) Bottom Mounted Instrumentation (BMI) Nozzles:

1) Bare metal examinations of 100% of the nozzles every other refueling outage.

c) Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material:

1) Bare metal visual examinations of 100% of the instrument nozzles each refueling outage.

d) RCS Dissimilar Metal Butt-Welds:

(Note that the implementation schedule for each unit is defined in the Program Plan)

100% volumetric every 6 years and bare metal visual examination once every three (3) refuelings outages when volumetric exams are not performed (MRP-139 Exam Category E):

- Safety Injection 1A
- Safety Injection 1B
- Safety Injection 2A
- Safety Injection 2B

Bare Metal visual examination once every three (3) refuelings (MRP-139 Exam Category K):

- PZR Spray 1A
- PZR Spray 1B
- Drain Line 1A

- Drain Line 1B
- Drain Line 2A
- Letdown Line
- Charging Line

e) RCS Piping Instrument Nozzles

1) Bare metal examinations of the 12 Cold Legs with SB-166 material nozzles once per ISI interval.
2) Bare metal examinations of the 8 RCP instrument taps nozzles once per ISI interval.
3) Bare metal examinations of the 8 Unit 2 Hot Leg pressure instrument nozzles every refueling outage.

Due to the repair/replace strategy implemented for indications/cracking, trending is not performed in the Palo Verde Nickel Alloy AMP.

RPV – Upper Head Penetrations

BMV, surface and volumetric examination frequencies for Reactor Vessel Upper Head Inspections are identified by the Nickel Alloy AMP for Alloy 600 locations and are consistent with ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a(g)(6)(ii)(D)(2) through(6). ASME Code Case N-729-1 Table 1 Item Number B4.20 specifies volumetric and surface examinations be performed on all nozzles every 8 calendar years or before 2.25 reinspection years (for crack propagation) whichever is less for reactor vessel upper head components composed of Alloy 600/82/182 material. Inspection frequency and susceptibility to crack initiation will be determined by ASME Code Case N-729-1 Table 1 and section 2400.

RPV BMI Nozzles, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles

BMV examination frequencies for BMI penetrations, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles are consistent with ASME Code Case N-722 subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4).

Acceptance Criteria – Element 6

Evaluations and acceptance criteria are in accordance with industry codes (e.g., ASME Code) or meet the acceptance of the NRC. For components included in EPRI 1010087 (MRP-139), as listed in Palo Verde Alloy 600 Management Program Plan, it requires that all indications found during inspections must be evaluated per ASME Section XI requirements. Indications that do not satisfy IWB-3500 acceptance criteria must be dispositioned by analysis (such as IWB-3600), repaired or replaced.

RPV- Upper Head Penetrations

Relevant flaw indications detected as a result of Bare Metal Visual examinations are evaluated in accordance with acceptable flaw evaluation criteria provided in ASME Code Case N-729-1 section 3140. Relevant flaw indications detected as a result of volumetric and surface examinations are evaluated in accordance with acceptable flaw evaluation criteria provided in ASME Code Case N-729-1 section 3130. For Bare Metal Visual examinations, once ISI has concluded evidence of leakage is present, the examination is forwarded to engineering for evaluation and disposition.

RPV BMI Nozzles, Pressurizer Instrument Nozzles in Unit 1 with 82/182 weld material, RCS Dissimilar Metal Butt-Welds, and RCS Piping Instrument Nozzles

For Alloy 600 reactor coolant pressure boundary locations other than the RPV Upper Head, relevant flaw indications detected as a result of BMV examinations are evaluated in accordance with acceptable flaw evaluation criteria (IWB-3522) provided in ASME Code Case N-722, subject to the conditions listed in 10 CFR 50.55a(g)(6)(ii)(E)(2) through(4). Indications that do not satisfy IWB-3500 acceptance criteria must be dispositioned by analysis (such as IWB-3600), repaired or replaced.

Corrective Actions – Element 7

Relevant indications failing to meet applicable acceptance criteria are repaired or evaluated in accordance with the plant corrective action program.

PVNGS site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B that are acceptable for addressing corrective actions.

Confirmation Process – Element 8

PVNGS QA procedures, review and approval processes and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B, which are acceptable in addressing confirmation processes.

Administrative Controls – Element 9

PVNGS QA procedures, review and approval processes and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B, which are acceptable in addressing administrative controls.

Operating Experience — Element 10

PVNGS has proactively replaced:

- all of the Alloy 600 pressurizer instrument nozzles (seven pressurizer nozzles in Unit 1 were welded using 82/182 weld material since the equivalent Alloy 690 weld material (52/152) was not commercially available at the time of the repair) and hot leg instrument nozzles in each Unit
- all pressurizer heater sleeves (36 per Unit)
- instrument nozzles in the steam generator cold leg plenum as part of the steam generator replacements on Units 1, 2 and 3.

A failure history, including repair or replacement information, search shows the following :

Component / Failure History / Repair or Replacements

a) Reactor Pressures Vessel (RPV)

- RPV Upper Head Penetrations / No CEDM indications. U2 vent line indications 2R12 / U2 vent line indications repaired by machining
- Bottom Mounted Instrument Nozzles (BMI) / No failures / None.

b) Pressurizer Nozzles

- Pressurizer instrument nozzles (7 each unit) / U1 1991 / Replaced with Alloy 690 material
- Pressurizer heater sleeves / Leaking nozzles, 6 circ and 6 axial indications (not leaking) / Preventively replaced all PZR sleeves in 3 units using external pad and partial nozzle replacement

c) Dissimilar Metal Welds

- PZR Spray / No Failures / FSWO 3 Units
- PZR Safeties / No failures / FSWO 3 Units
- Surge Line (HL and PZR Side) / No failures / FSWO 3 Units
- PZR Spray 1A and 1B / No failures / None
- Shutdown Cooling 1 and 2 / No Failures / FSWO 3 Units (Unit 3 planned Spring 2009)
- Safety Injection lines / No failures / None

- Drain Line 1A and 1B / No failures / None
- Drain Line 2A / No failures / None
- Letdown Line / No failures / None
- Charging Line / No failures / None

d) RCS Piping Instrument Nozzles

- 27 Hot Legs (each unit) / 5 cracked nozzles, suspect PWSCC / Preventively replaced all 27 nozzles in 3 units using partial nozzle replacement with OD j-weld
- 12 Cold Legs (each unit) / No failures / None
- RCP instrument taps / No failures / None

NRC Bulletin 2003-02 - Lower Head Penetrations

In response to NRC Bulletin 2003-02, "*Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity*", PVNGS performed visual examinations during refueling outages U1-R12 - ending Dec. 2005, U2-R12 - ending May 2005, U3-R11 - ending Dec. 2004, U3-R12 - ending May 2006 of all 61 bottom mounted instrumentation (BMI) nozzles by a PVNGS Level III VT-2 qualified examiner. No boric acid deposits were noted in the area of the nozzle annulus during the "as-found" inspections. The 61 nozzles showed no evidence of leakage.

NRC Bulletin 2004-01 - Pressurizer Penetrations

In response to NRC Bulletin 2004-01, PVNGS performed pressurizer heater sleeve visual inspections and did not identify any leakage.

On June 7, 2004, PVNGS Unit 3 went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves. The inspection did not identify any leakage.

On June 14, 2004, all three PVNGS units went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves in all three units. The inspection did not identify any leakage.

On July 13, 2004, Unit 2 went off-line and PVNGS personnel performed a bare metal, 360 degree, visual inspection of 100 percent of all pressurizer heater sleeves. The inspection did not identify any leakage.

The pressurizer instrument nozzles in all three units have been replaced with Alloy 690 nozzles. Also, during the 11th refueling outage, from Sept. 2003 through Dec. 2003, for Unit 2, 34 of 36 pressurizer heater sleeves (Alloy 600) were replaced with thermally treated SB-

167, Alloy 690, sleeves using the half-nozzle repair technique. The two sleeves that were not replaced were plugged during a previous outage using Alloy 690 material.

UNIT 1

In response to NRC Bulletin 2004-01 during Unit 1 refueling outage 12 ending December 2005, pressurizer bare metal visual inspections were performed and found no evidence of leakage. No relevant indications of through-wall leakage were identified during these inspections. No additional follow-up NDE was required. No relevant indications were observed. No boric acid residue was identified during the inspection of the pressurizer.

All 36 pressurizer heater sleeves were modified using the half-nozzle repair technique. The original heater sleeve was cut at a location within the pressurizer lower shell. A weld pad of Alloy 690 was overlaid on the exterior surface of the shell. New Alloy 690 sleeves were inserted and attached to the weld pad. This repair resulted in the relocation of the ASME pressure boundary weld from the inside surface to the outside surface of the pressurizer shell. The repairs were made using Alloy 690 material.

UNIT 2

In response to NRC Bulletin 2004-01 during Unit 2 refueling outage ending May 2005, pressurizer bare metal visual inspections were performed and found no evidence of leakage. No relevant indications of through-wall leakage were identified during this

inspection. No additional follow-up NDE was required. No boric acid residue was identified during the inspection of the Unit 2 pressurizer. No corrective actions were required.

UNIT 3

In response to NRC Bulletin 2004-01 during Unit 3 refueling outage 11 ending December 2004, PVNGS normally visually examines the pressurizer shell exposed by the gap between the insulation and the heater sleeves and other nozzles. However, during the heater sleeve modification project performed in Unit 3, the bottom shell insulation was removed and no corrosion was seen.

The Unit 3 pressurizer had three heater sleeves that were repaired during previous outages. These were repaired using a mechanical nozzle seal assembly (MNSA).

There were no relevant indications of through-wall leakage during the inspection of the Unit 3 pressurizer heater sleeves including the 3 sleeves previously repaired. No additional follow-up NDE was required based on the initial eddy current results.

No boric acid residue was identified during the inspection of the Unit 3 pressurizer.

Although there was no visual evidence of boron leakage identified at the start of the outage, APS had previously decided to permanently modify the heater sleeves during 3R11. All 36 heater sleeves, including the three previously repaired using a MNSA, were modified using the half-nozzle repair technique. The original heater sleeve was cut at a location within the pressurizer lower shell. A weld pad of Alloy 690 was overlaid on the exterior surface of the shell. New Alloy 690 half sleeves were inserted and attached to the weld pad. This repair resulted in the relocation of the ASME Pressure boundary weld from the inside surface to the outside surface of the pressurizer shell. The repairs were made using Alloy 690 material.

For Unit 3, refueling outage 12, by letter dated June 15, 2006, the NRC staff notified APS that the staff had closed their efforts with regard to the review of APS' Bulletin 2004-01 responses for PVNGS Units 1, 2, and 3.

Enhancements

None.

Conclusion

The continued implementation of the Nickel Alloy Aging Management Program provides reasonable assurance that aging effects will be managed such that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

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B2.1.35 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages the effects of loosening of bolted external connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation to ensure that electrical cable connections not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 and within the scope of license renewal are capable of performing their intended function.

As part of the predictive maintenance program, infrared thermography testing is performed on Non-EQ electrical cable connections, associated with active and passive components within the scope of license renewal. A representative sample of external connections will be tested at least once prior to the period of extended operation using infrared thermography to confirm that there are no aging effects requiring management. The infrared thermography will detect loosening of bolted connections or high resistance of cable connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The selected sample to be tested is based upon application (medium and low voltage), circuit loading, and environment. The technical basis for the sample selection is documented. The acceptance criteria for thermography testing will be based on the temperature rise above the reference temperature. The reference temperature will be ambient temperatures or the baseline temperature data from the same type of connections being tested. The one-time testing of a sample of Non-EQ electrical cable connectors is representative, with reasonable assurance, that Non-EQ electrical cable connections within similar application, circuit loading conditions, and environments are bounded by the testing.

Corrective actions for conditions that are adverse to quality will be performed in accordance with the corrective action program as part of the QA program. The corrective action program provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that, when implemented, will be consistent with Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02 and NUREG-1801, Section XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements".

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4.0 CHAPTER 4 - ENVIRONMENTAL CONSEQUENCES OF THE PROPOSED ACTION AND MITIGATING ACTIONS

NRC

"The report must contain a consideration of alternatives for reducing adverse impacts...for all Category 2 license renewal issues...." 10 CFR 51.53(c)(3)(iii)

"...The environmental report shall include an analysis that considers...the environmental effects of the proposed action...and alternatives available for reducing or avoiding adverse environmental effects...." 10 CFR 51.45(c) as adopted by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)

The environmental report shall discuss "The impact of the proposed action on the environment. Impacts shall be discussed in proportion to their significance" 10 CFR 51.45(b)(1) as adopted by 10 CFR 51.53(c)(2).

"...The information submitted...should not be confined to information supporting the proposed action but should also include adverse information." 10 CFR 51.45(e) as adopted by 10 CFR 51.53(c)(2)

Chapter 4 presents an assessment of the environmental consequences and potential mitigating actions associated with the renewal of the PVNGS operating license. The assessment tiers from NRC's *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996), which identifies and analyzes 92 environmental issues that NRC considers to be associated with nuclear power plant license renewal. In its analysis, NRC designated each of the 92 issues as Category 1, Category 2, or NA (not applicable) and required plant-specific analysis of only the Category 2 issues.

NRC designated an issue as Category 1 if, based on the result of its analysis, the following criteria were met:

- the environmental impacts associated with the issue were determined to apply either to all plants or, for some issues, to plants having a specific type of cooling system or other specified plant or site characteristic
- a single significance level (i.e., small, moderate, or large) was assigned to the impacts that would occur at any plant, regardless of which plant was being evaluated (except for collective offsite radiological impacts from the fuel cycle and from high-level waste and spent fuel disposal)
- mitigation of adverse impacts associated with the issue were considered in the analysis, and it was determined that additional plant-specific mitigation measures are likely to be not sufficiently beneficial to warrant implementation.

Absent new and significant information (Chapter 5), NRC rules do not require analyses of Category 1 issues, because NRC resolved them using generic findings presented in 10 CFR 51, Appendix B, Table B-1. An applicant may reference the generic findings or GEIS analyses for Category 1 issues.

If the NRC analysis concluded that one or more of the Category 1 criteria could not be met, the issue was assigned as Category 2. NRC requires plant-specific analyses for Category 2 issues. NRC designated two issues as "NA" (Issues 60 and 92), signifying that the categorization and impact definitions do not apply to these issues. Attachment A of this report lists the 92 issues and identifies the environmental report section that addresses each issue and, where appropriate, references supporting analyses in the GEIS.

Category 1 License Renewal Issues

NRC

"The environmental report for the operating license renewal stage is not required to contain analyses of the environmental impacts of the license renewal issues identified as Category 1 issues in Appendix B to subpart A of this part." 10 CFR 51.53(c)(3)(i)

"...[A]bsent new and significant information, the analysis for certain impacts codified by this rulemaking need only be incorporated by reference in an applicant's environmental report for license renewal...." 61 FR 28483.

APS has determined that, of the 69 Category 1 issues, 29 do not apply to PVNGS because they apply to design or operational features that do not exist at the facility. In addition, because APS does not plan to conduct any refurbishment activities, the NRC findings for the seven Category 1 issues that pertain only to refurbishment do not apply to this application. APS has reviewed the NRC Category 1 findings and has identified no new and significant information that would make the NRC findings inapplicable to PVNGS. Therefore, APS adopts by reference the NRC findings for these Category 1 issues.

Category 2 License Renewal Issues

NRC

"The environmental report must contain analyses of the environmental impacts of the proposed action, including the impacts of refurbishment activities, if any, associated with license renewal and the impacts of operation during the renewal term, for those issues identified as Category 2 issues in Appendix B to subpart A of this part...." 10 CFR 51.53(c)(3)(ii)

"The report must contain a consideration of alternatives for reducing adverse impacts, as required by § 51.45(c), for all Category 2 license renewal issues...." 10 CFR 51.53(c)(3)(iii)

NRC designated 21 issues as Category 2. Sections 4.1 through 4.20 address each of these issues (Section 4.17 addresses two issues), beginning with a statement of the issue. As is the case with Category 1 issues, some Category 2 issues apply to operational features that PVNGS does not have. In addition, some Category 2 issues apply only to refurbishment activities or to scenarios involving additional employment for managing plant aging. APS does not plan any refurbishment or additional employment. If an issue does not apply to PVNGS, the section explains the basis for inapplicability. Attachment A provides a summary of the applicability of each of the NRC's 92 issues to PVNGS.

reported in the FES for Construction (NRC 1975) and subsequently granted an operating license. Table 4-1 also presents actual discharges from the 91st Avenue plant indicating that discharges have, in fact, remained constant and, thus, less than expected when NRC licensed PVNGS.

The reason for the lack of growth in effluent from the 91st Avenue plant is that other waste water treatment plants have been constructed, including those for small communities and master planned developments that build treatment plants to process wastewater into treated effluent that can be used within the community. In 1995, effluent production in Maricopa County was approximately 241,200 acre-feet, of which 107,400 acre-feet were reused. In just three years, the production increased to 257,000 acre-feet, with an even larger increase in reuse, 175,000 acre-feet (Maricopa County 2001). The Arizona Department of Water Resources predicts that by 2025, treated effluent is projected to increase to 502,000 acre-feet per year (ADWR 1999). However, since PVNGS Unit 3 went into service in 1986, PVNGS demand on treated effluent has remained relatively constant, averaging approximately 67,000 acre-feet per year over 2001 to 2005 (Gunter 2006).

The 25-Year Master Plan for the 91st Avenue plant (SROG 2005) predicts that effluent from the 91st Avenue plant will again start to increase, providing a similar picture of increasing availability of treated effluent. By 2005, the actual effluent flow in the maximum month was 204.5 million gallons per day. The predicted maximum effluent flow in 2015 would be 230 million gallons per day. By 2030, that value could range from 236 to 266 million gallons per day. These values are for the 91st Avenue plant alone. Again, during this time, the PVNGS demand on treated effluent would remain constant, around 67,000 acre-feet per year, averaging 60 million gallons per day.

The FES for Operations predicted effluent flows from which, assuming 67,000 acre-feet of PVNGS demand, fractions of PVNGS use can be calculated. PVNGS was predicted to use approximately 45 percent of treated effluent production in 1986, with the percentage dropping to 27 percent in 2000. On the basis of these data (Table 4-1), NRC concluded "there will be a sufficient amount of sewage effluent available for use by the PVNGS during the critical year 1986 and throughout the life of the station." In 2000, the actual percentage was less than 26 percent (the 1998 value) and is projected to be 13 percent in 2025. As indicated by the SROG Master Plan, this trend of decreasing percentage would likely continue.

Given the constant rate of use of recycled water by PVNGS and the projections for increase of treated effluent in the area, water use conflicts with respect to the Gila River are expected to be much less influenced by PVNGS than by decisions by municipalities to either discharge or reuse portions of their effluent. Therefore, APS concludes that the impacts to surface water resources during the license renewal period from PVNGS' continued use of treated effluent would be SMALL and not warrant mitigation.

4.2 ENTRAINMENT OF FISH AND SHELLFISH IN EARLY LIFE STAGES

NRC

"If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations...or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from...entrainment." 10 CFR 51.53(c)(3)(ii)(B)

"...The impacts of entrainment are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems. Further, ongoing efforts in the vicinity of these plants to restore fish populations may increase the numbers of fish susceptible to intake effects during the license renewal period, such that entrainment studies conducted in support of the original license may no longer be valid...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 25

NRC made impacts on fish and shellfish resources resulting from entrainment a Category 2 issue, because it could not assign a single significance level (small, moderate, or large) to the issue. The impacts of entrainment are small at many facilities, but may be moderate or large at others. Also, ongoing restoration efforts may increase the number of fish susceptible to intake effects during the license renewal period (NRC 1996). Information needing to be ascertained includes (1) type of cooling system (whether once-through or cooling pond), and (2) status of Clean Water Act Section 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, PVNGS has mechanical draft cooling towers.

The issue is not applicable because PVNGS does not utilize once-through cooling or cooling pond heat dissipation systems.

4.3 IMPINGEMENT OF FISH AND SHELLFISH

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act 316(b) determinations...or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from...impingement...." 10 CFR 51.53(c)(3)(ii)(B)
>
> "...*The impacts of impingement are small at many plants but may be moderate or even large at a few plants with once-through and cooling-pond cooling systems*...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 26

NRC made impacts on fish and shellfish resources resulting from impingement a Category 2 issue, because it could not assign a single significance level to the issue. Impingement impacts are small at many facilities, but might be moderate or large at other plants (NRC 1996). Information that needs to be ascertained includes (1) type of cooling system (whether once-through or cooling pond) and (2) current Clean Water Act 316(b) determination or equivalent state documentation.

As Section 3.1.2 describes, PVNGS has mechanical draft cooling towers.

The issue is not applicable because PVNGS does not utilize once-through cooling or cooling pond heat dissipation systems.

4.4 HEAT SHOCK

NRC

> "If the applicant's plant utilizes once-through cooling or cooling pond heat dissipation systems, the applicant shall provide a copy of current Clean Water Act...316(a) variance in accordance with 40 CFR 125, or equivalent State permits and supporting documentation. If the applicant cannot provide these documents, it shall assess the impact of the proposed action on fish and shellfish resources resulting from heat shock...." 10 CFR 51.53(c)(3)(ii)(B)
>
> "...Because of continuing concerns about heat shock and the possible need to modify thermal discharges in response to changing environmental conditions, the impacts may be of moderate or large significance at some plants...." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 27

NRC made impacts on fish and shellfish resources resulting from heat shock a Category 2 issue, because of continuing concerns about thermal discharge effects and the possible need to modify thermal discharges in the future in response to changing environmental conditions (NRC 1996). Information to be ascertained includes: (1) type of cooling system (whether once-through or cooling pond) and (2) evidence of a Clean Water Act Section 316(a) variance or equivalent state documentation.

As Section 3.1.2 describes, PVNGS has mechanical draft cooling towers.

The issue is not applicable because PVNGS does not utilize once-through cooling or cooling pond heat dissipation systems.

4.9 IMPACTS OF REFURBISHMENT ON TERRESTRIAL RESOURCES

NRC

The environmental report must contain an assessment of "...the impact of refurbishment and other license-renewal-related construction activities on important plant and animal habitats...." 10 CFR 51.53(c)(3)(ii)(E)

"...Refurbishment impacts are insignificant if no loss of important plant and animal habitat occurs. However, it cannot be known whether important plant and animal communities may be affected until the specific proposal is presented with the license renewal application...." 10 CFR 51, Subpart A, Table B-1, Issue 40

"...If no important resource would be affected, the impacts would be considered minor and of small significance. If important resources could be affected by refurbishment activities, the impacts would be potentially significant...." (NRC 1996)

NRC made impacts to terrestrial resources from refurbishment a Category 2 issue because the significance of ecological impacts cannot be determined without considering site- and project-specific details (NRC 1996). Aspects of the site and project to be ascertained are: (1) the identification of important ecological resources, (2) the nature of refurbishment activities, and (3) the extent of impacts to plant and animal habitats.

The issue of impacts of refurbishment on terrestrial resources is not applicable to PVNGS because, as discussed in Section 3.2, APS has no plans for refurbishment or other license-renewal-related construction activities at PVNGS.

4.10 THREATENED OR ENDANGERED SPECIES

NRC

"Additionally, the applicant shall assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act." 10 CFR 51.53(c)(3)(ii)(E)

"Generally, plant refurbishment and continued operation are not expected to adversely affect threatened or endangered species. However, consultation with appropriate agencies would be needed at the time of license renewal to determine whether threatened or endangered species are present and whether they would be adversely affected." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 49

NRC made impacts to threatened and endangered species a Category 2 issue because the status of many species is being reviewed, and site-specific assessment is required to determine whether any identified species could be affected by refurbishment activities or continued plant operations through the renewal period. In addition, compliance with the Endangered Species Act requires consultation with the appropriate federal agency.

Section 2.2 of this Environmental Report describes the aquatic communities at PVNGS. Section 2.4 describes important terrestrial habitats at PVNGS and along the associated transmission corridors. Section 2.5 discusses threatened or endangered species that occur or may occur in the vicinity of PVNGS and along PVNGS-associated transmission corridors. As discussed in Section 3.1.3, the transmission lines that connect PVNGS to the regional transmission system are owned and maintained by the Salt River Project, APS, and Southern California Edison.

With the exception of the species identified in Section 2.5, APS is not aware of any threatened or endangered terrestrial or aquatic species that occur at PVNGS or along the associated transmission corridors. Although several threatened or endangered terrestrial species could occur along the transmission corridors, the PVNGS transmission corridors are located in desert habitat, and in general they do not require significant maintenance in terms of mowing, trimming, or clearing. Therefore, current operations of PVNGS and vegetation management practices along PVNGS transmission line corridors are not believed to adversely impact any listed terrestrial or aquatic species or its habitat. Furthermore, plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. Therefore, no adverse impacts to threatened or endangered terrestrial or aquatic species from future operations are anticipated and, thus, impacts are categorized as SMALL.

APS wrote to the Arizona Game and Fish Department, the California Department of Fish and Game, and the U.S. Fish and Wildlife Service requesting information on any listed species or critical habitats that might occur at PVNGS or along the associated transmission corridors, with particular emphasis on species that might be adversely affected by continued operation over the license renewal period. Agency responses are provided in Attachment B.

4.11 AIR QUALITY DURING REFURBISHMENT (NON-ATTAINMENT AREAS)

NRC

"If the applicant's plant is located in or near a nonattainment or maintenance area, an assessment of vehicle exhaust emissions anticipated at the time of peak refurbishment workforce must be provided in accordance with the Clean Air Act as amended." 10 CFR 51.53(c)(3)(ii)(F)

"...Air quality impacts from plant refurbishment associated with license renewal are expected to be small. However, vehicle exhaust emissions could be cause for concern at locations in or near nonattainment or maintenance areas. The significance of the potential impact cannot be determined without considering the compliance status of each site and the numbers of workers expected to be employed during the outage...." 10 CFR 51, Subpart A, Table B-1, Issue 50

NRC made impacts to air quality during refurbishment a Category 2 issue because vehicle exhaust emissions could be cause for some concern, and a general conclusion about the significance of the potential impact could not be drawn without considering the compliance status of each site and the number of workers expected to be employed during an outage (NRC 1996). Information needed would include: (1) the attainment status of the plant-site area, and (2) the number of additional vehicles as a result of refurbishment activities.

The issue of air quality during refurbishment is not applicable to PVNGS because, as discussed in Section 3.2, APS has no plans for refurbishment or other license-renewal-related construction activities at PVNGS.

4.12 MICROBIOLOGICAL ORGANISMS

NRC

> "If the applicant's plant uses a cooling pond, lake, or canal or discharges into a river having an annual average flowrate of less than 3.15×10^{12} ft^3/year (9×10^{10} m^3/year), an assessment of the impact of the proposed action on public health from thermophilic organisms in the affected water must be provided." 10 CFR 51.53(c)(3)(ii)(G)
>
> "These organisms are not expected to be a problem at most operating plants except possibly at plants using cooling ponds, lakes, or canals that discharge to small rivers. *Without site-specific data, it is not possible to predict the effects generically.*" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 57

Due to the lack of sufficient data for facilities using cooling ponds, lakes, or canals or discharging to small rivers, NRC designated impacts on public health from thermophilic organisms a Category 2 issue. Information to be determined is: (1) whether the plant uses a cooling pond, lake, or canal or discharges to a small river and (2) whether discharge characteristics (particularly temperature) are favorable to the survival of thermophilic organisms.

The issue is not applicable to PVNGS because the station does not use a cooling pond, lake or canal, or discharge to a small river.

already achieved by other means. APS prepared cost estimates for the remaining SAMAs and used the base risk value to screen out SAMAs that would not be cost-beneficial.

APS calculated the risk reduction that would be attributable to each remaining candidate SAMA (assuming SAMA implementation) and re-quantified the risk value. The difference between the base risk value and the SAMA-reduced risk value became the averted risk, or the value of implementing the SAMA. APS used this information in conjunction with the cost estimates for implementing each SAMA to perform a detailed cost/benefit comparison.

APS performed additional analyses to evaluate how the SAMA analysis would change if certain key parameters were changed, including re-assessing the cost benefit calculations using the 95th percentile level of the failure probability distributions. The results of the uncertainty analysis are discussed in Attachment D, Section D.7.

Based on the results of this SAMA analysis, none of the SAMAs have a positive net value. However, when the 95th percentile PRA results are considered, SAMAs 6 and 17 are cost beneficial. In addition, even though SAMA 23 produced a negative net value, APS decided to consider this SAMA for potential implementation.

- SAMA 6: Develop Procedures to Guide Recovery Actions for Spurious Electrical Protection Faults
- SAMA 17: Modify the Procedures to Preclude RCP Operations that Would Clear the Water Seals in the Cold Leg After Core Damage
- SAMA 23: Provide Cost-Risk Analysis for Procedure Enhancements to Direct Steam Generator Flooding for Release Scrubbing

None of these SAMAs are aging related. While these results are believed to accurately reflect potential areas for improvement at PVNGS, APS notes that this analysis should not necessarily be considered a formal disposition of these proposed changes, as other engineering reviews are necessary to determine the ultimate resolution. The SAMAs 6, 17, and 23 are the only SAMAs related to plant procedure improvements. The implementation cost estimates for these three SAMAs were provided with a contingency in the range of 25% to 75% to accommodate uncertainties. However, all three SAMAs (6, 17, and 23) are being considered for implementation regardless of their costs.

4.21 TABLES

Table 4-1. Projected and Actual Wastewater Effluent (acre-feet)

	1985	1990	1995	2000
FES-OP Projection for 91st Avenue plant[1]	143,470	177,810	211,800	247,740
91st Avenue plant actual	158,572	155,586	156,338	156,547

Source: NRC (1982); Lehner 2007
[1]*The larger of the two estimates is the City of Phoenix estimate, which is reported here.*

Table 4-2. Results of Induced Current Analysis.

Transmission Line	Limiting Case Induced Current (milliamperes)
Devers	<4.1[a]
Hassayampa #1 (analyzed to Kyrene)	3.0
Hassayampa #2	3.0
Hassayampa #3	4.9
Rudd	4.6
Westwing #1	4.6
Westwing #2	4.6

Source: TtNUS (2007a); TtNUS (2007b)
[a]Electric field measurements were taken at the location of greatest sag, not at the road crossing. The road crossing would have lesser electric field strength and, thus, lesser induced current.

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Section 4.11

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Assuming ideal wind conditions and a 35 percent capacity factor, a wind farm with a net output of 4,020 MWe would require about 563,143 acres (880 square miles) of which about 16,894 acres (26 square miles) would be occupied by turbines and support facilities. Based on the amount of land needed, the wind alternative would require a large greenfield site, which would result in a large environmental impact. Additionally, wind plants have aesthetic impacts, generate noise, and can harm flying birds and bats.

Arizona does not have sufficient wind resources for wind energy applications, the scale of this technology is too small to directly replace a power plant of the size of PVNGS, capacity factors are low (30 to 40 percent), and the land requirement (880 square miles) is large. Therefore, APS has concluded that wind power is not a reasonable alternative to PVNGS license renewal.

Solar

There are two basic types of solar technologies that produce electrical power: photovoltaic and solar thermal power. Photovoltaics convert sunlight directly into electricity using semiconducting materials. Solar thermal power systems use mirrors to concentrate sunlight on a receiver holding a fluid or gas, heating it, and causing it to turn a turbine or push a piston coupled to an electric generator. Solar thermal systems can be equipped with a thermal storage tank to store hot heat transfer fluid, providing thermal energy storage. By using thermal storage, a solar thermal plant can provide dispatchable electric power (Leitner and Owens 2003).

Solar technologies produce more electricity on clear, sunny days with more intense sunlight and when the sunlight is at a more direct angle (i.e., when the sun is perpendicular to the collector). Cloudy days can significantly reduce output, and no solar radiation is available at night. To work effectively, solar installations require consistent levels of sunlight (solar insolation) (Leitner and Owens 2003).

The lands with the best solar resources are usually arid or semi-arid. In addition, the average annual amount of solar energy reaching the ground needs to be 6.0 kilowatt-hours per square meter per day or higher for solar thermal power systems (Leitner 2002). Arizona has an arid climate and receives 6.75 to 7.75 kilowatt hours of solar radiation per square meter per day, making it one of the best places in the world to generate electricity from solar energy (NREL 2005). Recent estimates indicate that Arizona has the potential for roughly 285,567 MWe of solar power capacity (Leitner and Owens 2003).

The owners of PVNGS support the use of solar energy. APS has projects or future initiatives representing more than 285 MW of solar thermal and photovoltaic generation throughout its service area. These initiatives include research and demonstration projects, educational programs, and working with customers to interconnect photovoltaic systems to the electrical grid (PNW 2006). APS recently announced a decision to purchase power generated by the Solana Generating Station, a 280 MW concentrating solar plant to be built by 2011 near Yuma, Arizona (APS 2008). The Salt River Project also has solar generating stations with almost 875 kW of photovoltaic capacity (ADOC 2006). However, capacity factors for solar applications are too low to meet baseload requirements. Average annual capacity factors for solar power systems are relatively low (24 percent for photovoltaics and 30 to 32 percent for solar thermal power) compared to 90 to 95 percent for a large baseload plant such as a nuclear plant. (Leitner 2002)

Land requirements for solar plants are high. Estimates based on existing installations indicate that utility-scale plants would occupy about 7.4 acres per MWe for photovoltaic and 4.9 acres per MWe for solar thermal systems (DOE 2004). Assuming capacity factors of 24 percent for photovoltaics and 32 percent for solar thermal power, facilities having 3,942 MWe net capacity are estimated to require 121,545 acres (190 square miles), if powered by photovoltaic cells, and 60,362 acres (94 square miles), if powered by solar thermal power. Neither type of solar electric system would fit at the PVNGS site, and both would have large environmental impacts at a greenfield site.

Solar powered technologies, photovoltaic cells and solar thermal power do not currently compete with conventional technologies in grid-connected applications. Recent estimates indicate that the cost of electricity produced by photovoltaic cells is in the range of 18 to 23 cents per kilowatt-hour, and electricity from solar thermal systems can be produced for a cost in the range of 12 to 14 cents per kilowatt-hour (DOE 2006).

APS has concluded that, due to the high cost, low capacity factors, and the substantial amount of land needed to produce the desired output (approximately 94 to 190 square miles), solar power is not a reasonable alternative to PVNGS license renewal.

Hydropower

Hydroelectric power uses the energy of falling water to turn turbines and generate electricity. Power production increases with both greater water flow and greater fall. Hydropower currently provides about 6.6 percent of Arizona's electricity production.

According to the U.S. Hydropower Resource Assessment for Arizona (Conner and Francfort 1997), there are no remaining sites in Arizona that would be environmentally suitable for development of a large hydroelectric facility. As the GEIS points out in Section 8.3.4, hydropower's proportion of United States generating capacity is expected to decline because hydroelectric facilities have become difficult to site as a result of public concern over flooding, destruction of natural habitat, and alteration of natural river courses.

The GEIS estimates land use of 1,600 square miles per 1,000 MWe for hydroelectric power. Based on this estimate, replacement of PVNGS generating capacity would require flooding approximately 6,300 square miles, resulting in a large impact on land use. Further, operation of a hydroelectric facility would alter aquatic habitats above and below the dam, which would impact existing aquatic communities.

APS has concluded that due to the lack of suitable sites in Arizona for a large hydroelectric facility and the amount of land needed (approximately 6,300 square miles) hydropower is not a reasonable alternative to PVNGS license renewal.

Geothermal

Geothermal energy is a proven resource for power generation. Geothermal power plants use naturally heated fluids as an energy source for electricity production. To produce electric power, underground high-temperature reservoirs of steam or hot water are tapped by wells and the steam rotates turbines that generate electricity. Typically, water is then returned to the ground to recharge the reservoir (NREL 1997).

Geothermal energy can achieve average capacity factors of 95 percent and can be used for baseload power where this type of energy source is available (NREL 1997). Widespread application of geothermal energy is constrained by the geographic availability of the resource (NREL 1997). According to the Western Governor's Association Geothermal Taskforce Report (WGA 2006), there are approximately 20 MWe of known geothermal potential in Arizona that could be developed using existing technology. Evidence shows that the resource may be larger

Table 7-5. Solid Waste from Coal-Fired Alternative.

Parameter	Calculation	Result
Annual SO_x generated[a]	$\frac{14{,}522{,}211 \text{ tons coal}}{\text{yr}} \times \frac{0.85 \text{ tons S}}{100 \text{ tons coal}} \times \frac{64.1 \text{ tons } SO_2}{32.1 \text{ tons S}}$	246,754 tons of SO_x per year
Annual SO_x removed	$\frac{246{,}754 \text{ tons } SO_x}{\text{yr}} \times \frac{95}{100}$	234,417 tons of SO_x per year
Annual ash generated	$\frac{14{,}522{,}211 \text{ tons coal}}{\text{yr}} \times \frac{12.45 \text{ tons ash}}{100 \text{ tons coal}} \times \frac{99.9}{100}$	1,806,207 tons of ash per year
Annual ash recycled	$1{,}806{,}207 \text{ tons ash} \times \frac{90}{100}$	1,625,587 tons of ash recycled per year
Annual ash disposed	$1{,}806{,}207 \text{ tons generated} - 1{,}625{,}587 \text{ tons recycled}$	180,620 tons of ash disposed per year
Annual lime consumption[b]	$\frac{246{,}754 \text{ tons } SO_2}{\text{yr}} \times \frac{56.1 \text{ tons CaO}}{64.1 \text{ tons } SO_2}$	215,958 tons of CaO per year
Calcium sulfate[c]	$\frac{234{,}417 \text{ tons } SO_2}{\text{yr}} \times \frac{172 \text{ tons } CaSO_4 \bullet 2H_2O}{64.1 \text{ tons } SO_2}$	629,012 tons of $CaSO_4 \bullet 2H_2O$ per year
Annual scrubber waste[d]	$\frac{215{,}958 \text{ tons CaO}}{\text{yr}} \times \frac{100-95}{100} + 629{,}012 \text{ tons } CaSO_4 \bullet 2H_2O$	639,810 tons scrubber waste per year
Total volume of scrubber waste[e]	$\frac{639{,}810 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{102 \text{ lb}}$	501,811,701 ft^3 of scrubber waste
Total volume of ash disposed[f]	$\frac{180{,}621 \text{ tons}}{\text{yr}} \times 40 \text{ yr} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{ft^3}{100 \text{ lb}}$	144,496,582 ft^3 of ash
Total volume of solid waste	$501{,}811{,}701 \text{ ft}^3 + 144{,}496{,}582 \text{ ft}^3$	646,308,283 ft^3 of solid waste
Waste pile area (acres)	$\frac{646{,}305{,}283 \text{ ft}^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \text{ ft}^2}$	495 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(646{,}308{,}283 \text{ ft}^3/30 \text{ ft})}$	4,642 feet by feet square of solid waste

Based on annual coal consumption of 14,522,211 tons per year (Table 7-4).

a. Calculations assume 100 percent combustion of coal.
b. Lime consumption is based on total SO_2 generated.
c. Calcium sulfate generation is based on total SO_2 removed.
d. Total scrubber waste includes scrubbing media carryover.
e. Density of scrubber sludge is 102 lb/ft^3 (FHA 1997).
f. Density of coal bottom ash is 100 lb/ft^3 (FHA 1997).

S = sulfur
SO_x = oxides of sulfur
CaO = calcium oxide (lime)
$CaSO_4 \bullet 2H_2O$ = calcium sulfate dihydrate

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along the entire pipeline, through the use of an electrical continuity check to identify those with the highest potential for failure. Those pipe spools were then prioritized, and repaired during Water Reclamation Facility outages, a process that continues today. The repair process generally consists of wrapping the pipe spool with steel tendons, applying post-tensioning, and then providing a shotcrete cover over the new steel tendons. This system of monitoring the pipe condition and instituting repairs has proven to be effective as no further pipe failures have occurred.

9.1.6 Air Quality

Palo Verde received a Non-Title V Synthetic Minor Air Quality permit from the Maricopa County Air Quality Department on August 18, 2005. Since the permit was issued, three Notices of Violation (NOVs) have been issued. The first was on October 26, 2006, associated with work on an off-site pipeline that delivers water to Palo Verde. In this instance, a contractor failed to provide adequate trackout controls during an earthmoving operation. The second NOV was issued on November 22, 2006, for failure to comply with annual PM-10 emissions limits from on-site cooling towers. The third NOV was issued on November 2, 2007, for failure to comply with monthly PM-10 emissions limits from on-site cooling towers. These three NOVs were settled with Maricopa County on February 28, 2008, where Palo Verde, without admitting to the alleged violations, agreed to pay Maricopa County $79,619.45 (Bement, R, 2008). With the resolution of these NOVs, Palo Verde has no outstanding air quality compliance issues.

9.2 ALTERNATIVES

NRC

"...The discussion of alternatives in the report shall include a discussion of whether the alternatives will comply with such applicable environmental quality standards and requirements." 10 CFR 54.45(d) as adopted by 10 CFR 51.53(c)(2)

The coal, gas, new nuclear, and purchased power alternatives discussed in Chapter 7 probably could be constructed and operated to comply with all applicable environmental quality standards and requirements. APS notes that increasingly stringent air quality protection requirements could make the construction of a large fossil-fueled power plant infeasible in many locations.

Attachment D
Severe Accident Mitigation Alternatives

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D.2.1.12 CONTINUOUS QUALITY IMPROVEMENT PROCESS

The Palo Verde PRA has undergone considerable evolution since the original Individual Plant Examination (IPE) submittal. The history of the PRA model updates is described in Section D.2.3. A strong level of commitment is demonstrated by this development history.

The Palo Verde PRA staff has been maintained at a level such that nearly all technical work is performed in-house by qualified staff with strong plant-specific knowledge. The PRA Group consists of a supervisor, or Group Leader, one consulting engineer and six senior engineers. Five of these engineers held Senior Reactor Operator Licenses or SRO certification on Palo Verde or other stations. The Engineering Support Group collects failure, success, unavailability and plant operating data for various plant needs, including the Maintenance Rule and the PRA.

The Palo Verde PRA Group has also actively participated in the industry peer review process. One engineer has participated in every CEOG peer review. This participation is an effective means of understanding the plant design differences, and an excellent means of seeing the different modeling techniques.

D.2.2 PVNGS PRA MODEL OVERVIEW

Palo Verde uses the large fault tree/small event tree, also known as the linked fault tree, methodology. Basic failure events are modeled down to the component level. Level 1 (Core Damage Frequency, or CDF) and Level 2 (Large Early Release Frequency only, or LERF) are fully developed. A Level 3 (Dose Consequence) analysis was done to support the Individual Plant Examination (IPE), but has not been maintained.

The Internal Events model consists of twenty-eight (28)-initiating events, which proceed through their respective event trees. Failure branches are assigned a Core Melt (CM) or ATWS (Anticipated Transient Without Scram) plant damage state (PDS) and an appropriate Level 2 damage state. ATWS is modeled in separate event trees. Failure branches there are also assigned CM and the appropriate Level 2 PDS. Core Melt is defined as initiation of sustained uncovery of the top of the active fuel.

Internal flooding was analyzed using a screening process for the IPE. That analysis is still considered to be valid. Internal flooding is not currently modeled using event and fault trees. A task is currently underway through EPRI to update the flooding analysis. Section D.5.1.6.7 describes how Internal Flooding was addressed for the SAMA analysis.

External Events were examined as required by Generic Letter 88-20 Supplement 4, the IPE for External Events (IPEEE). None was analyzed by a fully developed PRA.

A full fire PRA has since been developed and incorporated into the PVNGS PRA model. Only buildings and external areas where a fire could not credibly interfere with normal plant operations were screened from consideration. No compartments within buildings housing plant equipment used for normal power production or emergency operations were screened. There are approximately 135 fire initiating events. These proceed first through fire event trees, which determine potential fire damage states (FDS). Each FDS is then carried through an event tree mimicking the internal events event trees. CM, ATWS and Level 2 plant damage states are assigned as in the internal events event trees. ERIN Engineering performed a peer review of the PVNGS Fire PRA in 2003. The category A or B Findings and Observations were all resolved. Only five F&Os of categories C and D were noted. They are yet to be addressed. None is expected to have a significant impact on the quality of the Fire PRA.

The existing PVNGS level 2 analysis was recently revised (with expert help provided by ERIN Engineering) in accordance with the guidelines provided by Westinghouse report WCAP-16341-P (WEST 2005). Westinghouse completed a utility-sponsored project to develop a simplified level 2 modeling approach that improved the robustness of the level 2 analysis. The method is consistent with NUREG/CR-6595, but with further emphasis on generating the models and data necessary for more realistic treatment of thermal and pressure induced steam generator tube ruptures. Also, more emphasis was placed on operator actions in severe accident management guidance. When combined with plant-specific assessments, the Westinghouse approach is expected to be capable of supporting both power uprate and license renewal.

D.2.3 PALO VERDE PRA DEVELOPMENT HISTORY

Numerous revisions to the PVNGS PRA model have been implemented since the Individual Plant Examination was performed (APS 2007d). These revisions include thousands of changes to event sequence and fault tree modeling, as well as data changes. Changes to the model and data are made in response to:

- Physical changes to the facility
- Changes to operating and maintenance procedures, as well as administrative controls
- Errors found in reviews of the model, or during its use
- Enhancements where experience has indicated that greater accuracy is needed to remove unnecessarily conservative assumptions

Coincident with conversion of the PRA model from Unix-based software and platform to a Windows-based platform using Relcon's Risk SpectrumTM software in 1996, the model was completely rebuilt to enhance documentation and control of the model and associated software. This effort led to the following improvements:

- Equipment failure rates were updated with referenceable sources.
- Control circuit failure analyses were completely re-performed and documented.
- Initiating Event methodology was documented and the initiating events were recalculated and Bayesian-updated.
- Common-cause failure methodology was re-performed and documented.
- Human Reliability Analysis was completely re-performed and documented based on current operating, maintenance, emergency and administrative control procedures.
- System modeling was reviewed and numerous updates made to such systems as Engineered Safety System Actuation, Auxiliary Feedwater, Low and High Pressure Safety Injection, Essential Spray Ponds (ultimate heat sink) and Chemical Volume and Control. Modeling of the non-class 1E electrical distribution systems was expanded to better capture power loss impact on non-class equipment credited in the model.
- The focus of Level 2 modeling was changed to Large Early Release Frequency.
- Since Risk SpectrumTM has extensive documentation capability, all references to station and external documents are included within the PRA database. This allows periodic comparison to the station's document database to identify revision changes.

The following changes represent corrections and enhancements to the model that improve its fidelity and accuracy, but did not necessarily have a significant impact on CDF or LERF:

- Refined modeling of power distribution failures as initiating events to ensure completeness. Definite system boundaries were defined. The two initiators, Loss of Channel A Vital AC and Loss of Channel B Vital AC, were changed to capture all losses of power due to station equipment failure from the Start-up Transformers, the 13.8KV, 4.16KV and 480VAC distribution systems to the battery chargers and the back-up voltage regulators for the Vital AC system. A more recent change split this initiator into several pieces to better capture where in the distribution systems problems originate that lead to plant trips or shutdowns.
- Updated Human Reliability Analysis, both to capture procedure changes and to ensure consistent and defensible modeling methodology. The EPRI HRA Calculator is used for new and updated HEPs.

- Added Reactor Coolant Pump High Pressure Seal Cooler Rupture as an initiating event. This was identified as a potential containment bypass event.
- Improved Steam Generator Tube Rupture modeling as the industry and NRC have addressed this issue. The model now includes multiple tube rupture sequences and pressure-induced tube rupture.
- Data update was performed in 1998 and again in 2006. As more plant-specific data has become available through failure data trending and Maintenance Rule requirements, failure rates for risk-important equipment have been Bayesian-updated. For most equipment included in the scope of the Maintenance Rule, plant-specific unavailability values are used.
- Added more detail to the switchyard modeling to better assess maintenance activities.
- Removed Reactor Coolant Pump seal leakage modeling following Westinghouse evaluation of CE seal designs and acknowledgement of Palo Verde's unique design.
- Added thermally-induced steam generator tube rupture following steam line break. This had no impact on results, but conforms to the industry standard.

Changes that had a significant impact on the CDF or LERF are summarized below:

- Added modeling of the Station Blackout GTGs, which were installed to address the Blackout Rule, 10 CFR 50.46. While the modeling of the GTGs was not credited in the IPE directly, it was used to address and close out USI A-45, which was included as part of the GL 88-20 submittal.
- Refined the GTG modeling to allow success with one GTG rather than requiring both for certain sequences. The GTGs have an output less than that of the Emergency Diesel Generators. One GTG is not capable of powering both an electric Auxiliary Feedwater Pump and a High Pressure Safety Injection (HPSI) pump, along with support equipment. Since most sequences only require AF, and not HPSI, one GTG is adequate for those sequences.
- Change of the test interval for Engineered Safety Features Activation System (ESFAS) relay testing from 62-day to 9-month staggered as a result of a Tech Spec change; resulting common-cause failure value changes were also incorporated. This resulted in a significant increase in both CDF and LERF. At the urging of the PRA group, these test intervals were later shortened to

Level 2 frequency total compared to the Level 1 CDF is partly due to the lower truncation values utilized; the Level 2 model uses a value of 1.0E-13 while the Level 1 model uses 1.0E-12. Another contributing factor is the generation of additional cutsets that are valid on a sequence and release category basis, but are non-minimal in the combined Level 2 results. The table below lists the total for each endstate. Most of the frequency comes from the damage class LATE, which is 91% of the total Level 2 frequency. LERF is a distant second with about 5%.

Endstate Frequency Totals

Endstate	Frequency	Percent Total
INTACT	1.72E-07	3.3%
LATE	4.79E-06	91.4%
LERF	2.77E-07	5.3%
SERF	0.00E+00	0.0%
	5.24E-06	100.0%

Figure D.2-2 shows the base case results using the refined release category grouping, which allows for the the more detailed evaluation of containment response characteristics required in the SAMA analysis. Table D.2-2 provides summary level descriptions of these release categories and identifies the contributing level 2 sequences.

D.2.8 CONCLUSION

The PVNGS PRA model is currently suitable for risk-informed applications that can support power uprate, license renewal, on-line risk assessments, and other regulatory risk-informed applications.

D.3 LEVEL 3 PRA ANALYSIS

The MACCS2 code (NRC 1998a) was used to perform the level 3 PRA for PVNGS. The input parameters given with the MACCS2 "Sample Problem A," which included the NUREG-1150 food model (NRC 1989), formed the basis for the present analysis. These generic values were supplemented with parameters specific to PVNGS and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Parameters describing the costs of evacuation, relocation and decontamination were escalated from the time of their formulation (1986) to more recent (March 2007) costs. Plant-specific release data included the time-activity distribution of nuclide releases and release frequencies. The behavior of the population during a release (evacuation parameters) was based on plant- and site-specific set points (i.e., declaration of a General Emergency) and evacuation time estimates (Maricopa 2005). These data were used in combination with site specific meteorology to simulate the probability distribution of exposure and economic impact risks from the 11 evaluated accident sequences at PVNGS to the surrounding population within 50 miles.

D.3.1 POPULATION

The population distribution was based on the 2000 census as accessed by SECPOP2000 (NRC 2003). The baseline population was determined for each of 160 sectors, consisting of sixteen compass directions for each of ten concentric distance rings with outer radii at 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles surrounding the site. The year 2000 total residential population was 1,572,110 No significant transient populations were identified (Maricopa 2005). Individual county growth rates (Arizona 2006, USCB 2000) were applied to estimate the population in the year 2040; all counties indicated a positive growth rate for the period of interest. The estimated year 2040 total population, used in the Level 3 risk analysis, was 3,588,726.

This discussion supports population projections used in the Palo Verde Severe Accident Mitigation Alternatives (SAMA) analysis.

The population surrounding Palo Verde Nuclear Generating Station, up to a 50-mile radius, was estimated based on the most recent United States Census Bureau decennial census data. The population distribution was estimated in 10 concentric rings at 0 to 1 mile, 1 to 2 miles, 2 to 3 miles, 3 to 4 miles, 4 to 5 miles, 5 to 10 miles, 10 to 20 miles, 20 to 30 miles, 30 to 40 miles, and 40 to 50 miles from the current reactors, and 16 directional sectors, each direction consisting of 22.5 degrees. The population estimate for the year 2040 was projected using an exponential growth rate calculated from state population projections.

The population distribution within 50 miles of the site was computed by overlaying the 2000 census block points data (the smallest unit of census data) on a map grid. SECPOP 2000, a code developed for the NRC by Sandia National Laboratories to calculate population by emergency planning zone sectors, was used to determine the

2000 resident population by sector. According to the 2005 Palo Verde Evacuation Time Analysis, other than the plant staff, there is no significant transient population within the 10-mile radius. Therefore, only resident population was projected in this analysis.

Once the 2000 resident population was determined for each of the 160 sectors, projections were made for year 2040. An exponential growth rate was calculated for each county based on county projections obtained from the Arizona Department of Economic Security (2006) and 2000 U.S. Census Bureau Data. Once county growth rates were determined, ArcGIS® was used to determine the total area within a sector, and the percentage of the area in each sector occupied by a particular county. The sectors were divided into fractions by county, and projections for each fraction were calculated based on the county growth rate. The population projections for the years in question were then totaled by sector, and rounded to the nearest whole number to obtain the final result. The results are used in the SAMA analysis for Palo Verde (TtNUS 2006).

D.3.2 ECONOMY AND AGRICULTURE

MACCS2 requires the spatial distribution of certain agriculture and economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) in the same manner as the population. This was done by applying the data from the 2002 National Census of Agriculture (USDA 2004) for each of the five counties surrounding the plant, to a distance of 50 miles. The value used for each of the 160 sectors was the data from each of the surrounding counties multiplied by the fraction of that county's area that lies within that sector. The land fraction (i.e., one minus water fraction) was analogously calculated for each sector as the sum of the individual county component areas divided by the sector area. Crop production parameters (e.g., fraction of farmland devoted to grains, vegetables, etc.) for the 50-mile region were also calculated from the county production data. Non-farm land property values were taken from state and local analyses (Arizona 2003, GPEC 2005). No economic parameters were derived using

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The averted cost-risk for the SAMA is the difference between the total base case cost-risk (MACR) and the total cost-risk with the SAMA implemented (provided on a site-basis):

SAMA 6 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,315,185	$352,815

D.6.2.2 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $363,374 (APS 2008a). The estimate is for a single unit, but it is assumed that the additional cost of implementing the procedure across the other two units is minimal. The estimate does not address any training or changes to training materials for the operators, but the cost provided is considered to be representative of the SAMA and $363,374 is used as the cost of implementation.

The SAMAs 6, 17, and 23 are the only SAMAs related to plant procedure improvements. The implementation cost estimates for these three SAMAs were provided with a contingency in the range of 25% to 75% to accommodate uncertainties. However, all three SAMAs (6, 17, and 23) are being considered for implementation regardless of their costs.

D.6.2.3 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 6 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$352,815	$363,374	-$10,559

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

D.6.3 SAMA NUMBER 8: ADD AUTO START/LOAD CAPABILITY TO THE GTGS

This change requires the addition of logic and hardware that will be able to start and load the GTGs when the EDGs fail to start or run. Currently, the operators must identify the EDG failures and manually align the GTGs for alternate emergency power. While the operator action to align the GTGs is considered to be reliable, further improvements to reliability are possible through automation of the process. It is assumed that the initiation logic will:

- Be capable of properly identifying bus undervoltage conditions
- Not interfere with the operation of the EDGs
- Govern the loading of the appropriate safety equipment after a successful GTG start
- Be diverse from the existing EDG start logic

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In order to represent this SAMA, database changes were made to mimic an automatic start function with an operator backup for cases when the AFW system initially functions. Credit could be taken for operator starts in the early time frame, but crediting this action would not provide much additional benefit and doing so is complicated by the additional need to diagnose the failure of the automatic start signal.

Automation of the GTG start signal was modeled by reducing the failure probability of the operator action to start the GTG to a probability consistent with an automated signal. Based on a review of the major contributors to the EDG start logic, a failure probability of 5.0E-04 was assumed. The model also includes an event that modifies the overall probability of a manual GTG start failure for cases when AFW A initially functions. This event always appears with the term for the early start failure so that the early/late "event pair" provides the late start failure probability. Retaining the late term's original failure probability is considered to represent a manual GTG start when the automatic function fails; this is only credited when additional time is available for action due to the initial operation of the AFW system. In addition, a fire model specific event for manual GTG generator start was reduced to 5.00E-04 to capture the contribution in the fire model.

The following table summarizes the changes that were made:

SAMA 8 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
AGT-FAILSTRT-2HR: R Operators Fail to Direct WRF Operator To Start GTGs	Failure probability changed from 1.6E-01 to 5.0E-04.
HE-GTGSTRT---2HR: Adjustment Factor - Additional 1 Hour to Start GTGs Given AFA Initially Runs	Failure probability of 2.5E-02 retained.
AGT-FAILSTRT-FHR: XE CR Operators Fail to Direct WRF Operators to Start GTGs - Post Fire	FIRE MODEL CHANGE ONLY - Failure probability changed from 4.80E-01 to 5.00E-04.

D.6.3.1 AVERTED COST-RISK

The model changes identified above yielded a reduction in the CDF, Dose-risk, and OECR. The results were used to calculate the averted cost-risk for this SAMA using the process described in Section D.6. The following tables summarize the PRA results given implementation of the SAMA and the corresponding averted cost-risk calculations:

SAMA 8 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF (per yr)
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	4.68E-06	10.60	$10,442	2.52E-06

SAMA 17 Total Cost-Risk

Internal Events Cost-Risk	Non-Fire External Events Cost-Risk	Fire Cost-Risk	Multiplier for Three Units	Total Cost-Risk (Site, SAMA Implemented)
$763,908	$354,453	$370,857	3	$4,467,654

The averted cost-risk for the SAMA is the difference between the total base case cost-risk (MACR) and the total cost-risk with the SAMA implemented (provided on a site-basis):

SAMA 17 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,467,654	$200,346

D.6.8.2 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $410,473 (APS 2008a). The estimate is for a single unit, but it is assumed that the additional cost of implementing the procedure across the other two units is minimal. The estimate does not address any training or changes to training materials for the operators, but the cost provided is considered to be representative of the SAMA and $410,473 is used as the cost of implementation.

The SAMAs 6, 17, and 23 are the only SAMAs related to plant procedure improvements. The implementation cost estimates for these three SAMAs were provided with a contingency in the range of 25% to 75% to accommodate uncertainties. However, all three SAMAs (6, 17, and 23) are being considered for implementation regardless of their costs.

D.6.8.3 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 17 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$200,346	$410,473	-$210,127

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

D.6.9 SAMA NUMBER 19: INSTALL HEAT SENSORS AT LIKELY IGNITION SOURCES TO ALLOW EARLY AUTOMATIC SUPPRESSION INITIATION

The heat sensors in fire compartments FZ 5A and FZ 5B, which are responsible for automatic fire suppression initiation, are currently placed too far from the potential

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ignition sources to ensure actuation in time to prevent propagation of the initiating fire. If heat sensors were installed near the potential ignition sources, it may be possible to prevent the spread of the fire into other critical areas.

It is assumed that if the portion of the PVNGS CDF and release consequences related to fire compartments FZ 5A and FZ 5B can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below:

- Determine the component of the total MACR attributable to external events
- Determine the component of the external events cost-risk attributable to fire events
- Determine the component of the fire-based cost-risk attributable to fire compartments FZ 5A and FZ 5B
- Calculate the percent reduction in fire compartment CDF that would occur for each of the fire compartments if the SAMA is implemented and reduce the cost-risk for the fire compartments by the same percent. The reduction in cost-risk is the averted cost-risk for this SAMA.

The baseline assumption for external events contributions in the PVNGS SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MACR is $778,000 for a single unit, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF can be estimated in several ways, but the process established in Section D.6.0 to calculate the fire-based contributions for the SAMAs requiring PRA model quantification is considered to be appropriate for PVNGS and is used here. The single-unit fire contribution to the MACR is, therefore, $417,008.

The cost-risk associated with each fire area can then be determined based on their relative contributions to the total fire CDF and the assumption that the CDF is proportional to cost-risk (Fire CDFs are provided in Section D.5.1.6.1):

Fire Compartment	Percent of Fire Risk	Corresponding Cost-Risk (single unit)
FZ 5A	13.0%	$54,211
FZ 5B	1.2%	$5004

The risk reduction possible for each of these areas is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the small cost-risk contributions from each of these fire compartments, it was conservatively assumed that this SAMA eliminates all risk associated with these compartments to simplify the

SAMA 23 Total Cost-Risk

Internal Events Cost-Risk	Non-Fire External Events Cost-Risk	Fire Cost-Risk	Multiplier for Three Units	Total Cost-Risk (Site, SAMA Implemented)
$753,802	$349,764	$417,008	3	$4,561,722

The averted cost-risk for the SAMA is the difference between the total base case cost-risk (MACR) and the total cost-risk with the SAMA implemented (provided on a site-basis):

SAMA 23 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,561,722	$106,278

D.6.13.2 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $415,620 (APS 2008a). The estimate is for a single unit, but it is assumed that the additional cost of implementing the procedure across the other two units is minimal. The estimate does not address any training or changes to training materials for the operators, but the cost provided is considered to be representative of the SAMA and $415,620 is used as the cost of implementation.

The SAMAs 6, 17, and 23 are the only SAMAs related to plant procedure improvements. The implementation cost estimates for these three SAMAs were provided with a contingency in the range of 25% to 75% to accommodate uncertainties. However, all three SAMAs (6, 17, and 23) are being considered for implementation regardless of their costs.

D.6.13.3 NET VALUE

The net value for this SAMA is the difference between the total averted cost-risk and the cost of implementation:

SAMA 23 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$106,278	$415,620	-$309,342

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative.

D.7 UNCERTAINTY ANALYSIS

Sensitivity cases were run for the following conditions to assess their impact on the overall SAMA evaluation:

- Use the 95th percentile PRA results in place of the mean PRA results.
- Use alternate MACCS2 input variables for selected cases.
- Use of corrected Reactor Building wake height
- Use of a 7 Percent Real Discount Rate

D.7.1 95TH PERCENTILE PRA RESULTS

The results of the SAMA analysis can be impacted by implementing conservative values from the PRA's uncertainty distribution. If the best estimate failure probability values were consistently lower than the "actual" failure probabilities, the PRA model would underestimate plant risk and yield lower than "actual" averted cost-risk values for potential SAMAs. Re-assessing the cost benefit calculations using the high end of the failure probability distributions is a means of identifying the impact of having consistently underestimated failure probabilities for plant equipment and operator actions included in the PRA model. This sensitivity uses the 95th percentile results to examine the impact of uncertainty in the PRA model.

For PVNGS, the Risk Spectrum software code was used to perform the Level 1 internal events model uncertainty analysis. The results of the CDF calculation are provided below:

PARAMETER	VALUE PER YEAR
Mean	5.088E-06
5%	1.45E-06
50%	3.80E-06
95%	1.38E-05

The PRA uncertainty calculation identifies the 95th percentile CDF as 1.38E-05 per year. This is a factor of 2.7 greater than the CDF point estimate produced by the PVNGS PRA (5.07E-06).

D.7.1.1 PHASE I IMPACT

For Phase I screening, use of the 95th percentile PRA results will increase the MACR and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase II analysis is typically small. This is due to the fact that the benefit obtained from

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