



NUREG-1961

Safety Evaluation Report

Related to the License Renewal of
Palo Verde Nuclear Generating
Station, Units 1, 2, and 3

Docket Numbers 50-528, 50-529, and 50-530

Arizona Public Service Company

Safety Evaluation Report

Related to the License Renewal of
Palo Verde Nuclear Generating
Station, Units 1, 2, and 3

Docket Numbers 50-528, 50-529, and 50-530

Arizona Public Service Company

Manuscript Completed: March 2011
Date Published: April 2011

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (PVNGS), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated December 11, 2008, and supplemented by letter dated April 14, 2009, Arizona Public Service Company (APS) (the applicant) submitted the LRA in accordance with Title 10 of the *Code of Federal Regulations*, Part 54 "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." APS requests renewal of the PVNGS operating licenses (facility operating license numbers NPF-41, NPF-51, and NPF-74) for a period of 20 years beyond the current expiration dates of midnight on June 1, 2025, for Unit 1; April 24, 2026, for Unit 2; and November 25, 2027, for Unit 3.

PVNGS is a three-unit, nuclear-powered, steam electric generating facility located in Maricopa County, AZ, approximately 26 miles west of the Phoenix metropolitan area boundary. The NRC issued the construction permits on May 25, 1976, for all three units, and it issued the operating licenses on June 1, 1985, for Unit 1; April 24, 1986, for Unit 2; and November 25, 1987, for Unit 3. PVNGS employs a pressurized water reactor (PWR) design with a dry ambient containment. Each of the units uses a System 80 PWR nuclear steam supply system provided by Combustion Engineering, Incorporated. Bechtel Power Corporation is responsible for the engineering and construction of the station and designed the balance of the plant. The licensed power output is 3,990 megawatts-thermal per unit with a net electrical output of approximately 1,346 megawatts-electric per unit.

On August 6, 2010, the staff issued an SER with Open Item Related to the License Renewal of Palo Verde Nuclear Generating Station, Units 1, 2, and 3, in which the staff identified one open item and five confirmatory items necessitating further review. This SER presents the status of the staff's review of information submitted through March 17, 2011, the cutoff date for consideration in the SER. The open and confirmatory items identified in the SER with Open Item were resolved before the staff made a final determination. SER Sections 1.5 and 1.6 summarize these open and confirmatory items. SER Section 6.0 provides the staff's final conclusion of the LRA review.

TABLE OF CONTENTS

Abstract.....	iii
Table of Contents.....	v
List of Tables.....	xii
Abbreviations	xiii
1.0 Introduction and General Discussion	1-1
1.1 Introduction.....	1-1
1.2 License Renewal Background.....	1-2
1.2.1 Safety Review.....	1-3
1.2.2 Environmental Review.....	1-4
1.3 Principal Review Matters.....	1-5
1.4 Interim Staff Guidance.....	1-6
1.5 Summary of Open Items	1-6
1.6 Summary of Confirmatory Items.....	1-10
1.7 Summary of Additional Items.....	1-12
1.8 Summary of Proposed License Conditions	1-13
2.0 Scoping and Screening Methodology	2-1
2.1 Scoping and Screening Methodology.....	2-1
2.1.1 Introduction.....	2-1
2.1.2 Summary of Technical Information in the Application.....	2-1
2.1.3 Scoping and Screening Program Review.....	2-2
2.1.3.1 Implementation Procedures and Documentation Sources for Scoping and Screening	2-3
2.1.3.2 Quality Controls Applied to License Review Application Development	2-6
2.1.3.3 Training	2-7
2.1.3.4 Conclusion of Scoping and Screening Program Review	2-8
2.1.4 Plant Systems, Structures, and Components Scoping Methodology ..	2-8
2.1.4.1 Application of the Scoping Criteria in 10 CFR 54.4(a)(1)	2-8
2.1.4.2 Application of the Scoping Criteria in 10 CFR 54.4(a)(2) ..	2-10
2.1.4.3 Application of the Scoping Criteria in 10 CFR 54.4(a)(3) ..	2-18
2.1.4.4 Plant-Level Scoping of Systems and Structures	2-22
2.1.4.5 Mechanical Scoping	2-23
2.1.4.6 Structural Scoping	2-25
2.1.4.7 Electrical Component Scoping	2-26
2.1.4.8 Scoping Methodology Conclusion	2-27
2.1.5 Screening Methodology.....	2-27
2.1.5.1 General Screening Methodology.....	2-27
2.1.5.2 Mechanical Component Screening	2-29
2.1.5.3 Structural Component Screening	2-30
2.1.5.4 Electrical Component Screening.....	2-31
2.1.5.5 Screening Methodology Conclusion.....	2-33
2.1.6 Summary of Evaluation Findings.....	2-33
2.2 Plant-Level Scoping Results	2-33
2.2.1 Introduction.....	2-33
2.2.2 Summary of Technical Information in the Application.....	2-33

Table of Contents

2.2.3	Staff Evaluation	2-33
2.2.4	Conclusion	2-35
2.3	Scoping and Screening Results: Mechanical Systems	2-35
2.3.1	Reactor Vessel, Internals, and Reactor Coolant System.....	2-35
2.3.1.1	Reactor Vessel and Internals	2-36
2.3.1.2	Reactor Coolant System	2-37
2.3.1.3	Pressurizer	2-38
2.3.1.4	Steam Generators	2-39
2.3.1.5	Reactor Core	2-40
2.3.2	Engineered Safety Features	2-41
2.3.2.1	Containment Leak Test System	2-41
2.3.2.2	Containment Purge System	2-41
2.3.2.3	Containment Hydrogen Control System	2-42
2.3.2.4	Safety Injection and Shutdown Cooling System.....	2-42
2.3.3	Auxiliary Systems	2-43
2.3.3.1	Fuel Handling and Storage System.....	2-45
2.3.3.2	Spent Fuel Pool Cooling and Cleanup System	2-45
2.3.3.3	Essential Cooling Water System	2-47
2.3.3.4	Essential Chilled Water System	2-48
2.3.3.5	Normal Chilled Water System	2-49
2.3.3.6	Nuclear Cooling Water System	2-50
2.3.3.7	Essential Spray Pond System	2-52
2.3.3.8	Nuclear Sampling System	2-53
2.3.3.9	Compressed Air System.....	2-54
2.3.3.10	Chemical Volume and Control System.....	2-55
2.3.3.11	Control Building Heating, Ventilation, and Air Conditioning System	2-57
2.3.3.12	Auxiliary Building Heating, Ventilation, and Air Conditioning System	2-58
2.3.3.13	Fuel Building Heating, Ventilation, and Air Conditioning System	2-59
2.3.3.14	Containment Building Heating, Ventilation, and Air Conditioning System	2-59
2.3.3.15	Diesel Generator Building Heating, Ventilation, and Air Conditioning System	2-60
2.3.3.16	Radwaste Building Heating, Ventilation, and Air Conditioning System	2-61
2.3.3.17	Turbine Building Heating, Ventilation, and Air Conditioning System	2-61
2.3.3.18	Miscellaneous Site Structures and Spray Pond Pump House Heating, Ventilation, and Air Conditioning System	2-62
2.3.3.19	Fire Protection System.....	2-63
2.3.3.20	Diesel Generator Fuel Oil Storage and Transfer System	2-70
2.3.3.21	Diesel Generator	2-70
2.3.3.22	Domestic Water System.....	2-72
2.3.3.23	Demineralized Water System.....	2-73
2.3.3.24	Water Reclamation Facility Fuel System.....	2-74
2.3.3.25	Service Gases (Nitrogen and Hydrogen) System	2-75
2.3.3.26	Gaseous Radwaste System	2-76
2.3.3.27	Radioactive Waste Drains System	2-76

	2.3.3.28	Station Blackout Generator System	2-78
	2.3.3.29	Cranes, Hoists, and Elevators	2-78
	2.3.3.30	Miscellaneous Auxiliary Systems In-Scope ONLY for Criterion 10 CFR 54.4(a)(2).....	2-79
2.3.4		Steam and Power Conversion Systems	2-81
	2.3.4.1	Main Steam System	2-81
	2.3.4.2	Condensate Storage and Transfer System	2-83
	2.3.4.3	Auxiliary Feedwater System.....	2-84
	2.3.4.4	Condensate System	2-85
	2.3.4.5	Feedwater System	2-85
	2.3.4.6	Main Turbine System	2-86
	2.3.4.7	Steam Generator Feedwater Pump Turbine System	2-86
	2.3.4.8	Feedwater Heater Extraction, Drains, and Vents System	2-87
2.4		Scoping and Screening Results: Structures	2-87
	2.4.1	Containment Building	2-88
	2.4.1.1	Summary of Technical Information in the Application	2-88
	2.4.1.2	Staff Evaluation	2-89
	2.4.1.3	Conclusion.....	2-89
	2.4.2	Control Building	2-90
	2.4.2.1	Summary of Technical Information in the Application	2-90
	2.4.2.2	Staff Evaluation and Conclusion	2-90
	2.4.3	Diesel Generator Building.....	2-90
	2.4.3.1	Summary of Technical Information in the Application	2-90
	2.4.3.2	Staff Evaluation and Conclusion	2-90
	2.4.4	Turbine Building.....	2-91
	2.4.4.1	Summary of Technical Information in the Application	2-91
	2.4.4.2	Staff Evaluation	2-91
	2.4.4.3	Conclusion.....	2-91
	2.4.5	Auxiliary Building	2-92
	2.4.5.1	Summary of Technical Information in the Application	2-92
	2.4.5.2	Staff Evaluation	2-92
	2.4.5.3	Conclusion.....	2-92
	2.4.6	Radwaste Building.....	2-92
	2.4.6.1	Summary of Technical Information in the Application	2-92
	2.4.6.2	Staff Evaluation and Conclusion	2-93
	2.4.7	Main Steam Support Structure	2-93
	2.4.7.1	Summary of Technical Information in the Application	2-93
	2.4.7.2	Staff Evaluation and Conclusion	2-93
	2.4.8	Station Blackout Generator Structures	2-94
	2.4.8.1	Summary of Technical Information in the Application	2-94
	2.4.8.2	Staff Evaluation and Conclusion	2-94
	2.4.9	Fuel Building.....	2-94
	2.4.9.1	Summary of Technical Information in the Application	2-94
	2.4.9.2	Staff Evaluation	2-95
	2.4.9.3	Conclusion.....	2-95
	2.4.10	Spray Pond and Associated Water Control Structures.....	2-95
	2.4.10.1	Summary of Technical Information in the Application	2-95
	2.4.10.2	Staff Evaluation and Conclusion	2-96
	2.4.11	Tank Foundations and Shells	2-96
	2.4.11.1	Summary of Technical Information in the Application	2-96
	2.4.11.2	Staff Evaluation and Conclusion	2-96

Table of Contents

2.4.12	Transformer Foundations and Electrical Structures	2-96
2.4.12.1	Summary of Technical Information in the Application	2-96
2.4.12.2	Staff Evaluation	2-97
2.4.12.3	Conclusion.....	2-97
2.4.13	Yard Structures (In-Scope).....	2-97
2.4.13.1	Summary of Technical Information in the Application	2-97
2.4.13.2	Staff Evaluation	2-98
2.4.13.3	Conclusion.....	2-98
2.4.14	Supports	2-99
2.4.14.1	Summary of Technical Information in the Application	2-99
2.4.14.2	Staff Evaluation and Conclusion	2-99
2.4.15	Fire Barriers	2-99
2.4.15.1	Summary of Technical Information in the Application	2-99
2.4.15.2	Staff Evaluation	2-100
2.4.15.3	Conclusion.....	2-101
2.5	Scoping and Screening Results: Electrical and Instrumentation and Control Systems	2-101
2.5.1	Electrical and Instrumentation and Control Systems Component Groups.....	2-102
2.5.1.1	Summary of Technical Information in the Application	2-102
2.5.1.2	Staff Evaluation	2-103
2.5.1.3	Conclusion.....	2-104
2.6	Conclusion for Scoping and Screening	2-104
3.0	Aging Management Review Results	3-1
3.0	Applicant's Use of the Generic Aging Lessons Learned Report.....	3-1
3.0.1	Format of the License Renewal Application	3-2
3.0.1.1	Overview of Table 1s.....	3-2
3.0.1.2	Overview of Table 2s.....	3-2
3.0.2	Staff's Review Process.....	3-3
3.0.2.1	Review of Aging Management Programs.....	3-4
3.0.2.2	Review of Aging Management Review Results.....	3-5
3.0.2.3	Updated Final Safety Analysis Report Supplement	3-6
3.0.2.4	Documents Reviewed	3-6
3.0.3	Aging Management Programs.....	3-6
3.0.3.1	Aging Management Programs Consistent with the Generic Aging Lessons Learned Report	3-9
3.0.3.2	Aging Management Programs Consistent with the Generic Aging Lessons Learned Report, with Exceptions or Enhancements.....	3-44
3.0.3.3	Aging Management Programs Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-128
3.0.4	Quality Assurance Program Attributes Integral to Aging Management Programs	3-134
3.0.4.1	Summary of Technical Information in the Application	3-134
3.0.4.2	Staff Evaluation	3-134
3.0.4.3	Conclusion.....	3-135
3.1	Aging Management of Reactor Vessel, Internals and Reactor Coolant System	3-136
3.1.1	Summary of Technical Information in the Application.....	3-136
3.1.2	Staff Evaluation	3-136

	3.1.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-151
	3.1.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-158
	3.1.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-179
	3.1.3	Conclusion	3-181
3.2		Aging Management of Engineered Safety Features Systems	3-181
	3.2.1	Summary of Technical Information in the Application	3-181
	3.2.2	Staff Evaluation	3-181
	3.2.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-189
	3.2.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-196
	3.2.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-203
	3.2.3	Conclusion	3-206
3.3		Aging Management of Auxiliary Systems	3-206
	3.3.1	Summary of Technical Information in the Application	3-207
	3.3.2	Staff Evaluation	3-207
	3.3.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-221
	3.3.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-230
	3.3.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-250
	3.3.3	Conclusion	3-269
3.4		Aging Management of Steam and Power Conversion Systems	3-269
	3.4.1	Summary of Technical Information in the Application	3-269
	3.4.2	Staff Evaluation	3-270
	3.4.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-275
	3.4.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-279
	3.4.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-288
	3.4.3	Conclusion	3-291
3.5		Aging Management of Structures and Component Supports	3-291
	3.5.1	Summary of Technical Information in the Application	3-291
	3.5.2	Staff Evaluation	3-292
	3.5.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-303

Table of Contents

3.5.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-306
3.5.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-321
3.5.3	Conclusion	3-327
3.6	Aging Management of Electrical and Instrumentation and Controls.....	3-328
3.6.1	Summary of Technical Information in the Application.....	3-328
3.6.2	Staff Evaluation	3-328
3.6.2.1	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report	3-331
3.6.2.2	Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended	3-332
3.6.2.3	Aging Management Review Results Not Consistent with or Not Addressed in the Generic Aging Lessons Learned Report	3-338
3.6.3	Conclusion	3-338
3.7	Conclusion for Aging Management Review Results.....	3-338
4.0	Time Limited Aging Analyses.....	4-1
4.1	Time Limited Aging Analyses	4-1
4.1.1	Identification of Time Limited Aging Analyses	4-1
4.1.2	Summary of Technical Information in the Application.....	4-1
4.1.3	Staff Evaluation	4-1
4.1.4	Conclusion	4-12
4.2	Reactor Vessel Neutron Embrittlement	4-12
4.2.1	Neutron Fluence, Upper Shelf Energy and Adjusted Reference Temperature	4-13
4.2.2	Pressurized Thermal Shock	4-16
4.2.3	Pressure Temperature Limits	4-17
4.2.4	Low Temperature Overpressure Protection.....	4-19
4.3	Metal Fatigue Analysis	4-19
4.3.1	Enhanced Fatigue Aging Management Program	4-21
4.3.2	American Society of Mechanical Engineers III Fatigue Analysis of Class 1 Vessels, Piping, and Components.....	4-42
4.3.3	Fatigue and Cycle Based Time Limited Aging Analyses of American Society of Mechanical Engineers III, Subsection NG, Reactor Pressure Vessel Internals	4-75
4.3.4	Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components (Generic Safety Issue 190).....	4-76
4.3.5	Assumed Thermal Cycle Count for Allowable Secondary Stress Range Reduction Factor in American National Standards Institute B31.1 and American Society of Mechanical Engineers III Class 2 and 3 Piping	4-82
4.4	Environmental Qualification of Electrical Equipment.....	4-85
4.4.1	Summary of Technical Information in the Application.....	4-85
4.4.2	Staff Evaluation	4-86
4.4.3	Updated Final Safety Analysis Report Supplement.....	4-86
4.4.4	Conclusion	4-87
4.5	Concrete Containment Tendon Prestress Analyses.....	4-87
4.5.1	Summary of Technical Information in the Application.....	4-87

4.5.2	Staff Evaluation	4-88
4.5.3	Updated Final Safety Analysis Report Supplement.....	4-89
4.5.4	Conclusion.....	4-89
4.6	Containment Liner Plate, Equipment Hatch and Personnel Air Locks, Penetrations, and Polar Crane Brackets	4-90
4.6.1	Absence of a Time Limited Aging Analysis for Containment Liner Plate, Polar Crane Brackets, Equipment Hatch and Personnel Air Locks, and Containment Penetrations (Except Main Steam, Main Feedwater, and Recirculation Sump Suction Penetrations)	4-90
4.6.2	Design Cycles for the Main Steam and Main Feedwater Penetrations	4-92
4.6.3	Design Cycles for the Recirculation Sump Suction Line Penetrations	4-93
4.7	Other Plant Specific Time Limited Aging Analyses	4-94
4.7.1	Load Cycle Limits of Cranes, Lifts, and Fuel Handling Equipment Designed to Crane Manufacturers Association of America Standard 70	4-94
4.7.2	Absence of Time Limited Aging Analyses for Metal Corrosion Allowances and Corrosion Effects	4-97
4.7.3	Inservice Flaw Growth Analyses that Demonstrate Structural Stability for 40 Years	4-97
4.7.4	Fatigue Crack Growth and Fracture Mechanics Stability Analyses of Half Nozzle Repairs to Alloy 600 Material in Reactor Coolant Hot Legs and Supporting Corrosion Analyses	4-98
4.7.5	Corrosion Analyses of Pressurizer Ferritic Materials Exposed to Reactor Coolant by Half Nozzle Repairs of Pressurizer Heater Sleeve Alloy 600 Nozzles	4-103
4.7.6	Absence of a Time Limited Aging Analysis for Reactor Vessel Underclad Cracking Analyses	4-104
4.7.7	Absence of a Time Limited Aging Analysis for a Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis.....	4-104
4.7.8	Building Absolute or Differential Heave or Settlement, Including Possible Effects of Changes in Perched Groundwater Lens	4-104
4.8	Absence of Time Limited Aging Analyses Supporting Title 10, Part 50.12, Exemptions, of the Code of Federal Regulations	4-108
4.9	Conclusion for Time Limited Aging Analyses	4-108
5.0	Review by the Advisory Committee on Reactor Safeguards	5-1
6.0	Conclusion	6-1
Appendix A: Palo Verde Nuclear Generating Station Units 1, 2, and 3 License Renewal Commitments		A-1
Appendix B: Chronology		B-1
Appendix C: Principal Contributors		C-1
Appendix D: References		D-1

Aging Management Review Results

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. Based on its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent.

3.1.2.1.2 Cracking Due to Primary Water Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-81 addresses cracking due to PWSCC for nickel-alloy or nickel-alloy clad SG divider plates exposed to reactor coolant. The LRA states that the SG primary channel dividers are made of nickel alloy. The applicant credited its Water Chemistry Program to manage the cracking due to PWSCC, consistent with the GALL Report.

The staff noted that, from international operating experience in SGs, extensive cracking due to PWSCC has been identified in SG divider plates fabricated from Alloy 600, even with proper primary water chemistry. The staff noted that cracks have been detected very close to the tubesheet and with depths of almost a quarter of the divider plate thickness. Therefore, the staff noted that the Primary Water Chemistry Program alone may not be effective in managing the aging effect of cracking due to PWSCC in SG divider plate assembly components fabricated from Alloy 600 and its associated weld metals.

The staff noted that these SG divider plate cracks could impact adjacent items such as the tubesheet and the channel head if they propagate to the boundary with these items. The staff further noted that for the tubesheet, PWSCC cracks in the divider plate assembly components fabricated from Alloy 600 and its associated weld metals could propagate to the tubesheet cladding with possible consequences to the integrity of the tube-to-tubesheet welds. Furthermore, for the channel head, the PWSCC cracks in the divider plate could propagate to the SG triple point and potentially affect the pressure boundary of the SG channel head.

UFSAR, Section 1.2.3.3, states that a vertical divider plate separates the inlet and outlet plenums in the lower head of the SGs, but the staff did not find information about the materials of the divider plate assembly nor its junction to the lower head and to the tubesheet in the UFSAR or the LRA.

The staff held conference calls on October 22, November 3 and 19, 2010, with the applicant to discuss and clarify the staff's concerns. The staff asked the applicant to clarify how the SG divider plate is assembled to the lower head and to the tubesheet and to identify the materials of the divider plate and associated welds. During the discussion, the staff also asked the applicant to provide information on how it will manage the possible effects of PWSCC on these welds if the compositions of the SG divider plate divider bar welds (all areas) are susceptible to PWSCC, thereby potentially compromising the RCS pressure boundary. The staff also requested information concerning the inspection method since it should be capable of detecting PWSCC. The applicant agreed to provide information on its management of this aging effect in these components.

By letter dated November 23, 2010, the applicant described how the SG primary side divider plates are attached to the channel head, stay cylinder, and tubesheet via a tongue-in-groove connection. The applicant stated that all components are manufactured from Alloy 690 material, and the SG specifications show the divider plate bars welded to the channel head, stay cylinder, and tubesheet cladding using Alloy 52, 82, 152, and 182 filler materials, but not all detailed information of SG specifications, especially about filler materials, was included in the UFSAR. The applicant further stated that there is no routine inspection requirement for the divider bar welds because (a) these welds do not provide a reactor coolant system pressure boundary; (b) these welds do not provide structural support to the SGs; (c) the divider plate "floats" in the tongue and groove, and the force on the divider plate transferred to the divider plate bar welds is the relatively low differential pressure between the SG inlet and outlet (compared with RCS

pressure); and (d) a crack in the divider bar weld due to PWSCC would need to propagate from the divider bar weld through the channel head cladding to get to the base metal.

However, in response to the staff's concern regarding potential failure of the RCS pressure boundary due to possible PWSCC of SG divider plate bar welds, the applicant committed (Commitment No. 61) to one of the following:

1. Perform an inspection of each PVNGS SG to assess the condition of the divider plate bar welds. The examination technique(s) will be capable of detecting PWSCC in the divider plate bar welds.
2. Perform an analytical evaluation of the SG divider plate bar welds in order to establish a technical basis which concludes that the SG RCS pressure boundary is adequately maintained with the presence of SG divider plate bar weld cracking.
3. If results of industry and NRC studies and operating experience document that potential failure of the SG RCS pressure boundary due to PWSCC cracking of SG divider plate bar welds is not a credible concern, the commitment will be revised to reflect that conclusion.

Moreover, the applicant stated that if the first option were selected, it would be completed for each SG in each unit during a SG tube eddy-current inspection outage. This inspection would be conducted between 20 and 25 calendar years of SG operation, according to the dates of SGs replacement for Units 1, 2 and 3 (fall of 2005, 2003, and 2007 respectively). The applicant clarified that for Units 1 and 3, this would approximately correspond to the first 5 years after entering the period of extended operation (i.e., for Unit 1, between September 1, 2025, and December 1, 2030; and for Unit 3, between September 1, 2027, and December 1, 2032). For Unit 2, this would correspond to a time period between 3 years prior to and 2 years after entering the period of extended operation (i.e., September 1, 2023, and December 1, 2028). The applicant further stated that if the second or third option were selected, it would be completed prior to September 1, 2023, when the first replaced SGs (Unit 2) would reach 20 years of operation.

By letter dated February 25, 2011, the applicant corrected information in the November 23, 2010, letter by stating that it determined, from reviewing each unit's SG as-built documentation, that the divider plate bars in Unit 2 were made of Alloy 600 as a result of a change report issued during fabrication. The applicant further stated that it had reviewed the as-built documentation to determine if there were other differences in SG primary-side materials between the units, and no other differences were found. However, the applicant also identified that the divider bar set screws and the divider patch plate cap screws in the SGs are made of materials other than Alloy 690.

In order to address potential PWSCC of the Unit 2 Alloy 600 SG divider plate bars, in its letter dated February 25, 2011, the applicant expanded Commitment No. 61 to include the Unit 2 SG divider plate bars within the scope of the committed analyses. The applicant also committed to include the exposed portions of the Unit 2 SG divider plate bars within the scope of the committed inspections. The applicant stated that inspection or analysis of the screws is not being included in this commitment because any possible PWSCC that may occur in the screws would not be expected to propagate to the reactor coolant pressure boundary material.

By letter dated March 17, 2011, the applicant modified Commitment No. 61 from inspecting the "exposed portions" of the divider plate bars to inspecting "accessible surfaces" of the divider plate bars in order to clarify the inspection of the divider plate bars in the Unit 2 SGs. This change was intended to use standard industry terminology to refer to surfaces that can be accessed for examination. The applicant also clarified its letter dated February 25, 2011, stating

Aging Management Review Results

that the installed divider patch plate cap screws in all SGs were made of Alloy 690. The applicant also clarified that the divider bar set screws were made of stainless steel and, since they are under a compressive stress, are not susceptible to PWSCC. Further, the set screws are welded in place.

In the final version of Commitment No. 61, the applicant commits to perform one of the following options:

1. Perform an inspection of each Palo Verde Unit 1, 2, and 3 steam generator to assess the condition of the divider plate bar welds in all units, and the accessible surfaces of the divider plate bars in Unit 2. The examination technique(s) will be capable of detecting PWSCC in the divider plate bar welds in all units, and in the accessible surfaces of the divider plate bars in Unit 2.
2. Perform an analytical evaluation of the steam generator divider plate bar welds in all units, and the divider plate bars in Unit 2, in order to establish a technical basis which concludes that the SG reactor coolant system pressure boundary is adequately maintained with the presence of steam generator divider plate bar weld cracking.
3. If results of industry and NRC studies and operating experience document that potential failure of the SG reactor coolant system pressure boundary due to PWSCC cracking of SG divider plate bar welds and the divider plate bars in Unit 2 is not a credible concern, this commitment will be revised to reflect that conclusion.

Based on its review, the staff finds the applicant's options and associated revised Commitment No. 61 acceptable because the applicant identified which parts of the divider plates were made of Alloy 600 or associated weld materials. Further, the applicant will assess the condition of the divider plate bar welds in all units and the accessible surfaces of the divider plate bars in Unit 2 using an appropriate option. If the applicant inspects each SG divider plate bar weld, it will do so with appropriate examination technique and in a time period consistent with the detection of potential PWSCC. The staff finds that the timing of this inspection for each unit is acceptable because the proposed implementation schedule allows operation of the SGs for between 20 and 25 years, and it is unlikely that significant detrimental PWSCC cracking will have initiated before this time. The staff also noted that the applicant could alternatively perform an evaluation of the welds or use the results of NRC and industry operating experience to rule out this aging effect.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 Aging Management Review Results Consistent with the Generic Aging Lessons Learned Report for Which Further Evaluation Is Recommended

In LRA Section 3.1.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the RV, internals, and RCS components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading

LRA Section 3.1.2.2.15 addresses changes in dimension due to void swelling for stainless steel and nickel-alloy reactor internal components exposed to reactor coolant as an aging effect that the applicant will manage, consistent with the SRP-LR, by the commitment of PVNGS RCS Supplement.

SRP-LR Section 3.1.2.2.15 states that changes in dimensions due to void swelling may occur in stainless steel and nickel-alloy PWR internal components exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement to participate in the industry programs for investigating and managing aging effects on reactor internals and to evaluate and implement the results of the industry programs as applicable to the reactor internals. In addition, upon completion of these programs, but not less than 24 months before entering the period of extended operation, the applicant must submit an inspection plan for reactor internals for the staff's review and approval.

As described in LRA Section 3.1.2.2.15, the applicant made a commitment to incorporate all three GALL Report recommendations, stated above, to manage this aging mechanism. PVNGS AMP B2.1.21 contains this commitment (Commitment No. 23). UFSAR Supplement A1.21 also identifies Commitment No. 23. Therefore, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.15 criteria. The staff also confirmed that LRA Table 3.1.2-1 identified the following GALL Report Table IV.B3 AMR items under this aging mechanism: IV.B3-4, IV.B3-13, IV.B3-14, IV.B3-19, and IV.B3-27. However, this LRA table does not cover all RPV internals in GALL Report Table IV.B3 under this aging mechanism. Therefore, by letter dated January 28, 2010, the staff issued RAI 3.1.2.2.15-1 and asked the applicant to clarify the disposition of the core support plate, fuel alignment pins, and core support column bolts of the lower internal assembly (IV.B3-19) and the fuel alignment plate, the fuel alignment plate guide lugs, and guide lug inserts of the upper internals assembly (IV.B3-27). Additionally, the staff asked the applicant to discuss the relationship between RV internals in-core instrumentation support structures (identified in LRA Table 3.1.2-1) and the core support plate, fuel alignment pins, and core support column bolts of the lower internal assembly (listed in the GALL Report Table IV.B3).

The staff reviewed the applicant's response to RAI 3.1.2.2.15-1, dated March 1, 2010. For GALL Report-specified items IV.B3-19 and IV.B3-27 components, some do not exist and some take different names in the PVNGS units. The only PVNGS unit component that seems inconsistent with the GALL Report is the fuel alignment plate guide lugs and guide lug inserts. Instead of classifying it under AMR item IV.B3-27 as in the GALL Report, this component is placed under GALL Report, AMR item IV.B3-13 as part of the PVNGS unit core shroud assembly. This is acceptable because the aging mechanism and recommended AMP for both GALL Report AMR items are identical. The applicant further clarified that the RV internals in-core instrumentation support structures are evaluated as part of the lower support structure assembly. Hence, RAI 3.1.2.2.15-1 is resolved. Based on the applicant's response to this RAI and the staff's evaluation presented earlier, the staff concludes that the applicant's program meets the SRP-LR Section 3.1.2.2.15 criteria. The applicant has demonstrated that it will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.16 against the following criteria in SRP-LR Section 3.1.2.2.16:

- LRA Section 3.1.2.2.16, item 1 refers to LRA Table 3.1.1, item 3.1.1.34 and addresses stainless steel and nickel-alloy reactor control rod drive head penetration pressure

housings exposed to reactor coolant (internal), which are being managed for cracking due to SCC and PWSCC. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the nickel alloy portion of the RV control element drive mechanism housing (lower) credits the Water Chemistry Program and the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program, which will be augmented by the Nickel-Alloy AMP. The applicant further stated that it will comply with applicable NRC orders and the UFSAR Commitment. The applicant also stated for the stainless steel RV control element drive mechanism housing (upper and lower) it credits the Water Chemistry Program and the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program. LRA Section 3.1.2.2.16.1 also refers to LRA Table 3.1.1, item 3.1.1-35 and addresses steel with stainless steel or nickel-alloy cladding primary side components. These components include SG upper and lower heads, tubesheets, and tube-to-tube sheet welds exposed to reactor coolant (internal) subject to cracking due to SCC and PWSCC. The applicant stated that LRA Table 3.1.1, item 3.1.1-35 is not applicable because the SGs are the recirculating type.

The staff reviewed LRA Section 3.1.2.2.16.1 against the criteria in SRP-LR Section 3.1.2.2.16, item 1, which states that cracking due to PWSCC could occur on the nickel-alloy control rod drive head penetration pressure housings. The GALL Report recommends ASME Section XI ISI and control of water chemistry to manage this aging and recommends no further AMR for PWSCC of nickel alloy if the applicant complies with applicable NRC orders and provides a commitment in the FSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines.

SER Sections 3.0.3.2.1, 3.0.3.1.1 and 3.0.3.3.1 document the staff's evaluations of the applicant's Water Chemistry Program, ASME Section XI ISI, Subsections IWB, IWC, and IWD Program and Nickel-Alloy AMP, respectively. The staff noted that the Water Chemistry Program controls the chemical environment to ensure that the aging effects due to contaminants are limited by managing the primary and secondary water. The staff noted that this is accomplished by limiting the concentration of chemical species known to cause corrosion and adding chemical species known to inhibit degradation by their influence on pH and dissolved oxygen levels. The staff also noted that this program is effective in creating an environment that is not conducive for cracking to occur. The staff noted that the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program includes requirements for the scheduling of examinations and tests for Class 1, 2, and 3 components. The staff further noted that this program requires periodic visual, surface, volumetric examinations, and leakage tests of Class 1, 2, and 3 pressure-retaining components. This program also provides measures for monitoring to detect aging effects before the loss of intended function and provides measures for the repair and replacement of components with aging effects. The staff noted that the Nickel-Alloy AMP will augment the ASME Section XI ISI, Subsections IWB, IWC, and IWD Program for nickel-alloy components. Furthermore, the Nickel-Alloy AMP consists of inspections, mitigation techniques, repair or replace activities, and monitoring of operating experience to manage the aging.

The SRP-LR states that no further AMR for PWSCC of nickel alloy is necessary if the applicant complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines. In addition, the applicant must credit its Water Chemistry Program and ASME Section XI ISI, Subsections IWB, IWC, and IWD Program for aging management. The staff noted that the applicant's commitment (Commitment No. 23) in LRA Appendix A, Section A1.21 states that it will implement applicable NRC orders, bulletins, and GLs associated with nickel alloys as well as staff-accepted industry guidelines. In addition, the applicant will participate in the industry initiatives, such as owners group programs

and the EPRI Materials Reliability Program, to manage the aging effects associated with nickel alloys. Upon completion of these programs, but not less than 24 months before entering the period of extended operation, the applicant will submit an inspection plan for RCS nickel-alloy pressure boundary components to the NRC for review and approval. The staff noted that the applicant's commitment includes the aspects from the SRP-LR recommendations and finds that it is consistent with the commitment described in SRP-LR 3.1.2.2.16, item 1. The staff also notes that all of the nickel-alloy AMR results lines that refer to LRA Table 3.1.1, item 3.1.1.34 are aligned with the applicant's commitment, as described in LRA Appendix A, Section A1.21. The staff finds the applicant's proposal acceptable because the applicant credits its Water Chemistry Program and ASME Section XI ISI, Subsections IWB, IWC, and IWD Program, augmented by its Nickel-Alloy AMP for nickel-alloy components. The applicant has provided the appropriate commitment in the UFSAR Supplement, and the AMR results lines refer to the commitment, consistent with the recommendations in the GALL Report and SRP-LR.

The staff reviewed GALL Report, AMR item IV.D2-4, which is associated with LRA Table 3.1.1, item 3.1.1.35. The staff noted that LRA Table 3.1.1, item 3.1.1.35 and GALL Report, AMR item IV.D2-4 recommendations for aging management are specific to the primary side components—upper and lower heads and tube sheets and tube-to-tube sheet welds for once-through SGs. The LRA also states that this item is not applicable because the SGs are recirculating-type. UFSAR Table 5.1-2 states that the SG tubes are fabricated from Alloy 690TT and that the tubesheet in contact with the reactor coolant is clad with weld deposited NiCrFe alloy, which is described as Alloy 600 cladding in LRA Section B2.1.34.

The staff noted that the components associated with SRP-LR Table 3.1.1, item 3.1.1-35, are applicable to the once-through type SGs that are found in Babcock & Wilcox PWRs as discussed in the following paragraphs.

SRP-LR Section 3.1.2.2.16.1 identifies that cracking due to PWSCC could occur on the primary coolant side of PWR steel SG tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Code, Section XI, ISI, Subsections IWB, IWC, and IWD, and Water Chemistry Programs to manage this aging effect. The SRP-LR also recommends no further AMR for PWSCC of nickel alloy if the applicant complies with applicable NRC Orders and provides a commitment in its UFSAR supplement to implement applicable NRC bulletins, generic letters, and staff-accepted industry guidelines. The GALL Report, revision 1 addresses this aging effect in item IV.D2-4, which is only applicable to once-through SGs and not applicable to recirculating SGs.

The staff noted that ASME Code, Section XI does not require inspection of the tube-to-tubesheet welds. In addition, no specific NRC orders or bulletins address inspection requirements for these welds. The staff is concerned that the region of the autogenous tube-to-tubesheet welds may have insufficient chromium content to prevent initiation of PWSCC if the tubesheet cladding or associated weld materials are Alloy 600. This may be the case even when the SG tubes are made from Alloy 690TT, which has been shown to have sufficient chromium content to prevent this aging effect. Consequently, a PWSCC crack initiated in the cladding region, close to a tube, may propagate into or through the weld, causing a failure of the weld and of the RCP boundary, even for recirculating SGs. For some plants, the RCP boundary in this area has been redefined by a license amendment such that the autogenous tube-to-tubesheet weld is no longer included in the RCP boundary. Since the staff has not approved such a redefinition of the RCP boundary for the PVNGS SGs, the staff

considers that the effectiveness of the Primary Water Chemistry Program should be verified to ensure PWSCC is not occurring and the RCP boundary is not breached.

The staff held conference calls with the applicant on October 22, November 3, and November 19, 2010, to discuss and clarify the staff's concerns. The staff asked the applicant how it managed PWSCC in SG tube-to-tubesheet welds if the tubesheet cladding is Alloy 600. The applicant agreed to provide information on its management of this aging mechanism.

By letter dated November 23, 2010, the applicant explained that the SGs tubes are manufactured from Alloy 690TT with a chromium content of 30 percent. The tubesheet cladding is composed of Alloy 82 with a chromium content of 18–20 percent and that the tube-to-tubesheet weld is an autogenous weld, which is created by melting the corner of the tubesheet clad to the tube end without adding filler metal. The applicant described statements from an industry review (MRP-115) that identified a threshold for PWSCC resistance for Alloys 600/82/182 with a chromium content of 22–30 percent. In comparison, the applicant stated it expected the chromium content of the tube-to-tubesheet welds to be 20–30 percent. The staff does not find this information to be a sufficient basis for precluding its concern about potential failure of the SG primary-to-secondary pressure boundary due to PWSCC of tube-to-tubesheet welds.

The applicant stated that the visual inspection performed every refueling outage on Alloy 82 repairs of several Alloy 600 high temperature components (half nozzle replacements using Alloy 690 nozzles welded with Alloy 82) have detected no leakage. However, the staff noted that the applicant did not provide information that would confirm the absence of cracking in these repaired areas. Further, the staff noted that differences in geometric configuration and fabrication do not allow for comparison of these repairs with the SG tube-to-tubesheet welds.

In response to the staff's concern, the applicant committed (Commitment No. 62) to the following:

In response to the NRC staff concern regarding potential failure of the steam generator primary-to-secondary pressure boundary due to PWSCC cracking of tube-to-tubesheet welds, APS commits to perform one of the following two resolution options:

1. Perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified:
 - a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate.
 - b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.
2. Perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to:
 - a. Establish a technical basis which concludes that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintained with the presence of tube-to-tubesheet weld cracking.
 - b. Establish a technical basis which concludes that the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function.

Moreover, the applicant stated that if the first option is selected, it would be completed for each SG in each unit during an eddy-current inspection outage. This outage would be chosen such that it is between 20 and 25 calendar years of SG operation, according to the dates of SG replacement for Units 1, 2 and 3 (fall of 2005, 2003, and 2007, respectively). For Units 1 and 3, the applicant stated the inspection would approximately correspond to the first 5 years after entering the period of extended operation (i.e., September 1, 2025, to December 1, 2030, and September 1, 2027, to December 1, 2032, respectively). For Unit 2, this would approximately correspond to 3 years prior to and 2 years after entering the period of extended operation (i.e., September 1, 2023, to December 1, 2028). The applicant further stated that if the second option is selected, it would be completed prior to September 1, 2023, the date when the first replaced SGs (Unit 2) will reach 20 years of operation.

Based on its review, the staff finds the applicant's commitment (Commitment No. 62) acceptable because it will manage the aging effect of cracking due to PWSCC in the SG tube-to-tubesheet welds either by demonstrating that those welds do not have a structural integrity or pressure boundary function or by implementing a one-time inspection. This one-time inspection will be capable of detecting PWSCC cracking on a representative number of tube-to-tubesheet welds for each SG in a time period consistent with the detection of potential PWSCC. The staff finds the timing of these inspections to be acceptable because the proposed implementation schedule allows operation of the SGs for between 20 and 25 years, and it is unlikely that significant detrimental PWSCC cracking will have initiated before this time. The staff also noted that, if the aging effect is revealed, this one-time inspection is accompanied by corrective actions, including an evaluation of the degradation and the implementation of routine inspections of the tube-to-tubesheet welds for the remaining life of the SGs.

- LRA Section 3.1.2.2.16.2 addresses nickel alloy and stainless steel pressurizer spray heads exposed to reactor coolant. The GALL Report recommends use of GALL AMP XI.M2 "Water Chemistry," and GALL AMP XI.M32 "One-Time Inspection." In addition, for nickel-alloy welded spray heads, the applicant must comply with applicable NRC orders and provide a commitment in the UFSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines to manage cracking due to SCC and PWSCC for this component group. The applicant stated that this item is not applicable because it has determined that the pressurizer spray heads are not included in scope of license renewal; therefore, it did not use the applicable GALL Report line.

The staff reviewed LRA Section 3.1.2.2.16.2 against the criteria in SRP-LR Section 3.1.2.2.16, item 2, which states that cracking due to SCC could occur on stainless steel pressurizer spray heads, and cracking due to PWSCC could occur on nickel-alloy pressurizer spray heads when exposed to reactor coolant. The SRP-LR also states the existing program relies on control of water chemistry to mitigate this aging effect. The GALL Report recommends one-time inspection to confirm that cracking is not occurring. For nickel-alloy welded spray heads, the GALL Report recommends no further AMR if the applicant complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines.

The staff reviewed the LRA scoping and screening results for the pressurizer, which indicate that the spray heads are not included in the scope of the license renewal. In addition, the staff reviewed the LRA aging management evaluation tables and did not identify the inclusion of the pressurizer spray heads. In its review, the staff further noted that LRA Section 3.1.2.2.16.2 indicates that the pressurizer spray heads are not included in the scope of the license renewal. However, the LRA section does not provide a

technical basis for why the pressurizer spray heads are not in the scope of the license renewal process and why this component is not managed by an AMP.

By letter dated April 1, 2010, the applicant stated that LRA Sections 3.1.2.1.3 and 3.1.2.2.16.2 and Tables 2.3.1-3, 3.1.1, and 3.1.2-3 have been revised to add the pressurizer spray heads to the scope of license renewal. The applicant stated that the Water Chemistry Program and One-Time Inspection Program are credited to manage the aging effects of cracking due to SCC and PWSCC of the nickel-alloy components. The applicant also stated that since the pressurizer spray head is not a pressure-retaining component and is not part of the RCPB, it is not included in the Alloy 600 Management Program Plan. The applicant further stated that it complies with applicable NRC orders and provides a commitment in the UFSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines.

SER Sections 3.0.3.2.1 and 3.0.3.1.6 document the staff's evaluations of the applicant's Water Chemistry Program and One-Time Inspection Program, respectively. Based on its review, the staff finds the LRA revision and the applicant's proposal to manage the aging effect of the pressurizer spray head acceptable because (1) the Water Chemistry Program monitors the water chemistry control parameters against the established parameter limits and, if a parameter exceeds the limit, the program performs adequate actions such that the water chemistry control continues to mitigate the aging effect, (2) the One-Time Inspection Program includes a one-time inspection of selected components to verify the effectiveness of the Water Chemistry Program, (3) the use of the Water Chemistry Program and One-Time Inspection Program to manage the aging effect is consistent with the GALL Report and SRP-LR, (4) the applicant also committed to comply with applicable NRC orders and provided a commitment in the UFSAR supplement to implement applicable bulletins, GLs, and staff-accepted industry guidelines in accordance with the SRP-LR and GALL Report. Based on its review, the staff's concern, described above, is resolved.

Based on the programs identified, the staff concludes that the applicant's programs and Commitment No. 23 meet SRP-LR Section 3.1.2.2.16 criteria. For those items that apply to LRA Section 3.1.2.2.16, the staff determines that the LRA is consistent with the GALL Report. In addition, the applicant has demonstrated that it will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.2.2.17 Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.17 against criteria in SRP-LR 3.1.2.2.17 which states cracking due to SCC, PWSCC, and IASCC could occur in PWR stainless steel and nickel-alloy RV internals components. The SRP-LR also states the existing program relies on control of water chemistry to mitigate these effects. It further states that no further AMR is necessary if the applicant provides a commitment in the UFSAR Supplement to participate in the industry programs for investigating and managing aging effects on reactor internals as well as to evaluate and implement the results of the industry programs as applicable to the reactor internals. In addition, upon completion of these programs, but not less than 24 months before entering the period of extended operation, the applicant must submit an inspection plan for reactor internals for the staff's review and approval. The staff noted that the applicant's commitment (Commitment No. 23) in LRA Appendix A, Section A1.21 is consistent with the commitment described in SRP-LR 3.1.2.2.17. The staff also notes that all of the AMR results lines that refer to Table 3.1.1, item 3.1.1-37 are aligned with the applicant's commitment as described in LRA Appendix A, Section A1.21. The staff finds the applicant's proposal acceptable because the applicant credits its Water Chemistry Program and has provided the

APPENDIX A

Palo Verde Nuclear Generating Station Units 1, 2, and 3 License Renewal Commitments

During the review of the Palo Verde Nuclear Generating Station, Units 1, 2, and 3 (PVNGS), license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff (the staff), Arizona Public Service Company (the applicant) made commitments related to aging management programs to manage aging effects for structures, systems and components. The following table lists these commitments along with the implementation schedules and sources for each commitment.

Table A-1. Palo Verde Nuclear Generating Station License Renewal Commitments

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
1	The summary descriptions of aging management programs, time-limited aging analyses, and license renewal commitments contained in LRA Appendix A, "Updated Final Safety Analysis Supplement," as required by 10 CFR 54.21(d), will be incorporated in the Updated Final Safety Analysis Report for PVNGS Units 1, 2, and 3 in the next update required by 10 CFR 50.71(e) following the issuance of the renewed operating licenses.	A0	The next 10 CFR 50.71(e) Updated Final Safety Analysis Report update, following issuance of the renewed operating licenses
2	Existing Quality Assurance Program is credited for license renewal.	A1 B1.3 Summary Descriptions of Aging Management	Ongoing
3	Existing ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program is credited for license renewal.	A1.1 B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Ongoing
4	Existing Water Chemistry Program is credited for license renewal.	A1.2 B2.1.2 Water Chemistry	Ongoing
5	Existing Reactor Head Closure Studs Program is credited for license renewal.	A1.3 B2.1.3 Reactor Head Closure Studs	Ongoing
6	Existing Boric Acid Corrosion Program is credited for license renewal.	A1.4 B2.1.4 Boric Acid Corrosion	Ongoing
7	Existing Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program is credited for license renewal.	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.	A1.6 B2.1.6 Flow-	Ongoing

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
		Accelerated Corrosion	
9	Existing Bolting Integrity Program is credited for license renewal.	A1.7	Ongoing
		B2.1.7 Bolting Integrity	
10	Existing Steam Generator Tube Integrity Program is credited for license renewal.	A1.8	Ongoing
		B2.1.8 Steam Generator Tube Integrity	
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 piping inspections using NDE techniques and related acceptance criteria.	A1.9	Prior to the period of extended operation ¹
		B2.1.9 Open-Cycle Cooling Water System	
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.	A1.10	Prior to the period of extended operation ¹ .
		B2.1.10 Closed-Cycle Cooling Water System	
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.	A1.11	Prior to the period of extended operation ¹ .
		B2.1.11 Inspection Of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	
14	Existing Fire Protection Program is credited for license renewal, AND Prior to the period of extended operation procedures will be enhanced to perform the testing of the electro-thermal links and functional testing of the halon and CO ₂ dampers every 18 months or at the frequency specified in the current licensing basis in effect upon entry into the period of extended operation.	A1.12	Prior to the period of extended operation ¹ .
		B2.1.12 Fire Protection	
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:	A1.13	Prior to the period of extended operation ¹ .
		B2.1.13 Fire Water System	
	<ul style="list-style-type: none"> 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, Sections 7.3.2.1, 7.3.2.2, 7.3.2.3, and 7.3.2.4. 		

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
16	<p>Existing Fuel Oil Chemistry Program is credited for license renewal, AND</p> <p>Prior to the period of extended operation:</p> <ul style="list-style-type: none"> Procedures will be enhanced to extend the scope of the program to include the station blackout generator (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 tank, 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, SBOG fuel oil storage tank, and SBOG skid fuel tanks. The onetime UT or PEC examination on the tank bottoms will be performed before the period of extended operation. 	<p>A1.14</p> <p>B2.1.14 Fuel Oil Chemistry</p>	Prior to the period of extended operation ¹ .
17	<p>Existing Reactor Vessel Surveillance Program is credited for license renewal, AND</p> <p>Prior to the period of extended operation:</p> <ul style="list-style-type: none"> The schedule will be revised to withdraw the next capsule at the equivalent clad-base metal exposure of approximately 54 effective full-power year (EFPY) expected for the 60-year period of operation, and to withdraw remaining standby capsules at equivalent clad-base metal exposures not exceeding the 72 EFPY expected for a possible 80-year second period of extended operation. This withdrawal schedule is in accordance with NUREG-1801, Section XI.M31, item 6, and with the ASTM E 185-82 criterion which states that capsules may be removed when the capsule neutron fluence is between one and two times the limiting fluence calculated for the vessel at the end of expected life. This schedule change must be approved by the NRC, as required by 10 CFR 50, Appendix H. If left in the reactor beyond the presently-scheduled withdrawal, the next scheduled surveillance capsule in each unit will reach a clad-base metal 54 EFPY equivalent at about 40 actual operating EFPY (40, 39, and 42 actual EFPY in Units 1, 2, and 3, respectively). Procedures will be enhanced to identify the withdrawal of the remaining standby capsules at 72 EFPY, at about 50 to 54 actual operating EFPY, near the end of the extended licensed operating period. The need to monitor vessel fluence following removal of the remaining standby capsules, and ex-vessel or in-vessel methods, will be addressed prior to removing the remaining capsules. 	<p>A1.15</p> <p>B2.1.15 Reactor Vessel Surveillance</p>	Prior to the period of extended operation ¹ .
18	<p>The One-Time Inspection Program conducts one-time inspections of plant system piping and components to verify the effectiveness of the Water Chemistry Program (A1.2), Fuel Oil Chemistry Program (A1.14), and Lubricating Oil Analysis Program (A1.23). The aging effects to be evaluated by the One-Time Inspection</p>	<p>A1.16</p> <p>B2.1.16 One-Time Inspection</p>	Within the ten year period prior to the period of extended operation ¹ .

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
19	<p>Program are loss of material, cracking, and reduction of heat transfer.</p> <p>The Selective Leaching of Materials 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.</p> <p>The Selective Leaching of Materials Program includes a one-time inspection (visual and/or mechanical methods) of a selected sample of components' internal surfaces to determine whether loss of material due to selective leaching is occurring. A sample size of 20 percent of the population, up to a maximum of 25 component inspections, will be established for each of the system material and environment combinations at the PVNGS site. If indications of selective leaching are confirmed, follow-up examinations or evaluations will be performed.</p>	<p>A1.17</p> <p>B2.1.17 Selective Leaching of Materials</p>	<p>Within the ten year period prior to the period of extended operation¹.</p>
20	<p>The Buried Piping and Tanks Inspection Program is a new program that will be implemented prior to the period of extended operation.</p> <p>Within the ten year period prior to entering the period of extended operation an opportunistic or planned inspection of buried tanks at the PVNGS site will be performed.</p> <p>The visual inspections noted below of piping in a soil environment within the scope of license renewal will be conducted within the ten-year period prior to entering the period of extended operation, and during each ten year period after entering the period of extended operation, except the initial diesel generator fuel oil piping inspection will be performed between January 1, 2012, and December 31, 2015. Each inspection will:</p> <ul style="list-style-type: none"> • select accessible locations where degradation is expected to be high; • excavate and visually inspect the circumference of the pipe • examine at least ten feet of pipe <p>a. Metallic Piping not Cathodically-Protected</p> <p>At least two excavations and visual inspections of stainless steel piping will be conducted in each unit. Stainless steel piping within the scope of license renewal exists in the following systems:</p> <ul style="list-style-type: none"> • Chemical and Volume Control (CH) • Condensate Transfer and Storage (CT) • Fire Protection (FP) <p>b. Steel Piping Cathodically-Protected</p> <p>At least two excavations and visual inspections of cathodically-protected steel piping will be conducted in each unit. In one of the units, at least one of these inspections will be performed on diesel generator fuel oil piping.</p> <p>c. Steel Piping with Potentially Degraded Cathodic</p>	<p>A1.18</p> <p>B2.1.18 Buried Piping and Tanks Inspection</p>	<p>Perform the buried piping and tanks inspections within the ten year period prior to the period of extended operation¹, except the initial diesel generator fuel oil piping inspection will be performed between 1/1/12 and 12/31/15.</p> <p>AND</p> <p>Perform the buried piping inspections during each ten year period after entering the period of extended operation.</p> <p>AND</p> <p>Implement the additional enhancements to the Buried Piping and Tanks Inspection Program prior to the period of operation¹.</p>

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	Protection		
	At least three excavations and visual inspections of fire protection steel piping with potentially degraded bonding straps will be conducted at the PVNGS site.		
	Prior to the period of extended operation, the Buried Piping and Tanks Inspection Program will include provisions to: (1) ensure electrical power is maintained to the cathodic protection system for in-scope buried piping at least 90 percent of the time (e.g., monthly verification that the power supply circuit breakers are closed or other verification that power is being provided to the system), and (2) ensure that the National Association of Corrosion Engineers cathodic protection system surveys are performed at least annually.		
21	<p>The One-Time Inspection of ASME Code Class 1 Small-Bore Piping 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.</p> <p>For ASME Code Class 1 small-bore piping, volumetric examinations on selected butt weld locations will be performed to detect cracking. Butt weld volumetric examinations will be conducted in accordance with ASME Section XI with acceptance criteria from Paragraph IWB-3000 and IWB-2430. Weld locations subject to volumetric examination will be selected based on the guidelines provided in EPRI TR-112657. Socket welds that fall within the weld examination sample will be examined following ASME Section XI Code requirements. At least 10 percent of the socket welds in ASME Code Class 1 piping that is less than four inches nominal pipe size and greater than or equal to one inch nominal pipe size will be selected per unit for ultrasonic testing examination, up to a maximum of 25 weld examinations. The sample will be selected based on risk insights and those welds with the potential for aging degradation.</p>	<p>A1.19</p> <p>B2.1.19 One-Time Inspection of ASME Code Class 1 Small-Bore Piping</p>	Within the six year period prior to the period of extended operation ¹ .
22	The External Surfaces Monitoring 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.	<p>A1.20</p> <p>B2.1.20 External Surfaces Monitoring Program</p>	Prior to the period of extended operation ¹ .
23	<p>The applicant will complete the tasks described:</p> <p>a. Reactor Coolant System Nickel Alloy Pressure Boundary Components</p> <p>Implement applicable (1) NRC Orders, Bulletins and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines, (3) participate in the industry initiatives, such as owners group programs and the EPRI Materials Reliability Program, for managing aging effects associated with nickel alloys, (4) upon completion of these programs, but not less than 24 months before entering the period of extended operation, APS will submit an inspection plan for reactor coolant system nickel alloy pressure boundary components to the NRC for review and approval, and</p>	<p>A1.21</p> <p>B2.1.21 Reactor Coolant System Supplement</p> <p>3.1.2.2.16.2 Pressurizer Spray Head Cracking</p>	Not less than 24 months prior to the period of extended operation ¹ .

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	<p>b. Reactor Vessel Internals</p> <p>(1) Participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, APS will submit an inspection plan for reactor internals to the NRC for review and approval.</p> <p>c. Pressurizer Spray Heads</p> <p>Comply with applicable NRC Orders and implement applicable (1) Bulletins and Generic Letters, and (2) staff-accepted industry guidelines.</p>		
24	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components 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.	<p>A1.22</p> <p>B2.1.22 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components</p>	Prior to the period of extended operation ¹ .
25	Existing Lubricating Oil Analysis Program is credited for license renewal.	<p>A1.23</p> <p>B2.1.23 Lubricating Oil Analysis</p>	Ongoing
26	The Electrical Cables and 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.	<p>A1.24</p> <p>B2.1.24 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements</p>	Prior to the period of extended operation ¹ .
27	<p>Existing Electrical Cables And Connections Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits Program is credited for license renewal , AND</p> <p>Prior to the period of extended operation:</p> <ul style="list-style-type: none"> Procedures will be enhanced to identify license renewal scope, require cable testing of ex-core neutron monitoring cables, require an evaluation of the calibration results for non-EQ area radiation monitors, and require acceptance criteria for cable testing be established based on the type of cable and type of test performed. 	<p>A1.25</p> <p>B2.1.25 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits</p>	Prior to the period of extended operation ¹ .
28	<p>The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program is credited for license renewal, AND</p> <p>Prior to the period of extended operation procedures will be enhanced to:</p> <ul style="list-style-type: none"> Extend the scope of the program to include low voltage (480V and above) non-EQ inaccessible power cables and associated manholes. Perform the cable inspections on at least an annual frequency and perform the cable testing on a six year 	<p>A1.26</p> <p>B2.1.26 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements</p>	Prior to the period of extended operation ¹ .

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	frequency.		
29	Existing ASME Section XI, Subsection IWE Program is credited for license renewal.	A1.27 B2.1.27 ASME Section XI, Subsection IWE	Ongoing
30	Existing ASME Section XI, Subsection IWL Program is credited for license renewal.	A1.28 B2.1.28 ASME Section XI, Subsection IWL	Ongoing
31	Existing ASME Section XI, Subsection IWF Program is credited for license renewal.	A1.29 B2.1.29 ASME Section XI, Subsection IWF	Ongoing
32	Existing 10 CFR 50, Appendix J Program is credited for license renewal.	A1.30 B2.1.30 10 CFR 50, Appendix J	Ongoing
33	Existing Masonry Wall Program is credited for license renewal, AND Prior to the period of extended operation, procedures will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Masonry Wall Program, which is part of the Structures Monitoring Program.	A1.31 B2.1.31 Masonry Wall Program	Prior to the period of extended operation ¹ .
34	Existing Structures Monitoring Program is credited for license renewal, AND Prior to the period of extended operation: <ul style="list-style-type: none"> • The Structures Monitoring Program will be enhanced to specify ACI 349.3R-96 as the reference for qualification of personnel to inspect structures under the Structures Monitoring Program. • For structures within the scope of license renewal, the Structures Monitoring Program will be enhanced to establish the frequency of inspection for each unit at a 5 year interval, with the exception of exterior surfaces of the following nonsafety-related structures, below-grade structures, and structures within a controlled interior environment, which will be inspected at an interval of 10 years: <ul style="list-style-type: none"> – Fire Pump House (Yard Structures) – Radwaste Building – Station Blackout Generator Structures – Turbine Building – Non-Safety Related Tank Foundations and Shells – Non-Safety Related Transformer Foundations and Electrical Structures • The Structures Monitoring Program will be enhanced to quantify the acceptance criteria and critical parameters for monitoring degradation, and to provide guidance for identifying unacceptable conditions requiring further technical evaluation or corrective action. Procedures will also be enhanced to incorporate applicable industry codes, standards and guidelines (e.g., ACI 349.3R-96, 	A1.32 B2.1.32 Structures Monitoring Program	Prior to the period of extended operation ¹ .

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	ANSI/ASCE 11-90, etc.) for acceptance criteria.		
35	Existing Regulatory Guide 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.	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.	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.	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 .
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.	A1.36 B2.1.36 Metal Enclosed Bus	Prior to the period of extended operation and once every ten years thereafter.
39	No later than two years prior to the period of extended operation, the following enhancements will be implemented <ul style="list-style-type: none"> Cumulative usage factor (CUF) tracking will be implemented for NUREG/CR-6260 locations not monitored by cycle counting (CC) (the reactor vessel shell and lower head (juncture) location will be monitored by CC). For PVNGS locations identified in NUREG/CR-6260 and monitored by CUF, fatigue usage factor action limits will be required for including effects of the reactor coolant environment. The Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced to include a computerized program to track and manage both CC and fatigue usage factor. FatiguePro® will be used for CC and cycle-based fatigue monitoring methods. FatiguePro® is an EPRI-licensed product. The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary Program will monitor plant transients as required by PVNGS Technical Specification 5.5.5. CUFs will be calculated for a subset of ASME III Class 1 reactor coolant pressure boundary vessel and piping locations and component locations with Class 1 analyses. The following methods will be used: <ul style="list-style-type: none"> The Metal Fatigue of Reactor Coolant Pressure Boundary Program will be enhanced to use cycle-based fatigue and stress-based fatigue CUF calculations to monitor fatigue. FatiguePro® will be used for CC and cycle-based fatigue monitoring 	4.3.1 Fatigue Aging Management Program A2.1 B3.1 Metal Fatigue of Reactor Coolant Pressure Boundary	No later than two years prior to the period of extended operation ¹ .

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	<p>methods. FatiguePro® is an EPRI-licensed product.</p> <ul style="list-style-type: none"> – The stress-based fatigue method will use a fatigue monitoring software program that incorporates a three-dimensional, six-component stress tensor method meeting ASME III NB-3200 requirements. • The enhanced Metal Fatigue of Reactor Coolant Pressure Boundary Program will provide action limits on cycles and on CUF that will initiate corrective actions before the licensing basis limits on fatigue effects at any location are exceeded. – In order to ensure sufficient cycle count margin to accommodate occurrence of a low-probability transient, corrective actions must be taken before the remaining number of allowable occurrences for any specified transient becomes less than 1.0. – CUF action limits will be established to require corrective action when the calculated CUF (from cycle-based or stress-based monitoring) for any monitored location is projected to reach 1.0 within the next two or three operating cycles. In order to ensure sufficient margin to accommodate occurrence of a low-probability transient, corrective actions will be taken while there is still sufficient margin to accommodate at least one occurrence of the worst-case design transient event (i.e., with the highest fatigue usage per event cycle). 		
40	Existing Environmental Qualification Program is credited for license renewal, AND Maintaining qualification through the extended license renewal period requires that existing EQ evaluations be re-evaluated.	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 <ul style="list-style-type: none"> • 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 minimum required value (MRV) and predicted lower limit (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." 	A2.3 B3.3 Concrete Containment Tendon Prestress 4.5 Concrete Containment Tendon Prestress	Prior to the period of extended operation ¹ .

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	<ul style="list-style-type: none"> 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. 		
42	The applicant will confirm the reactor coolant system 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	Completed		
44	Completed		
45	See Item No. 46		
46	An extension of In-Service Inspection Relief Request 31, Revision 1 authorization will be requested for the period of extended operation, supported by a continuation of the cold shutdown time monitoring program.	4.7.4 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	Prior to the period of extended operation ¹ .
47	Deleted (Staff note: this was in the PVNGS Environmental Report)		
48	Deleted (Staff note: this was in the PVNGS Environmental Report)		
49	Deleted (Staff note: this was in the PVNGS Environmental Report)		
50	The Fuse Holder Program is a new program that will be implemented prior to 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.	A1.37 B2.1.37 Fuse Holder	Prior to the period of extended operation and once every 10 years thereafter.
51	Completed		
52	Deleted (Staff note: this was in the PVNGS Environmental Report)		
53	Completed		
54	Completed		
55	Completed		
56	The spray pond wall rework/repair methods are currently being determined, and the rework/repair is planned to begin in 2011. As Unit 1 spray ponds have the most degradation, work is planned to start there, followed by Units 2 and 3. It is expected that the work will be completed in all three units in 2015.	PVNGS letter dated June 21, 2010	12/31/2015
57	No later than two years prior to the period of extended operation, APS will confirm the conservatism of the F_{en} value of 1.49 using the methods specified in NUREG/CR-6909, and will use the F_{en} calculated using the NUREG/CR-6909 methods if it is more conservative than the 1.49 value.	PVNGS letter dated June 29, 2010	No later than two years prior to the period of extended operation ¹ .

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
58	No later than two years prior to the period of extended operation, APS will perform a reanalysis of the pressurizer heater penetrations to consider EAF effects using the formulas and methodology given in NUREG/CR-6909.	PVNGS letter dated June 29, 2010	No later than two years prior to the period of extended operation ¹ .
59	As documented in CRAI 3337611, Engineering Study 13-MS-B089, "Cavitation in Safety Injection System," APS identified 26 components and associated piping in each PVNGS unit potentially susceptible to cavitation under design basis maximum flow conditions. One location in each unit, the HPSI recirculation piping downstream of throttle valve JSIBUV0667, has been confirmed to be susceptible to cavitation erosion, and a 7.5-year time-based replacement schedule described below has been established. All of the remaining 25 locations identified as potentially susceptible to cavitation in Unit 2, 20 of the locations in Unit 1, and 15 of the locations in Unit 3 have been inspected by ultrasonic testing (UT) and demonstrated no degradation. The remaining five locations in Unit 1 are scheduled to be inspected in the Unit 1 fall 2011 refueling outage. Of the remaining ten locations in Unit 3, five will be inspected in the Unit 3 fall 2010 outage and five will be inspected in the Unit 3 spring 2012 outage. Therefore, the inspections in all three units will be completed no later than June 30, 2012. If any of the remaining components and associated piping is found to be susceptible to cavitation or a form of flow-related degradation, it will be incorporated into a replacement plan similar to that for the HPSI recirculation piping downstream of throttle valve JSIBUV0667.	PVNGS letter dated July 30, 2010	6/30/2012
60	The reactor coolant system transient and cycle tracking procedure 73ST-9RC02 and UFSAR Section 3.9.1 will be enhanced to discuss corrective actions that need to be taken prior to ASME Section III fatigue design limits being exceeded and to state that corrective actions may be required for other fatigue-related analyses, such as certain ASME Section XI supplemental fatigue flaw growth or cycle-dependent fracture mechanics evaluations that are dependent on the number of occurrences of design transients.	PVNGS letter dated October 13, 2010	11/30/2010
61	<p>The applicant will perform one of the following three resolution options:</p> <p>1. Perform an inspection of each steam generator at PVNGS to assess the condition of the divider plate bar welds in all units and the divider plate bars in Unit 2. The examination technique(s) will be capable of detecting PWSCC in the divider plate bar welds in all units, and in the accessible surfaces of the divider plate bars in Unit 2.</p> <p>OR</p> <p>2. Perform an analytical evaluation of the steam generator divider plate bar welds in all units, and the divider plate bars in Unit 2, in order to establish a technical basis which concludes that the SG reactor coolant system pressure boundary is adequately maintained with the presence of steam generator divider plate bar weld cracking.</p> <p>OR</p> <p>3. If results of industry and NRC studies and operating</p>	<p>PVNGS letter dated November 23, 2010 as modified by letters dated February 25, 2011 and March 17, 2011</p>	<p>If Option (1) is selected, it will be completed for each SG in each unit during an SG tube eddy-current inspection outage between 20 and 25 calendar years of SG operation.</p> <p>If Option (2) or Option (3) is selected, it will be completed prior to 9/1/2023.</p>

Appendix A

Item Number	Commitment	License Renewal Application Section	Implementation Schedule
	experience document that potential failure of the SG reactor coolant system pressure boundary due to PWSCC cracking of SG divider plate bar welds and the divider plate bars in Unit 2 is not a credible concern, this commitment will be revised to reflect that conclusion.		
62	<p>The applicant will perform one of the following two resolution options:</p> <p>1. Perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified:</p> <p>The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate.</p> <p>An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.</p> <p>OR</p> <p>2. Perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to:</p> <p>Establish a technical basis which concludes that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintained with the presence of tube-to-tubesheet weld cracking.</p> <p>Establish a technical basis which concludes that the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function.</p>	PVNGS letter dated November 23, 2010	<p>If Option (1) is selected, it will be completed for each SG in each unit during an SG tube eddy-current inspection outage between 20 and 25 calendar years of SG operation.</p> <p>If Option (2) is selected, it will be completed prior to 9/1/2023.</p>
63	<p>No later than two years prior to the period of extended operation, the applicant will confirm that:</p> <p>The plant-specific components listed in LRA Table 4.3-11 (except the pressurizer surge line pressurizer elbow) are bounding for the generic NUREG/CR-6260 locations and the additional location (pressurizer heater penetrations). If locations are found that are not bounded by the Table 4.3-11 components, APS will perform new analyses as necessary to bound such locations.</p> <p>AND</p> <p>The LRA Table 4.3-11 locations selected for environmentally assisted fatigue analyses consist of the most limiting CUF locations for the plant (beyond the generic EAF locations identified in the NUREG/CR-6260 guidance). If the Table 4.3-11 locations are not bounding, APS will perform an environmentally assisted fatigue analysis for the additional CUF locations not bounded by the Table 4.3-11 locations. If the component with the most limiting CUF is composed of nickel alloy, the methodology used to perform the environmentally-assisted fatigue calculation for nickel alloy will be consistent with NUREG/CR-6909.</p>	PVNGS letter dated December 3, 2010	No later than two years prior to the period of extended operation.

⁽¹⁾ "Prior to period of extended operation," "prior to operation beyond 32 EFPY," and "prior to the end of the current licensed operating period," is prior to the following PVNGS Operating License expiration dates: Unit 1: June 1, 2025; Unit 2: April 24, 2026; Unit 3: November 25, 2027.