Palo Verde Nuclear Generating Station

Applicant's
Environmental Report;
Operating License Renewal Stage

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ACRONYMS AND ABBREVIATIONS

ACC	Arizona Corporation Commission
APP	Aquifer Protection Permit
AQCR	Air Quality Control Region
ASLD	Arizona State Land Department
BADCT	Best Available Demonstrated Control Technology
Btu	British thermal unit
CEQ	Council Environmental Quality
CWA	Clean Water Act
DSM	Demand-side management
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FES	Final Environmental Statement
ft^3	cubic foot
gal	gallon
GEIS	Generic Environmental Impact Statement
gpm	gallons per minute
ISO	International Standards Organization
IVM	Integrated Vegetation Management
kWh	kilowatt hour
lb	pound
LOS	Level of service
MAG	Maricopa Association of Governments
MGD	million gallons per day
MM	million
MSA	Metropolitan Statistical Area
msl	mean sea level
MW	megawatt
MWe	megawatts-electric
MWt	megawatts-thermal
NAAQS	National Ambient Air Quality Standards
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NMFS	National Marine Fisheries Service
NOV	Notices of Violation
NO_x	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Places

ACRONYMS AND ABBREVIATIONS (continued)

NSPS	New Source Performance Standard
NWHC	National Wildlife Health Center
PM	particulate matter
SAMA	severe accident mitigation alternatives
SCE	Southern California Edison
SCR	selective catalytic reduction
SHPO	State Historic Preservation Officer
SO_x	sulfur oxides
SROG	Subregional Operating Group
TDS	total dissolved solids
TSP	total suspended particulates
UA	University of Arizona
WRF	Water Reclamation Facility
yr	year

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1.0 CHAPTER 1 - INTRODUCTION

1.1 PURPOSE AND NEED FOR ACTION

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants in accordance with the Atomic Energy Act of 1954, as amended, and NRC implementing regulations. Arizona Public Service Company (APS) operates the Palo Verde Nuclear Generating Station (PVNGS) near Phoenix in Maricopa County, Arizona, pursuant to NRC Operating Licenses NPF-41 (expires December 31, 2024), NPF-51 (expires December 9, 2025), and NPF-74 (expires March 25, 2027) under Docket Numbers STN 50-528, STN 50-529, and STN 50-530, respectively.

APS has prepared this environmental report in conjunction with its application to NRC to renew PVNGS operating licenses for an additional 20 years each, in compliance with the following NRC regulations:

- Title 10, Energy, Code of Federal Regulations (CFR), Part 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, Section 54.23, Contents of Application-Environmental Information (10 CFR 54.23).
- Title 10, Energy, CFR, Part 51, Environmental Protection Requirements for Domestic Licensing and Related Regulatory Functions, Section 51.53, Post-Construction Environmental Reports, Subsection 51.53(c), Operating License Renewal Stage [10 CFR 51.53(c)].

NRC has defined the purpose and need for the proposed action, the renewal of the operating licenses for nuclear power plants such as PVNGS, as follows:

> ...The purpose and need for the proposed action (renewal of an operating license) is to provide an option that allows for power generation capability beyond the term of a current nuclear power plant operating license to meet future system generating needs, as such needs may be determined by State, utility, and, where authorized, Federal (other than NRC) decision makers.... (NRC 1996a)

The renewed operating licenses would allow for an additional 20 years of plant operation beyond the current PVNGS licensed operating period of 40 years.

1.2 ENVIRONMENTAL REPORT SCOPE AND METHODOLOGY

NRC regulations for domestic licensing of nuclear power plants require environmental review of applications to renew operating licenses. NRC regulation 10 CFR 51.53(c) requires that an applicant for license renewal submit with its application a separate document entitled Applicant's Environmental Report - Operating License Renewal Stage. In determining what information to include in the PVNGS Environmental Report, APS has relied on NRC regulations, licensing precedent, and the following supporting documents:

> NRC supplemental information in the *Federal Register* (NRC 1996b; NRC 1996c; NRC 1996d; and NRC 1999a)
>
> *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996a and NRC1999b)
>
> *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses* (NRC 1996e)
>
> *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response* (NRC 1996f)

APS has prepared Table 1-1 to verify compliance with regulatory requirements. Table 1-1 indicates where the environmental report responds to each requirement of 10 CFR 51.53(c). In addition, each section of Chapter 4 is prefaced by pertinent regulatory language and applicable supporting document language.

1.3 PALO VERDE NUCLEAR GENERATING STATION LICENSEE AND OWNERSHIP

PVNGS is owned by Arizona Public Service Company (29.10 percent), Salt River Project (SRP) (17.49 percent), Southern California Edison (SCE) (15.80 percent), El Paso Electric Company (15.80 percent), Public Service Company of New Mexico (10.20 percent), Southern California Public Power Authority (5.91 percent), and the Department of Water and Power of the City of Los Angeles (5.70 percent). APS is the plant operator and is authorized to act as agent for the owners and has exclusive responsibility and control over the physical construction, operation, and maintenance of the facility. SRP operates the switchyard at PVNGS. SRP also owns and operates six of the transmission lines (one line jointly owned with APS). SCE owns and operates the Devers transmission line.

1.4 TABLES

Table 1-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements.

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(1)	Entire Document
10 CFR 51.53(c)(2), Sentences 1 and 2	3.0 Proposed Action
10 CFR 51.53(c)(2), Sentence 3	7.2.2 Environmental Impacts of Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(1)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(2)	6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(3)	7.0 Alternatives to the Proposed Action 8.0 Comparison of Environmental Impacts of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(4)	6.5 Short-Term Use Versus Long-Term Productivity of the Environment
10 CFR 51.53(c)(2) and 10 CFR 51.45(b)(5)	6.4 Irreversible or Irretrievable Resource Commitments
10 CFR 51.53(c)(2) and 10 CFR 51.45(c)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation 7.2.2 Environmental Impacts of Alternatives 8.0 Comparison of Environmental Impact of License Renewal with the Alternatives
10 CFR 51.53(c)(2) and 10 CFR 51.45(d)	9.0 Status of Compliance
10 CFR 51.53(c)(2) and 10 CFR 51.45(e)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.3 Unavoidable Adverse Impacts
10 CFR 51.53(c)(3)(ii)(A)	4.1 Water Use Conflicts (Plants with Cooling Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River with Low Flow) 4.6 Groundwater Use Conflicts (Plants Using Cooling Towers or Cooling Ponds and Withdrawing Makeup Water from a Small River)

Table 1-1. Environmental Report Responses to License Renewal Environmental Regulatory Requirements. (Continued)

Regulatory Requirement	Responsive Environmental Report Section(s)
10 CFR 51.53(c)(3)(ii)(B)	4.2 Entrainment of Fish and Shellfish in Early Life Stages 4.3 Impingement of Fish and Shellfish 4.4 Heat Shock
10 CFR 51.53(c)(3)(ii)(C)	4.5 Groundwater Use Conflicts (Plants Using >100 gpm of Groundwater) 4.7 Groundwater Use Conflicts (Plants Using Ranney Wells)
10 CFR 51.53(c)(3)(ii)(D)	4.8 Degradation of Groundwater Quality
10 CFR 51.53(c)(3)(ii)(E)	4.9 Impacts of Refurbishment on Terrestrial Resources 4.10 Threatened or Endangered Species
10 CFR 51.53(c)(3)(ii)(F)	4.11 Air Quality During Refurbishment (Non-Attainment Areas)
10 CFR 51.53(c)(3)(ii)(G)	4.12 Microbiological Organisms
10 CFR 51.53(c)(3)(ii)(H)	4.13 Electric Shock from Transmission-Line Induced Current
10 CFR 51.53(c)(3)(ii)(I)	4.14 Housing Impacts 4.15 Public Utilities: Public Water Supply Availability 4.16 Education Impacts from Refurbishment 4.17 Offsite Land Use
10 CFR 51.53(c)(3)(ii)(J)	4.18 Transportation
10 CFR 51.53(c)(3)(ii)(K)	4.19 Historic and Archaeological Resources
10 CFR 51.53(c)(3)(ii)(L)	4.20 Severe Accident Mitigation Alternatives
10 CFR 51.53(c)(3)(iii)	4.0 Environmental Consequences of the Proposed Action and Mitigating Actions 6.2 Mitigation
10 CFR 51.53(c)(3)(iv)	5.0 Assessment of New and Significant Information
10 CFR 51, Appendix B, Table B-1, Footnote 6	2.6.2 Minority and Low-Income Populations

1.5 REFERENCES

NRC (U.S. Nuclear Regulatory Commission) 1996a. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), Volumes 1 and 2, NUREG-1437, Washington, D.C., May.

NRC (U.S. Nuclear Regulatory Commission) 1996b. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses," *Federal Register*, Vol. 61, No. 109, June 5.

NRC (U.S. Nuclear Regulatory Commission) 1996c. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Correction," *Federal Register*, Vol. 61, No. 147, July 30.

NRC (U.S. Nuclear Regulatory Commission) 1996d. "Environmental Review for Renewal of Nuclear Power Plant Operating Licenses," *Federal Register*, Vol. 61, No. 244, December 18.

NRC (U.S. Nuclear Regulatory Commission) 1996e. *Regulatory Analysis for Amendments to Regulations for the Environmental Review for Renewal of Nuclear Power Plant Operating Licenses*, NUREG-1440, Washington, D.C., May.

NRC (U.S. Nuclear Regulatory Commission) 1996f. *Public Comments on the Proposed 10 CFR Part 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response*, Volumes 1 and 2, NUREG-1529, Washington, DC, May.

NRC (U.S. Nuclear Regulatory Commission) 1999a. "Changes to Requirements for Environmental Review for Renewal of Nuclear Power Plant Operating Licenses; Final Rules," *Federal Register*, Vol. 64, No. 171, September 3.

NRC (U.S. Nuclear Regulatory Commission) 1999b. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), Section 6.3, "Transportation" and Table 9-1, "Summary of findings on NEPA issues for license renewal of nuclear power plants," NUREG-1437, Volume 1, Addendum 1, Washington, DC, August.

2.0 CHAPTER 2 - SITE AND ENVIRONMENTAL INTERFACES

2.1 LOCATION AND FEATURES

PVNGS is in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area. The nearest population center is the Phoenix metropolitan area (Figure 2-1), which includes the following major cities: Phoenix, Tempe, Mesa, Glendale, Peoria, Scottsdale, and Sun City. The town of Buckeye (estimated 2006 population 29,615) is approximately 16 miles to the east of PVNGS. The nearest town is Wintersburg (Figure 2-2).

The PVNGS site boundary encloses approximately 4,280 acres. Figure 2-3 depicts the PVNGS site boundary. The site buildings and adjacent, developed areas comprise approximately 720 acres. There are approximately 605 surface acres of water on the site in various large ponds (Section 3.1.2). Facilities on the property include the three reactor containment buildings, three turbine buildings, nine cooling towers (three per unit), plus various buildings auxiliary to the reactors, warehouses, a low-level waste storage building, station blackout generators, a chemical storage facility, a vehicle maintenance facility, small ponds and retention tanks, the Energy Information Center, administration buildings, an outdoor firing range, various landfills, and miscellaneous supporting buildings. The Water Reclamation Facility is an important facility on the site (Section 3.1.2).

PVNGS is in the Sonoran Desert section of the Basin and Range Physiographic Province, which is characterized by long, hot summers, cool winters, and warm springs. Although the site itself is mostly flat, scattered about the vicinity are small hills and buttes. The surrounding area has elevations ranging from 900 to 1,000 feet above mean sea level. Approximately six miles northwest of the site, the Palo Verde Hills rise abruptly to nearly 2,200 feet. Buckeye Valley, through which the Gila River flows, is east and southeast of the site.

2.2 AQUATIC COMMUNITIES

Onsite Waterbodies

PVNGS is the only nuclear plant in the U.S. that does not withdraw cooling (or makeup) water from a natural water body and that discharges cooling water (cooling tower blowdown) to a man-made water body with no outlet and no hydraulic connection to any natural waterbody. As discussed in more detail in Section 3.1.2, PVNGS obtains its makeup water primarily from two sewage treatment plants in the Phoenix area (91st Avenue and Tolleson).; PVNGS is also linked via pipeline to the Goodyear treatment plant and discharges cooling tower blowdown to lined ponds on the PVNGS property. Treated effluent from the Phoenix sewage treatment plants is pumped to the PVNGS Water Reclamation Facility, where it undergoes additional filtering and treatment before it is pumped to an 85-acre storage reservoir and a 45-acre water storage reservoir for use as makeup water. Cooling tower blowdown, which is high in salts and solids, is currently discharged to one of two evaporation ponds. Pond 1 is 250 acres; Pond 2 is 230 acres. A third 180-acre evaporation pond is under construction. The locations of the ponds are shown in Figure 3.1.

The storage reservoir and evaporation ponds were designed to function as engineered components of the station’s condenser cooling water system and were never intended to provide habitat for aquatic organisms. The Final Environmental Statement for construction (FES-CP) (NRC 1975) observed that there were no natural water bodies on or adjacent to the PVNGS site. Thus, NRC concluded that there were no aquatic communities that would be affected by plant construction. With regard to the impacts of cooling system operation on aquatic communities, the FES noted (page 5-2) that:

> The PVNGS cooling system will not draw water from any natural watercourse, nor will it discharge heat or chemicals to any natural water body. Thus, no aquatic impacts can result.

The FES for operation (FES-OP; NRC 1982), like the FES-CP, notes (page 5-13) that “there are no natural aquatic systems on the PVNGS site.” It describes the (asphalt and Hypalon-lined) storage reservoir and the evaporation pond as “artificial aquatic habitat” that would not affect the “integrity of any (aquatic) populations…in the PVNGS region….”

Notwithstanding the intended industrial use of the storage reservoir and evaporation ponds and water quality conditions that would eliminate most aquatic organisms (i.e., high levels of salts and dissolved solids, extreme diel fluctuations in water temperature, high water temperatures in summer months), simple aquatic communities composed of hardy, euryhaline organisms have developed in the evaporation ponds. These communities are composed of algae (e.g., the blue-green “algae” *Coccochloris* sp. and diatoms *Chaetoceros* sp. and *Nitzschia* sp.), brine shrimp (*Artemia* sp.), and water boatmen (*Trichocorixa* sp.) (Hillmer 1996). These three groups form an uncomplicated food chain in which brine shrimp feed on algae and water boatmen prey on brine shrimp. Hillmer (1996) observed that these organisms show pronounced cycles of abundance, with brine shrimp sometimes rapidly increasing and decimating the algae on which they rely, at which point they “succumb to starvation.” Scientists studying trophic dynamics of the Great Salt Lake have observed dramatic increases in water boatmen in unusually wet years that were associated with equally dramatic decreases in brine shrimp abundance, suggesting that these hypersaline systems with their simple food chains may be altered by bottom-up changes (i.e., water quality changes) or top-down changes (i.e., predation by insects at the top of the food chain) (Wurtsbaugh 1992).

The storage reservoir, despite having much lower chloride and dissolved solids concentrations, contains fewer aquatic organisms and virtually no brine shrimp. Chloride concentrations in the two evaporation ponds ranged from 21,000 to 52,000 milligrams per liter (mg/L; approximately 38,000 to 94,000 mg/L salinity) in 2005, whereas chloride concentrations in the storage reservoir ranged from 260 to 330 mg/L (< 1,000 mg/L salinity) (Brown and Caldwell 2006). Brine shrimp in the southwestern U.S. are typically found in ponds and lakes with salinities ranging from 54,000 to 230,000 mg/L (Cole and Brown 1967). The treated effluent from the Phoenix-area wastewater treatment plants is chlorinated at the PVNGS Water Reclamation Facility to remove pathogenic micro-organisms. Chlorination also kills algae and other non-pathogenic organisms that might otherwise increase in number in the storage reservoir. Studies in the mid-1990s showed that algae numbers were “much lower” in the storage reservoir than the two evaporation ponds (Hillmer 1996).

The storage reservoirs and evaporation ponds are both lined, the former to prevent seepage and the latter to prevent chemical constituents in blowdown from contaminating underlying groundwater. Therefore, rooted aquatic vegetation that could provide food and cover for waterfowl has not become established in the ponds and around the pond margins. Large numbers of waterfowl use the two evaporation ponds and the Water Reclamation Facility reservoir for stopovers during migration (November-March), when 5,000 or more ducks are commonly observed in the evaporation ponds and reservoir (Hillmer 1996). Waterfowl at PVNGS include several species of ducks, as well as birds such as the American coot, Western grebe, eared grebe, great blue heron, snowy egret, white-faced ibis, Western sandpiper, and Wilson’s phalarope. Northern shovellers and ruddy ducks are the two most common duck species in PVNGS ponds.

Between November 30, 1994 and January 26, 1995, a total of 829 dead ducks were found in the PVNGS evaporation ponds and Water Reclamation Facility reservoir. The large majority of these were found in the two evaporation ponds (Hillmer 1996). Almost all carcasses were Northern shovellers and ruddy ducks. APS worked closely with the Arizona Game and Fish Department, the U.S. Fish and Wildlife Service, the U.S. Geological Survey National Wildlife Health Center (NWHC), the University of Arizona (UA) Environmental Research Laboratory, and the UA Veterinary Diagnostic Laboratory to determine the cause of the mortalities and to prevent similar reoccurrences. Bird carcasses were sent to the UA Veterinary Diagnostic Laboratory and the NWHC’s laboratory in Madison, Wisconsin, for necropsy.

A sampling program was implemented at that time to: (1) identify algae and micro-organisms present in the ponds and determine whether they are toxic or can concentrate toxins, and (2) to determine if chemical parameters in the water could have caused the avian mortalities. After more than a year of data collection and analyses, the cause of the mortalities was not determined. Resident algae and micro-organisms as well as chemical parameters do not appear to have caused the mortalities. In addition, necropsies and analyses of carcasses ruled out avian cholera and other bacterial infections, viral infections, sodium toxicity, lead poisoning, and pesticide toxicity (Hillmer 1996). The carcasses were negative for avian botulism (Hillmer 1996), but personnel from the UA Veterinary Diagnostic Laboratory nevertheless suspected avian botulism, and pointed out that the partially decayed conditions of the carcasses made diagnosis of this condition problematic.

Thirteen Wilson's phalarope carcasses were observed and recovered in August of 1995 shortly after several hundred Wilson's phalaropes arrived at PVNGS. Three of the 13 carcasses were sent to the UA Veterinary Diagnostic Laboratory for necropsy. The necropsies did not identify the cause of death but the lab's investigators stated that the deaths appeared to be an infectious disease and furthermore, since the birds had just arrived, the condition had probably occurred during migration prior to arrival at PVNGS (Hillmer 1996).

A possible cause of the mortalities during the winter of 1994-1995 is that the birds were exposed to some sort of adverse condition or agent during their migration to PVNGS. Other than the mortalities during the winter of 1994-1995 and August 1995, there have been no other mass avian mortalities. Small numbers of dead waterfowl are occasionally seen in the evaporation ponds or Water Reclamation Facility reservoirs by APS personnel collecting water samples, performing pond inspections, or conducting security patrols. This is not unusual considering that thousands of waterfowl are often present in these water bodies.

Offsite Waterbodies

Since PVNGS diverts treated effluent that would otherwise be discharged to the Gila River, where it could support riparian habitat, this Environmental Report considers the impact of license renewal (continued operation) on the flow of the Gila River and on in-stream and riparian ecological communities.

After the opening of the 91st Avenue Waste Water Treatment Plant in 1958 in the southwestern suburbs of Phoenix, the annual volume of water discharged from the plant to the Salt River (just west of its confluence with the Gila River) increased from 5,600 acre-feet (original output) to 65,100 acre-feet in 1973 (NRC 1975). Riparian vegetation became established in the 6-mile stretch ("Segment B") of the Salt River below the 91st Avenue Plant over the 1964-1973 period, which the NRC (1975) attributed to the increased flow of treated effluent.

The FES-OP predicted that PVNGS's use of treated sewage effluent would reduce the amount of riparian habitat in the Salt and Gila Rivers below the City of Phoenix's 91st Avenue Plant. The FES-OP notes specifically (page 5-11) that "…diversion of wastewater for PVNGS and Buckeye Irrigation District could result in a reduction of high-quality wildlife habitat in Segment B in 1986 (but) most of the riparian habitat would recover by the year 2000…"

However, NRC staff was careful to point out that this reduction in riparian habitat was a theoretical one:

> …the staff concludes that this diversion will not adversely affect characteristic desert aquatic population structure because the existing stream management programs and water quality do not allow such communities to develop. (NRC 1982, page 5-1)

Review of the 91st Avenue Wastewater Treatment Plant 25-Year Facility Master Plan (SROG 2005) indicates that although critical riparian and wetland habitats along the Salt and Gila Rivers have been lost because of water resources development in the area, three projects will play significant roles in the transformation of the 91st Avenue Plant and possibly other WWTPs to major providers of reclaimed water. The three projects are:

- The Agua Fria Linear Recharge Project
- The Tres Rios Constructed Wetlands Project

- The Rio Salado Oeste Project

The Agua Fria Reclaimed Water Recharge Project is a planned construction linear groundwater recharge and recovery facility. The project will recharge the aquifer with reclaimed effluent from the 91st Avenue Plant, store it, and recover it for future use. Construction of the recharge facility is presently scheduled for the period between 2008 and approximately 2010.

The Tres Rios Constructed Wetlands Project is a joint effort between SROG and the United States Army Corps of Engineers to construct wetlands along the Salt River downstream of the 91st Avenue Plant. The project will restore eight miles of unique riparian habitat between 83rd Avenue and the confluence of the Salt, Gila and Agua Fria Rivers using reclaimed effluent from the 91st Avenue Plant. Construction for the wetlands phase of the project could begin as early as 2009.

The Rio Salado Oeste Project will restore habitat to approximately eight miles of the riparian riverbed zone of the Salt River encompassing 5,300 acres between 19th Avenue and 83rd Avenue. The quantities and sources of water required to sustain the project have not yet been defined, but it is anticipated that reclaimed water supplements for the project would be supplied from the 23rd Avenue Plant, rather than the 91st Avenue Plant.

Rio Salado Oeste will adjoin the Tres Rios habitat restoration project and the Rio Salado projects to the east. When completed, the three projects will effectively merge into one continuous riparian habitat restoration zone.

2.3 GROUNDWATER RESOURCES

PVNGS is on approximately 4,280 acres of relatively flat desert terrain in the Hassayampa River valley, which was previously used for irrigated agriculture (APS 2001). The site is within the Lower Hassayampa groundwater sub-basin of the Phoenix Active Management Area as defined by the Arizona Department of Water Resources (APS 2001). The Lower Hassayampa sub-basin encompasses an area of approximately 400 square miles (APS 2001). The entire Hassayampa sub-basin encompasses 1,200 square miles. Groundwater flow into and out of the Hassayampa sub-basin has been calculated at approximately 29,000 acre-feet annually (Maricopa County 2001). It is estimated that approximately 4.8 million acre-feet of groundwater within the Hassayampa sub-basin are available to a depth of 1,200 feet below land surface in this sub-basin (Maricopa County 2001).

The hydrogeologic setting of the site is characterized by three major sedimentary units, each having distinctly different lithologic and hydrologic characteristics. These units are the Upper Alluvial Unit, the Middle Fine-Grained Unit, and the Lower Coarse-Grained Unit (APS 2001). The Upper Alluvial Unit primarily consists of fluvial silty and gravelly sand with discontinuous clay and silty clay lenses. This unit extends to a varying depth of 30 to 60 feet beneath the site. The Middle Fine-Grained Unit consists of massive, continuous layers of clay and silty clay, with discontinuous lenses of clayey silt, clayey sand, and silty sand. The unit beneath the site is approximately 270 feet thick. The Lower Coarse-Grained Unit consists of variably cemented conglomerate of volcanic flow, tuff, and sandstone (NRC 1982).

In the vicinity of the site, the groundwater reservoir consists of a laterally extensive regional aquifer (Lower Course-Grained Unit) which occurs throughout the Lower Hassayampa groundwater sub-basin. The regional aquifer occurs under unconfined and confined conditions. The thickness of the Lower Course-Grained Unit is not known. In the vicinity of the Palo Verde Hills, the unit is more than 1,400 feet thick. The regional aquifer at the site is under confined conditions (APS 2001).

The primary recharge to the regional aquifer in the site vicinity is underflow from the Upper Hassayampa groundwater sub-basin located north of the PVNGS site (APS 2001). Groundwater recharge within the Hassayampa sub-basin occurs as streambed recharge from the Gila and Hassayampa Rivers, from ephemeral streams, from mountain front recharge, and from incidental recharge from agricultural irrigation and canal leakage (Maricopa County 2001). The general direction of flow within the regional aquifer is to the south toward a large cone of depression southwest of the site caused by pumping for agricultural irrigation. In the vicinity of the site, precipitation, surface runoff, and return flow from irrigation provide a small portion of the total recharge to the regional aquifer, partly due to the Middle Fine-grained Unit that restricts downward migration of recharge water (APS 2001).

In the immediate vicinity of the site a localized perched water zone is separated from the regional aquifer by the Middle Fine-Grained Unit, including the Palo Verde Clay (APS 2001). The perched groundwater is primarily contained within the Upper Alluvial Unit and has a lower boundary consisting of an aquitard, the Middle Fine-Grained Unit. The aquitard appears to be continuous beneath the site and the vicinity. Although the upper portion of the Middle Fine-Grained Unit is saturated by downward flow from the Upper Alluvial Unit, it is not considered part of the perched system due to its very low permeability (0.001 gallons per day per square foot) (APS 2001).

Groundwater levels within the regional aquifer have risen since 1975 due to the steady decline in agricultural use (PVNGS 2006). However, this reduction in agricultural use has also reduced mounding in the perched Alluvial Aquifer, resulting in a lowering of groundwater levels in this aquifer (PVNGS 2006).

Groundwater quality in Maricopa County is generally characterized as fair to good, particularly in unincorporated areas. In some areas, treatment for fluoride and total dissolved solids (TDS) is necessary before human consumption is possible. Poor water quality can be found in the upper alluvial unit. Poor water quality is generally found only in the East and West Salt River Valley sub-basins, with contaminants including TDS, sulfates, nitrates, volatile organic compounds, pesticides, and metals. The major contributors of these contaminants are industry, agriculture, dry well injections, unregulated landfills, and leaking underground storage tanks (Maricopa County 2001).

Surface water pollutants come from both point source and non-point sources such as pipes, channels, tunnels, and ditches that discharge pollutants as well as runoff from agricultural fields, vacant lots, construction sites, and urban development. In Maricopa County, agriculture, industry, construction, wastewater treatment plants, drinking water treatment plants, natural sources, hydromodification, landfills, and resource extraction contribute to surface water pollution. Some of the pollutants include metals, TDS, turbidity, suspended solids, pathogens, and pesticides (Maricopa County 2001).

PVNGS's 2006 Annual Radiological Environmental Report does not indicate the presence of measurable radiological impacts to the environment due to PVNGS operations during 2006. In samples that contain radioactivity, the radioactivity is attributed to natural background/cosmic radioactivity (APS 2007).

PVNGS has been evaluating tritium in groundwater and the potential to release tritium to groundwater since early 2006 (APS 2006a). Comprehensive testing of plant structures and piping was performed, including pressure testing of underground piping, excavation of areas around process tanks and underground pipes, and evaluation of below-grade sumps. No leaks were identified.

APS believes the tritium may have come from three sources. Atmospheric deposition studies indicate that tritium can become entrained in rainfall, particularly when the boric acid concentrators are in operation (APS 2006b). The practice of boric acid concentration operation at the facility during rainfall events was discontinued in the 1990s. A second probable source of tritium was from condensate from air handling units on the Auxiliary Building roofs. This condensate could be carried with rainfall or roof washing through the scuppers to the ground. A third possible source of tritium is from small, undocumented historic spills.

APS believes that tritiated water from one or more of the three sources penetrated permeable soils (gravel areas, damaged asphalt) and resides in sand lenses surrounding buried pipe, electrical ducts, ventillation tunnels, and vaults (APS 2006c). A total of twenty wells were drilled in the three units at depths of approximately 10 to 13, 25, and 50 feet below ground surface, and ambient subsurface water monitoring of these wells is in progress. Unit 3 has the most permeable ground cover and the greatest volume of shallow subsurface water. Unit 2 is intermediate in permeable ground cover and has intermediate shallow subsurface water. Unit 1 has the least permeable ground cover and has no shallow subsurface water. Asphalt repairs and sealing around structures is underway. Once the ground surface is made less permeable and ambient monitoring is sufficient to characterize subsurface water quality, a remediation plan will be implemented. Quarterly progress reports have been submitted to the Arizona

Department of Environmental Quality (APS 2006d), (APS 2007a), (APS 2007b), (APS 2007c), (APS 2007d), (APS 2008a), (APS 2008b).

Three shallow aquifer wells, ranging in depth from 80 to 90 feet below ground surface, were drilled around the units. Groundwater monitoring results from these wells indicate that tritium is not present in the shallow aquifer (APS 2008c). Tritium has not been detected in groundwater from other site wells screened in the shallow, intermediate (Palo Verde Clay), and deeper (regional) aquifers (APS 2008c).

2.4 CRITICAL AND IMPORTANT TERRESTRIAL HABITATS

PVNGS is in Maricopa County, Arizona. Terrain within the site is relatively flat, with an approximate elevation of 950 feet above mean sea level (msl). Surface elevations in the surrounding area range from 900 to 1,000 feet msl. The Palo Verde Hills, with a maximum elevation of nearly 2,200 feet msl, are located about six miles northwest of the site (NRC 1975).

The PVNGS site encompasses approximately 4,280 acres. Approximately 720 acres support the generating facility and associated buildings, maintenance facilities, parking lots, roads, railroads, and transmission corridors. Two existing evaporation ponds encompass 480 acres and the Water Reclamation Facility reservoirs cover 130 acres.

PVNGS is in the Lower Colorado Valley subdivision of the Sonoran Desert. This area is characterized by long, hot summers and cool winters. Most of the land within ten miles of the site is open desert (NRC 1975), but is becoming increasingly sparsely populated. Vegetation on the site is divided into five native plant communities: creosote bush plains, saltbush plains, mesquite washes, creosote bush-saltbush plains, and creosote bush-cacti hills (NRC 1975). About half of the native plant species at the PVNGS site are annual or biennial herbs and grasses, most of which appear only in early spring or after winter rains. Creosote bush (*Larrea divaricata*) is the most common shrub at the site. Burrobush (*Ambrosia dumosa*) and saltbush (*Atriplex* spp.) are also common shrubs at the site (NRC 1975). Terrestrial habitats at PVNGS are typical of those in the region, and there are no critical, unusual, or rare terrestrial habitats at the site.

A variety of reptiles, amphibians, birds, and mammals are found in the Lower Colorado Valley subdivision of the Sonoran Desert and at PVNGS. Many species inhabit the PVNGS area permanently (e.g. Western whiptail lizard, Western diamondback rattlesnake, deer mouse, cactus mouse, roadrunner), while others are migratory (e.g. horned lark, Western tanager) and use the site on a seasonal basis or are transients. There is no federally designated critical habitat (or proposed critical habitat) for threatened or endangered terrestrial species in the vicinity of PVNGS.

Section 3.1.3 describes the transmission lines that were built to connect PVNGS to the transmission grid system (Figures 3-2 and 3-3). The corridors pass through land that is primarily agricultural, open range, and desert. Many areas of native vegetation have been moderately to heavily disturbed by cattle grazing.

The 235-mile-long PVNGS-to-Devers transmission line (Figure 3-3), by far the longest PVNGS-associated transmission line, passes through more relatively undisturbed terrestrial habitats than the other PVNGS transmission lines. It crosses the Kofa National Wildlife Refuge in La Paz County, Arizona, and the Coachella Valley National Wildlife Refuge in Riverside County, California. It passes slightly north of the Chuckwalla Mountains Wilderness Area and slightly south of the Joshua Tree National Park.

The Kofa National Wildlife Refuge is managed by the U.S. Fish and Wildlife Service. The refuge encompasses 665,400 acres of pristine desert and two mountain ranges: the Kofa Mountains and the Castle Dome Mountains.

The Coachella Valley National Wildlife Refuge near Palm Springs, California, managed by the U.S. Fish and Wildlife Service, contains palm oasis woodlands, perennial desert pools, and sand dune habitats. The 3,709-acre refuge also contains federally designated critical habitat for the Coachella Valley fringe-toed lizard (CPUC 2006).

Although the PVNGS-to-Devers transmission line does not cross the Chuckwalla Mountains Wilderness Area, it does cross federally designated critical habitat for the Mojave population of the desert tortoise located in and slightly north of the Chuckwalla Mountains Wilderness Area.

Vegetation maintenance on tribal and public lands requires biological clearances in advance of performing the work (APS undated). APS incorporates Integrated Vegetation Management (IVM) principles to manage vegetation on its transmission corridors, which involve selectively controlling tall-growing vegetation while preserving low-growing herbaceous and woody plants. In addition, clearing or treatment of vegetation is unnecessary in areas such as deep ravines where trees will never grow tall enough to interfere with the transmission system (APS undated). Since the PVNGS transmission corridors are located in desert habitat, they generally do not require significant maintenance in terms of mowing, trimming, or clearing.

2.5 THREATENED OR ENDANGERED SPECIES

Table 2-1 presents protected animal and plant species that have been recorded in counties within which PVNGS and associated transmission lines are located. The Rudd, Westwing #1 and #2, and Hassayampa #1 (including all the way to Kyrene), #2 and #3 transmission lines are entirely within Maricopa County, Arizona (Figure 3-2). The 235-mile Devers transmission line lies within Maricopa and La Paz counties in Arizona and Riverside County, California (Figure 3-3).

Species in Table 2-1 are those that are federally listed (USFWS 2006a) or listed by the California Department of Fish and Game (CDFG 2006) as endangered or threatened or are proposed or candidates for listing; classified as "wildlife of special concern" by the Arizona Game & Fish Department (AGFD 2006); and plants protected by the Arizona Department of Agriculture (AGFD 2006).

The species included in Table 2-1 are those that meet one of the following conditions:

- Records maintained by U.S. Fish and Wildlife Service Region 2 (USFWS 2006b) indicate the species has been recorded in La Paz or Maricopa counties, Arizona.
- Records maintained by the Arizona Game & Fish Department (AGFD 2006) indicate the species has been recorded in La Paz or Maricopa counties, Arizona.
- Records maintained by U.S. Fish and Wildlife Service Carlsbad Fish and Wildlife office (USFWS 2006c) indicate the species has been recorded in Riverside County, California.

As shown in Table 2-1, numerous federally listed and state-listed species have been recorded in counties within which PVNGS and associated transmission lines are located. Information on status, distribution, and life histories of these species can be found at Arizona Game & Fish Department (AGFD 2006) and USFWS (2006a, b) websites.

APS is not aware of any federally listed species at PVNGS. The Final Environmental Statement for Operation of PVNGS (NRC 1982) stated that no federally listed species had been observed at the PVNGS site, but three were located in the vicinity of PVNGS or its transmission lines: the peregrine falcon (*Falco peregrinus*), the bald eagle (*Haliaeetus leucocephalus*), and the Yuma clapper rail (*Rallus longirostris yumanensis*). The peregrine falcon and the bald eagle are no longer federally listed.

The Yuma clapper rail is federally listed as endangered. Habitat for this species consists of freshwater marshes containing dense stands of cattails and bulrushes, especially mature marshes along margins of shallow ponds with stable water levels interspersed with areas of open water and drier, upland benches. It eats crayfish, small fish, clams, isopods, and various insects (NatureServe 2006). The Yuma clapper rail has been known to nest along the Colorado River in the vicinity of the PVNGS-to-Devers River crossing (NRC 1982).

As mentioned in Section 2.4, the PVNGS-to-Devers transmission line passes through more relatively undisturbed terrestrial habitats than the other PVNGS transmission lines. The corridor crosses federally designated critical habitat for the Mojave population of the desert tortoise (*Gopherus agassizii)* in the vicinity of the Chuckwalla Mountains Wilderness Area. The Mojave population of the desert tortoise consists of all desert tortoises occurring north and west of the

Colorado River in California, Nevada, Utah, and Arizona, and is federally listed as threatened. The Sonoran population of the desert tortoise occurs south and east of the Colorado River in Arizona and Mexico. The Sonoran desert tortoise is federally designated as threatened due to its close resemblance in appearance to the Mojave desert tortoise. Habitat for this species (both Mojave and Sonoran populations) occurs primarily in the hills and rocky mountainous terrain of scrub vegetation communities. Desert tortoises are typically found along washes and rocky areas, where they burrow. Areas of creosote bush can also provide habitat for this species. Sonoran desert tortoises have been recorded within three miles of the PVNGS-to-Devers transmission line (CPUC 2006). Mojave Desert tortoises could be present where the corridor crosses the federally designated critical habitat.

The PVNGS-to-Devers transmission line also crosses federally designated critical habitat for the Coachella Valley fringe-toed lizard (*Uma inornata*) within the Coachella Valley National Wildlife Refuge near Palm Springs, California. This species is federally listed as threatened. It typically inhabits sand dune habitats interspersed with hardpan areas containing widely spaced desert shrubs, and requires fine loose sand for burrowing. The major threats to this species include urban development, sand and gravel mining operations, and off-road vehicle usage (CPUC 2006).

As discussed in Section 2.2, there are no natural waterbodies on or adjacent to the PVNGS site. Thus, no aquatic populations, other than the plankton and invertebrates that have established themselves in the Water Reclamation Facility reservoirs and evaporation ponds. No sensitive aquatic species are present. However, PVNGS transmission lines do cross several Arizona and California counties in which state- and federally listed aquatic species occur, as indicated in Table 2-1. Based on available information, the only waterbody crossed by PVNGS-associated transmission lines that is known to contain listed species is the lower Colorado River, which is crossed by the PVNGS-to-Devers 525-kilovolt transmission line (see Figure 3-3). The reach of the river crossed by the PVNGS-to-Devers line has been designated critical habitat for the razorback sucker (59 Federal Register 13374).

The fishes of the lower Colorado River, a unique assemblage dominated by chubs and suckers found nowhere else in the U.S., have been the focus of intensive study and management since the early 1940s, when California Fish and Game biologists discovered the degree to which these unusual fishes were imperiled (Mueller and Marsh undated). Agency efforts to restore these fisheries over the intervening years were apparently piecemeal and less than successful, but led (in part) to development of the Lower Colorado River Multi-Species Conservation Program, a “coordinated, comprehensive, long-term multi-agency effort” to work towards the recovery of endangered species in the lower Colorado River basin (BOR 2006). A *Final Fish Augmentation Plan* developed by the Program’s steering committee members, calls for stocking 660,000 endangered razorback suckers and 620,000 endangered bonytail chubs in the lower Colorado River over a 50-year period, as a step toward recovery of these endangered species (LCRMCP 2006).

The razorback sucker (*Xyrauchen texanus*), listed as endangered by the USFWS in 1991, was once abundant in the lower Colorado River and its tributaries, including the Salt and Gila Rivers. But as dams were erected on the Colorado River and its major tributaries, more and more sections of these rivers were rendered unsuitable for this species. Fish and game commissions and agencies began stocking non-native fish species in lower Colorado River basin waters in the late 19th century, a practice that accelerated into the 1940s and proved to be devastating to razorback sucker populations already suffering the effects of habitat alteration (Tyus 1998). Non-native fish species competed with native species for space (habitat) and food. Non-native fish species such as carp, channel catfish, and flathead catfish feed on razorback sucker eggs and larvae; other non-native species, such as largemouth bass feed on juvenile razorback suckers. The combination of habitat alteration, competition, and predation from non-native species led the U.S. Fish and Wildlife Service to speculate in 1998 that there had been a 90 percent decline in the razorback sucker's original range and abundance (Tyus 1998). As of January 2006, only two wild populations of razorback suckers survive below the Grand Canyon, one in Lake Mead and one in Lake Mojave (LCRMCP 2006). Unknown numbers of planted razorback suckers occupy reservoir and river reaches below Davis Dam (Lake Mojave), supported by releases over the past two decades of more than 100,000 fish by state and federal agencies.

The bonytail chub (*Gila elegans*), listed by the USFWS as endangered in 1980, experienced the most dramatic decline of the endemic big-river fishes of the Colorado (Mac et al. 1998). Once plentiful, the species began to decline after construction of the Hoover Dam, and became increasingly scarce in the lower river over the 1926-1950 period. The authors of the *Final Fish Augmentation Plan* (LCRMCP 2006) note that

> at this time it appears no wild populations of bonytail chubs exist in the lower Colorado River. Augmented populations (from stockings) of this species are known to be in both Lake Havasu and Lake Mojave, and may be found in the river between these two reservoirs..

Historically found in mainstream portions of the Colorado River and its major tributaries, including the Salt and Gila Rivers in Arizona, populations survive mainly in the two aforementioned reservoirs, where bonytails are typically found in open water (AGFD Undated).

As noted previously in this section, the *Final Fish Augmentation Plan* calls for stocking 660,000 (endangered) razorback suckers and 620,000 (endangered) bonytail chubs in the lower Colorado River over a 50-year period. With regard to the reach of the river crossed by the PVNGS-to-Devers line, the *Plan* calls for stocking 300,000 razorback suckers (at least 300 mm long) and 220,000 bonytails (at least 300 mm long) over a 50-year period (LCRMCP 2006).

2.6 DEMOGRAPHY

2.6.1 Regional Demography

The Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants presents a population characterization method that is based on two factors: “sparseness” and “proximity” (NRC 1996). “Sparseness” measures population density and city size within 20 miles of a site and categorizes the demographic information as follows:

Demographic Categories Based on Sparseness

		Category
Most sparse	1.	Less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles
	2.	40 to 60 persons per square mile and no community with 25,000 or more persons within 20 miles
	3.	60 to 120 persons per square mile or less than 60 persons per square mile with at least one community with 25,000 or more persons within 20 miles
Least sparse	4.	Greater than or equal to 120 persons per square mile within 20 miles
Source: NRC (1996)		

“Proximity” measures population density and city size within 50 miles and categorizes the demographic information as follows:

Demographic Categories Based on Proximity

		Category
Not in close proximity	1.	No city with 100,000 or more persons and less than 50 persons per square mile within 50 miles
	2.	No city with 100,000 or more persons and between 50 and 190 persons per square mile within 50 miles
	3.	One or more cities with 100,000 or more persons and less than 190 persons per square mile within 50 miles
In close proximity	4.	Greater than or equal to 190 persons per square mile within 50 miles
Source: NRC (1996)		

The GEIS then uses the following matrix to rank the population category as low, medium, or high.

GEIS Sparseness and Proximity Matrix

		Proximity			
		1	2	3	4
Sparseness	1	1.1	1.2	1.3	1.4
	2	2.1	2.2	2.3	2.4
	3	3.1	3.2	3.3	3.4
	4	4.1	4.2	4.3	4.4

Low Population Area

Medium Population Area

High Population Area

Source: NRC (1996)

APS used 2000 census data from the U.S. Census Bureau (USCB 2000) with geographic information system software (ArcView®) to determine most demographic characteristics in the PVNGS vicinity. The calculations (TtNUS 2006) determined that approximately 16,000 people live within 20 miles of PVNGS, for a population density of 13 persons per square mile. The nearest population center with population over 25,000 is Goodyear, approximately 28 miles from the plant. Applying the GEIS sparseness measures results in the most sparse category, Category 1 (less than 40 persons per square mile and no community with 25,000 or more persons within 20 miles).

To calculate the proximity measure, APS determined that approximately 1,572,110 people live within 50 miles of PVNGS, for a population density of 200 persons per square mile (TtNUS 2006). Applying the GEIS proximity measures, PVNGS is classified as Category 4 (greater than or equal to 190 persons per square mile within 50 miles). Therefore, according to the GEIS sparseness and proximity matrix, PVNGS ranks of sparseness, Category 1, and proximity, Category 4, result in the conclusion that PVNGS is located in a medium population area.

The nearest major metropolitan area is Phoenix, Arizona (34 miles east), with a 2000 population of 1,321,045 (USCB 2000). The closest town is Wintersburg (3 miles northwest).

All or parts of 5 counties, the City of Phoenix, and the Phoenix-Mesa-Scottsdale, AZ Metropolitan Statistical Area (MSA) are located within 50 miles of PVNGS (Figure 2-1).

From 1990 to 2000, the population of the Phoenix-Mesa-Scottsdale, AZ MSA increased from 2,238,480 to 3,251,876, an increase of 45.3 percent (USCB 2003a). It was the 14th largest

(USCB 2003a) and 5th fastest growing MSA in the United States (USCB 2003b). From 2000 to 2007, the MSA population increased another 29 percent to 4,179,427 (USCB 2007).

Because approximately 98 percent of employees at PVNGS reside in Maricopa County, it is the county with the greatest potential to be socioeconomically affected by license renewal (Section 3.4). Table 2-2 shows population estimates and decennial growth rates for Maricopa County. Values for the State of Arizona are provided for comparison. The table is based on U.S. Census Bureau (USCB) data for 1980, 1990, and 2000, and Arizona Workforce Informer projections through 2050 (AWI 2006).

Over the last couple of decades, Maricopa County and the State of Arizona have experienced similarly large positive growth rates (Table 2-2). Because Maricopa County's 2000 population represented approximately 60 percent of the State of Arizona's total population (USCB 2000), it is understandable that the growth rates were similar. Regional demographers project the growth rates for Maricopa County and the State (approximately 35 to 45 percent in the 1980s and 1990s) to slow to approximately 9 percent by 2055 (AWI 2006). However, by the year 2050, the end of the decade of the 20-year renewal period for the three PVNGS units, the Maricopa County and Arizona populations are both projected to increase by approximately 150 percent over 2000 levels. By 2050, the population of Maricopa County is projected to increase to more than 7.6 million and Arizona to more than 12.8 million people (Table 2-2).

2.6.2 Minority and Low-Income Populations

NRC performed environmental justice analyses for previous license renewal applications and concluded that a 50-mile radius could reasonably be expected to contain potential environmental impact sites and that the state was appropriate as the geographic area for comparative analysis. APS has adopted this approach for identifying the PVNGS minority and low-income populations that could be affected by PVNGS operations.

APS used ArcView® geographic information system software to determine the minority characteristics by block group. APS included all block groups if any part of their area lay within 50 miles of PVNGS. The 50-mile radius includes 1,256 block groups (Table 2-3).

2.6.2.1 Minority Populations

The NRC Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues defines a "minority" population as: American Indian or Alaskan Native; Asian; Native Hawaiian or other Pacific Islander; Black Races; and Hispanic Ethnicity. Additionally, NRC's guidance requires that (1) all other single minorities are to be treated as one population and analyzed, and (2) the aggregate of all minority populations are to be treated as one population and analyzed. The guidance indicates that a minority population exists if either of the following two conditions exists:

- The minority population in the census block group or environmental impact site exceeds 50 percent.
- The minority population percentage of the environmental impact area is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

For each of the 1,256 block groups within the 50-mile radius, APS calculated the percent of the block group's population represented by each minority. If any block group minority percentage exceeded 50 percent, then the block group was identified as containing a minority population. APS selected the entire State of Arizona as the geographic area for comparative analysis, and calculated the percentages of each minority category in the State. If any block group percentage exceeded the corresponding State percentage by more than 20 percent, then a minority population was determined to exist (TtNUS 2006).

Census data for Arizona (USCB 2000) characterizes 4.99 percent of the population as American Indian or Alaskan Native; 1.80 percent Asian; 0.13 percent Native Hawaiian or other Pacific Islander; 3.10 percent Black races; 11.63 percent all other single minorities; 2.86 percent multi-racial; 24.50 percent aggregate of minority races; and 25.25 percent Hispanic ethnicity.

Table 2-3 presents the numbers of block groups in each county in the 50-mile radius that exceed the threshold for minority populations. Figures 2-4 through 2-10 locate the minority block groups within the 50-mile radius.

Twenty-one census block groups within the 50-mile radius have Black Minority populations that exceed the state average by 20 percent or more. Of those, two have Black Minority populations of 50 percent or more. They are all located in the Phoenix metropolitan area.

Four census block groups within the 50-mile radius have American Indian or Alaskan Native Minority populations that exceed the state average by 20 percent or more. All four census block groups also meet the 50 percent criteria. They are all located on the Gila River and Maricopa Indian Reservations. Portions of three Indian Reservations fall within a 50-mile radius of the PVNGS site: the Gila, Maricopa (Ak Chin), and Tohono O'odham.

Three census block groups within the 50-mile radius have Asian Minority populations that exceed the state average by 20 percent or more. Of those, one has Asian Minority populations of 50 percent or more. They are all located in the Phoenix metropolitan area.

One-hundred and ninety-four census block groups within the 50-mile radius have All Other Single Minority populations that exceed the state average by 20 percent or more. Of those, 36 have All Other Single Minority populations of 50 percent or more. They are located in southwestern Maricopa County and the Phoenix metropolitan area.

Six census block groups within the 50-mile radius have Multi-Racial Minority populations that exceed the state average by 20 percent or more. Of those, 2 have Multi-Racial Minority populations of 50 percent or more. They are located in the Phoenix metropolitan area.

Two-hundred and forty-nine census block groups within the 50-mile radius have Aggregate Minority populations that exceed the state average by 20 percent or more. Of those, 178 have Aggregate Minority populations of 50 percent or more. They are primarily located in northwestern Pinal County, southern Maricopa County, and the Phoenix metropolitan area.

Three-hundred and sixty-four census block groups within the 50-mile radius have Hispanic Ethnicity populations that exceed the state average by 20 percent or more. Of those, 322 have Hispanic Ethnicity populations of 50 percent or more. They are primarily located in northeastern Yuma County, southwestern Maricopa County, and the Phoenix metropolitan area.

There are no Native Hawaiian or Other Pacific Islander populations that meet either the 20 percent or the 50 percent criteria within a 50-mile radius of PVNGS.

2.6.2.2 Low-Income Populations

NRC guidance defines low-income population based on statistical poverty thresholds (NRC 2004) if either of the following two conditions are met:

- The low-income population in the census block group or the environmental impact site exceeds 50 percent.
- The percentage of households below the poverty level in an environmental impact area is significantly greater (typically at least 20 percentage points) than the low-income population percentage in the geographic area chosen for comparative analysis.

APS divided USCB low-income households in each census block group by the total households for that block group to obtain the percentage of low-income households per block group. Using the State of Arizona as the geographical area chosen for comparative analysis, APS determined that 11.79 percent of Arizona households are considered as low-income (TtNUS 2006). Table 2-3 identifies the low-income block groups in the region of interest, based on NRC's two criteria. Figure 2-11 locates the low-income block groups.

One-hundred and eight census block groups within the 50-mile radius have low-income households that exceed the state average by 20 percent or more. Of those, 21 have 50 percent or more low-income households. They are primarily located in the southern half of the Phoenix metropolitan area and south of the Phoenix metropolitan area.

2.7 TAXES

The owners of PVNGS pay annual property taxes to Maricopa County, so the focus of this analysis is on Maricopa County.

From 2001 through 2006, Maricopa County collected between $2.7 and $3.7 billion annually in property tax revenues (see Table 2-4). Each year, Maricopa County collects these taxes, retains a portion for county operations, and disburses the remainder to the Saddle Mountain School District, county education services, a local community college, fire districts, the Central Arizona Water Conservation District, libraries, flood control programs, and the county healthcare district.

For the years 2001 through 2006, PVNGS' property taxes have represented 1.3 to 1.8 percent of Maricopa County's total tax revenues (Table 2-4). The plant's tax payments have remained relatively constant over the 6-year period, but the county's revenues have gradually increased. Therefore, in recent years, the plant's payments have represented an even smaller percentage of the county's total property tax revenues. Throughout the license renewal period, the plant's tax payments are expected to remain relatively constant.

2.8 LAND USE PLANNING

Maricopa County is the focus of this discussion because the majority (approximately 98 percent) of the permanent PVNGS workforce lives in this county (Section 3.4) and because PVNGS pays property taxes to Maricopa County. Maricopa County contains the Phoenix metropolitan area, a region which is locally referred to as the "Valley of the Sun" or "the Valley." For this section, subregions of the Valley are referred to as the "West Valley," "East Valley," "North Valley," or "South Valley."

Maricopa County covers 9,203 square miles of land (USCB 2006). From 1990 to 2000, Maricopa County's population growth rate was 44.8 percent, while the population of the state of Arizona grew 40 percent (Section 2.6). Over the same period, 1990 to 2000, the number of housing units in Maricopa County increased by 31.3 percent, while the total number of units in the state increased by 31.9 percent (USCB 1990; USCB 2000). In the year 2000, the Phoenix-Mesa-Scottsdale, MSA, which contains Maricopa County, was the 14th largest and 5th fastest growing MSA in the United States (Section 2.6.1). Recent county information (MAG 2007) indicates that in 2005 the Maricopa County population had grown to 3,681,025, a 20 percent increase over the year 2000.

In Arizona, land use in incorporated areas is generally controlled by local municipalities and land use in unincorporated areas is controlled by counties. However, as smaller municipalities have grown and merged with other municipalities, planning has become more of a regional and cooperative effort. In 1998, the Arizona Legislature passed the *Growing Smarter Act* and, in 2000, *Growing Smarter Plus*, to address these efforts. There are two primary long-range planning and policy development organizations for the Phoenix metropolitan region: the Maricopa County Planning and Development Department and the Maricopa Association of Governments (MAG). Both organizations have conducted research and planning, but the MAG's research and planning has been more extensive and is, therefore, the major source of the information for this section. The MAG-defined region, covering approximately 9,955 square miles, is comprised of Maricopa County and portions of Pinal and Yavapai Counties. MAG representatives include county, city, town, and Indian tribe officials. Approximately two-thirds of the MAG region's population growth has been through in-migration. The primary reasons for such growth have been ample employment opportunities, affordable housing, and a moderate cost of living. The majority of the in-migrating population comes from Rocky Mountain or Pacific states, especially California (MAG 2005).

Local and regional planners use comprehensive land use planning, zoning, and subdivision regulations to control development. They encourage growth in areas where public facilities such as water and sewer systems exist or are scheduled to be built in the future. They also promote the preservation of the communities' natural resources, but have no growth control measures. Table 2-5 details current and planned land use in the MAG region. More than half of the land in the MAG region is still available for development (MAG 2005).

Over the last several decades, the MAG region's urban development has been characterized as increasingly dispersed. The dispersal has been attributed to the region's flat topography and the availability of land on the edges of the urban areas. Most development has occurred in the West Valley, northern Pinal County, and the North Valley, however, all urban edges are being developed to some extent. Planners expect this trend to continue. From 2000 to 2004, the urbanized portion of the region expanded by 55,000 acres, approximately 33 acres per day (MAG 2005).

The highest population concentrations (more than 8,000 persons per square mile) have occurred on the west side of Phoenix (and extending to 91st Avenue), along the I-17 corridor between Thomas and Camelback Roads, and east of the Piestewa Freeway north of Loop 202. Other areas of high concentration are in Mesa, Tempe, and Glendale. Areas of lowest population concentration (less than 250 persons per square mile) are outside the boundaries of the regional transportation system (MAG 2005).

Since the early 1970s, major residential developments, called master planned communities, have become the preferred form of development. Because the MAG region has few topographical constraints, these developments have fueled the urban edge expansion. This kind of expansion has been experienced primarily in the West Valley, northern Maricopa County, and northern Pinal County. Maricopa County's active, planned and proposed major developments have the capacity to absorb the addition of 100,000 people annually for 20 more years (MAG 2005).

The highest concentrations of commercial development are located along the MAG region's major transportation corridors, primarily within the boundaries of those corridors (MAG 2005).

The protection of regional open space is a priority for regional planners. Concentrations of regional open space are located in the mountains, throughout the Valley, and in northeastern and southern Maricopa County.

The Arizona State Land Department (ASLD) is the largest nonfederal landholder in the MAG region. The ASLD owns approximately 14 percent of the land in the MAG region and is entrusted with assuring the "highest and best use" of the land. The majority of the land is in the north, northwest, and western part of Maricopa County. The land may be converted to any type of use, as approved by the ASLD (MAG 2005).

The PVNGS site boundary encloses approximately 4,280 acres, which includes approximately 605 acres of water in various large ponds (Figure 2-3 and Section 3.1.2). The PVNGS site is mostly flat, but scattered about the vicinity are small hills and buttes. Land use in the PVNGS' immediate vicinity is primarily rural, composed of open space and scattered low-density residential developments with lower-priced single family housing. Aside from the PVNGS site, there is little industrial or commercial activity in the vicinity.

2.9 SOCIAL SERVICES AND PUBLIC FACILITIES

2.9.1 Public Water Supply

Because PVNGS is located in Maricopa County, and the majority of the operations workforce resides there (Section 3.4), the discussion of public water supply systems is limited to Arizona and Maricopa County. PVNGS [potable and non-potable] water is supplied primarily through two of four groundwater wells on the station site and the purchase of reclaimed water from Tolleson, Phoenix, and Goodyear (Section 3.1.2). The reclaimed water is used for station operations other than human consumption and fire protection and is stored in reservoir(s) on the PVNGS site. Potable water is obtained primarily from two of the four groundwater wells on the site. Between 2001 and 2005, the PVNGS domestic water system averaged approximately 1,200 gallons per minute of groundwater. PVNGS water supplies are described in more detail in Sections 2.3, 2.11, 4.1, and 4.5.

Arizona

The subtropical desert climate and rapid population growth rates in Arizona inspired the Arizona Legislature, in 1980, to enact the 1980 Groundwater Management Code and create the Arizona Department of Water Resources (ADWR) (ADWR 2006). It was enacted to relieve a growing problem of groundwater overdraft in parts of Arizona by promoting water conservation and long-range water resources planning. Areas where groundwater overdraft concerns were the greatest were labeled Active Management Areas (AMAs); there are currently five (ADWR 2006). The ADWR has established a number of programs including underground storage and recovery (recharge) programs, the establishment of the Arizona Water Bank, and the Assured Water Supply Program that requires proof of a 100-year water supply before a subdivision plat within an AMA may be approved (ADWR 2006).

State officials project that, by 2025, Arizona’s population will exceed six million within the AMAs and an additional 1.8 million in the rest of the state (ADWR 2006). Substantial progress has been made in moving toward the use of sustainable water supplies, particularly in transitioning from primarily non-renewable, groundwater-based supplies to increasing dependence on surface water and reclaimed water, or “treated effluent.”

Water supplies in Arizona include Colorado River water, surface water other than Colorado River water, groundwater, and treated effluent (ADWR 2006).

Colorado River Water

The federal government constructed a system of reservoirs on the Colorado River for use in these states: Arizona, California, Nevada, New Mexico, Utah, Colorado, and Wyoming. Rights to use Colorado River water are quantified in a body of law known as the "Law of the River." Based on this body of law, Arizona has the right to use 2.8 million acre-feet annually of Colorado River water. At most, an average 1.5 million-acre feet of Colorado River water can be delivered to Maricopa, Pinal, and Pima Counties.

Surface water

Arizona's major renewable water resource is surface water from lakes, rivers, and streams. However, because of the desert climate, surface water supplies can vary dramatically. In order to best use surface water, storage reservoirs and delivery systems have been constructed throughout the state. Most notable are the major reservoir storage systems located on the Salt, Verde, Gila, and Agua Fria rivers. Almost all of the natural surface water in Arizona has been developed.

Groundwater

Groundwater contributes approximately 40 percent of the state's supply. Throughout this century, however, groundwater overdraft has been a concern in Arizona. Though a large amount of water remains stored in Arizona's aquifers, its availability is limited by location, depth and quality.

Treated effluent

Reclaimed water is the only source of water in which supplies are increasing in Arizona. As the population grows, so does treated wastewater that can be recycled. Reclaimed water is treated to a quality that can be used for purposes such as agriculture, golf courses, parks, industrial cooling, or maintenance of wildlife areas.

Maricopa County

Much of Maricopa County within the Phoenix AMA. The AMA is located in central Arizona, covers 5,646 square miles, and consists of seven groundwater basins (ADWR 2006). The AMA is characterized by a mix of water uses, with a heavy and increasing emphasis on municipal and industrial uses. Multiple sources of water (Colorado, Salt, and Verde Rivers water, treated effluent, and groundwater) are available. Annually, an average of approximately 2.3 million acre-feet of water is used in the AMA (ADWR 2006). Of that amount, 1.4 million acre-feet is renewable water (Colorado, Salt, and Verde Rivers water, and effluent) and 900,000 acre-feet is groundwater. The Phoenix AMA is currently in an overdraft condition in the amount of approximately 251,000 acre-feet annually (ADWR 2006). The Phoenix AMA is drained by the Gila River and four principal tributaries: the Salt, the Verde, the Agua Fria, and the Hassayampa Rivers. Other tributaries include Queen Creek, New River, Skunk Creek, Cave Creek, Waterman Wash, and Centennial Wash. Water storage reservoirs have been constructed on the Salt, Verde, Gila, and Agua Fria Rivers, enabling higher rates of surface annual precipitation annually (ADWR 2006).

Table 2-6 provides details of Maricopa County's largest municipal water suppliers, which have surface water sources.

2.9.2 Transportation

Maricopa County has experienced a high rate of population growth over the last two decades and a corresponding increase in demand on the transportation system. County development patterns have been largely low-density, suburban growth, with limited non-residential land use and few employment centers outside of the urban areas. High automobile dependency and two-worker households have also contributed to increased demand (Maricopa County 2002). Issues facing transportation planning officials in the area include: air quality, congestion, fuel taxation, an incomplete freeway system, insufficient public transit, low-density urban sprawl and an inefficient roadway network, and transportation funding sources (or lack thereof) (Maricopa County 2002). State and local government officials are planning transportation infrastructure upgrades and expansions to mitigate these issues (Maricopa County 2002). Maricopa County covers approximately 9,203 square miles (USCB 2006).

Interstate 10 is the nearest major roadway to PVNGS. It is approximately 6 miles north of the station and has an east-west orientation. The City of Phoenix is on Interstate 10, approximately 34 miles east. In Phoenix, Interstate 10 intersects with Interstate 17 and numerous state highways. Interstate 10 is a major trucking route connecting the area to Los Angeles to the west, and the southeastern United States to the east. Interstate 17 runs north-south through Phoenix to Flagstaff where it connects with Interstate 40 and markets in the Midwest. In addition, Interstate 8 provides access to southern California, connecting to Interstate 10 just south of Phoenix (Figures 2-1 and 2-2).

Road access to PVNGS is via Wintersburg Road (Figure 2-3). A few miles north of PVNGS, Wintersburg Road intersects with Salome Highway and, approximately 6 miles north, it intersects with Interstate 10. Employees traveling from the north, northwest, and west would use Salome Highway or Interstate 10 to reach the station. Employees traveling from the southwest, and south of PVNGS would use Elliot and Wintersburg Roads. Employees traveling from the northeast, east, southeast, and south would use Salome Highway or Interstate 10. During shift change, there is some congestion on the station's access road as vehicles await access to the station via the security gate, but it generally does not cause congestion on Wintersburg Road.

As part of its Environmental Health and Safety program at PVNGS, APS implements a travel reduction program. Because the Phoenix area is an EPA-designated non-attainment area for ozone and particulate matter, APS promotes employee travel reduction activities and offers subsidies to encourage employees to use alternative means of transportation. Subsidies cover a portion of the costs for vanpooling, bus fares, and carpool parking.

- Vanpooling -- APS maintains a fleet of 169 vans that operate daily for employees commuting between PVNGS and the Phoenix area. APS began operating this program in 1994 and there are currently over 1,230 participants. APS' total vanpool mileage averages between 2.8 and 3 million miles per year. APS' single occupancy rate of approximately 30% greatly exceeds the company's target of 60% single occupancy trips. This program removes over 500 vehicles from operation daily and the anticipated pollution savings is approximately 900,000 to 960,000 pounds of emissions per year.

- Travel reduction incentives – a subsidy toward vanpool expenses, a subsidy for employees who commute by bus, an exemption from parking fees (at headquarters) for carpools, reserved parking and an exemption from parking fees (at headquarters) for carpools with three or more people.

APS also accommodates compressed work weeks, telecommuting, and videoconferencing. As a result of these programs, APS has significantly reduced its contribution of pollutants and traffic congestion to the area.

In determining the significance levels of transportation impacts for license renewal, NRC uses the Transportation Research Board's level of service (LOS) definitions (NRC 1996). The Arizona Department of Transportation makes LOS determinations for selected roadways in the state. LOS data are unavailable and annual average daily traffic volumes are substituted. Table 2-7 lists roadways in the vicinity of PVNGS and the annual average number of vehicles per day, as determined by the Arizona Department of Transportation and the Maricopa County Department of Transportation.

Maricopa County is served by one international airport, the Phoenix Sky Harbor International Airport, which accommodates over 555,200 takeoffs and landings annually, and nine municipal airports (GPEC Undated).

Maricopa County is served by two transcontinental railroads, Union Pacific and Burlington Northern Santa Fe, and 10 intrastate railroads. The railroads provide freight services only and the nearest inter-modal facility is located off Interstate 10, near Grant and 67th Avenues (GPEC Undated).

2.10 METEOROLOGY AND AIR QUALITY

PVNGS is in Maricopa County in southwest Arizona, a region characterized by a desert-type climate. This area, which is in the Intermountain Plateau climatic zone, is the driest region of the U.S. Typical characteristics of this large, arid region include abundant sunshine, infrequent precipitation, low relative humidity, large diurnal temperature ranges, moderate wind speeds, and intense summer thunderstorms. The area normally experiences mid-afternoon temperatures above 100°F in the summer and relatively mild winter temperatures. Prevailing winds are from the southwest during the spring and summer months and from the east and northeast during the fall and winter months.

Arizona has a distinct two-season rainfall pattern (a winter season and a monsoon season). The first occurs during the winter months from November or December through the middle of March when the area is subjected to occasional storms from the Pacific Ocean. The second rainfall period (monsoon season) occurs during July and August when Arizona is subjected to widespread thunderstorm activity in which the moisture supply originates in the Gulf of Mexico, in the Pacific Ocean off the west coast of Mexico, and in the Gulf of California. May and June are the driest months.

The topography of the general area is generally flat with an approximate elevation of 950 feet above mean sea level (msl). The Palo Verde Hills, with a maximum elevation of 2,172 feet above msl, are located approximately 5 miles to the west and north of the site. Scattered hills with peak elevations of 1,100 feet above msl are located within 2 miles of the site (PVNGS 2006, Chapter 2). Meteorological information, as it relates to analysis of severe accidents, is described in Attachment D.

Under the Clean Air Act, the U.S. Environmental Protection Agency (EPA) has established National Ambient Air Quality Standards (NAAQS) that specify maximum concentrations for carbon monoxide (CO), particulate matter with aerodynamic diameters of 10 microns or less (PM_{10}), particulate matter with aerodynamic diameters of 2.5 microns or less ($PM_{2.5}$), ozone, sulfur dioxide (SO_2), lead, and nitrogen dioxide (NO_2) (40 CFR 50). Areas of the United States having air quality as good as or better than the NAAQS are designated by EPA as attainment areas. Areas having air quality that is worse than the NAAQS are designated by EPA as non-attainment areas. Those areas that were previously designated nonattainment and subsequently redesignated to attainment due to meeting the NAAQS are maintenance areas. States with maintenance areas are required to develop an air quality maintenance plan as an element of the State Implementation Plan (40 CFR 51; 40 CFR 81).

PVNGS is in the Maricopa, Arizona Intrastate Air Quality Control Region (AQCR) (40 CFR 81.36). Within the Maricopa AQCR, the Phoenix metropolitan area is designated as basic nonattainment with respect to the 8-hour ozone standard and serious nonattainment for PM_{10}. The Phoenix metropolitan area is also designated as a maintenance area under the CO standard. The remainder of the Maricopa AQCR, including the PVNGS site, is designated as an attainment area for all other NAAQS (40 CFR 81.303).

In October 2006, EPA issued a final rule that revises the 24-hour $PM_{2.5}$ standard and revokes the annual PM_{10} standard (71 FR 61144). Nonattainment designations for PM_{10} are not affected by the new rule, but additional nonattainment areas could be designated under the new $PM_{2.5}$ standard.

2.11 CULTURAL RESOURCES

Area History in Brief

Prehistory

The cultures that existed in the general region of southwestern Arizona in which the Palo Verde Hills are located were the Desert, Yuman, Hohokam, Pima, Spanish, and Anglo. The earliest known culture of the Palo Verde Hills – Hassayampa River area was the Desert Culture (7,000 B.C. to 100 A.D.). This culture reflected the difficulties of adjusting to the harsh environment of the area. The people were nomadic hunters and gatherers. Desert Culture remains include rock enclosures, core and flake tools, shrines, rock outlines, trails, and grinding implements (APS 1974).

The Desert Culture is believed to have been ancestral to the Yuman. Yuman-speaking people inhabited the lower Gila River Valley as late as the historic period. The Yuman included the Maricopa, Western Yavapai, Yuma, and the Cocomaricopa groups. The Yavapai were the easternmost of the Yuman groups and occupied western Arizona as early as the 16th century as hunters and gatherers, with marginal agricultural activity. The subgroup whose territory encompassed the PVNGS station site was the Western Yavapai. Small groups of Western Yavapai exploited all available ecological zones (desert, river, and mountain environments) searching for game and plants (APS 1974).

The Maricopa and Cocomaricopa were riverine agricultural groups that moved along the Gila River in response to pressure from the Yavapai and other Yumans. Trails were constructed by the Yuman people for travel, trade, and war (APS 1974).

The Hohokam Culture dominated the southern half of Arizona from 300 B.C. to 1,400 A.D., and is noted for extensive canal irrigation farming (APS 1974).

The Pima Culture descended from the Hohokam Culture and consisted of two groups: Papago Indians, to 1,400 A.D, and Pima Indians, from approximately 1,400 A.D. to 1,600 A.D. Both cultures emphasized irrigation agriculture. There is little evidence of the Pima occupation in the Palo Verde Hills – Hassayampa River area (APS 1974).

History

European contact with the area began with the Spanish conquistadores such as Coronado, de Niza, Diaz, and others who traveled along the south and east sides of the Gila River in the 1500s and 1600s. Their influence was minimal and little information exists on their movement through the Palo Verde Hills. On the basis of these early explorations, the State of Arizona, including what is now Maricopa County, was claimed by Spain around 1537 (APS 1974).

Not until the United States–Mexican War of 1846 did the Palo Verde Hills–Hassayampa River area first attract settlers. Of particular significance to this region during the Mexican War were the United States military activities commanded by General Kearney and Lt. Colonel Cooke. General Kearney traveled across Arizona in 1846 and his supply column traveled a slightly different route under the command of Lt. Colonel Cooke. The column traveled down the San Pedro River to the Pima Indian Villages and cut across the desert to reach the Gila River near the present-day city of Gila Bend. The routes set by Kearney and Cooke set the pattern for future travel and settlement through this region of Arizona (APS 1974).

In the mid 1800s, during the California gold rush, prospectors on the way to California passed through the region on the routes set by Kearney and Cooke. Prospecting activities commenced in this area as well. The increase in mining activity fueled greater conflict with the Indians, prompting the United States to increase its military there. Mining and military activities served as catalysts in furthering regional development. The forts and mining settlements offered a market for produce and livestock and provided the foundation for irrigated farming along the Gila River. Beginning in 1857 and 1858, mail was carried over the Cooke trail. Phoenix was founded in 1865 and Tempe was founded in 1871. Commercial settlements also developed along the Salt River (APS 1974). Maricopa County was officially established in 1871. The county was named in honor of the Maricopa Indians. Maricopa County's boundaries were set in 1881 and have not changed since (Maricopa County 2006). Completion of the Southern Pacific Railway in 1882 linked the area to the rest of the nation (APS 1974).

Wintersburg, the town nearest the PVNGS site, is an agriculturally-based community that was settled by World War I veteran homesteaders who had hopes of receiving government-sponsored irrigation. The irrigation project never developed. Some people attempted farming with pump wells, but many departed after establishing their claims. Evidence of these early farming attempts has been recorded in the area (APS 1974).

Initial Operation

In the Final Environmental Statement (FES) for operation of PVNGS (NRC 1982), NRC stated that there were no historic properties, natural areas, or scenic features on or near the PVNGS site. NRC reported that, based on an archaeological survey of the station site by the Museum of Northern Arizona (APS-contracted), there were 13 archaeological sites on the PVNGS site and a number of others in the site vicinity. NRC also reported that the archaeological evidence at these sites had been preserved and analyzed to the satisfaction of the Arizona State Historic Preservation Officer (SHPO) (NRC 1982).

In addition to a survey of the station site, APS contracted with the Museum of Northern Arizona to evaluate the wastewater conveyance pipeline right-of-way, from the 91st Avenue Sewage Treatment Plant to the PVNGS site (NRC 1982). This identified 13 archaeological sites near the right-of-way. NRC reported that there were no registered historic properties located in or near the pipeline right-of-way (NRC 1982).

When planning for transmission line construction, APS developed four projects, labeled, Projects 1, 2, 3, and 4. Projects 1 and 3 are described below. Projects 2 and 4 were cancelled before the FES was published. In Project 1, three 525 kilovolt lines were to be constructed: Westwing substation (44 miles), Kyrene Generating Station (82 miles), and Saguaro substation (121 miles), but the line to Saguaro was never constructed (NRC 1982). In Project 3, a 345-kilovolt line was to run 195 miles from the Greenlee substation in Greenlee County, Arizona to the Rio Grande Generating Station near El Paso, Texas and would not actually connect to PVNGS. Not part of one of the numbered projects was another 525-kilovolt line that was to be constructed to the Devers substation (235 miles) in southern California.

A number of archaeological sites were identified along the routes. Two sites were excavated and their contents analyzed. The Bureau of Land Management, Arizona SHPO, and the Advisory Council on Historic Prevention determined that five sites found along the Kyrene corridor would not be adversely affected by the transmission line. NRC reported that there were no historic properties located in or near the Project 1 transmission line corridors (NRC 1982).

For the proposed route in Project 3, NRC reported that archaeological surveys performed by the New Mexico Environmental Institute indicated minimal impact on archaeological sites. No historic properties or natural features were located on this route (NRC 1982).

Finally, in the FES-OP, NRC concluded that, based on the surveys undertaken and the mitigation plans developed, the operation of PVNGS would not adversely impact existing archaeological resources or historic sites. NRC staff committed to work with APS to get a formal determination of eligibility to the Keeper of the National Register for four sites in the wastewater conveyance system and a letter from the New Mexico SHPO on the sites in the Project 3 corridor (NRC 1982).

Current Status

PVNGS has *Procedure 91DP-0EN02*, which describes how to perform an environmental (including cultural resources) review of proposed changes to the facility, plant operation, procedures, or proposed tests or experiments. An environmental review and evaluation is used to identify if the proposed change is an unreviewed environmental condition requiring prior NRC approval and also to identify if any environmental permits (local, state, or federal) are required or need to be modified. Thus, the procedure identifies the need to assess whether cultural resources will be impacted.

Environmental reviews are performed by the APS Environmental Department and the Department makes recommendations for completing a proposed project. An example of a recent project requiring a cultural resources evaluation is the construction of Evaporation Pond No. 3 on APS property south of the existing ponds. In 2006, a cultural survey was conducted on approximately 526 acres. Based on the results of the survey (ACS 2006), it was determined that no historic properties would be affected by the construction of the Evaporation Pond No. 3.

Additionally, APS is performing a Class III cultural resource survey of the entire APS transmission system to 1) inventory the system for long-term environmental planning purposes, and 2) prepare for a large-scale vegetation maintenance project that will be implemented in the future. The survey will cover all transmission lines, 69 kV and above, and is scheduled to be completed within four years. The transmission lines included in the scope of this ER have yet to be surveyed.

An additional safeguard is found in PVNGS Procedure 37DP-9ZZ11 (Excavation, Placement and Backfill). This procedure requires that "all work activities should be stopped and the Environmental Department contacted if an artifact (e.g. an item of possible historical or archeological interest) is found during any earthmoving or excavation activities."

As of 2008, the National Register of Historic Places (NRHP) lists 328 locations in Maricopa County (U.S. Department of the Interior 2008). Of these 328 locations, one (the Hassayampa River Bridge), falls within 6 miles of PVNGS property. The Hassayampa River Bridge was added to the list in 1988 and is on Old U.S. 80, spanning the Hassayampa River. As of 2006, the NRHP lists 55 locations that have been determined eligible for inclusion in the NRHP, in Maricopa County (U.S. Department of the Interior 2006). Of these 55 locations, none fall within 6 miles of PVNGS property.

2.12 OTHER PROJECTS AND ACTIVITIES

As indicated on Figure 2-2, there are few urban areas and little industrial development within the 6-mile radius of PVNGS. There are no Federal projects nearby that could provide environmental impacts cumulative to PVNGS operations. Nevertheless, there are several nearby power plants within what is termed the Palo Verde Hub. These plants are indicated on Figure 2-2.

Commissioned in 2002 by APS, the Red Hawk Power Station is a two-unit combined-cycle natural gas-fired plant that produces a total of 1,060 megawatts of electricity. The plant uses approximately 4 million gallons per day of makeup water from the PVNGS Water Reclamation Facility (approximately 7 percent of production) and does not discharge any wastewater. It is 3 miles south of PVNGS.

The Mesquite Power Generating Station was built by Mesquite Power, a wholly-owned subsidiary of Sempra Generation. It is a 1,250 megawatt, gas-fired combined-cycle facility. This single-unit facility is 3 miles south of PVNGS and is directly west of the Red Hawk plant.

The Arlington Valley Energy Facility is another single-unit, combined-cycle plant south of Palo Verde. It was commissioned in 2002 by Duke Energy. The plant produces 570 megawatts of electrical power. The plant is directly west of the Mesquite plant as indicated on Figure 2-2.

The New Harquahala Generating Company, an affiliate of Pacific Gas & Electric, began operation of the Harquahala Generating Station in 2003. It is approximately 17 miles northwest of PVNGS and is an 1,100 megawatt, gas-fired, combined-cycle facility. This station is not considered part of the Palo Verde Hub.

Located between the Red Hawk and Mesquite stations, the 525-kilovolt Hassayampa substation provides interconnections within the Palo Verde Hub. This substation is owned by the Salt River Project and is directly connected to PVNGS, Red Hawk, Mesquite, Arlington Valley, and Harquahala stations.

A related project is the Palo Verde-to-Devers No. 2 transmission line project. This project would not connect to PVNGS but to the Harquahala station near the Palo Verde hub. If constructed, it would parallel the existing Palo Verde to Devers No. 1 line (Section 3.1.3). The 230-mile line traverses the northern boundary of the Kofa National Wildlife Refuge on its way to the Devers substation north of Palm Springs, California. The Arizona Corporation Commission has rejected the construction of this line, so it may not be constructed.

Another project is the Palo Verde Hub-to-TS-5 substation 525-kilovolt transmission line project. This line would run from a new switchyard near the Harquahala station to a substation north of Buckeye, Arizona. This APS line, scheduled for operation 2009, would run approximately 29 miles (APS 2005).

2.13 TABLES AND FIGURES

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California).

Scientific Name	Common Name	Federal Status[1]	State Status		County[4]
			AZ[2]	CA[3]	
Birds					
Aechmophorus clarkii	Clark's grebe	-	WC	-	La Paz
Ardea alba	Great egret	-	WC	-	La Paz, Maricopa
Buteogallus anthracinus	Common black hawk	-	WC	-	Maricopa
Ceryle alcyon	Belted kingfisher	-	WC	-	Maricopa
Charadrius alexandrinus nivosus	Western snowy plover	T[5]	WC	-	Maricopa
Coccyzus americanus occidentalis	Western yellow billed cuckoo	C	WC	E	La Paz, Maricopa, Riverside
Dendrocygna autumnalis	Black bellied whistling duck	-	WC	-	Maricopa
Empidonax traillii extimus	Southwestern willow flycatcher	E	WC	E	La Paz, Maricopa, Riverside
Falco peregrinus anatum	American peregrine falcon	-	WC	E	La Paz, Maricopa
Glaucidium brasilianum cactorum	Cactus ferruginous pygmy-owl	-	WC	-	Maricopa
Haliaeetus leucocephalus	Bald eagle	-	WC	E	La Paz, Maricopa, Riverside
Ictinia mississippiensis	Mississippi kite	-	WC	-	Maricopa
Ixobrychus exilis	Least bittern	-	WC	-	La Paz, Maricopa
Laterallus jamaicensis coturniculus	California black rail	-	WC	T	La Paz

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California). (Continued)

Scientific Name	Common Name	Federal Status[1]	State Status		County[4]
			AZ[2]	CA[3]	
Pandion haliaetus	Osprey	-	WC	-	Maricopa
Pelecanus occidentalis	Brown pelican	E	WC	E	La Paz, Maricopa, Riverside
Polioptila californica californica	Coastal California gnatcatcher	T	-	-	Riverside
Rallus longirostris yumanensis	Yuma clapper rail	E	WC	T	La Paz, Maricopa, Riverside
Sterna antillarum browni	California least tern	E	-	E	Riverside
Strix occidentalis lucida	Mexican spotted owl	T	WC	-	Maricopa
Vireo bellii pusillus	Least Bell's vireo	E	-	E	Riverside
Mammals					
Antilocapra americana sonoriensis	Sonoran pronghorn	E	WC	-	Maricopa
Dipodomys merriami parvus	San Bernardino kangaroo rat	E	-	-	Riverside
Dipodomys stephensi	Stephens' kangaroo rat	E	-	T	Riverside
Lasiurus blossevillii	Western red bat	-	WC	-	La Paz, Maricopa
Lasiurus xanthinus	Western yellow bat	-	WC	-	La Paz, Maricopa
Leptonycteris curasoae yerbabuenae	Lesser long nosed bat	E	WC	-	Maricopa
Macrotus californicus	California leaf nosed bat	-	WC	-	La Paz, Maricopa
Ovis canadensis	Peninsular bighorn sheep	E	-	E	Riverside
Panthera onca	Jaguar	E	WC	-	Riverside

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California). (Continued)

Scientific Name	Common Name	Federal Status[1]	State Status		County[4]
			AZ[2]	CA[3]	
Spermophilus tereticaudus chlorus	Palm Springs ground squirrel	C	-	-	Riverside
Reptiles					
Eumeces gilberti arizonensis	Arizona skink	-	WC	-	Maricopa
Gopherus agassizii (Sonoran population)	Sonoran desert tortoise	SAT	WC	-	La Paz, Maricopa
Gopherus agassizii (Mojave population)	Mojave desert tortoise	T	WC	T	Riverside
Uma inornata	Coachella Valley fringe-toed lizard	T	-	E	Riverside
Uma scoparia	Mojave fringe toed lizard	-	WC	-	La Paz
Thamnophis eques megalops	Northern Mexican gartersnake	-	WC	-	Maricopa
Amphibians					
Batrachoseps aridus	Desert slender salamander	E	-	E	Riverside
Bufo californicus	Arroyo toad	E	-	-	Riverside
Gastrophryne olivacea	Great Plains narrow-mouthed toad	-	WC	-	Maricopa
Pternohyla fodiens	Lowland burrowing treefrog	-	WC	-	Maricopa
Rana aurora draytoni	California red-legged frog	T	-	-	Riverside
Rana muscosa	Mountain yellow-legged frog	E	-	-	Riverside
Rana yavapaiensis	Lowland leopard frog	-	WC	-	La Paz, Maricopa
Fish					
Catostomus santaanae	Santa Ana sucker	T	-	-	Riverside
Catostomus sp. 3	Little Colorado sucker	-	WC	-	Maricopa
Cyprinodon macularius	Desert pupfish	E	WC	E	La Paz, Maricopa, Riverside
Gila elegans	Bonytail chub	E	WC	E	La Paz, Maricopa, Riverside
Gila robusta	Roundtail chub	-	WC	-	Maricopa
Gila intermedia	Gila chub	E	WC	-	Maricopa

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California). (Continued)

Scientific Name	Common Name	Federal Status[1]	State Status AZ[2]	State Status CA[3]	County[4]
Poeciliopsis occidentalis occidentalis	Gila topminnow	E	WC	-	La Paz, Maricopa
Ptychocheilus lucius	Colorado squawfish	E	WC	E	Riverside
Xyrauchen texanus	Razorback sucker	E	WC	E	La Paz, Maricopa, Riverside
Invertebrates					
Branchinecta lynchii	Vernal pool fairy shrimp	T	-	-	Riverside
Euphydryas editha quino	Quino checkerspot butterfly	E	-	-	Riverside
Rhaphiomidas terminatus abdominalis	Delhi Sands flower-loving fly	E	-	-	Riverside
*Streptocephalus wootton*i	Riverside fairy shrimp	E	-	-	Riverside
Vascular Plants					
Abutilon parishii	Pima Indian mallow	-	SR	-	Maricopa
Agave arizonica	Arizona agave	E	HS	-	Maricopa
Agave delamateri	Tonto Basin agave	-	HS	-	Maricopa
Agave murpheyi	Hohokam agave	-	HS	-	Maricopa
Agave toumeyana bella	Toumey agave	-	SR	-	Maricopa
Allium bigelovii	Bigelow onion	-	SR	-	Maricopa
Allium munzii	Munz's onion	E	-	T	Riverside
Ambrosia pumila	San Diego ambrosia	E	-	-	Riverside
Astragalus lentiginosus coachellae	Coachella Valley milk-vetch	E	-	-	Riverside
Astragalus tricarinatus	Triple-ribbed milk-vetch	E	-	-	Riverside
Atriplex coronata notatior	San Jacinto Valley crownscale	E	-	E	Riverside
Berberis nevinii	Nevin's barberry	E	-	E	Riverside
Brodiaea filifolia	Thread-leaved brodiaea	T	-	E	Riverside

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California). (Continued)

Scientific Name	Common Name	Federal Status[1]	State Status		County[4]
			AZ[2]	CA[3]	
Ceanothus ophiochilus	Vail Lake ceanothus	T	-	E	Riverside
Dodecahema leptoceras (Centrostegia l.)	Slender-horned spineflower	E	-	E	Riverside
Echinomastus erectocentrus acunensis	Acuna cactus	C	HS	-	Maricopa
Eriastrum densifolium sanctorum	Santa Ana River woolly-star	E	-	E	Riverside
Erigeron parishii	Parish's daisy	T	-	-	Riverside
Erigeron piscaticus	Fish Creek fleabane	-	SR	-	Maricopa
Eriogonum ripleyi	Ripley wild buckwheat	-	SR	-	Maricopa
Eryngium aristulatum parishii	San Diego button celery	E	-	E	Riverside
Ferocactus cylindraceus cylindraceus	California barrel cactus	-	SR	-	Maricopa
Ferocactus cylindraceus eastwoodiae	Golden barrel cactus	-	SR	-	Maricopa
Ferocactus emoryi	Emory's barrel cactus	-	SR	-	Maricopa
Fremontodendron californicum	Flannel bush	-	SR	-	Maricopa
Mammillaria viridiflora	Varied fishhook cactus	-	SR	-	La Paz, Maricopa

Table 2-1. Endangered and Threatened Species Recorded in La Paz and Maricopa Counties (Arizona) and Riverside County (California). (Continued)

Scientific Name	Common Name	Federal Status[1]	State Status		County[4]
			AZ[2]	CA[3]	
Navarretia fossalis	Spreading navarretia	T	-	-	Riverside
Opuntia echinocarpa	Straw top cholla	-	SR	-	La Paz, Maricopa
Opuntia engelmannii flavispina	Cactus apple	-	SR	-	Maricopa
Orcuttia californica	California orcutt grass	E	-	E	Riverside
Phacelia stellaris	Brand's phacelia	C	-	-	Riverside
Pholisma arenarium	Scaly sandplant	-	HS	-	La Paz
Purshia subintegra	Arizona cliff rose	E	HS	-	Maricopa
Stenocereus thurberi	Organ pipe cactus	-	SR	-	Maricopa
Trichostema austromontanum compactum	Hidden Lake bluecurls	T	-	-	Riverside
Tumamoca macdougalii	Tumamoc globeberry	-	SR	-	Maricopa

1. E = Endangered; T = Threatened; C = Candidate; SAT = Similarity of Appearance (Threatened); PD = proposed delisting; - = Not listed (USFWS 2006a).
2. Arizona (AZ): WC = Wildlife of special concern; HS = Highly safeguarded, no collection allowed (plants); SR = Salvage restricted, collection only with permit (plants); - = Not listed (AGFD 2006).
3. California (CA): E = Endangered; T = Threatened; - = Not listed (CDFG 2006)
4. Source of County Occurrence: AGFD 2006, USFWS 2006b, USFWS 2006c
5. The Western snowy plover is federally listed as threatened in California, Oregon, and Washington, and is not federally listed elsewhere (USFWS 2006a).

Table 2-2. Estimated Population and Decennial Growth Rates.

Population and Decennial Growth Rate				
	Maricopa County		**Arizona**	
Year	Number	Percent	Number	Percent
1980[a]	1,509,052	--	2,718,215	--
1990[a]	2,122,101	40.6%	3,665,228	34.8%
2000[b]	3,072,149	44.8%	5,130,632	40.0%
2010[c]	4,217,427	37.3%	6,999,810	36.4%
2020[c]	5,276,074	25.1%	8,779,567	25.4%
2030[c]	6,207,980	17.7%	10,347,543	17.9%
2040[c]	7,009,664	12.9%	11,693,553	13.0%
2050[c]	7,661,423	9.3%	12,830,829	9.7%

[a]USCB (1995)
[b]USCB (2000)
[c]AWI (2006)

Table 2-3. Environmental Justice Summary.

Block Groups within 50 miles of PVNGS with minority or low-income populations more than 20% greater than the state percentage.										
County Name	**Number of Block Groups**	**Black**	**American Indian or Alaskan Native**	**Asian**	**Native Hawaiian or Other Pacific Islander**	**Some Other Race**	**Multi-Racial**	**Aggregate**	**Hispanic**	**Low-Income Households**
La Paz	3	0	0	0	0	0	0	0	0	0
Maricopa	1245	21	2	3	0	194	6	247	363	108
Pinal	4	0	2	0	0	0	0	2	0	0
Yavapai	2	0	0	0	0	0	0	0	0	0
Yuma	2	0	0	0	0	0	0	0	1	0
TOTALS:	**1256**	**21**	**4**	**3**	**0**	**194**	**6**	**249**	**364**	**108**
Block Groups within 50 miles of PVNGS with minority or low-income populations greater than 50%.										
County Name	**Number of Block Groups**	**Black**	**American Indian or Alaskan Native**	**Asian**	**Native Hawaiian or Other Pacific Islander**	**Some Other Race**	**Multi-Racial**	**Aggregate**	**Hispanic**	**Low-Income Households**
La Paz	3	0	0	0	0	0	0	0	0	0
Maricopa	1245	2	2	1	0	36	2	176	321	21
Pinal	4	0	2	0	0	0	0	2	0	0
Yavapai	2	0	0	0	0	0	0	0	0	0
Yuma	2	0	0	0	0	0	0	0	1	0
TOTALS:	**1256**	**2**	**4**	**1**	**0**	**36**	**2**	**178**	**322**	**21**
		Black	**American Indian or Alaskan Native**	**Asian**	**Native Hawaiian or Other Pacific Islander**	**Some Other Race**	**Multi-Racial**	**Aggregate**	**Hispanic**	**Low-Income Households**
Arizona Percentages		3.10	4.99	1.80	0.13	11.63	2.86	24.50	25.25	11.79
Source: TtNUS (2006)										

Table 2-4. PVNGS Generating Station Tax Information 2001-2006.

Year	Maricopa County Tax Revenues[a]	Total Property Tax Paid by All PVNGS Owners[b]	Percent of Maricopa County Revenues
2001	$2,659,615,708	$46,435,850	1.8
2002	$2,854,130,768	$44,299,997	1.6
2003	$3,096,828,870	$50,646,767	1.6
2004	$3,299,298,161	$51,113,977	1.6
2005	$3,539,611,438	$53,047,288	1.5
2006	$3,709,344,714	$46,819,639	1.3

[a]Maltagliati (2007a)
[b]Maltagliati (2007b)

Table 2-5. Existing and Planned Land Use in the MAG Region.

Developed Land Use, 2004		
Land Use Category	***Square Miles***	***Percent of Total***
Residential	530	12.0
Employment-Generating	220	5.0
Mixed Use	--	0.0
Open Space/Nondevelopable	3,400	77.3
Other	250	5.7
Total	4,400	100.0
Planned Undeveloped Land Use		
Land Use Category	***Square Miles***	***Percent of Total***
Residential	3,350	68.4
Employment-Generating	150	3.1
Mixed Use	410	8.4
Open Space/Nondevelopable	980	20.0
Other	10	0.2
Total	4,900	100.0
Future Land Use – Existing and Planned		
Land Use Category	***Square Miles***	***Percent of Total***
Residential	3,880	41.7
Employment-Generating	370	4.0
Mixed Use	410	4.4
Open Space/Nondevelopable	4,380	47.1
Other	260	2.8
Total	9,300	100.0
Source: MAG (2005)		

Table 2-6. Major Maricopa County Public Water Suppliers.

Water Supplier	Total Treated Water Delivered (2005) (Acre-Feet)	Maximum Permitted Capacity (2006) (Acre-Feet)
City of Chandler	54,165	77,487
Town of Gilbert	37,105	44,065
City of Glendale	44,364	64,179
City of Mesa	90,870	121,944
City of Peoria	21,797	41,684
City of Phoenix	302,364	450,116
City of Scottsdale	76,025	106,405
City of Tempe	49,800	77,222
Source: EPA (2006), House (2006)		

Table 2-7. Traffic Counts for Roads in the Vicinity of PVNGS.

Roadway and Location	Annual Average Daily Traffic (AADT)
I-10, Exit 81, Salome Hwy., to Exit 94, 411th Ave. - Tonopah	25,700[a] (2005)
I-10, Exit 94, Tonopah, to Exit 98, Wintersburg Rd.	25,200[a] (2005)
I-10, Exit 98, Wintersburg Rd., to Exit 103, 339th Ave.	22,100[a] (2005)
I-10, Exit 103, 339th Ave., to Exit 109, Palo Verde Rd.	25,300[a] (2005)
I-10, Exit 109 Palo Verde Rd., to Exit 112, SR 85 / Oglesby Rd.	25,800[a] (2005)
I-10, Exit 112, SR 85 / Oglesby Rd., to Exit 114, Miller Rd.	43,800[a] (2005)
Wintersburg Rd. from I-10 to Van Buren	3,389[c] (2006)
Wintersburg Rd. from Van Buren to Salome Road	3,255[c] (2006)
Wintersburg Rd. from Salome Road to Elliott	4,788[c] (2006)
Elliot Road, at 355th Ave.	275[b] (1997-2003 avg.)
Elliot Road, at 383rd Rd.	162[b] (1997-2003 avg.)

[a]ADOT (2005)
[b]MCDOT (2004)
[c]Hiatt (2007)

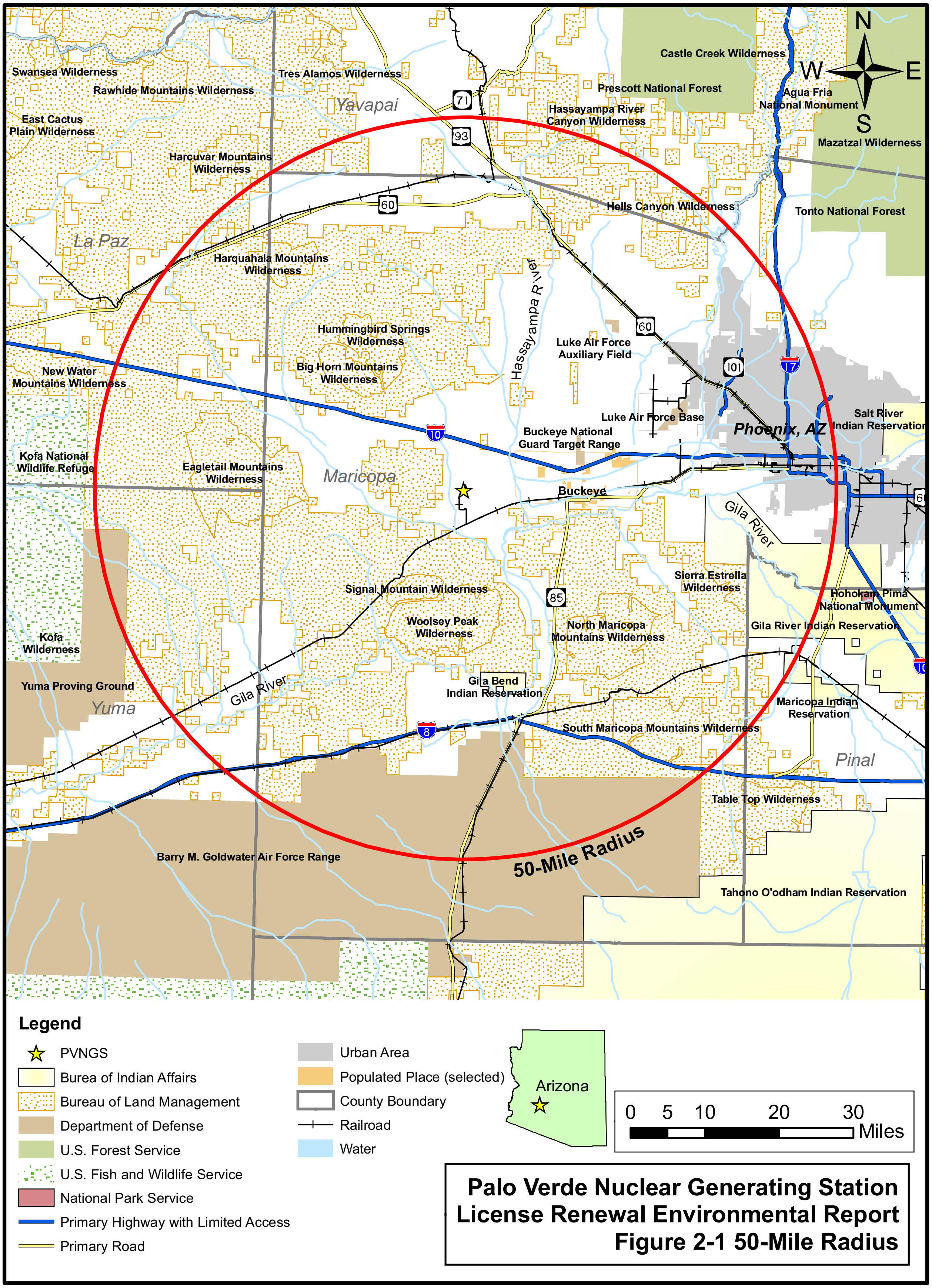

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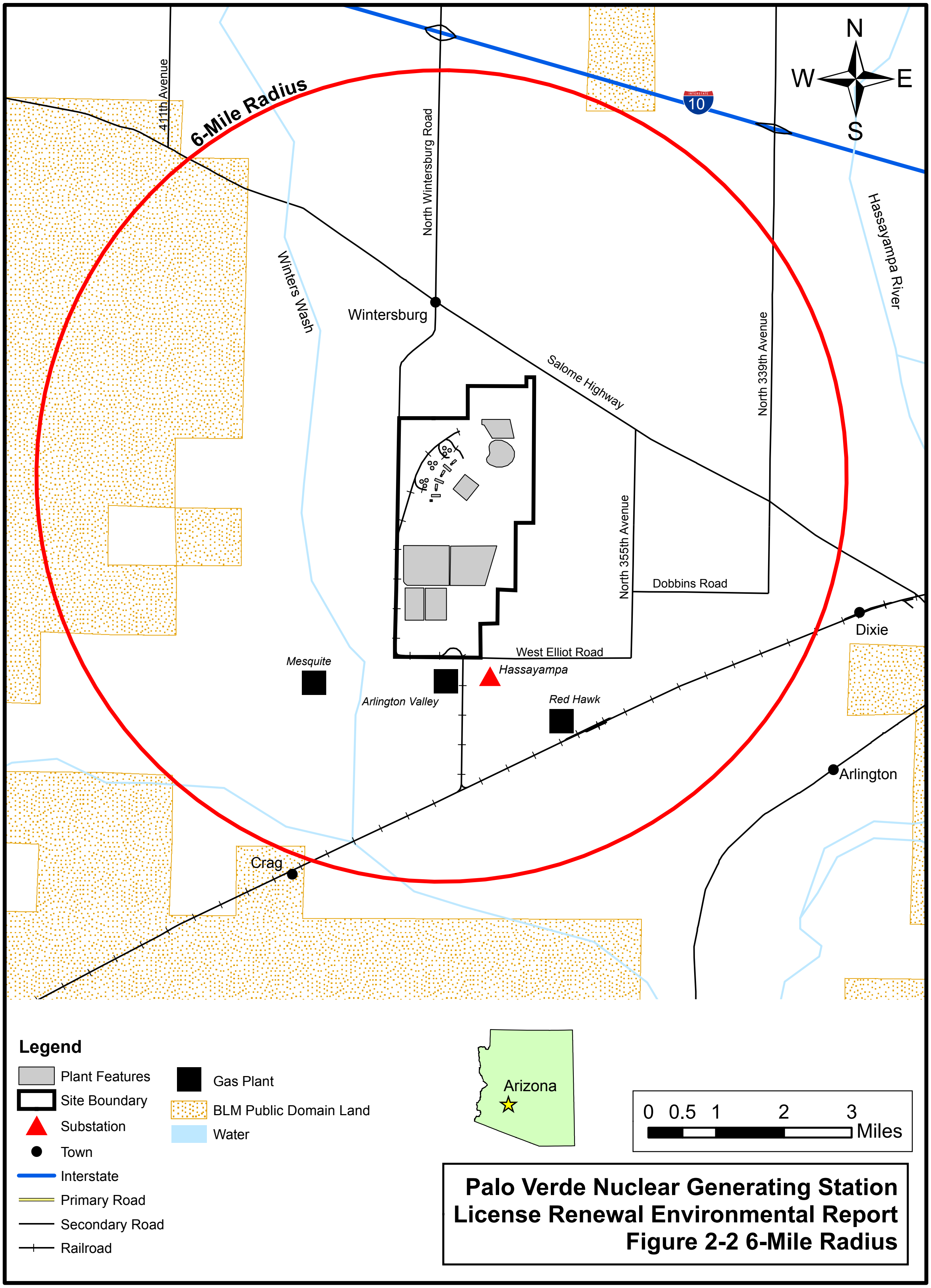
Figure 2-1 50-Mile Radius



Palo Verde Nuclear Generating Station License Renewal Environmental Report Figure 2-2 6-Mile Radius

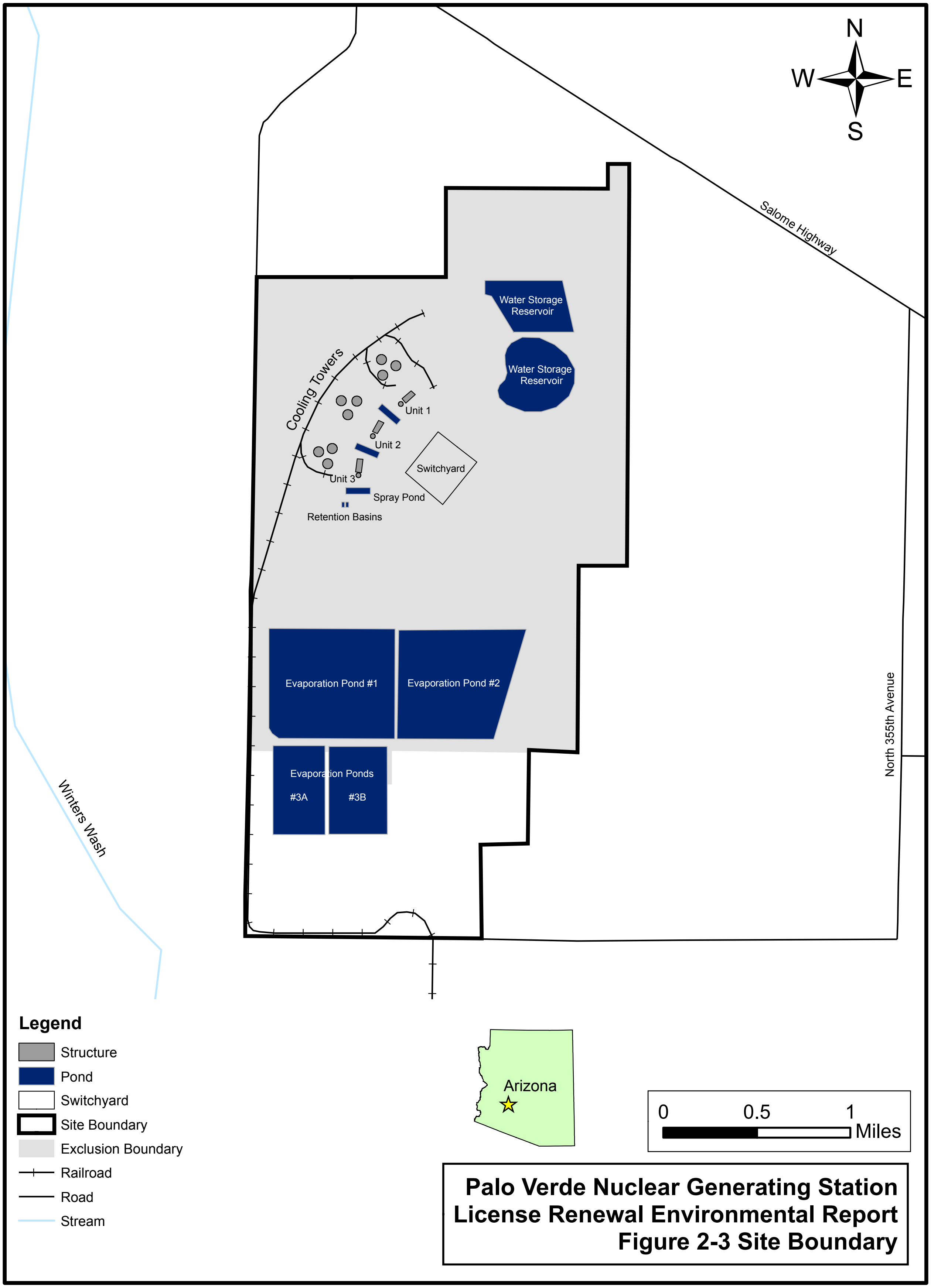


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Figure 2-3 Site Boundary

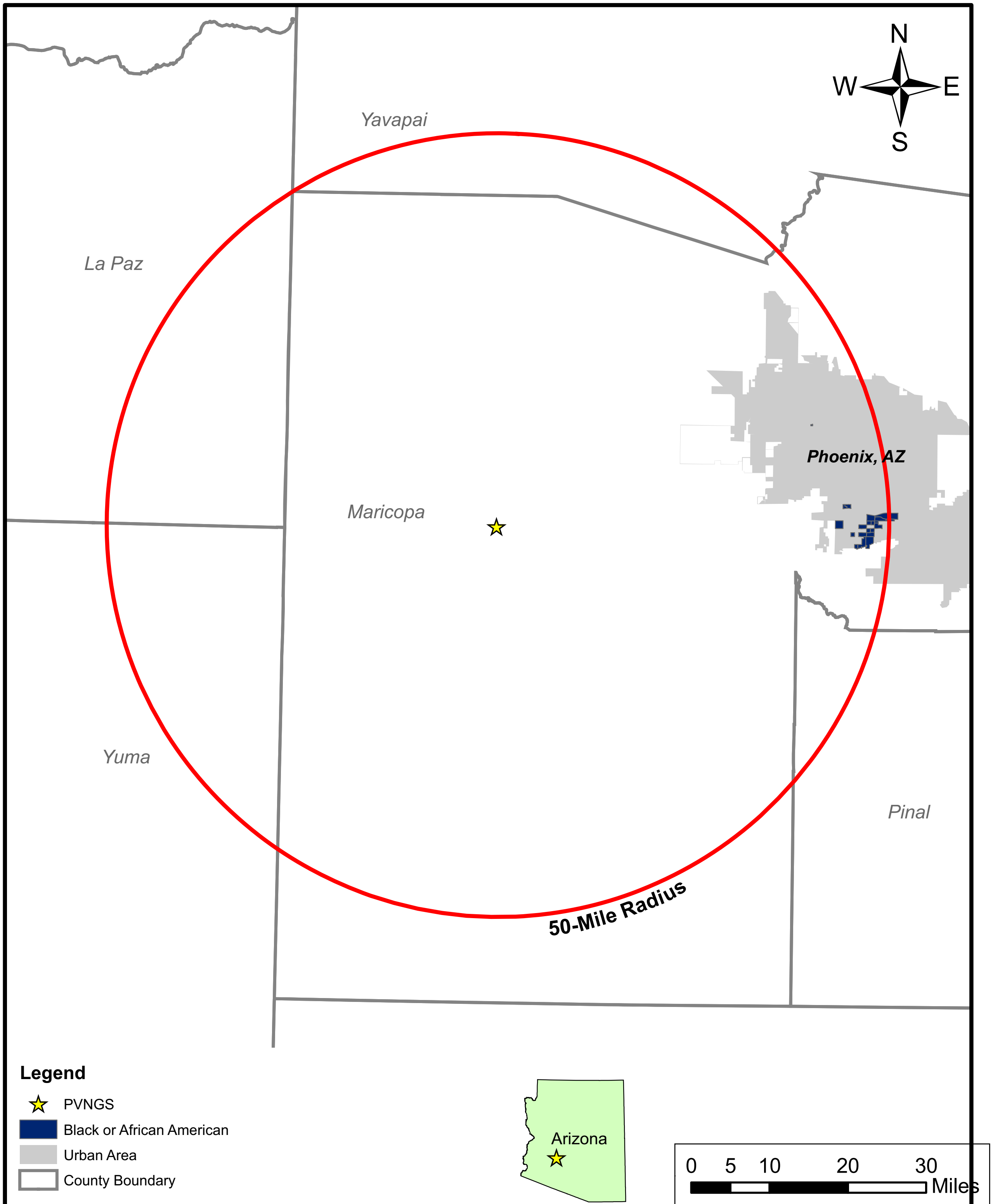

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Figure 2-4 Black Races Minority Population

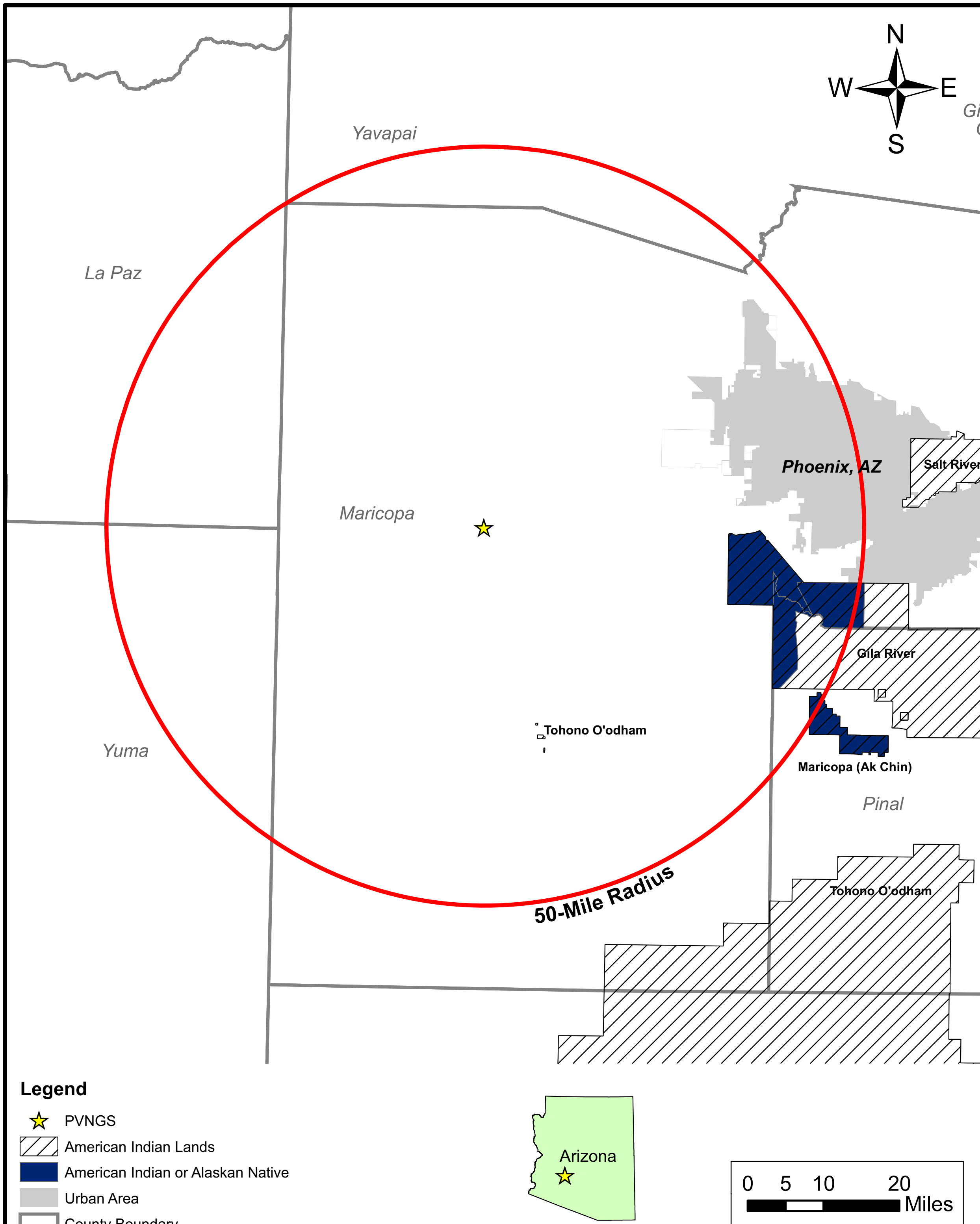

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Figure 2-5 American Indian or Alaskan Native Minority Population

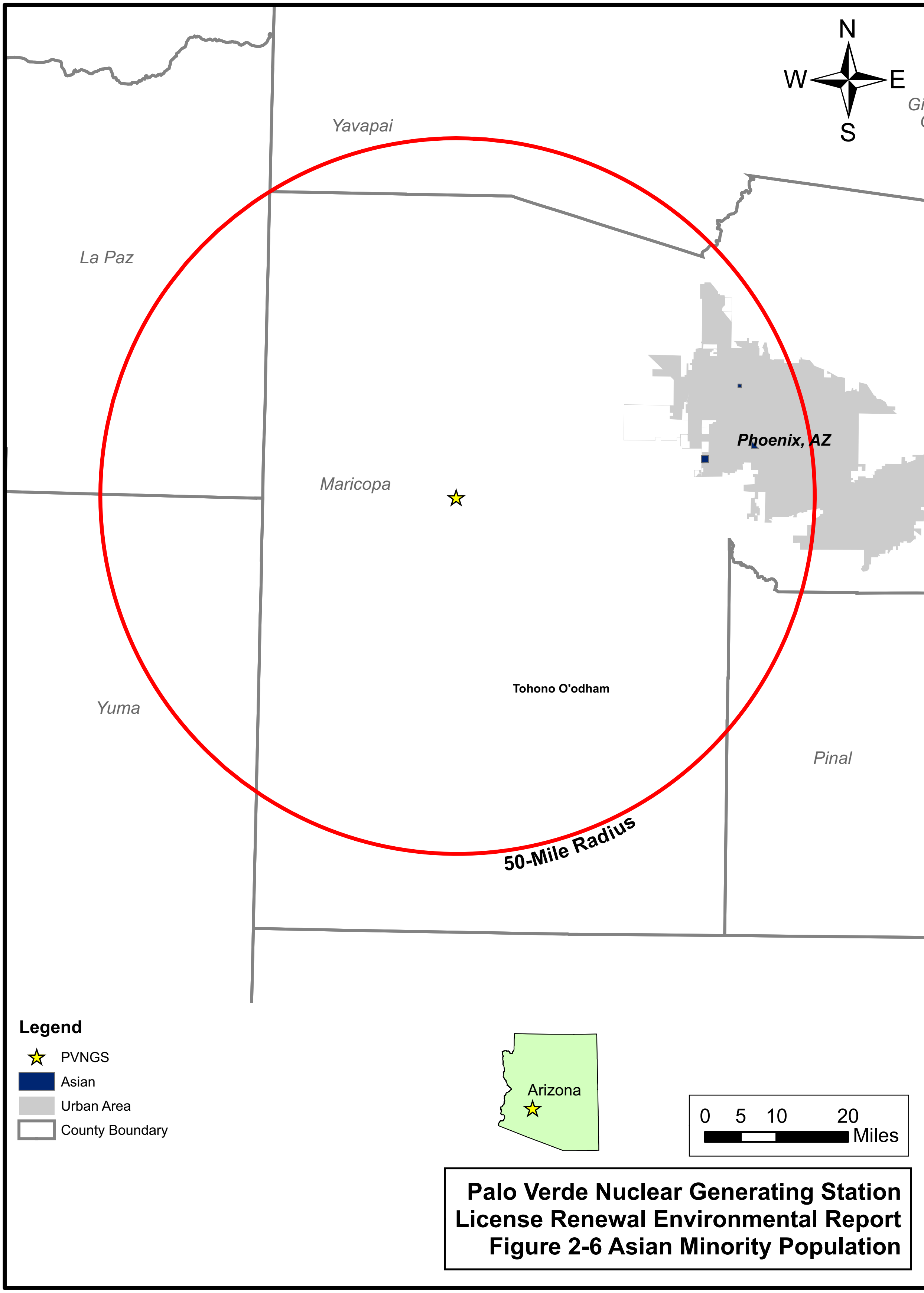

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Figure 2-6 Asian Minority Population

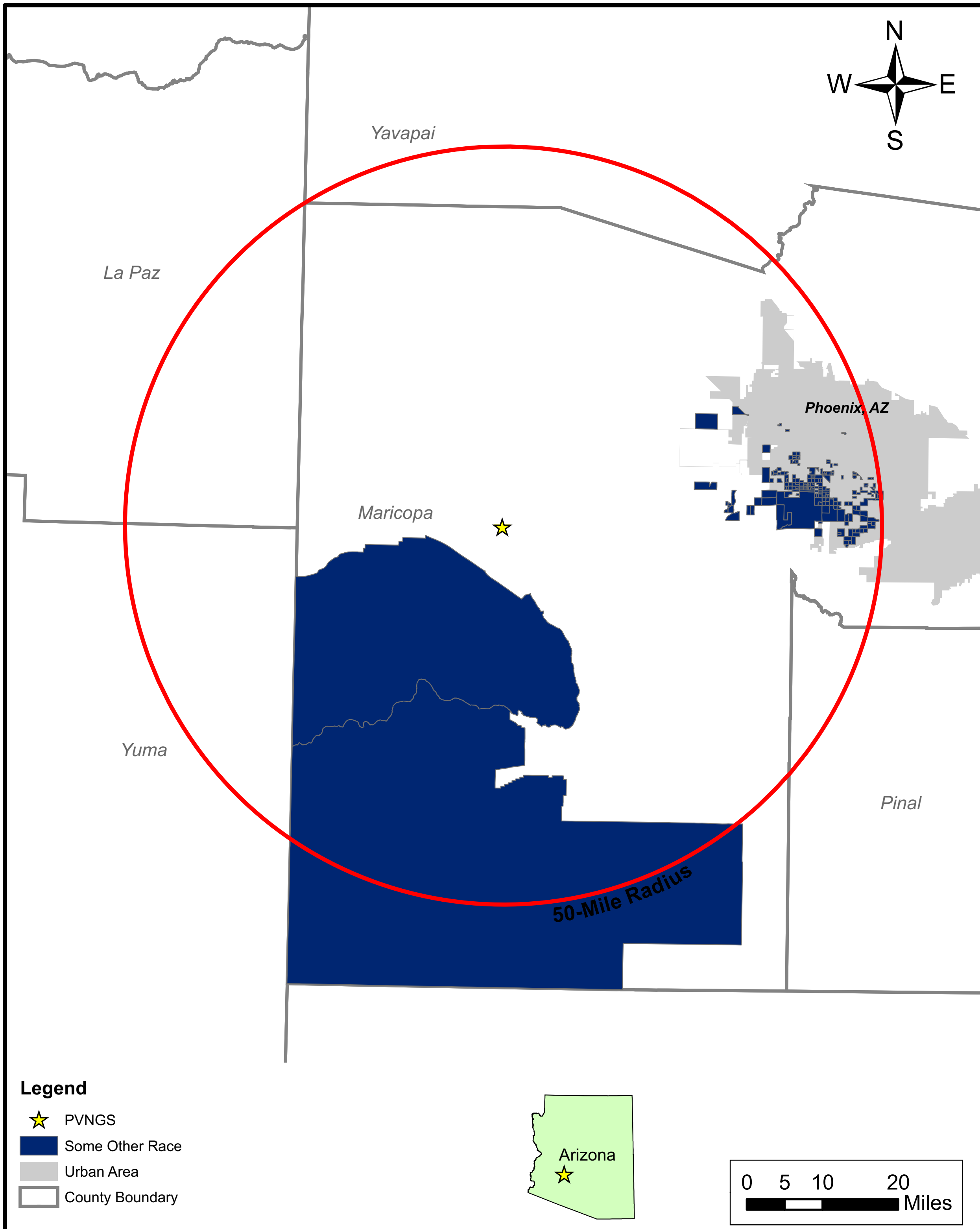

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Figure 2-7 Some Other Minority Population

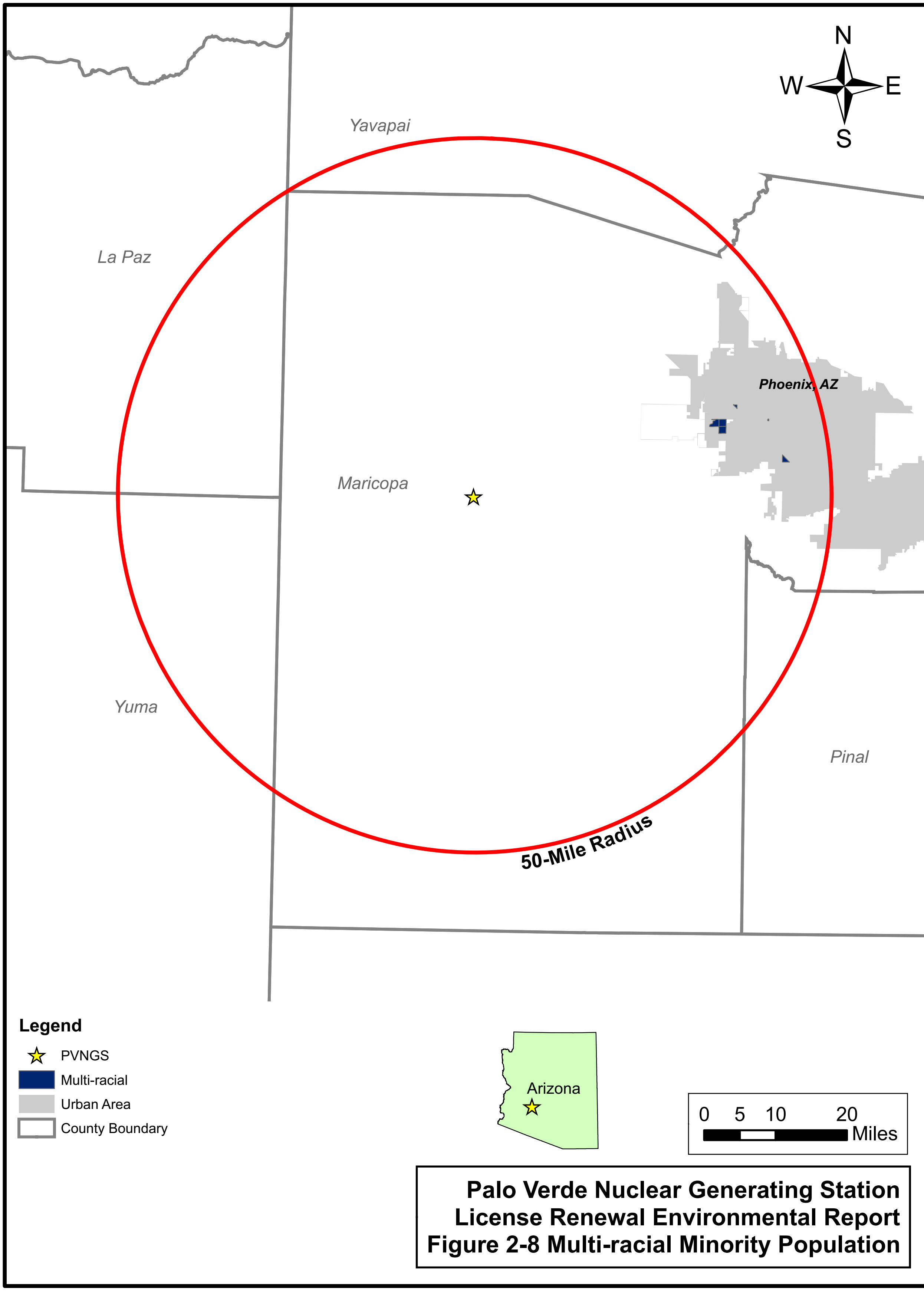

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Figure 2-8 Multi-racial Minority Population

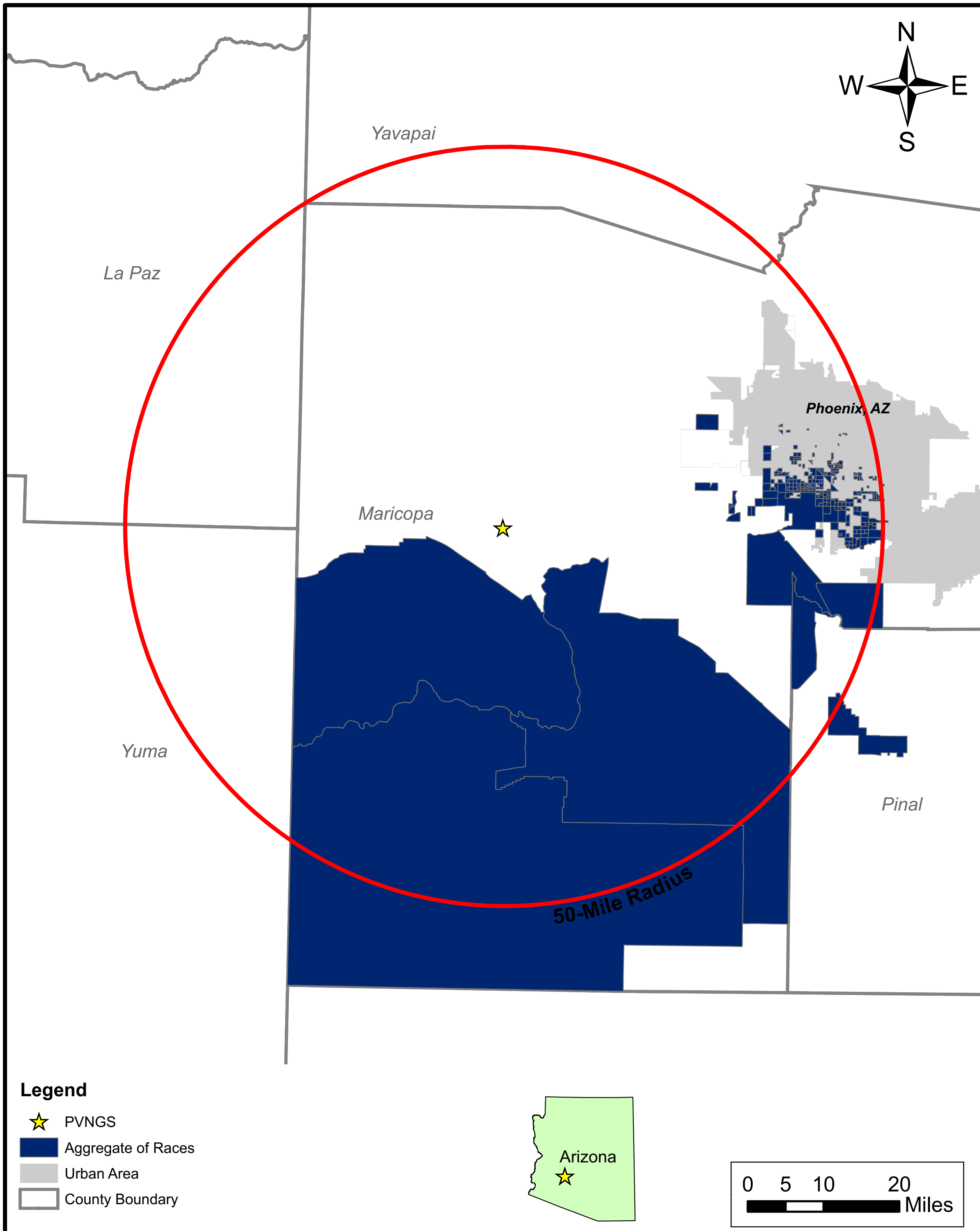

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Figure 2-9 Aggregate Minority Population

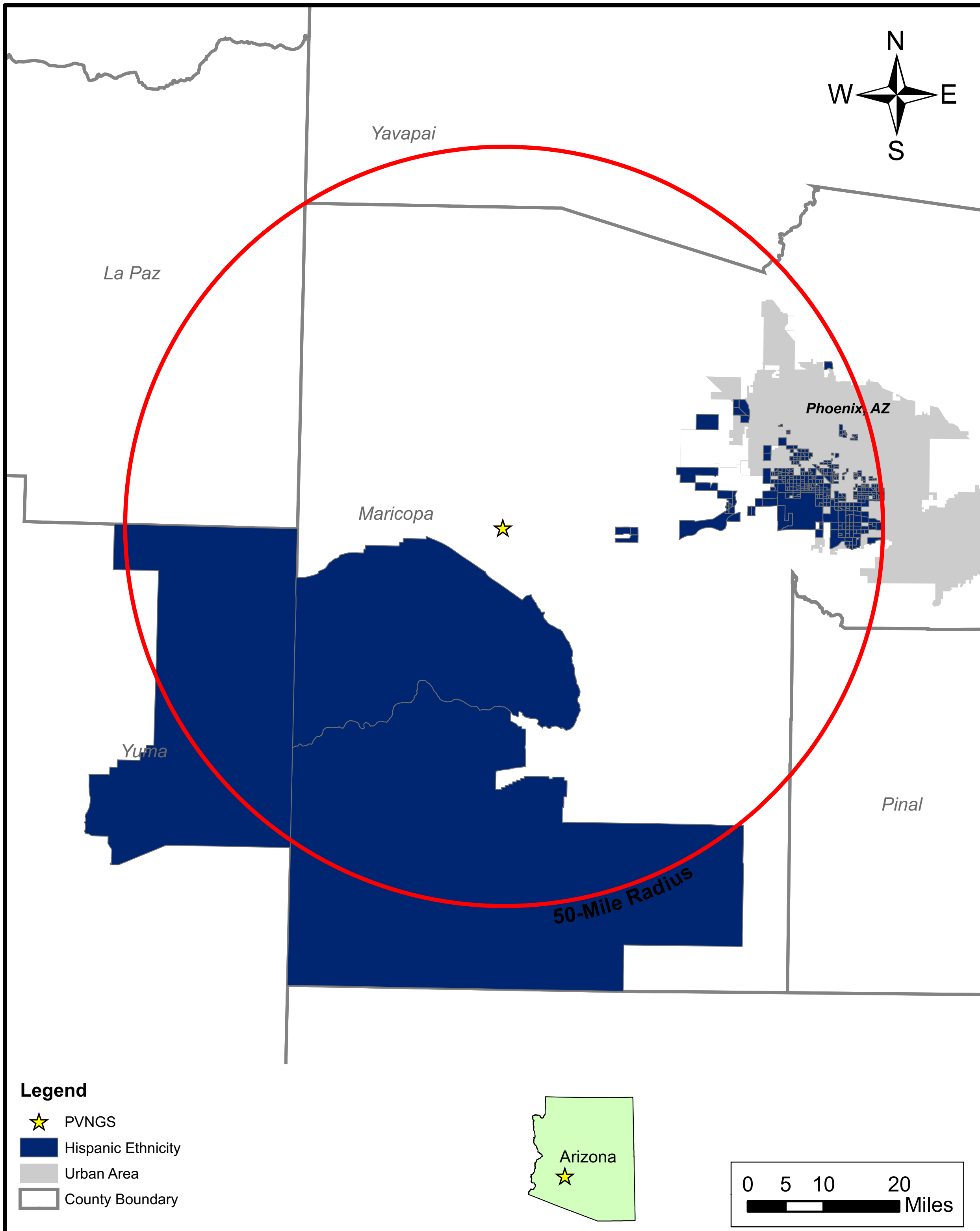

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Figure 2-10 Hispanic Ethnicity Population

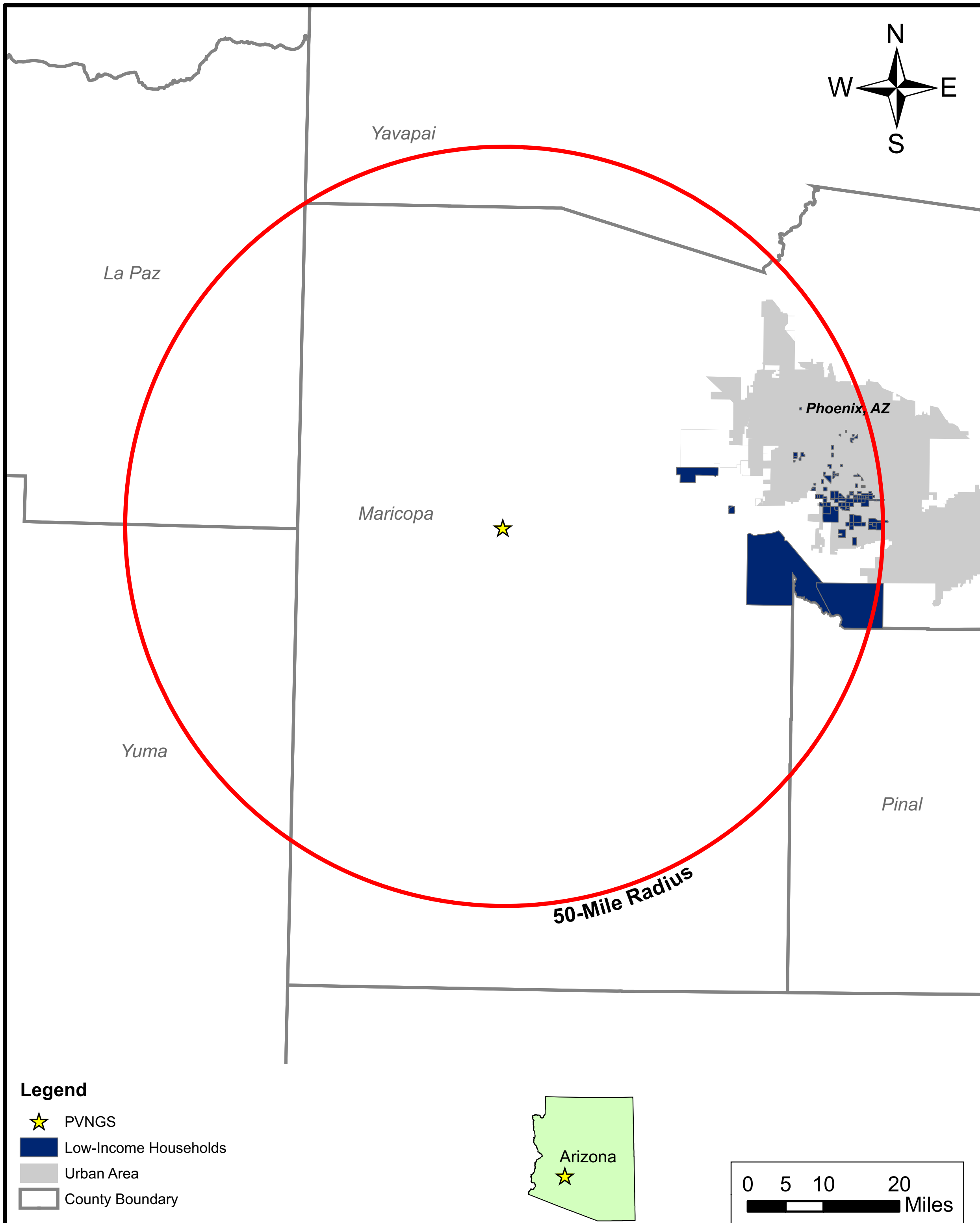

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Figure 2-11 Low-Income Population

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3.0 CHAPTER 3 - PROPOSED ACTION

NRC

"The report must contain a description of the proposed action...." 10 CFR 51.53(c)(2)

APS proposes that NRC renew the operating licenses for PVNGS for an additional 20 years beyond the current licenses' expiration dates of December 31, 2024 for Unit 1, December 9, 2025 for Unit 2, and March 25, 2027 for Unit 3. Renewal of the operating licenses would give APS and the State of Arizona the option of relying on PVNGS to meet future baseload electricity needs. Section 3.1 discusses the major features of the plant and the operation and maintenance practices directly related to the license renewal period. Sections 3.2 through 3.4 address potential changes that could occur as a result of license renewal.

3.1 GENERAL PLANT INFORMATION

PVNGS is a three-unit nuclear-powered steam electric generating facility that began commercial operation between January 1986 (Unit 1) and January 1988 (Unit 3). The nuclear reactor for each unit is a Combustion Engineering System 80 pressurized water reactor (PWR) producing a reactor core power of 3990 megawatts-thermal [MWt]. The nominal net electrical capacity is 1,346 megawatts-electric [MWe]. Figure 3-1 depicts the site layout.

The following subsections provide information on the reactor and containment systems, the cooling and auxiliary water systems, the electrical transmission system, and the Water Reclamation Facility. Additional information about PVNGS is available in the final environmental statement for operation of the plant (NRC 1982), the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996), and the PVNGS Updated Final Safety Analysis Report (APS 2005).

3.1.1 Reactor and Containment Systems

The nuclear steam supply system at PVNGS is a two-loop Combustion Engineering pressurized water reactor. The reactor core heats water to approximately 617 degrees Fahrenheit. Because the pressure exceeds 2,200 pounds per square inch, the water does not boil. The heated water is pumped to two U-tube heat exchangers known as steam generators where the heat boils the water on the shell-side into steam. After drying, the steam is routed to the turbines. The steam yields its energy to turn the turbines, which are connected to the electrical generator. The nuclear fuel is low-enriched uranium dioxide with enrichments less than 5 percent by weight uranium-235 and fuel burnup levels with a batch average less than 60,000 megawatt-days per metric ton uranium. Typical burnup is approximately 50,000 megawatt-days per metric ton uranium and maximum burnup is up to 60,000 megawatt days per metric ton uranium. PVNGS operates on an 18-month refueling cycle.

The reactor, steam generators, and related systems are enclosed in a containment building that is designed to prevent leakage of radioactivity to the environment in the improbable event of a rupture of the reactor coolant piping. The containment building is a pre-stressed, reinforced concrete cylinder with a slab base and a hemispherical dome. A welded steel liner is attached to the inside face of the concrete shell to insure a high degree of leak tightness. In addition, the 4-foot thick concrete walls serve as a radiation shield for both normal and accident conditions.

The containment building is ventilated to maintain pressure and temperatures within acceptable limits. Exhaust from the ventilation system is monitored for radioactivity before being released to the environment through the plant vent. High efficiency particulate air filters are available to filter the air before releasing it. The containment can be isolated if needed.

3.1.2 Cooling and Auxiliary Water Systems

The water systems most pertinent to license renewal are those that directly interface with the environment. The Circulating Water System, Domestic and Demineralized Water Systems, Sanitary Waste Treatment Facility, Evaporation Ponds, and the Water Reclamation Facility all have environmental interfaces. There are two influent water sources to PVNGS. The primary source is waste water effluent from sewage treatment plants in the Phoenix area. The second is the on-site groundwater wells. The plant uses more than 100 gallons per minute of groundwater. PVNGS does not discharge any wastewater to any natural water body.

Circulating Water System

The Circulating Water System for each unit consists of a main condenser, cooling towers, circulating water pumps, a chemical injection system and makeup and blowdown systems. Each unit's Circulating Water System removes the waste heat of normal operations and rejects it to the atmosphere via three round mechanical draft cooling towers for each unit. Each tower is approximately 303 feet in base diameter and 64 feet high and has 16 fans. A 2007 study found the cooling towers to be sufficiently degraded that total replacement will be required. The study recommended replacement of all 9 towers, in the existing locations, with similarly designed mechanical draft cooling towers (APS 2007). This 7 year replacement project will begin in approximately 2008.

As a result of evaporation, the salts in the condenser cooling water are highly concentrated. To maintain the chemical concentrations at no more than 15 times that of the makeup water, a quantity of the circulating water is discharged as blowdown to evaporation ponds (see below). Makeup water to replace water lost to evaporation, drift, and blowdown is provided by the wastewater effluent that has been treated in the Water Reclamation Facility (see below).

In each unit, circulating water is pumped through the main condenser by four 25-percent-capacity vertical, wet-pit pumps with a capacity of 140,000 gallons per minute (gpm) each. Total water through a condenser is 560,000 gpm. Each unit uses an average of approximately 15,000 gpm of makeup water.

PVNGS injects anti-scalants and dispersants, biocides, and corrosion inhibitors into the Circulating Water System to maintain the system and prevent fouling by corrosion and biological organisms. PVNGS uses sodium hypochlorite manufactured onsite as well as purchased through vendors to chlorinate the water.

Water Reclamation Facility

The Water Reclamation Facility (WRF) receives wastewater effluent from the City of Phoenix 91st Avenue sewage treatment plant, and from the Tolleson and Goodyear sewage treatment plants. The waste water flows by gravity through a pipe to a low point adjacent to the

Hassayampa River from which it is pumped to the WRF (Figure 3-1). The total length of the pipe is approximately 36 miles.

At the WRF, the water undergoes biological nitrification, lime treatment, filtration, and chlorination (sodium hypochlorite). Sludge from the treatment processes is centrifuged, dried, and disposed in an onsite landfill. The treated water is stored in lined reservoirs. From the reservoirs, makeup water is pumped to the Circulating Water System. Blowdown from the Circulating Water System is sent to evaporation ponds. The facility can treat up to 90 million gallons per day (MGD), but typical production is approximately 65 MGD. In addition to the approximately 60 MGD used as makeup water by PVNGS, the WRF also provides approximately 3-7 MGD to the Red Hawk plant, a nearby two-unit, gas-fired power plant owned by Pinnacle West, the parent corporation of APS.

The initial 85-acre storage reservoir's liner has deteriorated and leaks from the reservoir exceed the Aquifer Protection Permit limits. PVNGS has constructed a new 45-acre reservoir that will have sufficient capacity to support plant operations until the 80-acre reservoir is repaired.

Domestic and Demineralized Water Systems

Two onsite wells provide groundwater to the domestic water system, including fire protection. The groundwater is filtered, processed by reverse osmosis, and chlorinated to produce potable water. Potable water from the domestic water system is used as the influent to the demineralized water plant. The plant uses mixed bed demineralizers and discharges its waste to the Water Reclamation Facility for reuse. Between 2001 and 2005 the PVNGS domestic water system averaged 1,232 gpm (see Section 2.3) of groundwater.

Sanitary Waste Treatment Facility

Sanitary waste is directed to the Sanitary Waste Treatment Facility, an above-ground package plant where it undergoes aerobic treatment. Liquid effluent from the facility goes to the Water Reclamation Facility for reuse. Sludge is disposed in an on-site landfill.

Evaporation Ponds

PVNGS currently has two lined evaporation ponds to receive blowdown and all liquid waste that is not recycled. The ponds store and evaporate the blowdown and other waste water. Pond 1 is 250 acres, and Pond 2 is 230 acres. New Evaporation Pond No. 3 is currently under construction and is being built using a Best Available Demonstrated Control Technology (BADCT), a geosynthetic clay liner, with two overlaying HDPE liners, including a leachate collection and recovery system, plus soil cement side armoring. Following that, the existing liner in Evaporation Pond No. 2 will be replaced with the same BADCT liner system. This liner is approaching the end of its useful life. Following that, the existing liner in Evaporation Pond Number 1 will be replaced with the same BADCT liner system. The liner in Evaporation Pond No. 1 is a double liner system with leak detection that was re-installed in 1991-1992, following discovery of a liner tear. The site ADEQ Aquifer Protection Permit No. 100388 requires notification of liner tear/repairs, and requires monitoring wells around these ponds and quarterly sampling. Although alert levels have been recorded in some of these wells, no aquifer water quality violations have been recorded.

Retention Tanks

These tanks store non-hazardous industrial wastewater and sewage treatment plant effluent. Monitoring wells are located adjacent to the retention tanks, and are sampled quarterly. In 2006, the original retention basins were replaced with above-ground retention tanks, in part due to cracks in the gunite liners. The new retention tanks are no longer in the site Aquifer Protection Permit (APP), because they are above ground and no longer have the potential to contaminate groundwater. The old retention basins were demolished and closed under a clean-closure plan in 2007-2008.

Water Storage Reservoirs

For the first 20 years of operation, treated effluent from the Water Reclamation Facility was stored in a lined 80-acre water storage reservoir. The liner for this reservoir reached the end of its useful life after 20 years and developed leaks that required repairs. In order to completely replace the old liner, a new 45-acre water storage reservoir was constructed and placed into service in 2007. Then the 80-acre reservoir was drained and a new double-liner with a leachate collection system was installed. During this construction project, the inner wall slope was changed from 3:1 to 4:1, resulting in a new surface area of 85 acres. Following completion of this construction, the 85-acre water storage reservoir was placed back in service in early 2008. A study is currently under way to determine if any leakage from this reservoir reached and had any impact on the underlying shallow aquifer. This study should be complete in 2009.

3.1.3 Transmission Facilities

The Final Environmental Statement (FES-OP) (NRC 1982) identified four 525-kilovolt and one 345-kilovolt transmission lines that were to be constructed to connect PVNGS to the electric grid. Three of the 525 kilovolt lines were to be constructed as part of Project 1: Westwing substation (44 miles), Kyrene Generating Station (82 miles), and Saguaro substation (121 miles). Not part of one of the numbered projects is the other 525-kilovolt line to be constructed to the Devers substation (235 miles) in California. The 345-kilovolt line (Project 3) was to run 195 miles from Greenlee substation in Greenlee County, Arizona to the Rio Grande Generating Station near El Paso, Texas and would not actually connect to PVNGS. (Projects 2 and 4 that were described in the FES-CP were cancelled before the FES was published.)

Subsequent to the publication of the FES, several changes were made to the transmission system.

- The line to Saguaro was not constructed.
- An additional line to Westwing was constructed in 1983.
- An additional line to the North Gila substation was constructed and placed into service in 1984.
- A new substation was constructed at Hassayampa in 2001 and the North Gila and Kyrene lines were connected to this substation. The short connections between PVNGS and Hassayampa that originally connected to North Gila became identified as Hassayampa #3. The short connection between PVNGS and Hassayampa that originally connected to Kyrene became identified as Hassayampa #1.

- An additional line to Rudd was constructed in 2003.
- The Greenlee-Rio Grande line was determined to not be related to PVNGS.

As a result of these system changes, the transmission lines of interest for this report are different than those described in the FES. Figures 3-2 and 3-3 are maps of the transmission system of interest. The following transmission lines are owned by the Salt River Project, except that Devers is owned by Southern California Edison and Rudd is jointly owned by APS and Salt River Project.

- Westwing #1 and #2 – These two 525-kilovolt lines extend east and north for 45 miles in a 330-foot wide corridor to the Westwing Substation northwest of Phoenix.
- Rudd – Starting in a common corridor with Westwing #1 and #2, this 525-kilovolt line runs for 37 miles to the Rudd Substation in Phoenix. After leaving the Westwing corridor, the Rudd corridor width is 160 feet.
- Hassayampa #1 – The FES reported this line to the Kyrene Generating Station and it is described here as running from PVNGS to Kyrene. The line runs south to the Hassayampa substation for 3 miles, then turns to the southeast for 20 miles to the Jojoba Substation, and then runs another 52 miles to the Kyrene Generating Station south of Tempe, Arizona. The corridor width for this 525-kilovolt line varies from 75 to 200 feet, except that the 3-mile length it shares with Hassaymapa #2 is 330 feet wide.
- Hassayampa #2 – This 525-kilovolt line runs in the same corridor as Hassayampa #1 to Hassayampa substation, a distance of 3 miles. The combined corridor width is approximately 330 feet.
- Hassayampa #3 – The 525-kilovolt line roughly parallels the Hassayampa #1 and #2 to the Hassaymapa substation but in a separate corridor. The line then continues south and west in a 200-foot-wide corridor to the North Gila substation near Yuma, Arizona. For purpose of analysis in this environmental report, the line is considered to be the original 114 miles to North Gila substation.
- Devers – This 235-mile line runs westward from the plant to the Devers Substation north of Palm Springs, California. The corridor width is typically 200 feet.

In total, the transmission lines of interest to Section 4.13 are contained in approximately 530 miles of corridor using approximately 13,000 acres. The corridors pass through land that is primarily agricultural and desert. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways. Much of the land crossed is Federal property; the Federal land of greatest interest is identified in Sections 2.4 and 2.5. Corridors that pass through farmlands generally continue to be used as farmland. APS, Salt River Project, and Southern California Edison plan to maintain these transmission lines, which are integral to the larger transmission system, indefinitely. The intention is for these transmission lines to remain a permanent part of the transmission system even after PVNGS is decommissioned.

The transmission lines were designed and constructed in accordance with the National Electrical Safety Code (for example, IEEE 1997) and other industry guidance that was current when the lines were built. Ongoing surveillance and maintenance of these transmission facilities ensure continued conformance to design standards. These maintenance practices are described in Section 4.13.

3.2 REFURBISHMENT ACTIVITIES

NRC

"The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures...This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

"…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories…(2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item...." (NRC 1996)

APS has addressed potential refurbishment activities in this environmental report in accordance with NRC regulations and complementary information in the NRC *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) for license renewal (NRC 1996). NRC requirements for the renewal of operating licenses for nuclear power plants include the preparation of an integrated plant assessment (IPA) (10 CFR 54.21). The IPA must identify and list systems, structures, and components subject to an aging management review. Items that are subject to aging and might require refurbishment include, for example, the reactor vessel, piping, supports, and pump casings (see 10 CFR 54.21 for details), as well as those that are not subject to periodic replacement.

In turn, NRC regulations for implementing the National Environmental Policy Act require license renewal phase environmental reports to describe in detail and assess the environmental impacts of any refurbishment activities such as planned major modifications to systems, structures, and components or plant effluents [10 CFR 51.53(c)(2)]. Resource categories to be evaluated for impacts of refurbishment include terrestrial resources, threatened and endangered species, air quality, housing, public utilities and water supply, education, land use, transportation, and historic and archaeological resources.

The PVNGS IPA conducted by APS under 10 CFR 54 (included as part of this license renewal application) has not identified the need to undertake any major refurbishment or replacement actions to maintain the functionality of important systems, structures, and components during the PVNGS license renewal period. APS has already replaced its steam generators and turbine rotors in Units 1, 2, and 3. These plant modifications have been done to meet the current license life. APS plans to replace all 9 mechanical draft cooling towers serving the 3 Units with new mechanical draft cooling towers, to be constructed in the current locations, from approximately 2008 through 2015. These cooling towers are degrading and must be replaced to meet the current license life (APS 2007). Accordingly, APS has determined that license renewal regulations in 10 CFR 51.53(c)(3)(ii) do not require APS to assess the impact of refurbishment on plant and animal habitats, estimated vehicle exhaust emissions, housing availability, land use, public schools, or highway traffic on local highways. (See 10 CFR 51.53(c)(3)(ii)(E), (F), (I), (J), respectively.)

3.3 PROGRAMS AND ACTIVITIES FOR MANAGING THE EFFECTS OF AGING

NRC

> "The report must contain a description of … the applicant's plans to modify the facility or its administrative control procedures...This report must describe in detail the modifications directly affecting the environment or affecting plant effluents that affect the environment…." 10 CFR 51.53(c)(2)

> "…The incremental aging management activities carried out to allow operation of a nuclear power plant beyond the original 40-year license term will be from one of two broad categories: (1) SMITTR actions, most of which are repeated at regular intervals, and (2) major refurbishment or replacement actions, which usually occur fairly infrequently and possibly only once in the life of the plant for any given item." NRC 1996, Section 2.6.3.1, pg. 2-41. ("SMITTR" is defined in NRC 1996 as surveillance, monitoring, inspections, testing, trending, and recordkeeping.)

The IPA required by 10 CFR 54.21 identifies the programs and inspections for managing aging effects at PVNGS. These programs are described in the *License Renewal Application, Palo Verde Nuclear Generating Station, Units 1, 2, and 3* to which this Environmental Report is appended.

3.4 EMPLOYMENT

Current Workforce

APS employs approximately 2,200 permanent employees and approximately 620 long-term contract employees at PVNGS, a three-unit facility. Over 98 percent of the permanent employees live in Maricopa County, Arizona. The remaining employees are distributed across 13 counties in Arizona, with numbers ranging from 1 to 8 employees per county. One individual lives outside of Arizona.

PVNGS is on an 18-month refueling cycle. During refueling outages, site employment increases above the permanent workforce by as many as 350 workers for about 45 days of temporary duty.

License Renewal Increment

Performing the license renewal activities described in Sections 3.2 and 3.3 could necessitate increasing the PVNGS staff workload by some increment. The size of this increment would be a function of the schedule within which APS must accomplish the work and the amount of work involved. Because APS has determined that no refurbishment is needed (Section 3.2), the analysis of license renewal employment increment focuses on programs and activities for managing the effects of aging (Section 3.3).

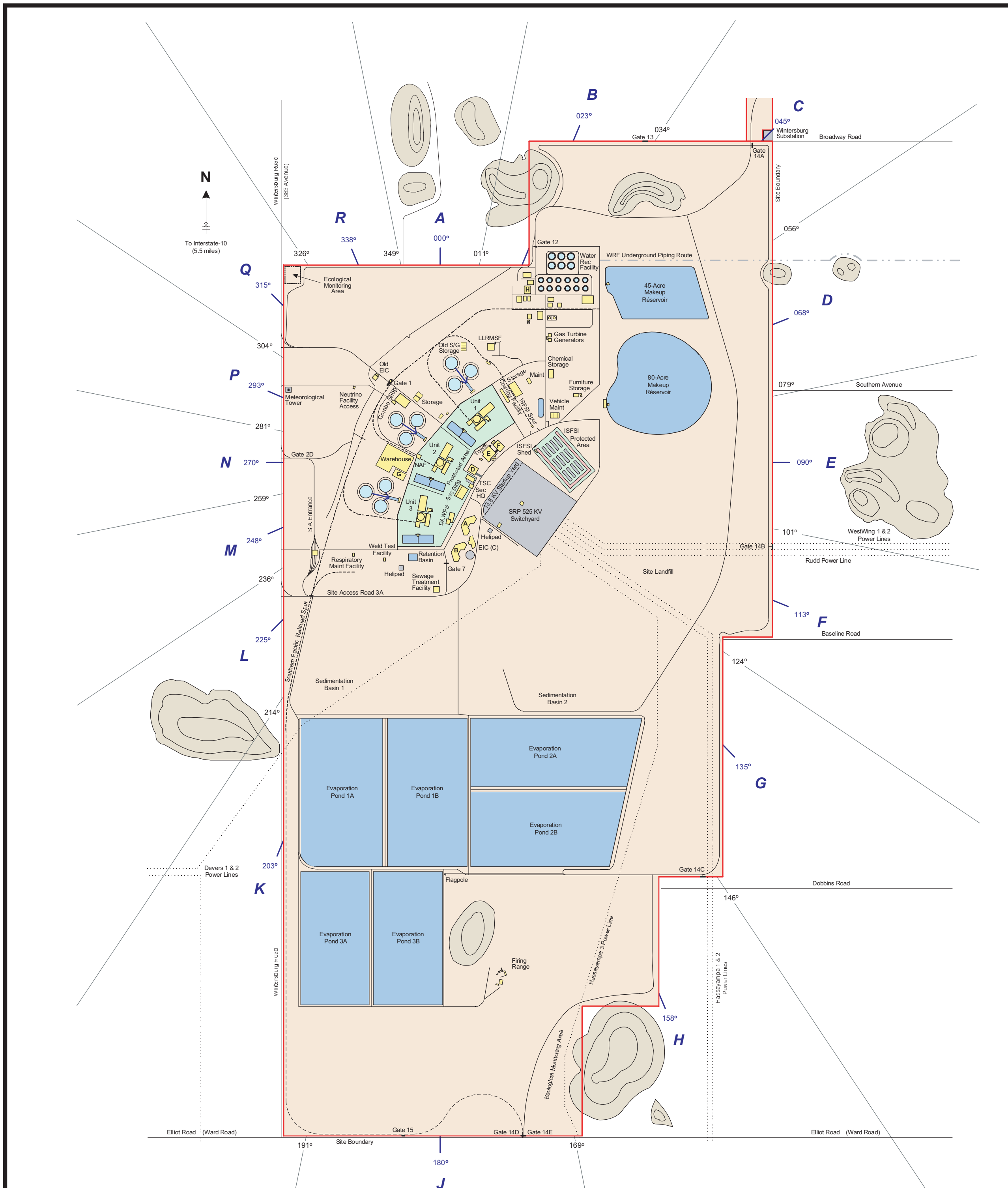
The GEIS (NRC 1996) assumes that NRC would renew a nuclear power plant license for a 20-year period, plus the duration remaining on the current license, and that NRC would issue the renewal approximately 10 years prior to license expiration. In other words, the renewed license would be in effect for approximately 30 years. The GEIS further assumes that the utility would initiate surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) activities at the time of issuance of the new license and would conduct license renewal SMITTR activities throughout the remaining 30-year life of the plant, sometimes during full-power operation (NRC 1996), but mostly during normal refueling and the 5- and 10-year in-service inspection and refueling outages (NRC 1996).

APS has determined that the GEIS scheduling assumptions are reasonably representative of PVNGS incremental license renewal workload scheduling. Many PVNGS license renewal SMITTR activities would have to be performed during outages. Although some PVNGS license renewal SMITTR activities would be one-time efforts, others would be recurring, periodic activities that would continue for the life of the plant.

The GEIS estimates that the most additional personnel needed to perform license renewal SMITTR activities would typically be 60 persons during the 3-month duration of a 10-year in-service inspection and refueling outage. Having established this upper value for what would be a single event in 20 years, the GEIS uses this number as the expected number of additional permanent workers needed per unit attributable to license renewal. GEIS Section C.3.1.2 uses this approach in order to "...provide a realistic upper bound to potential population-driven impacts…."

APS has identified no need for significant new aging management programs or major modifications to existing programs. APS anticipates that existing "surge" capabilities for routine activities, such as outages, will enable APS to perform the increased SMITTR workload without increasing PVNGS staff. Therefore, APS has no plans to add non-outage employees to support PVNGS operations during the license renewal term. APS believes that increased SMITTR tasks can be performed within this schedule and employment level.

3.5 FIGURES



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-1 General Plant Layout

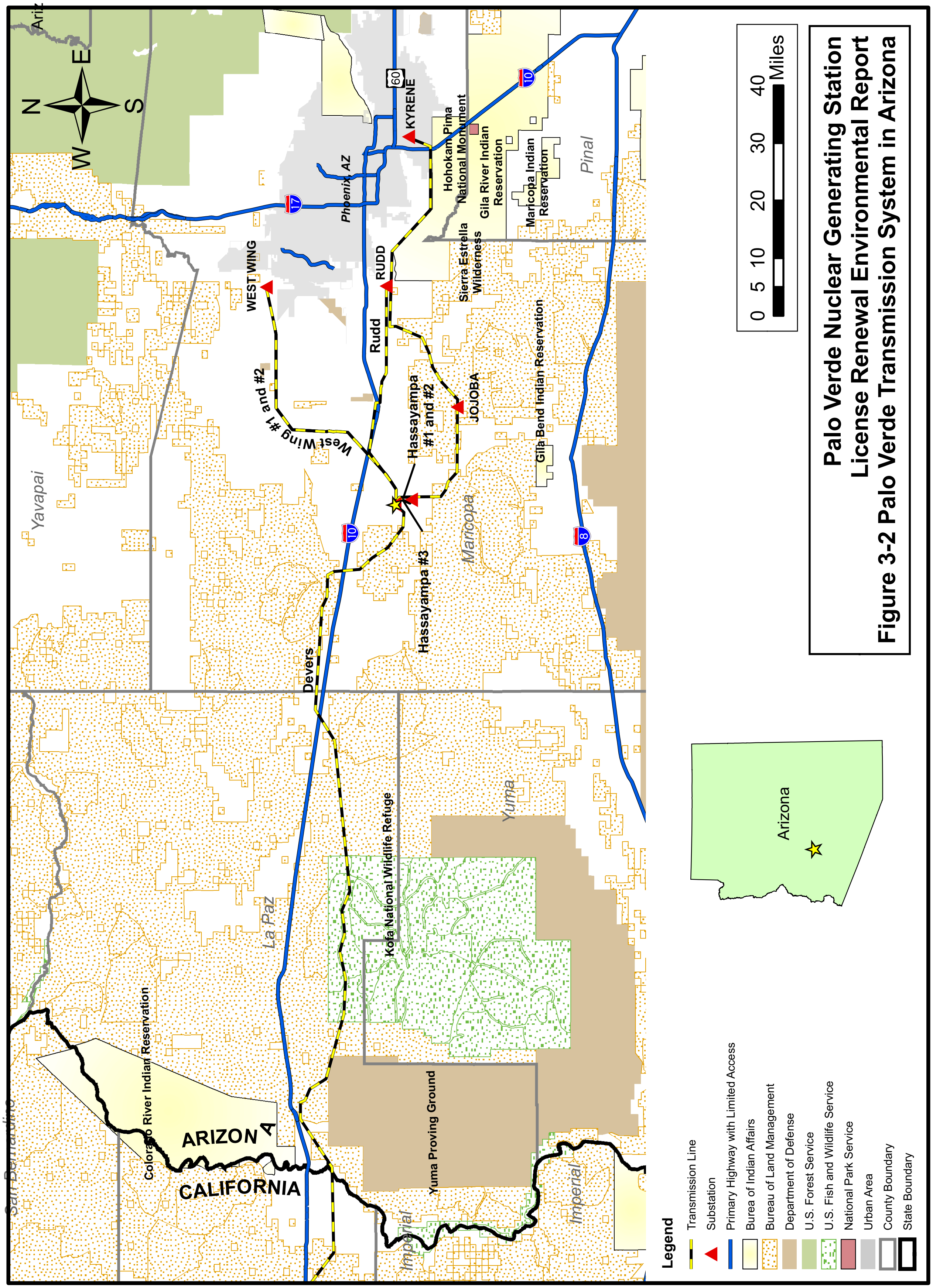
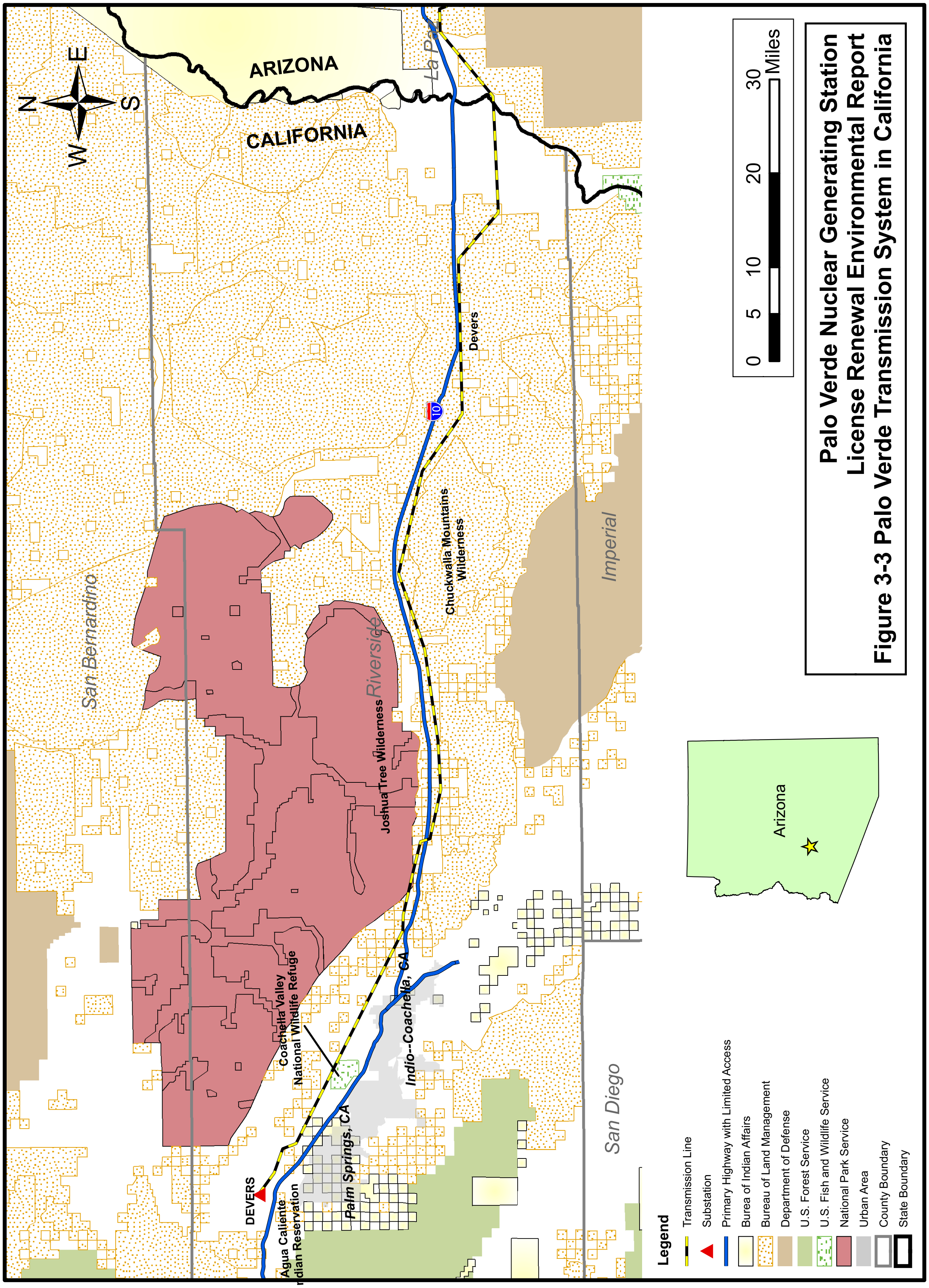


Figure 3-2 Palo Verde Transmission System in Arizona



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-3 Palo Verde Transmission System in California

3.6 REFERENCES

APS (Arizona Public Service Company) 2005. *Palo Verde Nuclear Generating Station Updated Final Safety Analysis Report*, Revision 13, Palo Verde Nuclear Generating Station, Wintersburg, Arizona, June.

IEEE (Institute of Electrical and Electronics Engineers) 1997. *National Electrical Safety Code*, 1997 Edition, New York, New York.

NRC (U.S. Nuclear Regulatory Commission) 1982. *Final environmental Statement related to the operation of Palo Verde Nuclear Generating Station, Units 1, 2, and 3*. Office of Nuclear Reactor Regulation, Washington, D.C., February.

NRC (U.S. Nuclear Regulatory Commission) 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), *Volumes 1 and 2, NUREG-1437*, Washington, D.C., May.

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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 1996a), 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…." (NRC 1996b).

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.

For the 11 Category 2 issues that APS has determined to be applicable to PVNGS, analyses are provided. These analyses include conclusions regarding the significance of the impacts relative to the renewal of the operating license for PVNGS and, when applicable, discuss potential mitigative alternatives. APS has identified the significance of the impacts associated with each issue as either Small, Moderate, or Large, consistent with the criteria that NRC established in 10 CFR 51, Appendix B, Table B-1, Footnote 3 as follows:

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purposes of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission’s regulations are considered small.

MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.

LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource.

In accordance with National Environmental Policy Act practice, APS considered ongoing and potential additional mitigation in proportion to the significance of the impact to be addressed (i.e., impacts that are small receive less mitigative consideration than impacts that are large).

“NA” License Renewal Issues

NRC determined that its categorization and impact-finding definitions did not apply to two issues (Issues 60 and 92); however, APS included these issues in Attachment A. Applicants currently do not need to submit information on chronic effects from electromagnetic fields (10 CFR 51, Appendix B, Table B-1, Footnote 5). For environmental justice, NRC does not require information from applicants, but noted that it will be addressed in individual license renewal reviews (10 CFR 51, Appendix B, Table B-1, Footnote 6). APS has included minority and low-income demographic information in Section 2.6.2.

4.1 WATER USE CONFLICTS (PLANTS USING COOLING TOWERS OR COOLING PONDS AND WITHDRAWING MAKEUP WATER FROM A SMALL RIVER WITH LOW FLOW)

NRC

> "If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is 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 the flow of the river and related impacts on in-stream and riparian ecological communities must be provided…" 10 CFR 51.53(c)(3)(ii)(A).

> "…The issue has been a concern at nuclear power plants with cooling ponds and at plants with cooling towers. Impacts on instream and riparian communities *near* these plants could be of moderate significance in some situations…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 13

The water-use issue associated with operation of cooling ponds is the availability of adequate stream flows to provide makeup water, particularly during droughts or in the context of increasing in-stream or off-stream uses (NRC 1996). For this reason, NRC made surface water use conflicts a Category 2 issue.

PVNGS uses a closed-loop cooling system with cooling towers. The plant does not use river water for cooling. PVNGS uses treated effluent from Phoenix-area wastewater treatment plants for all of its nonsafety-related cooling systems. The treated effluent from the Phoenix 91st Avenue waste water treatment plant, the Tolleson wastewater treatment facility, and the Goodyear wastewater treatment facility is conveyed to PVNGS by means of a pipeline and pumping facilities and is treated in the PVNGS on-site Water Reclamation Facility to meet plant water quality requirements (Section 3.1). This effluent could have been discharged to the Salt River immediately upstream of its confluence with the Gila River. The Gila River is considered a small river. Since PVNGS diverts treated effluent that would otherwise be discharged to the Gila River system, supporting riparian habitat, replenishing groundwater in the alluvial aquifer, and providing surface water for other users, NRC raised the issue of water use conflicts for PVNGS in its GEIS (NRC 1996).

The Phoenix area is drained by the Gila River and its four principal tributaries: the Salt, the Verde, the Agua Fria, and the Hassayampa Rivers. Regulated water storage reservoirs have been constructed on the Salt, Verde, Gila, and Agua Fria Rivers allowing for a relatively high surface water use in some areas. All of the streams and washes within the area are ephemeral, either naturally or due to upstream diversion. The Gila River is regulated by the Ashurst-Hayden Dam near Florence, Arizona, about 50 land miles southeast of Phoenix. Between the dam and the confluence with the Salt River, the flow is primarily ephemeral. West of the confluence with the Salt River, the Gila is primarily perennial due to effluent discharges from waste water treatment plants (Maricopa County 2001). At Estrella Parkway, just downstream of the confluence with the Salt River, the Gila River 13-year average flow is 2.64×10^{10} cubic feet per year (USGS 2006).

In its FES for Operations (NRC 1982), NRC presented projections of flows from the 91st Avenue plant for 1985 through 2000 as reproduced in Table 4-1. NRC concluded that the availability of water in the Salt and Gila Rivers downstream of the 91st Avenue plant would be similar to that 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 1996a). 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 1996a). 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 1996a). 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.

4.5 GROUNDWATER USE CONFLICTS (PLANTS USING >100 GPM OF GROUNDWATER)

NRC

"If the applicant's plant…pumps more than 100 gallons (total onsite) of groundwater per minute, an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Plants that use more than 100 gpm may cause ground-water use conflicts with nearby ground-water users…." 10 CFR 51, Subpart A, Table B-1, Issue 33

NRC made groundwater use conflicts a Category 2 issue because, at a withdrawal rate of more than 100 gallons per minute (gpm), a cone of depression could extend offsite. This could deplete the groundwater supply available to offsite users, an impact that could warrant mitigation. Information to ascertain includes: (1) PVNGS groundwater withdrawal rate (whether greater than 100 gpm), (2) drawdown at property boundary location, and (3) impact on neighboring wells.

There are two primary permitted wells on the PVNGS (55-613123, 55-613124, and a small firing range well 55-900619) installed into the regional aquifer (Section 2.3) that provide water for domestic use, fire protection, and to the demineralized water system. From 2001 through 2005, PVNGS pumped groundwater from these wells at a total production rate of 1,987 acre-feet per year (1,232 gallons per minute) (Gunter 2006). Therefore, the issue of groundwater use conflicts does apply.

In order to determine potential offsite impacts to wells, the 1,232 gpm annual average cumulative well yield from 2001 through 2005 was used to calculate drawdown as though it had been pumped from a single onsite well. Well 55-613124 was used, because it is the well closest to a PVNGS [western property] boundary (approximately 15,882 feet). The well is one for which pump test data are available. A confined aquifer scenario was used to simulate site conditions. The equations used in the calculations assume that the aquifer is homogeneous, isotopic, with negligible recharge and gradient, and that boundary impacts do not occur. Assuming minimal recharge made the scenario very conservative. It was also assumed that the pumping rate used in the modeling (1,232 gpm) was consistent from the initial plant startup period. Based on the conservative results of the modeling, pumping at a rate of 1,232 gpm in Well 55-613124 would theoretically create a drawdown of the potentiometric surface of 8.3 feet at a distance of 15,882 feet from the pumping well during the 40-year operating period. At the end of the 20-year license renewal period, the potentiometric surface drawdown would be 8.8 feet, an increase in drawdown of 0.5 feet from the original (40-year) period drawdown (Gunter 2006).

PVNGS installed a new high capacity production well in 2007, and an aquifer test was performed on the well after construction was complete. This well is expected to be added as an approved drinking water well in 2008, and will replace degraded well 55-613124, resulting in continued use of groundwater at historic rates

The regional aquifer's potentiometric surface was evaluated by comparing maps from the 1975 Environmental Report Construction Permit Stage (APS 1975) and a 2001 map from the PVNGS Updated FSAR (PVNGS 2006) to groundwater elevation data from the PVNGS' 2005 Annual Monitoring and Compliance Report (Brown and Caldwell 2006). The comparison indicates that the groundwater elevation data from 2005 are consistent with the maps from the earlier documents and indicates there has been little to no impact due to operations of the groundwater wells at PVNGS.

As discussed in Section 2.3, groundwater flow into and out of the Hassayampa sub-basin has been calculated at approximately 29,000 acre-feet (9.45 billion gallons) annually. It is estimated that approximately 4.8 million acre-feet of groundwater within the Hassayampa sub-basin are available for use (Maricopa County 2001). Based on the groundwater use data from 2001 through 2005, PVNGS pumps 1,232 gpm (1,987 acre-feet per year) or 6.8 percent of the water that flows through the Hassayampa sub-basin.

Given the conservatively calculated additional 0.5 feet of drawdown that would occur during the license renewal period and that PVNGS uses 6.8 percent of groundwater that passes through the Hassayampa sub-basin, APS concludes that the impacts to the regional aquifer system over the license renewal period would be SMALL and would not warrant mitigation.

4.6 GROUNDWATER USE CONFLICTS (PLANTS USING COOLING TOWERS OR COOLING PONDS AND WITHDRAWING MAKEUP WATER FROM A SMALL RIVER)

NRC

> "If the applicant's plant utilizes cooling towers or cooling ponds and withdraws make-up water from a river whose annual flow rate is less than 3.15×10^{12} ft^3/year…[t]he applicant shall also provide an assessment of the impacts of the withdrawal of water from the river on alluvial aquifers during low flow." 10 CFR 51.53(3)(ii)(A)

> "…Water use conflicts may result from surface water withdrawals from small water bodies during low flow conditions which may affect aquifer recharge, especially if other groundwater or upstream surface water users come on line before the time of license renewal…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 34

NRC made groundwater use conflicts a Category 2 issue because consumptive use of withdrawals from small rivers could adversely impact aquifer recharge. This is a particular concern during low flow conditions and could create a cumulative impact due to upstream consumptive use.

PVNGS uses a closed-loop cooling system with cooling towers. The plant does not use river water for cooling. PVNGS uses treated effluent from Phoenix-area wastewater treatment plants for all of its nonsafety-related cooling systems. The treated effluent from the Phoenix 91st Avenue waste water treatment plant, the Tolleson wastewater treatment facility, and the Goodyear wastewater treatment facility is conveyed to PVNGS by means of a pipeline and pumping facilities and is treated in the PVNGS on-site Water Reclamation Facility to meet plant water quality requirements (Section 3.1). This effluent could have been discharged to the Salt River immediately upstream of its confluence with the Gila River. The Gila River is considered a small river. Since PVNGS diverts treated effluent that would otherwise be discharged to the Gila River system, supporting riparian habitat, replenishing groundwater in the alluvial aquifer, and providing surface water for other users, NRC raised the issue of water use conflicts for PVNGS in its GEIS (NRC 1996).

Precipitation is the main source of groundwater recharge in the area. Historically, stream channel recharge was much larger, but diversion of surface water for irrigation, commercial, industrial, and municipal uses has greatly depleted this source of recharge leaving the streams and rivers to run intermittently in most places (ADWR 1999). Therefore, unrecycled treated effluent discharged to the Gila River system is an important contributor to recharge.

Section 4.1 presents information indicating that the PVNGS fractional demand on treated effluent has been decreasing since the beginning of three-unit operations in 1986. Projections as far as 2030 show that this trend is expected to continue (ADWR 1999; SROG 2005). To encourage use of treated effluent, the Arizona Department of Water Resources' Third Management Plans provides incentives to all municipal, industrial, and agricultural users of effluent. Treated effluent production in the area is projected to increase to 502,000 acre-feet per year by 2025 (ADWR 1999).

APS concludes that impacts to the alluvial aquifer during the license renewal period from PVNGS' continued use of treated effluent would be SMALL because PVNGS demand on surface water is now a smaller fraction than when NRC licensed the plant and the state promotes and regulates the use of treated effluent for appropriate water uses, including cooling water. Accordingly, mitigation measures to increase recharge of the aquifer are not warranted.

4.7 GROUNDWATER USE CONFLICTS (PLANTS USING RANNEY WELLS)

NRC

"If the applicant's plant uses Ranney wells…an assessment of the impact of the proposed action on groundwater use must be provided." 10 CFR 51.53(c)(3)(ii)(C)

"…Ranney wells can result in potential ground-water depression beyond the site boundary. Impacts of large ground-water withdrawal for cooling tower makeup at nuclear power plants using Ranney wells must be evaluated at the time of application for license renewal…." 10 CFR 51, Subpart A, Table B-1, Issue 35

NRC made this groundwater use conflict a Category 2 issue because large quantities of groundwater withdrawn from Ranney wells could degrade groundwater quality at river sites by induced infiltration of poor-quality river water into an aquifer.

This issue does not apply to PVNGS because PVNGS does not use Ranney wells.

4.8 DEGRADATION OF GROUNDWATER QUALITY

NRC

> "If the applicant's plant is located at an inland site and utilizes cooling ponds, an assessment of the impact of the proposed action on groundwater quality must be provided." 10 CFR 51.53(c)(3)(ii)(D)

> "…Sites with closed-cycle cooling ponds may degrade ground-water quality. For plants located inland, the quality of the ground water in the vicinity of the ponds must be shown to be adequate to allow continuation of current uses…" 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 39

NRC made degradation of groundwater quality a Category 2 issue because evaporation from closed-cycle cooling ponds concentrates dissolved solids in the water and settles suspended solids. In turn, seepage into the water table aquifer could degrade groundwater quality.

The issue of groundwater degradation does not apply to PVNGS because the plant does not use cooling water ponds. As Section 3.1.2 describes, PVNGS discharges all releases to lined evaporation ponds.

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 1996a)

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 1996a). 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.

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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 1996a). 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.

4.13 ELECTRIC SHOCK FROM TRANSMISSION-LINE INDUCED CURRENTS

NRC

The environmental report must contain an assessment of the impact of the proposed action on the potential shock hazard from transmission lines ". ...[i]f the applicant's transmission lines that were constructed for the specific purpose of connecting the plant to the transmission system do not meet the recommendations of the National Electric Safety Code for preventing electric shock from induced current…" 10 CFR 51.53(c)(3)(ii)(H)

"Electrical shock resulting from direct access to energized conductors or from induced charges in metallic structures have not been found to be a problem at most operating plants and generally are not expected to be a problem during the license renewal term. However, site-specific review is required to determine the significance of the electric shock potential at the site." 10 CFR 51, Subpart A, Appendix B, Table B 1, Issue 59

NRC made impacts of electric shock from transmission lines a Category 2 issue because, without a review of each plant's transmission line conformance with the National Electrical Safety Code (NESC) (IEEE 1997) criteria, NRC could not determine the significance of the electrical shock potential. In the case of PVNGS, there have been no previous NRC or NEPA analyses of transmission-line-induced current hazards. Therefore, this section provides an analysis of the plant's transmission lines' conformance with the NESC standard. The analysis is based on computer modeling of induced current under the lines.

Objects located near transmission lines can become electrically charged due to their immersion in the lines' electric field. This charge results in a current that flows through the object to the ground. The current is called "induced" because there is no direct connection between the line and the object. The induced current can also flow to the ground through the body of a person who touches the object. An object that is insulated from the ground can actually store an electrical charge, becoming what is called "capacitively charged." A person standing on the ground and touching a vehicle or a fence receives an electrical shock due to the sudden discharge of the capacitive charge through the person's body to the ground. After the initial discharge, a steady-state current can develop of which the magnitude depends on several factors, including the following:

- the strength of the electric field which, in turn, depends on the voltage of the transmission line as well as its height and geometry
- the size of the object on the ground
- the extent to which the object is grounded.

In 1977, a provision to the NESC was adopted (Part 2, Rules 232C1c and 232Dd3c) that describes how to establish minimum vertical clearances to the ground for electric lines having voltages exceeding 98-kilovolt alternating current to ground. The clearance must limit the induced current (or steady-state current) due to electrostatic effects to 5 milliamperes if the largest anticipated truck, vehicle, or equipment were short-circuited to ground. By way of comparison, the setting of ground fault circuit interrupters used in residential wiring (special breakers for outside circuits or those with outlets around water pipes) is 4 to 6 milliamperes.

As described in Section 3.1.3, there are seven 525-kilovolt lines that were specifically constructed to distribute power from PVNGS to the electric grid. APS' analysis of these transmission lines began by identifying the limiting case for each line. The limiting case is the configuration along each line where the potential for current-induced shock would be greatest. Once the limiting case was identified, APS calculated the electric field strength for each transmission line, then calculated the induced current.

APS calculated electric field strength and induced current using a computer code called ACDCLINE, produced by the Electric Power Research Institute. The results of this computer program have been field-verified through actual electrostatic field measurements by several utilities. The input parameters included the design features of the limiting-case scenario, the NESC requirement that line sag be determined at 120ºF conductor temperature, and the maximum vehicle size under the lines (a tractor-trailer).

The results of the analysis are presented in Table 4-2. All of the seven lines conform to the 5 milliampere standard. Details of the analysis, including the input parameters for each line's limiting case, can be found in TtNUS (2007a) and TtNUS (2007b).

Salt River Project, APS, and Southern California Edison, the owners of PVNGS transmission lines, have surveillance and maintenance procedures that provide assurance that design ground clearances will not change. These procedures include routine aerial inspections that include checks for encroachments, broken conductors, broken or leaning structures, and signs of trees burning, any of which would be evidence of clearance problems. Ground inspections include examination for clearance at questionable locations, integrity of structures, and surveillance for dead or diseased trees that might fall on the transmission lines. Problems noted during any inspection are brought to the attention of the appropriate organization(s) for corrective action.

APS' assessment under 10 CFR 51 concludes that electric shock is of SMALL significance, because the NESC standard is not exceeded. Accordingly, no mitigation measures are required.

4.14 HOUSING IMPACTS

NRC

> The environmental report must contain "...[a]n assessment of the impact of the proposed action on housing availability…" 10 CFR 51.53(c)(3)(ii)(I)
>
> "…Housing impacts are expected to be of small significance at plants located in a medium or high population area and not in an area where growth control measures that limit housing development are in effect. Moderate or large housing impacts of the workforce associated with refurbishment may be associated with plants located in sparsely populated areas or areas with growth control measures that limit housing development…." 10 CFR 51, Subpart A, Table B-1, Issue 63
>
> "...[S]mall impacts result when no discernible change in housing availability occurs, changes in rental rates and housing values are similar to those occurring statewide, and no housing construction or conversion occurs…." (NRC 1996)

NRC made housing impacts a Category 2 issue because impact magnitude depends on local conditions that NRC could not predict for all plants at the time of GEIS publication (NRC 1996). Local conditions that need to be ascertained are: (1) population categorization as small, medium, or high and (2) applicability of growth control measures.

Refurbishment activities and continued operations could potentially produce housing impacts due to increased staffing. As described in Section 3.2, PVNGS does not plan to perform refurbishment. APS concludes that there would be no refurbishment-related impacts to area housing and no analysis is therefore required. Accordingly, the following discussion focuses on impacts of continued PVNGS operations on local housing availability.

Sections 2.6 and 2.8 indicate that PVNGS is located in a medium population area that is not subject to growth control measures that limit housing development. NRC regulatory criteria at 10 CFR 51, Subpart A, Table B-1, Issue 63, indicate that housing impacts are expected to be of small significance at plants located in a medium or high population area and in an area where growth control measures that limit housing development are not in effect. Additionally, APS anticipates that existing "surge" capabilities for routine activities, such as outages, will enable APS to perform the increased surveillance, monitoring, inspections, testing, trending, and recordkeeping (SMITTR) workload without increasing PVNGS staff (Section 3.4). Therefore, APS concludes that since there would be no increase in staffing, no housing impacts would be experienced and, therefore, the appropriate characterization of PVNGS license renewal housing impacts would be SMALL.

4.15 PUBLIC UTILITIES: PUBLIC WATER SUPPLY AVAILABILITY

NRC

> The environmental report must contain "…an assessment of the impact of population increases attributable to the proposed project on the public water supply." 10 CFR 51.53(c)(3)(ii)(I)
>
> "…An increased problem with water shortages at some sites may lead to impacts of moderate significance on public water supply availability…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 65
>
> "Impacts on public utility services are considered small if little or no change occurs in the ability to respond to the level of demand and thus there is no need to add capital facilities. Impacts are considered moderate if overtaxing of facilities during peak demand periods occurs. Impacts are considered large if existing service levels (such as quality of water and sewage treatment) are substantially degraded and additional capacity is needed to meet ongoing demands for services." (NRC 1996)

NRC made public utility impacts a Category 2 issue because an increased problem with water availability, resulting from pre-existing water shortages, could occur in conjunction with plant demand and plant-related population growth (NRC 1996). Local information needed would include: (1) a description of water shortages experienced in the area and (2) an assessment of the public water supply system's available capacity.

NRC's analysis of impacts to the public water supply system considered both plant demand and plant-related population growth demands on local water resources. As discussed in Section 3.2, no refurbishment is planned for PVNGS and no refurbishment impacts are therefore expected. As Section 3.4 indicates, APS anticipates no increase in PVNGS employment attributable to license renewal. Section 2.6 describes the PVNGS regional demography. Section 2.9.1 describes the public water supply systems in the area, their permitted capacities, and current demands. Accordingly, the following discussion focuses on impacts of continued operations on local public utilities.

PVNGS obtains potable water primarily from two of four onsite groundwater wells. Between 2001 and 2005, the PVNGS domestic water system averaged 1,232 gpm of groundwater. Operations- or staff-related plant water use is not expected to change during the license renewal term. Currently, area municipal water suppliers have additional capacity and local water system planners are using various programs and technologies to ensure adequate water supplies for future use. Because APS has no plans to increase PVNGS staffing for license renewal activities, there would be no increase in area population. Therefore, APS concludes that impacts on public water supply would be SMALL and not require mitigation.

4.16 EDUCATION IMPACTS FROM REFURBISHMENT

NRC

The environmental report must contain "…[a]n assessment of the impact of the proposed action on…public schools (impacts from refurbishment activities only) within the vicinity of the plant…." 10 CFR 51.53(c)(3)(ii)(I)

"…Most sites would experience impacts of small significance but larger impacts are possible depending on site- and project-specific factors…." 10 CFR 51, Subpart A, Table B-1, Issue 66

"…[S]mall impacts are associated with project-related enrollment increases of 3 percent or less. Impacts are considered small if there is no change in the school systems' abilities to provide educational services and if no additional teaching staff or classroom space is needed. Moderate impacts are generally associated with 4 to 8 percent increases in enrollment. Impacts are considered moderate if a school system must increase its teaching staff or classroom space even slightly to preserve its pre-project level of service….Large impacts are associated with project-related enrollment increases above 8 percent…." (NRC 1996).

NRC made refurbishment-related impacts to education a Category 2 issue because site- and project-specific factors determine the significance of impacts (NRC 1996). Local factors to be ascertained include: (1) project-related enrollment increases and (2) status of the student/teacher ratio.

The issue of education impacts from 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.

4.17 OFFSITE LAND USE

4.17.1 Offsite Land Use - Refurbishment

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on... land-use... (impacts from refurbishment activities only) within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"…Impacts may be of moderate significance at plants in low population areas…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 68

"…[I]f plant-related population growth is less than 5 percent of the study area's total population, off-site land-use changes would be small, especially if the study area has established patterns of residential and commercial development, a population density of at least 60 persons per square mile, and at least one urban area with a population of 100,000 or more within 50 miles…." (NRC 1996).

NRC made impacts to offsite land use as a result of refurbishment activities a Category 2 issue because land-use changes could be considered beneficial by some community members and adverse by others. Local conditions to be ascertained include: (1) plant-related population growth, (2) patterns of residential and commercial development, and (3) proximity to an urban area with a population of at least 100,000.

This issue is not applicable to PVNGS because, as Section 3.2 discusses, APS has no plans for refurbishment at PVNGS.

4.17.2 Offsite Land Use – License Renewal Term

NRC

The environmental report must contain "…an assessment of the impact of the proposed action on …land-use…within the vicinity of the plant…" 10 CFR 51.53(c)(3)(ii)(I)

"Significant changes in land use may be associated with population and tax revenue changes resulting from license renewal." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 69

"…[I]f plant-related population growth is less than five percent of the study area's total population, off-site land-use changes would be small…" (NRC 1996).

"If the plant's tax payments are projected to be small, relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development." (NRC 1996).

NRC made impacts to offsite land use during the license renewal term a Category 2 issue because land-use changes may be perceived as beneficial by some community members and adverse by others. Therefore, NRC could not assess the potential significance of site-specific offsite land-use impacts (NRC 1996). Site-specific factors to be considered in an assessment of new tax-driven land-use impacts include: (1) the size of plant-related population growth compared to the area's total population, (2) the size of the plant's tax payments relative to the community's total revenue, (3) the nature of the community's existing land-use pattern, and (4) the extent to which the community already has public services in place to support and guide development.

The Generic Environmental Impact Statement (GEIS) (NRC 1996) presents an analysis of offsite land use for the renewal term that is characterized by two components: population-driven and tax-driven impacts.

Population-Related Impacts

Based on the GEIS case-study analysis, NRC concluded that all new population-driven land-use changes during the license renewal term at all nuclear plants would be small. Population growth caused by license renewal would represent a much smaller percentage of the local area's total population than the percentage presented by operations-related growth (NRC 1996).

Tax-Revenue-Related Impacts

Determining tax-revenue-related land use impacts is a two-step process. First, the significance of the plant's tax payments on taxing jurisdictions' tax revenues is evaluated. Then, the impact of the tax contribution on land use within the taxing jurisdiction's boundaries is assessed.

Tax Payment Significance

NRC has determined that the significance of tax payments as a source of local government revenue would be large if the payments are greater than 20 percent of revenue, moderate if the payments are between 10 and 20 percent of revenue, and small if the payments are less than 10 percent of revenue (NRC 1996).

Land Use Significance

NRC defined the magnitude of land-use changes as follows (NRC 1996):

Small - very little new development and minimal changes to an area's land-use pattern.

Moderate - considerable new development and some changes to land-use pattern.

Large - large-scale new development and major changes in land-use pattern.

NRC further determined that, if the plant's tax payments are projected to be small, relative to the community's total revenue, new tax-driven land-use changes during the plant's license renewal term would be small, especially where the community has pre-established patterns of development and has provided adequate public services to support and guide development (NRC 1996).

PVNGS Tax Impacts

Table 2-4 provides a comparison of total tax payments made by PVNGS to Maricopa County and Maricopa County's annual property tax revenues. For the years 2001 through 2006, PVNGS's property taxes have represented 1.3 to 1.8 percent of Maricopa County's total tax revenues. Using NRC's criteria, PVNGS's tax payments are of small significance to Maricopa County.

PVNGS Land Use Impacts

As stated in Section 2.8, from 1990 to 2000, Maricopa County's population growth rate was 44.8 percent (Section 2.6). Over the same period, the number of housing units in Maricopa County increased by 31.3 percent. The Phoenix-Mesa-Scottsdale, AZ MSA, which contains Maricopa County, was the 14th largest and 5th fastest growing MSA in the United States (Section 2.6). Approximately two-thirds of the Maricopa Association of Government (MAG) region's (Section 2.8) population growth has been through in-migration. The primary reasons for such growth have been ample employment opportunities, affordable housing, and a moderate cost of living.

The MAG region's urban development has been characterized as increasingly dispersed. The dispersal has been attributed to the region's flat topography and the availability of land on the edges of the urban areas. Most development has occurred in the West Valley, northern Pinal County, and the North Valley, however, all urban edges are being developed to some extent. Planners expect this trend to continue. More than half of the land in the MAG region is still available for development.

Local and regional planners use comprehensive land use planning, zoning, and subdivision regulations to control development. They encourage growth in areas where public facilities such as water and sewer systems exist or are scheduled to be built in the future. They also promote the preservation of the communities' natural resources, but have no growth control measures.

In conclusion, there will be no increase in license renewal-related population. Also, using NRC's criteria, PVNGS's tax payments are of SMALL significance to Maricopa County.

The Phoenix-Mesa-Scottsdale, AZ MSA is one of the fastest growing regions in the United States. Relative to the size of the surrounding population and level of commercial and industrial activity in this region, PVNGS has had a small impact on the local economy and tax base. The tax base is very large and tax payments made by PVNGS are comparatively small. Any changes to the infrastructures of Maricopa County would be attributable to the large population inmigration already experienced by the County and a large pool of residential, industrial, and commercial tax payers.

License renewal would not generate additional tax revenues, but would continue the small beneficial impact of the plant on the county. Therefore, the land-use impacts of PVNGS' license renewal term are expected to be SMALL, with very little new development and minimal changes to the area's land-use pattern.

4.18 TRANSPORTATION

NRC

> The environmental report must "...assess the impact of highway traffic generated by the proposed project on the level of service of local highways during periods of license renewal refurbishment activities and during the term of the renewed license." 10 CFR 51.53(c)(3)(ii)(J)
>
> "…Transportation impacts…are generally expected to be of small significance. However, the increase in traffic associated with additional workers and the local road and traffic control conditions may lead to impacts of moderate or large significance at some sites…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 70
>
> Small impacts would be associated with U.S. Transportation Research Board Level of Service A, having the following condition: "…Free flow of the traffic stream; users are unaffected by the presence of others." and Level of Service B, having the following condition: "…Stable flow in which the freedom to select speed is unaffected but the freedom to maneuver is slightly diminished…." (NRC 1996)

NRC made impacts to transportation a Category 2 issue, because impact significance is determined primarily by road conditions existing at the time of license renewal, which NRC could not forecast for all facilities (NRC 1996). Local road conditions to be ascertained are: (1) level of service conditions and (2) incremental increases in traffic associated with refurbishment activities and license renewal staff.

As described in Section 3.2, no refurbishment is planned and no refurbishment impacts to local transportation are therefore anticipated. As described in Section 3.4, no additional license renewal employment increment is expected. Therefore, APS expects license-renewal impacts to transportation to be SMALL and mitigation would not be necessary.

4.19 HISTORIC AND ARCHAEOLOGICAL RESOURCES

NRC

The environmental report must contain an assessment of "…whether any historic or archaeological properties will be affected by the proposed project." 10 CFR 51.53(c)(3)(ii)(K)

"Generally, plant refurbishment and continued operation are expected to have no more than small adverse impacts on historic and archaeological resources. However, the National Historic Preservation Act requires the Federal agency to consult with the State Historic Preservation Officer to determine whether there are properties present that require protection." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 71

"Sites are considered to have small impacts to historic and archaeological resources if (1) the State Historic Preservation Officer (SHPO) identifies no significant resources on or near the site; or (2) the SHPO identifies (or has previously identified) significant historic resources but determines they would not be affected by plant refurbishment, transmission lines, and license-renewal term operations and there are no complaints from the affected public about altered historic character; and (3) if the conditions associated with moderate impacts do not occur." (NRC 1996).

NRC made impacts to historic and archaeological resources a Category 2 issue, because determinations of impacts to historic and archaeological resources are site-specific and the National Historic Preservation Act mandates that impacts must be determined through consultation with the State Historic Preservation Officer (NRC 1996).

In the FES for operations (NRC 1982), NRC concluded that, based on the surveys undertaken and the mitigation plans developed, the operation of PVNGS would not adversely impact archaeological resources or historic sites. NRC staff committed to work with APS to get a formal determination of eligibility to the Keeper of the National Register for four sites in the wastewater conveyance system and a letter from the New Mexico SHPO on the sites in the Project 3 corridor (Section 2.11).

As discussed in Section 3.2, APS has no refurbishment plans and no refurbishment-related impacts are anticipated. APS is not aware of any historic or archaeological resources that have been affected by PVNGS operations, including operation and maintenance of transmission lines.

APS is aware, however, that the site vicinity and the surrounding environs have potential for containing cultural resources. APS has an environmental review and evaluation procedure to ensure the protection of protected cultural resources. Because APS has no plans to construct additional facilities at PVNGS during the license renewal term and the plant procedure should protect any resources encountered during the license renewal term, APS concludes that operation of generation and transmission facilities over the license renewal term would have SMALL impacts to cultural resources; hence, no mitigation would be warranted.

4.20 SEVERE ACCIDENT MITIGATION ALTERNATIVES

NRC

The environmental report must contain a consideration of alternatives to mitigate severe accidents "…if the staff has not previously considered severe accident mitigation alternatives for the applicant's plant in an environmental impact statement or related supplement or in an environment assessment..." 10 CFR 51.53(c)(3)(ii)(L)

"…The probability weighted consequences of atmospheric releases, fallout onto open bodies of water, releases to ground water, and societal and economic impacts from severe accidents are small for all plants. However, alternatives to mitigate severe accidents must be considered for all plants that have not considered such alternatives…." 10 CFR 51, Subpart A, Appendix B, Table B-1, Issue 76

Section 4.20 summarizes APS' analysis of alternative ways to mitigate the impacts of severe accidents. Attachment D provides a detailed description of the severe accident mitigation alternatives (SAMA) analysis.

The term "accident" refers to any unintentional event (i.e., outside the normal or expected plant operation envelope) that results in the release or a potential for release of radioactive material to the environment. NRC categorizes accidents as "design basis" or "severe." Design basis accidents are those for which the risk is great enough that NRC requires plant design and construction to prevent unacceptable accident consequences. Severe accidents are those that NRC considers too unlikely to warrant design controls.

NRC concluded in its license renewal rulemaking that the unmitigated environmental impacts from severe accidents met its Category 1 criteria. However, NRC made consideration of mitigation alternatives a Category 2 issue because not all plants had completed ongoing regulatory programs related to mitigation (e.g., individual plant examinations and accident management). Site-specific information to be presented in the license renewal environmental report includes: (1) potential SAMAs; (2) benefits, costs, and net value of implementing potential SAMAs; and (3) sensitivity of analysis to changes in key underlying assumptions.

APS maintains a probabilistic safety assessment model to use in evaluating the most significant risks of radiological release from PVNGS fuel into the reactor and from the reactor into the containment structure. For the SAMA analysis, APS used the model output as input to an NRC-approved model that calculates economic costs and dose to the public from hypothesized releases from the containment structure into the environment (Attachment D). Then, using NRC regulatory analysis techniques, APS calculated the monetary value of the unmitigated PVNGS severe accident risk. The result represents the monetary value of the base risk of dose to the public and worker, offsite and onsite economic impacts, and replacement power. This value became a cost/benefit-screening tool for potential SAMAs; a SAMA whose cost of implementation exceeded the base risk value could be rejected as being not cost-beneficial.

APS used industry, NRC, and PVNGS-specific information to create a list of 23 SAMAs for consideration. APS analyzed this list and screened out SAMAs that would not apply to the PVNGS design, that APS had already implemented, or that would achieve results that APS had 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. APS will consider the three SAMAs using the appropriate PVNGS design process outside the license renewal process.

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 4.17

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Section 4.18

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5.0 CHAPTER 5 - ASSESSMENT OF NEW AND SIGNIFICANT INFORMATION

5.1 ASSESSMENT

NRC

"…The environmental report must contain any new and significant information regarding the environmental impacts of license renewal of which the applicant is aware." 10 CFR 51.53(c)(3)(iv)

The U.S. Nuclear Regulatory Commission (NRC) licenses the operation of domestic nuclear power plants and provides for license renewal. License renewal applications must include an environmental report (10 CFR 54.23) with the content as prescribed in 10 CFR 51. In an effort to streamline the environmental review, NRC has resolved most of the environmental issues generically and only requires an applicant's analysis of the remaining issues.

While NRC regulations do not require an applicant's environmental report to contain analyses of the impacts of those environmental issues that have been generically resolved [10 CFR 51.53(c)(3)(i)], the regulations do require that an applicant identify any new and significant information of which the applicant is aware [10 CFR 51.53(c)(3)(iv)]. The purpose of this requirement is to alert NRC staff to such information so the staff can determine whether to seek the Commission's approval to waive or suspend application of the rule with respect to the affected generic analysis. NRC has explicitly indicated, however, that an applicant is not required to perform a site-specific validation of Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) conclusions (NRC 1996a).

APS expects that new and significant information would include:

- Information that identifies a significant environmental issue not covered in the GEIS and codified in the regulation, or

- Information that was not covered in the GEIS analyses and that leads to an impact finding different from that codified in the regulation.

NRC does not specifically define the term "significant." For the purpose of its review, APS used guidance available in Council on Environmental Quality (CEQ) regulations. The National Environmental Policy Act authorizes CEQ to establish implementing regulations for federal agency use. NRC requires license renewal applicants to provide NRC with input, in the form of an environmental report, that NRC will use to meet National Environmental Policy Act requirements as they apply to license renewal (10 CFR 51.10). CEQ guidance provides that federal agencies should prepare environmental impact statements for actions that would significantly affect the environment (40 CFR 1502.3), focus on significant environmental issues (40 CFR 1502.1), and eliminate from detailed study issues that are not significant [40 CFR 1501.7(a)(3)]. The CEQ guidance includes a lengthy definition of "significantly" that requires consideration of the context of the action and the intensity or severity of the impact(s) (40 CFR 1508.27). APS expects that moderate or large impacts, as defined by NRC, would be significant. Chapter 4 presents the NRC definitions of "moderate" and "large" impacts.

The new and significant assessment process that APS used during preparation of this license renewal application included: (1) interviews with APS and PVNGS subject experts on the validity of the conclusions in the GEIS as they relate to PVNGS, (2) an extensive review of documents related to environmental issues at PVNGS, (3) correspondence with state and federal agencies to determine if the agencies had concerns not addressed in the GEIS (Attachments B and C), (4) a review of reports submitted to NRC in accordance with Section 5.4 of the Environmental Protection Plan, (5) a review of other license renewal applications for pertinent issues, (6) credit for the oversight provided by inspections of plant facilities by state and federal regulatory agencies, and (7) interfaces with allied nuclear plants under the Strategic Teaming and Resource Sharing alliance.

APS is aware of no new and significant information regarding the environmental impacts of renewing the Palo Verde Nuclear Generating Station (PVNGS) operating licenses.

While APS recognizes that the Commission has held that, under NEPA, an applicant for a renewed operating license(s) need not consider the impacts of terrorism (AmerGen 2007), it also recognizes the ruling of the United States Court of Appeals for the Ninth Circuit regarding the consideration of terrorism in NRC licensing actions (Ninth Circuit 2006). Therefore, because PVNGS is located in the Ninth Circuit, and as a matter of discretion, APS has included the following discussion in this ER.

Because PVNGS is already an operating nuclear generating facility, the consideration of risk posed by a term of renewed plant operation is not necessarily the same as that associated with licensing a new nuclear facility. Thus, consideration of the possible environmental impacts of a terrorist attack at an existing facility must take into account the protections afforded an existing facility and recognize that it is already sited and has been operating for at least 20. Moreover, as a threshold matter, it is imperative to note that the possibility of a terrorist attack affecting the operation of PVNGS is very remote and that postulating potential environmental impacts from a terrorist attack involves substantial speculation.

In this regard, the PVNGS has had active and robust security measures in place since initial operation including a trained armed security force and multiple physical barriers surrounding the Owner Controlled Area and Protected Area. State of the art sensors monitor the Owner Controlled Area and Protected Area and are monitored on a 24-hour basis by dedicated security force staff. Contingency plans have been developed for potential security related events. Personnel access to the Protected Area and vital areas is restricted by electronic measures to prevent unauthorized entry, and access level is based on employment position needs. Employees with access to the Protected Area undergo detailed background checks, and all personnel seeking access to the Owner Controlled Area must undergo a search and demonstrate a legitimate need to access the Owner Controlled Area to the security force prior to entry.

Details of the security procedures and systems are safeguards information that are restricted to those employees with a need to know. Following the events of September 11, 2001, the NRC issued increased security requirements, and PVNGS has complied with those requirements. Thus, it is highly unlikely that a hostile force could successfully overcome these security measures and gain entry into the sensitive facilities, and even less likely that they could do this quickly enough to prevent operators from putting plant reactors into safe shutdown mode.

A security threat that is more frequently identified by members of the public or in the media, however, is an attack using hijacked jet airliners. The likelihood of this occurring is equally remote in light of heightened security awareness, but this threat has been carefully studied.

The Nuclear Energy Institute (NEI) commissioned the Electric Power Research Institute (EPRI) to conduct an impact analysis of a large jet airliner being purposefully crashed into sensitive nuclear facilities, including nuclear reactor containment buildings, used fuel storage ponds, used fuel dry storage facilities, and used fuel transportation containers. The EPRI analysis was peer reviewed upon completion. Using conservative analyses, EPRI concluded that there would be no release of radionuclides from nuclear facilities or containers, as they are already designed to withstand potentially destructive events.

Nuclear reactor containment buildings, for example, have thick concrete walls with heavy reinforcing steel. They are designed to withstand, among other things, large earthquakes, extreme overpressures, and tornado and hurricane-force winds. Using computer models, a large transport category multiengine jet aircraft was crashed into containment structures that were representative of all U.S. nuclear power containment types. The containment structures suffered some crushing and chipping at the maximum impact point but were not breached. The results of this analysis are summarized in an NEI paper entitled, “Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant’s Structural Strength” (NEI 2002). (For security reasons, the EPRI analysis has not been publicly released).

The EPRI analysis is fully consistent with research conducted by the NRC. When NRC recently considered such threats, then-NRC Commissioner McGaffigan observed (NRC 2007):

> As NRC has said repeatedly, our research showed that in most (the vast majority of) cases an aircraft attack would not result in anything more than a very expensive industrial accident in which no radiation release would occur. In those few cases where a radiation release might occur, there would be no challenge to the emergency planning basis currently in effect to deal with all beyond-design-basis events, whether generated by mother nature, or equipment failure, or terrorists.

In the very remote likelihood that a terrorist attack did successfully breach the physical and other safeguards at PVNGS resulting in the release of radionuclides, the consequences of such a release are reasonably discussed in the GEIS (NRC 1996b). In the GEIS, the Commission discussed sabotage as the potential initiator of a severe accident. The Commission generically determined the risk to be of small significance for all nuclear power plants. Thus, no further evaluation of the potential environmental impacts of a terrorist attack is necessary because the GEIS analysis of severe accident consequences bounds the potential consequences that might result from a large scale radiological release, irrespective of the initiating cause.

Finally, no matter how small the risk of a radiological emergency, the NRC requires all nuclear power plants to have and periodically test emergency plans that are coordinated with federal, state and local responders. The goal of preparedness is to reduce the risk to the public during an emergency. In an emergency, the NRC and APS would activate their Incident Response Programs. APS specialists would evaluate the situation and identify ways to end the emergency, while the NRC would monitor the event closely, keeping government offices informed. If a radiation release occurred, then the plant would make protective action recommendations to state and local officials, such as evacuating areas around the plant (NRC 2008).

5.2 REFERENCES

AmerGen (AmerGen Energy Co., LLC; Oyster Creek Nuclear Generating Station) 2007. *appeal filed sub nom. New Jersey Department of Environmental. Protection. v. NRC*, No. 07-2271 (3d Cir.), CLI-07-8, 65 NRC 124, 129.

NEI (Nuclear Energy Institute) 2002. *Deterring Terrorism: Aircraft Crash Impact Analyses Demonstrate Nuclear Power Plant's Structural Strength*. Washington, D.C.

Ninth Circuit 2006. *San Luis Obispo Mothers for Peace v. NRC*, 449 F.3d 1016.

NRC (U.S. Nuclear Regulatory Commission) 1996a. *Public Comments on the Proposed 10 CFR 51 Rule for Renewal of Nuclear Power Plant Operating Licenses and Supporting Documents: Review of Concerns and NRC Staff Response.* Volumes 1 and 2. NUREG-1529. Washington, DC. May.

NRC (U.S. Nuclear Regulatory Commission) 1996b. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*, Volume 1, p. 5-18, NUREG-1437, Washington, D.C., May.

NRC (U.S. Nuclear Regulatory Commission) 2007. *Commission Voting Record, SECY-06-0219, Final Rulemaking to Revise 10 C.F.R. 73.1, Design Basis Threat (DBT) Requirements (Jan. 29, 2007)*, Attachment, Commissioner McGaffigan's Additional Comments, at 1.

NRC (U.S. Nuclear Regulatory Commission) 2008. Modified from *Security Spotlight*, January 2. Original, together with additional NRC information is available online at http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/security-spotlight/preparedness-response.html.

6.0 CHAPTER 6 - SUMMARY OF LICENSE RENEWAL IMPACTS AND MITIGATING ACTIONS

6.1 LICENSE RENEWAL IMPACTS

APS has reviewed the environmental impacts of renewing the PVNGS operating license and has concluded that all impacts would be SMALL and would not require additional mitigation. This environmental report documents the basis for APS' conclusion. Chapter 4 incorporates by reference the NRC findings for the 33 Category 1 issues that apply to PVNGS, all of which have impacts that are SMALL (Attachment A, Table A-1). Chapter 4 also analyzes Category 2 issues, all of which are either not applicable or, have impacts that would be SMALL. Table 6-1 identifies the impacts that PVNGS license renewal would have on resources associated with Category 2 issues.

6.2 MITIGATION

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 and balances…alternatives available for reducing or avoiding adverse environmental effects.…" 10 CFR 51.45(c) as incorporated by 10 CFR 51.53(c)(2) and 10 CFR 51.53(c)(3)(iii)

All impacts of license renewal are SMALL and would not require mitigation (Section 4.13). Current operations include monitoring activities that would continue during the term of the license renewal. APS performs routine monitoring activities to ensure the safety of workers, the public, and the environment. These activities include:

- The Radiological Environmental Monitoring Program
- Water quality monitoring
- Emissions monitoring
- Groundwater level monitoring
- Environmental Protection Plan monitoring and reporting requirements

These monitoring programs and activities ensure that the plant's permitted emissions and discharges are within regulatory limits and any unusual or off-normal emissions or discharges would be quickly detected, thus, mitigating potential impacts.

6.3 UNAVOIDABLE ADVERSE IMPACTS

NRC

The environmental report shall discuss "Any adverse environmental effects which cannot be avoided should the proposal be implemented" 10 CFR 51.45(b)(2) as adopted by 10 CFR 51.53(c)(2)

This environmental report adopts by reference NRC findings for applicable Category 1 issues, including discussions of any unavoidable adverse impacts (Attachment A, Table A-1). APS examined the 11 Category 2 issues applicable to PVNGS (Section 4.0) and identified the following unavoidable adverse impacts of license renewal. However, the impacts are not a result of license renewal specifically, but are continuations of existing impacts.

- PVNGS would continue to use approximately 1,200 gpm of groundwater from the Hassayampa subbasin. This water would be unavailable for other uses.
- Because the land surrounding the plant is flat, some structures are visible from offsite. This visual impact would continue during the license renewal term.
- Procedures for the disposal of sanitary, chemical, and radioactive wastes are intended to reduce adverse impacts from these sources to acceptably low levels. A small impact would be present as long as the plant is in operation. Solid radioactive wastes are a product of plant operations and long-term disposal of these materials is addressed in NRC's waste confidence rule.
- Operation of PVNGS results in a very small increase in radioactivity in the air. However, fluctuations in doses from natural background radiation may be expected to exceed the small incremental increase in dose to the local population attributable to continued plant operation. Operation of PVNGS also establishes a very low probability risk of accidental radiation exposure to inhabitants of the area.

6.4 IRREVERSIBLE AND IRRETRIEVABLE RESOURCE COMMITMENTS

NRC

The environmental report shall discuss "Any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented." 10 CFR 51.45(b)(5) as adopted by 10 CFR 51.53(c)(2)

The continued operation of PVNGS for the license renewal term would result in the following irreversible and irretrievable resource commitments:

- Nuclear fuel, which is consumed in the reactor and converted to radioactive waste
- The land required to dispose of spent nuclear fuel and low-level radioactive wastes generated as a result of plant operations, and solid and sanitary wastes generated from normal industrial operations
- Elemental materials that would become radioactive
- Materials used for the normal industrial operations of the plant that cannot be recovered or recycled or that are consumed or reduced to unrecoverable forms

6.5 SHORT-TERM USE VERSUS LONG-TERM PRODUCTIVITY OF THE ENVIRONMENT

NRC

The environmental report shall discuss "The relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity...." 10 CFR 51.45(b)(4) as adopted by 10 CFR 51.53(c)(2)

The current balance between short-term use and long-term productivity at PVNGS was established when the plant began operating in 1984. The PVNGS Final Environmental Statement for Construction (NRC 1975) evaluated the impacts of constructing and operating PVNGS in Maricopa County, Arizona. Approximately 4,280 acres were acquired for the plant and buffer areas, and approximately 15 square miles are used for transmission line corridors. The plant withdraws approximately 2,000 acre-feet of groundwater per year for potable water and uses recycled waste water from Phoenix for cooling water. Maricopa County is desert with marginal agricultural lands. PVNGS converted 4,280 acres of marginal agricultural land to energy production, which enhances the economic stability of the region. The land uses in the transmission corridor rights-of-way generally have not changed as a result of construction of transmission lines – agricultural land and desert remain under the lines.

After decommissioning, groundwater withdrawal would cease, and some restoration of the site would occur. It is likely that the recycled waste water ponds and evaporation ponds would be remediated and closed and the waste water transferred to agricultural and other purposes. Thus, the "trade-off" between the production of electricity and changes in the local environment is reversible to some extent.

Experience with other experimental, developmental, and commercial nuclear plants has demonstrated the feasibility of decommissioning and dismantling such plants sufficiently to restore a site to its former use. The degree of dismantlement, would take into account the intended new use of the site and a balance among health and safety considerations, salvage values, and environmental impact. However, decisions on the ultimate disposition of these lands have not yet been made. Continued operation for an additional 20 years would not increase the short-term productivity impacts described here.

6.6 TABLES

Table 6-1. Category 2 Environmental Impacts Related to License Renewal at PVNGS.

No.	Issue	Environmental Impact
Surface Water Quality, Hydrology, and Use (for all plants)		
13	Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	**SMALL**. Cooling water is piped from Phoenix wastewater treatment facilities rather than being discharged to the Gila River. PVNGS uses approximately 35 percent of its contracted allocation. If this treated effluent were not used by PVNGS, it would be available for use under contract by other commercial activities and for irrigation. The amount of water used by PVNGS is approximately 11 percent of the average annual flow of the Gila River at the USGS gaging station at Estrella Parkway.
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)		
25	Entrainment of fish and shellfish in early life stages	**None**. PVNGS has a closed cycle cooling system that does not withdraw cooling water from surface water.
26	Impingement of fish and shellfish in early life stages	**None**. PVNGS has a closed cycle cooling system that does not withdraw cooling water from surface water.
27	Heat shock	**None**. PVNGS has a closed cycle cooling system that discharges cooling water to lined evaporation ponds.
Groundwater Use and Quality		
33	Groundwater use conflicts (potable and service water, and dewatering; plants that use > 100 gpm)	**SMALL**. PVNGS withdraws approximately 1,200 gallons per minute. A predicted conservative drawdown of 8.3 feet at the property boundary would occur during the life of the current operating permit. An additional 0.5 feet of drawdown would occur during the license renewal period. PVNGS uses 6.8 percent of the Hassayampa sub-basin groundwater.
34	Groundwater use conflicts (plants using cooling towers or cooling ponds that withdraw make-up water from a small river)	**SMALL**. Cooling water is piped from Phoenix wastewater treatment facilities, but the waste water could have been discharged to the Gila River, a small river, if it were not being used by PNVGS. The cooling water represents 0.05 percent of the groundwater in the Phoenix metropolitan area and 0.1 percent of the groundwater in the Phoenix active management area.
35	Groundwater use conflicts (Ranney wells)	**None**. PVNGS does not use Ranney wells. Therefore, this issue does not apply.
39	Groundwater quality degradation (cooling ponds at inland sites)	**None**. PVNGS does not use cooling ponds. Therefore, this issue does not apply.

Table 6-1. Category 2 Environmental Impacts Related to License Renewal at PVNGS. (Continued)

No.	Issue	Environmental Impact
Terrestrial Resources		
40	Refurbishment impacts	**None**. No impacts are expected because PVNGS will not undertake refurbishment. Therefore, this issue does not apply.
Threatened or Endangered Species		
49	Threatened or endangered species	**SMALL**. APS does not plan to alter current operations over the license renewal period. Neither APS nor natural resource agencies have identified any concerns about impacts of current operations.
Air Quality		
50	Air quality during refurbishment (nonattainment and maintenance areas)	**None**. No impacts are expected because PVNGS will not undertake refurbishment. Therefore, this issue does not apply.
Human Health		
57	Microbiological organisms (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	**None**. PVNGS does not discharge to surface waters. Therefore, this issue does not apply.
59	Electric shock from transmission line-induced currents	**SMALL.** The induced currents at the seven locations under the PVNGS transmission lines are less than 5.0 milliamperes, which is the National Electric Safety Code standard for preventing electric shock from induced current.
Socioeconomics		
63	Housing impacts	**SMALL.** For the purpose of license renewal, APS does not plan on any refurbishment and does not plan to add employees. Therefore, there would be no increased demand on housing because of license renewal.
65	Public services: public utilities	**SMALL.** For the purpose of license renewal, APS does not plan on any refurbishment and does not plan to add employees. Therefore, there would be no increased demand on public utilities because of license renewal.
66	Public services: education (refurbishment)	**None.** No impacts are expected because PVNGS would not undertake refurbishment. Therefore, this issue does not apply.
68	Offsite land use (refurbishment)	**None.** No impacts are expected because PVNGS would not undertake refurbishment. Therefore, this issue does not apply.
69	Offsite land use (license renewal term)	**SMALL**. Although APS and the other owners pay a large amount of tax, the amount is not a significant fraction of Maricopa County tax revenues. License renewal would not generate additional tax revenues, but would continue the small beneficial impact of the plant on the county. Therefore, continued operation is expected to have a SMALL impact on local land use.
70	Public services: transportation	**SMALL.** For the purpose of license renewal, APS does not plan on any refurbishment and does not plan to add employees. Therefore, there would be no increased demand on the local transportation infrastructure because of license renewal.

Table 6-1. Category 2 Environmental Impacts Related to License Renewal at PVNGS. (Continued)

No.	Issue	Environmental Impact
71	Historic and archaeological resources	**SMALL.** APS does not plan on any refurbishment or transmission-line corridor changes during the license renewal term. Continued plant site operations are not expected to impact cultural resources. The Arizona State Historic Preservation Office concurs.
Postulated Accidents		
76	Severe accidents	**SMALL.** The benefit/cost analysis did not identify any cost-effective aging-related severe accident mitigation alternatives.

6.7 REFERENCES

NRC (U.S. Nuclear Regulatory Commission) 1975. *Environmental Statement Related to Construction of Palo Verde Nuclear Generating Station Units 1, 2, and 3*. Arizona Public Service Company. Docket Nos. STN 50-528, STN 50-529, and STN 50-530. Office of Nuclear Reactor Regulation. Washington, D.C. September.

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7.0 CHAPTER 7 - ALTERNATIVES TO THE PROPOSED ACTION

NRC

The environmental report shall discuss “Alternatives to the proposed action…” 10 CFR 51.45(b)(3), as adopted by reference at 10 CFR 51.53(c)(2)

“...The report is not required to include discussion of need for power or economic costs and benefits of ... alternatives to the proposed action except insofar as such costs and benefits are either essential for a determination regarding the inclusion of an alternative in the range of alternatives considered or relevant to mitigation....” 10 CFR 51.53(c)(2)

“While many methods are available for generating electricity, and a huge number of combinations or mixes can be assimilated to meet a defined generating requirement, such expansive consideration would be too unwieldy to perform given the purposes of this analysis. Therefore, NRC has determined that a reasonable set of alternatives should be limited to analysis of single, discrete electric generation sources and only electric generation sources that are technically feasible and commercially viable….” (NRC 1996a).

“…The consideration of alternative energy sources in individual license renewal reviews will consider those alternatives that are reasonable for the region, including power purchases from outside the applicant’s service area....” (NRC 1996b).

Chapter 7 evaluates alternatives to PVNGS license renewal. The chapter identifies actions that the owners of PVNGS [i.e., Arizona Public Service Company (APS), Salt River Project, El Paso Electric Company, Southern California Edison, Public Service Company of New Mexico, Southern California Public Power Authority, and the Los Angeles Dept. of Water & Power] might take, and associated environmental impacts, if NRC chooses not to renew the plant’s operating licenses. The chapter also addresses PVNGS actions that the owners of PVNGS have considered, but would not take, and identifies bases for determining that such actions would be unreasonable.

APS divided its alternatives discussion into two categories, “no-action” and “alternatives that meet system generating needs.” In considering the level of detail and analysis that it should provide for each category, APS relied on the NRC decision-making standard for license renewal:

> …the NRC staff, adjudicatory officers, and Commission shall determine whether or not the adverse environmental impacts of license renewal are so great that preserving the option of license renewal for energy planning decision makers would be unreasonable. [10 CFR 51.95(c)(4)]

APS has determined that the analysis of alternatives should focus on comparative impacts, specifically whether an alternative’s impacts would be greater, smaller, or similar to the proposed action.

Providing additional detail or analysis serves no function if it only brings to light additional adverse impacts of alternatives to license renewal. This approach is consistent with regulations of the Council on Environmental Quality, which provide that the consideration of alternatives (including the proposed action) should enable reviewers to evaluate their comparative merits (40 CFR 1500-1508). APS considers Chapter 7 sufficient with regard to providing detail about alternatives to establish the basis for necessary comparisons to the Chapter 4 discussion of impacts from the proposed action.

In characterizing environmental impacts from alternatives, APS has used the same definitions of SMALL, MODERATE, and LARGE that are presented in the introduction to Chapter 4.

7.1 NO-ACTION ALTERNATIVE

APS uses "no-action alternative" to refer to a scenario in which NRC does not renew the PVNGS operating license. Components of this alternative include replacing the generating capacity of PVNGS and decommissioning the facility, as described below.

PVNGS provides approximately 4,020 megawatts of electricity to its owners and customers. Any alternative would be unreasonable if it did not include replacing the baseload capacity of PVNGS. Replacement alternatives include (1) building new generating capacity, (2) purchasing power from the wholesale market, or (3) reducing power requirements through demand reduction. Section 7.2.1 describes each of these possibilities in detail, and Section 7.2.2 describes environmental impacts from feasible alternatives.

The Generic Environmental Impact Statement (GEIS) (NRC 1996a) defines decommissioning as the safe removal of a nuclear facility from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the license. NRC-evaluated decommissioning options include immediate decontamination and dismantlement and safe storage of the stabilized and defueled facility for a period of time, followed by additional decontamination and dismantlement. Regardless of the option chosen, decommissioning must be completed within a 60-year period. Under the no-action alternative, APS would continue operating PVNGS until the existing licenses expire, then initiate decommissioning activities in accordance with NRC requirements. The GEIS describes decommissioning activities based on an evaluation of a smaller reactor than the units at PVNGS (the "reference" pressurized-water reactor is the 1,175-megawatt-electric [MWe] Trojan Nuclear Plant). This description is applicable to decommissioning activities that APS would conduct at PVNGS.

As the GEIS notes, NRC has evaluated environmental impacts from decommissioning. NRC-evaluated impacts include impacts of occupational and public radiation dose; impacts of waste management; impacts to air and water quality; and ecological, economic, and socioeconomic impacts. NRC indicated in the *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities; Supplement 1* (NRC 2002a) that the environmental effects of greatest concern (i.e., radiation dose and releases to the environment) are substantially less than the same effects resulting from reactor operations. APS adopts by reference the NRC conclusions regarding environmental impacts of decommissioning.

APS notes that decommissioning activities and their impacts are not discriminators between the proposed action and the no-action alternative. APS will have to decommission PVNGS regardless of the NRC decision on license renewal; license renewal would only postpone decommissioning for another 20 years. NRC has established in the GEIS that the timing of decommissioning operations does not substantially influence the environmental impacts of decommissioning. APS adopts by reference the NRC findings (10 CFR 51, Appendix B, Table B-1, Decommissioning) to the effect that delaying decommissioning until after the renewal term would have small environmental impacts. The discriminators between the proposed action and the no-action alternative are to be found within the choice of generation replacement options. Section 7.2.2 analyzes the impacts from these options.

APS concludes that the decommissioning impacts under the no-action alternative would not be substantially different from those occurring following license renewal, as identified in the GEIS

(NRC 1996a) and in the decommissioning generic environmental impact statement (NRC 2002a). These impacts would be temporary and would occur at the same time as the impacts from meeting system generating needs.

7.2 ALTERNATIVES THAT MEET SYSTEM GENERATING NEEDS

PVNGS has a net baseload capacity of 4,020 MWe, and in 2005 generated approximately 25.8 terawatt-hours of electricity (EIA 2006a). This power, equivalent to the energy used by approximately 2,224,000 residential customers (SWEEP 2005), would be unavailable to PVNGS' customers if its operating licenses were not renewed. If the PVNGS operating licenses were not renewed, the owners of PVNGS would need to build new generating capacity, purchase power, or reduce power requirements through demand reduction to ensure they meet the electric power requirements of their customers.

APS considers the current mix of power generation options in Arizona to be one indicator of what the owners of PVNGS consider to be feasible alternatives. In 2004, electric generators in Arizona had a total generating capacity of 24,303 MWe. This capacity includes units fueled by natural gas (39.1 percent), coal (22.2 percent), nuclear (15.7 percent), hydroelectric (12.0 percent), dual-fired (i.e., gas and oil; 10.4 percent), oil (0.5 percent), and non-hydroelectric renewables (0.05 percent). In 2004, the electric industry in Arizona provided approximately 81.4 terawatt-hours of electricity. Actual utilization of generating capacity in Arizona was dominated by coal (38.1 percent), followed by natural gas (27.0 percent), nuclear (26.9 percent), hydroelectric (6.6 percent), other gases (1.3 percent), non-hydroelectric renewables (0.05 percent) and oil (0.04 percent) (EIA 2006b). Figures 7-1 and 7-2 illustrate Arizona's electric industry generating capacity and utilization, respectively.

Comparison of baseload generating capacity with actual utilization of this capacity indicates that coal and nuclear are used by electric generators in Arizona substantially more, relative to their capacity, than either oil-fired or gas-fired generation. This condition reflects the relatively low fuel cost and baseload suitability for nuclear power and coal-fired plants, and relatively higher use of oil and gas-fired units to meet peak loads. Comparison of capability and utilization for oil and gas-fired facilities indicates a strong preference of gas firing over oil firing, indicative of higher cost and greater air emissions associated with oil firing. Energy production from renewable sources is similarly preferred from a cost standpoint, but capacity is limited and utilization can vary substantially depending on resource availability.

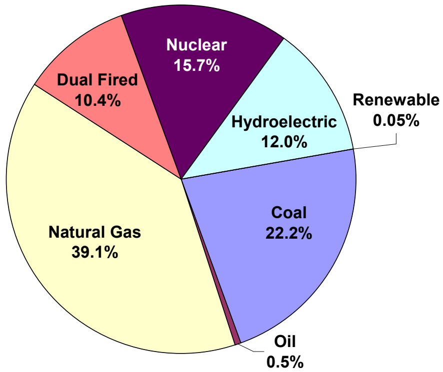

Figure 7-1. Arizona Generating Capacity by Fuel Type, 2004

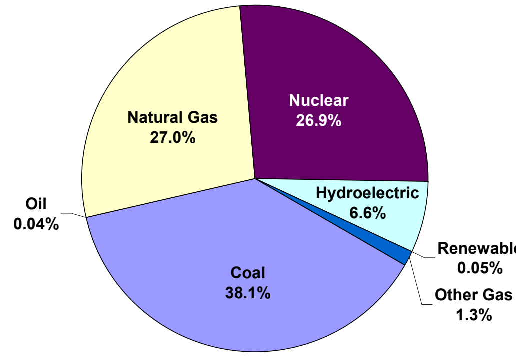

Figure 7-2. Arizona Generation by Fuel Type, 2004

7.2.1 Alternatives Considered

Technology Choices

For the purposes of this environmental report, APS conducted evaluations of alternative generating technologies to identify candidate technologies that would be capable of replacing the net baseload capacity of the nuclear units at PVNGS.

Based on these evaluations, it was determined that feasible new plant systems to replace the capacity of the PVNGS nuclear units are limited to pulverized-coal, gas-fired combined-cycle, and new nuclear units for baseload operation. This conclusion is supported by the generation utilization information presented above that identifies coal as the most heavily utilized non-nuclear generating technology in the state. APS would use gas as the primary fuel in its combined-cycle turbines because of the economic and environmental advantages of gas over oil. Manufacturers now have large standard sizes of combined-cycle gas turbines that are economically attractive and suitable for high-capacity baseload operation. For the purposes of the PVNGS license renewal environmental report, APS has limited its analysis of new generating capacity alternatives to the technologies it considers feasible: pulverized coal-fired, gas-fired, and advanced nuclear units. APS chose to evaluate combined-cycle turbines in lieu of simple-cycle turbines because the combined-cycle option is more economical. The benefits of lower operating costs for the combined-cycle option outweigh its higher capital costs.

Mixture

NRC indicated in the GEIS that, while many methods are available for generating electricity and a large number of combinations or mixes can be assimilated to meet system needs, it would be impractical to analyze all the combinations. Therefore, NRC determined that alternatives evaluation should be limited to analysis of single discrete electrical generation sources and only those electric generation technologies that are technically reasonable and commercially viable (NRC 1996a). Consistent with the NRC determination, APS has not evaluated mixes of generating sources. The impacts from coal-fired, gas-fired, and nuclear generation presented in this chapter would bound the impacts from any combination of the three technologies.

Electric Power Industry Restructuring

Nationally, the electric power industry has been undergoing a transition from a regulated monopoly to a competitive market environment. Efforts to deregulate the electric utility industry began with passage of the National Energy Policy Act of 1992. Provisions of this act required electric utilities to allow open access to their transmission lines and encouraged development of a competitive wholesale market for electricity. The Act did not mandate competition in the retail market, leaving that decision to the states (NEI 2000).

On December 26, 1996, the Arizona Corporation Commission (ACC) formed the framework for deregulation of the electric power industry with the passage of its Retail Electric Competition Rule. The rule created a partially competitive market. On May 29, 1998, the Arizona Legislature passed the Electric Power Competition Act that called for retail competition for all electric consumers in the state by December 31, 2000. Both regulatory structures allow a consumer to remain with the existing utility serving the geographic area or to choose competitive services, including electricity generation, metering, meter reading, and billing and collections (Davenport 2003).

Competition for electric generation existed from December 1999 through March 2001 when multiple new companies were selling power in Arizona. However, economic conditions caused these new companies to leave the Arizona retail market. Consumer demand to switch companies was also low. In fact, only approximately 340 of the over 1.25 million customers eligible for electric competition switched from their traditional service. The absence of competitive electricity providers in Arizona's retail market combined with low consumer demand has effectively suspended retail competition for electricity generation (Davenport 2003).

Although the legal framework for retail competition is in place, there is virtually no retail competition in Arizona. None of the certified competitive suppliers are attempting to market to residential customers and the few commercial and industrial customers that initially switched suppliers have now returned to the incumbent utility. Should retail competition develop in the future, all electricity customers in the area would be able to choose among competing power suppliers, including those located outside the region. As such, electric generation would be based on the customers' needs and preferences, the lowest price, or the best combination of prices, services, and incentives.

Alternatives

The following sections present fossil-fuel-fired generation (Section 7.2.1.1), advanced light water reactor (Section 7.2.1.2), and purchased power (Section 7.2.1.3) as reasonable alternatives to license renewal. Section 7.2.1.4 discusses reduced demand and presents the basis for concluding that it is not a reasonable alternative to license renewal. Section 7.2.1.5 discusses other alternatives that APS has determined are not reasonable and the APS bases for these determinations.

7.2.1.1 Construct and Operate Fossil-Fuel-Fired Generation

APS analyzed locating hypothetical new coal- and gas-fired units at the existing PVNGS site and at an undetermined greenfield site. APS concluded that PVNGS is the preferred site for new construction because this approach would minimize environmental impacts by building on previously disturbed land and by making the most use possible of existing facilities, such as transmission lines, roads and parking areas, office buildings, and components of the cooling system. Locating hypothetical units at the existing site has, therefore, been applied to the coal- and gas-fired units.

For comparability, APS selected gas- and coal-fired units of equal electric power capacity. Three units, each with a net capacity of 1,314 MWe could be assumed to replace the 4,020-MWe PVNGS net capacity. However, industry experience indicates that, although custom size units can be built, using standardized sizes is more economical. For example, standard-sized units include a gas-fired combined-cycle plant of 780 MWe net capacity. Five of these standard-sized units would have 3,900 MWe net capacity. For comparability, APS set the net power of the coal-fired unit equal to the gas-fired plants (3,900 MWe). Although this provides less capacity than the existing unit, it ensures against overestimating environmental impacts from the alternatives. The shortfall in capacity could be replaced by other methods (see Mixture in Section 7.2.1).

It must be emphasized, however, that these are hypothetical scenarios. APS does not have plans for such construction at PVNGS.

Gas-Fired Generation

For purposes of this analysis, APS assumed development of a modern natural gas-fired combined-cycle plant with design characteristics similar to those being developed elsewhere in the west, and with a generating capacity similar to PVNGS. The High Desert Power Project in Victorville, California meets these general criteria. Five units with similar equipment to the High Desert Power Project would meet the criteria for replacing PVNGS capacity. Therefore, APS used characteristics of this plant and other relevant resources in defining the PVNGS gas-fired alternative. APS assumes that the representative plant would be located at the PVNGS site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). Table 7-1 presents the basic gas-fired alternative characteristics.

Coal-Fired Generation

NRC has routinely evaluated coal-fired generation alternatives for nuclear plant license renewal. In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC analyzed 2,400 MWe of coal-fired generation capacity. APS has reviewed the NRC analysis, considers it to be sound, and notes that it analyzed less generating capacity than the 3,900 MWe discussed in this analysis. In defining the PVNGS coal-fired alternative, APS has used site- and Arizona-specific input and has applied the NRC analysis, where appropriate.

Table 7-2 presents the basic coal-fired alternative emission control characteristics. APS based its emission control technology and percent control assumptions on alternatives that the U.S. Environmental Protection Agency (EPA) has identified as being available for minimizing emissions (EPA 1998). APS assumes that the representative plant would be located at the PVNGS site, which offers potential advantages of existing infrastructure (e.g., cooling water system, transmission, roads, and technical and administrative support facilities). For the purposes of analysis, APS has assumed that coal and lime (calcium oxide) would be delivered to PVNGS via an existing rail spur.

7.2.1.2 Construct and Operate New Nuclear Reactors

Since 1997, the NRC has certified four new standard designs for nuclear power plants under 10 CFR 52, Subpart B. These designs are the U.S. Advanced Boiling Water Reactor (10 CFR 52, Appendix A), the System 80+ Design (10 CFR 52, Appendix B), the AP600 Design (10 CFR 52, Appendix C), and the AP1000 Design (10 CFR 52, Appendix D). All of these plants are light-water reactors. NRC evaluated 2,258 MWe of new nuclear generation capacity as an alternative for the McGuire Nuclear Station (NRC 2002b). APS has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed less generating capacity than the 3,900 MWe discussed in this analysis. In defining the PVNGS new nuclear reactor alternative, APS has used site- and Arizona-specific input and has scaled from the NRC analysis, where appropriate. See Table 8-2 for a detailed description.

7.2.1.3 Purchased Power

APS has evaluated conventional and prospective power supply options that could be reasonably implemented before the existing PVNGS license expires. The source of this purchased power is speculative, but may reasonably include new generating facilities developed within the PVNGS service territory, elsewhere in Arizona, or in neighboring states. The technologies that would be used to generate this purchased power are similarly speculative. APS assumes that the generating technology used to produce purchased power would be one of those that NRC analyzed in the GEIS. For this reason, APS is adopting by reference the GEIS description of the alternative generating technologies as representative of the purchase power alternative. Of these technologies, facilities fueled by coal, combined-cycle facilities fueled by natural gas, and advanced light-water reactor facilities are the most cost effective for providing baseload capacity.

APS anticipates that additional transmission infrastructure would be needed in the event that the owners of PVNGS purchase power to replace PVNGS capacity.

7.2.1.4 Demand Side Management

Demand-side management (DSM) programs reduce customer energy consumption and overall electricity use. Because there would be no construction, there would be no new environmental impacts created from this alternative. The owners of PVNGS offer a variety of DSM programs that either conserve energy or allow the company to reduce customers' load requirements during periods of peak demand. These DSM programs generally fall into three categories:

Conservation Programs

Educational programs that encourage the wise use of energy

Energy Efficiency Programs

Discounted residential rates for homes that meet specific energy efficiency standards

Incentive programs that encourage customers to replace old, inefficient appliances or equipment with new high-efficiency appliances or equipment

Load Management Programs

Standby Generator Program – encourages customers to let electric companies switch loads to the customer's standby generators during periods of peak demand

Interruptible Service Program – encourages customers to allow blocks of their load to be interrupted during periods of peak demand

Time-of-Use Pricing – encourages customers to discontinue usage during specific times.

The owners of PVNGS consider reducing demand as an essential part of their operations, and include the energy savings from DSM programs in their long-range plans for meeting projected demand. The available energy savings from DSM programs are insufficient to maintain service reliability to PVNGS customers in the face of population and employment growth in the region. Energy conservation would offset only a small fraction of the energy supply lost by the shutdown of PVNGS. For these reasons, APS determined that DSM programs are not an effective substitute for large baseload units operating at high-capacity factors, including PVNGS.

7.2.1.5 Other Alternatives

This section identifies alternatives that APS has determined are not reasonable and the APS bases for these determinations. APS accounted for the fact that PVNGS is a baseload generator and that any feasible alternative to PVNGS would also need to be able to generate baseload power. In performing this evaluation, APS relied heavily upon NRC's GEIS (NRC 1996a).

Wind

Wind power, by itself, is not suitable for large baseload generation. As discussed in Section 8.3.1 of the GEIS, wind has a high degree of intermittence, and average annual capacity factors for wind plants are relatively low (less than 30 percent). Wind power, in conjunction with energy storage mechanisms, might serve as a means of providing baseload power. However, current energy storage technologies are too expensive for wind power to serve as a large baseload generator.

Based on American Wind Energy Association (2002) estimates, Arizona has the technical potential (the upper limit of renewable electricity production and capacity that could be brought online, without regard to cost, market acceptability, or market constraints) for roughly 1,090 MWe of installed wind power capacity. The full exploitation of wind energy is constrained by a variety of factors including land availability and land-use patterns, surface topography, infrastructure constraints, environmental constraints, wind turbine capacity factor, wind turbine availability, and grid availability. When these constraints on wind energy development are considered, the achievable wind energy potential is expected to fall to approximately 20 to 40 percent of technical potential estimates or 218 to 436 MWe, which is substantially less than the energy required (4,020 MWe) to replace the generating units at PVNGS.

Wind farms, the most economical wind option, generally consist of 10 to 50 turbines in the 1 to 3 MWe range. Estimates based on existing installations indicate that a utility-scale wind farm would require about 50 acres per MWe of installed capacity. Wind farm facilities would occupy 3 to 5 percent of the wind farm's total acreage (McGowan and Connors 2000).

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 2006b). 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 in the long-term as binary technology advances, more exploration is performed in promising areas, and deeper drilling becomes more economical (WGA 2006).

Geothermal power plants require relatively little land. An entire geothermal field uses 1 to 8 acres per MWe (Shibaki 2003). Assuming a 95 percent capacity factor, a geothermal power plant with a net output of 3,942 MWe would require at least 4,149 acres (6 square miles).

The owners of PVNGS support the use of geothermal resources. APS has signed contracts for 45 MW of geothermal energy and is investigating the development of an additional 20 MW of geothermal energy in the southwest (PNW 2006).

The major environmental concerns associated with geothermal development are the release of small quantities of carbon dioxide and hydrogen sulfide, noise, and disposal of sludge and spent geothermal fluids (Shibaki 2003, NREL 1997). Subsidence and reservoir depletion may be a concern if withdrawal of geothermal fluids exceeds natural recharge or injection (Shibaki 2003).

APS has concluded that, due to inadequate resources and the lack of an environmental advantage, geothermal energy is not a reasonable alternative to PVNGS license renewal.

Wood Energy

As discussed in the GEIS (NRC 1996a), the use of wood waste to generate electricity is largely limited to those states with significant wood resources. The pulp, paper, and paperboard industries in states with adequate wood resources generate electric power by consuming wood and wood waste for energy, benefiting from the use of waste materials that could otherwise represent a disposal problem.

The owners of PVNGS support the use of wood energy. APS is constructing two wood energy systems that burn forest waste to create energy (PNW 2006). However, according to the U.S. Department of Energy, Arizona does not have enough wood resources to replace the generating capacity of PVNGS (Walsh et al. 2000).

Further, as discussed in Section 8.3.6 of the GEIS (NRC 1996a), construction of a wood-fired plant would have an environmental impact that would be similar to that for a coal-fired plant, although facilities using wood waste for fuel would be built on a smaller scale. Like coal-fired plants, wood-waste plants require large areas for fuel storage, processing, and waste (i.e., ash) disposal. Additionally, operation of wood-fired plants has environmental impacts, including impacts on the aquatic environment and air. Wood has a low heat content that makes it unattractive for baseload applications. It is also difficult to handle and has high transportation costs.

APS has concluded that, due to inadequate resources, the lack of an environmental advantage, low heat content, handling difficulties, and high transportation costs, wood energy is not a reasonable alternative to PVNGS license renewal.

Municipal Solid Waste

As discussed in Section 8.3.7 of the GEIS (NRC 1996a), the initial capital costs for municipal solid waste plants are greater than for comparable steam turbine technology at wood-waste facilities. This is due to the need for specialized waste separation and handling equipment.

The decision to burn municipal solid waste to generate energy is usually driven by the need for an alternative to landfills, rather than by energy considerations. The use of landfills as a waste disposal option is likely to increase in the near term; however, it is unlikely that many landfills will begin converting waste to energy because of unfavorable economics, particularly with electricity prices declining.

Estimates in the GEIS suggest that the overall level of construction impacts from a waste-fired plant should be approximately the same as that for a coal-fired plant. Additionally, waste-fired plants have the same or greater operational impacts (including impacts on the aquatic environment, air, and waste disposal). Some of these impacts would be moderate, but still larger than the environmental effects of PVNGS license renewal.

APS has concluded that, due to the high costs and lack of environmental advantages, burning municipal solid waste to generate electricity is not a reasonable alternative to PVNGS license renewal.

Other Biomass-Derived Fuels

In addition to wood and municipal solid waste fuels, there are several other concepts for fueling electric generators, including burning energy crops, converting crops to a liquid fuel such as ethanol (ethanol is primarily used as a gasoline additive), and gasifying energy crops (including wood waste). As discussed in the GEIS, none of these technologies has progressed to the point of being competitive on a large scale or of being reliable enough to replace a baseload plant such as PVNGS.

Further, estimates in the GEIS suggest that the overall level of construction impacts from a crop-fired plant should be approximately the same as that for a wood-fired plant. Additionally, crop-fired plants would have similar operational impacts (including impacts on the aquatic environment and air). These systems also have large impacts on land use, due to the acreage needed to grow the energy crops.

APS has concluded that, due to the high costs and lack of environmental advantage, burning other biomass-derived fuels is not a reasonable alternative to PVNGS license renewal.

Petroleum

Arizona has several petroleum (oil)-fired power plants. However, oil-fired generation represents small portion of the overall generation mix in Arizona and is more expensive than nuclear, gas-, or coal-fired generation. Future increases in petroleum prices are expected to make oil-fired generation increasingly more expensive than gas- or coal-fired generation. Also, construction and operation of an oil-fired plant would have environmental impacts. For example, Section 8.3.11 of the GEIS (NRC 1996a) estimates that construction of a 1,000-MWe oil-fired plant would require about 120 acres. Additionally, operation of oil-fired plants would have environmental impacts (including impacts on the aquatic environment and air) that would be similar to those from a coal-fired plant.

APS has concluded that, due to the high costs and lack of obvious environmental advantage, oil-fired generation is not a reasonable alternative to PVNGS license renewal.

Fuel Cells

Fuel cells work without combustion and its environmental side effects. Power is produced electrochemically by passing a hydrogen-rich fuel over an anode and air over a cathode and separating the two by an electrolyte. The only by-products are heat, water, and carbon dioxide. Hydrogen fuel can come from a variety of hydrocarbon resources by subjecting them to steam under pressure. Natural gas is typically used as the source of hydrogen.

Fuel cell power plants are in the initial stages of commercialization. While more than 800 large stationary fuel cell systems have been built and operated worldwide, the global electricity generating capacity using large stationary fuel cells was approximately 105 MWe in 2006 (Fuel Cell Today 2006). In addition, the largest stationary fuel cell power plant yet built is only 11 MWe (Fuel Cell Today 2003). Recent estimates suggest that manufacturers would need to at least triple their production capacity to achieve a competitive price of $1,500 to $2,000 per kilowatt (Shipley and Elliott 2004).

APS thinks that this technology has not matured sufficiently to support production for a facility the size of PVNGS. APS has concluded that, due to cost and production limitations, fuel cell technology is not a reasonable alternative to PVNGS license renewal.

Delayed Retirement

As the NRC noted in the GEIS (NRC 1996a), extending the lives of existing non-nuclear generating plants beyond the time they were originally scheduled to be retired represents another potential alternative to license renewal. APS is not aware of plans for retiring any of Arizona's electric generating plants and the state expects to need additional capacity in the near future. Nationally, fossil plants slated for retirement tend to be ones that are old enough to have difficulty in meeting today's restrictions on air contaminant emissions. In the face of increasingly stringent restrictions, delaying retirement in order to compensate for a plant the size of PVNGS would appear to be unreasonable without major construction to upgrade or replace plant components. APS concludes that the environmental impacts of such a scenario are bounded by its coal- and gas-fired alternatives. For these reasons, the delayed retirement of non-nuclear generating units is not considered a reasonable alternative to PVNGS license renewal.

7.2.2 Environmental Impacts of Alternatives

This section evaluates the environmental impacts of alternatives that APS has determined to be reasonable alternatives to PVNGS license renewal: gas-fired generation, coal-fired generation, new nuclear generation, and purchased power.

7.2.2.1 Gas-Fired Generation

NRC evaluated environmental impacts from gas-fired generation alternatives in the GEIS, focusing on combined-cycle plants. Section 7.2.1.1 presents APS' reasons for defining the gas-fired generation alternative as a combined-cycle plant on the PVNGS site. Land-use impacts from gas-fired units on PVNGS would be less than those from the existing plant. Reduced land requirements, due to a smaller facility footprint, would reduce impacts to ecological, aesthetic, and cultural resources. A smaller workforce could have adverse socioeconomic impacts. Human health effects associated with air emissions would be of concern.

In the GEIS Supplement for McGuire Nuclear Station (NRC 2002b), NRC evaluated the environmental impacts of constructing and operating five 482-MWe combined-cycle gas-fired units as an alternative to a nuclear power plant license renewal. APS has reviewed the NRC analysis, believes it to be sound, and notes that it analyzed less generating capacity than the 3,900 MWe of net power discussed in this analysis. In defining the PVNGS gas-fired alternative, APS has used site- and Arizona-specific input and has scaled from the NRC analysis, where appropriate.

Air Quality

Natural gas is a relatively clean-burning fossil fuel that primarily emits nitrogen oxides (NO_x), a regulated pollutant, during combustion. A natural gas-fired plant would also emit small quantities of sulfur oxides (SO_x), particulate matter, and carbon monoxide, all of which are regulated pollutants. Control technology for gas-fired turbines focuses on NO_x emissions. APS estimates the gas-fired alternative emissions to be as follows:

SO_x = 323 tons per year

NO_x = 1,037 tons per year

Carbon monoxide = 215 tons per year

Filterable Particulates = 181 tons per year (all particulates are $PM_{2.5}$)

Table 7-3 shows how APS calculated these emissions.

In 2004, Arizona was ranked 45th nationally in sulfur dioxide (SO_2) emissions (EIA 2006b). Therefore, the electric power plants in 44 states emitted more SO_2 than those located in Arizona. The acid rain requirements of the Clean Air Act Amendments capped the nation's SO_2 emissions from power plants. Each company with fossil-fuel-fired units was allocated SO_2 allowances. To be in compliance with the Act, the companies must hold enough allowances to cover their annual SO_2 emissions. APS would need to obtain SO_2 credits to operate a fossil-fuel-burning plant at the PVNGS site.

NO_x effects on ozone levels, SO_2 allowances, and NO_x emission offsets could all be issues of concern for gas-fired combustion. While gas-fired turbine emissions are less than coal-fired boiler emissions, and regulatory requirements are less stringent, the emissions are still substantial. APS concludes that emissions from the gas-fired alternative at PVNGS would noticeably alter local air quality, but would not destabilize regional resources (i.e., air quality). Air quality impacts would therefore be MODERATE.

Waste Management

The solid waste generated from this type of facility would be minimal. The only noteworthy waste would be from spent selective catalytic reduction (SCR) catalyst used for NO_x control. The SCR process for a 2,400 MWe plant would generate approximately 1,500 cubic feet of spent catalyst per year (NRC 2002b). Based on this estimate, a 3,900 MWe plant would generate approximately 2,440 cubic feet of spent catalyst per year. APS concludes that gas-fired generation waste management impacts would be SMALL.

Other Impacts

The ability to construct the gas-fired alternative on the existing PVNGS site would reduce construction-related impacts. A new gas pipeline would be required for the gas turbine generators in this alternative. To the extent practicable, APS would route the pipeline along existing, previously disturbed, rights-of-way to minimize impacts. Approximately 6 miles of new pipeline construction would be required to connect PVNGS to an existing pipeline near the plant. A 16-inch diameter pipeline would necessitate a 50-foot-wide corridor, resulting in the disturbance of as much as 40 acres. APS estimates that 154 acres would be needed for a plant site; this much previously disturbed acreage is available at PVNGS, reducing loss of terrestrial habitat. Aesthetic impacts, erosion and sedimentation, fugitive dust, and construction debris impacts would be noticeable, but small. APS estimates a peak construction workforce of 946. Due to the proximity of the site to the Phoenix metropolitan area, APS thinks that the surrounding communities would experience small demands on housing and public services. APS estimates a workforce of 131 for gas operations. The reduction in work force would result in adverse socioeconomic impacts. APS thinks these impacts would be small and would be mitigated by the site's proximity to the Phoenix metropolitan area.

The additional stacks and boilers would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

APS estimates that other construction and operation impacts would be SMALL. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.2 Coal-Fired Generation

NRC evaluated environmental impacts from coal-fired generation alternatives in the GEIS (NRC 1996a). NRC concluded that construction impacts could be substantial, due in part to the large land area required (which can result in natural habitat loss) and the large workforce needed. NRC pointed out that siting a new coal-fired plant where an existing nuclear plant is located would reduce many construction impacts. NRC identified major adverse impacts from operations as human health concerns associated with air emissions, waste generation, and losses of aquatic biota due to cooling water withdrawals and discharges.

The coal-fired alternative that APS has defined in Section 7.2.1.1 would be located at PVNGS.

Air Quality

A coal-fired plant would emit SO_x, NO_x, particulate matter, and carbon monoxide, all of which are regulated pollutants. As Section 7.2.1.1 indicates, APS has assumed a plant design that would minimize air emissions through a combination of boiler technology and post-combustion pollutant removal. APS estimates the coal-fired alternative emissions to be as follows:

SO_x = 11,727 tons per year

NO_x = 3,631 tons per year

Carbon monoxide = 3,631 tons per year

Particulates:

PM_{10} (particulates having a diameter of less than 10 microns) = 208 tons per year

$PM_{2.5}$ (particulates having a diameter of less than 2.5 microns) = 0.904 tons per year

Table 7-4 shows how APS calculated these emissions.

The Section 7.2.2.1 discussion of regional air quality is applicable to the coal-fired generation alternative. In addition, NRC noted in the GEIS that adverse human health effects from coal combustion have led to important federal legislation in recent years and that public health risks, such as cancer and emphysema, have been associated with coal combustion. NRC also mentioned global warming and acid rain as potential impacts. APS concludes that federal legislation and large-scale concerns, such as global warming and acid rain, are indications of concerns about destabilizing important attributes of air resources. However, SO_2 emission allowances, low NO_x burners, overfire air, fabric filters or electrostatic precipitators, and scrubbers are regulatorily-imposed mitigation measures. As such, APS concludes that the coal-fired alternative would have MODERATE impacts on air quality; the impacts would be noticeable and greater than those of the gas-fired alternative, but would not destabilize air quality in the area.

Waste Management

APS concurs with the GEIS assessment that the coal-fired alternative would generate substantial amounts of solid waste. The coal-fired plant would annually consume approximately 14,500,000 tons of coal with an ash content of 12.45 percent (Tables 7-4 and 7-2, respectively). After combustion, 90 percent of this ash, approximately 1,630,000 tons per year, would be marketed for beneficial reuse. The remaining ash, approximately 181,000 tons per year, would be collected and disposed of onsite. In addition, approximately 640,000 tons of scrubber sludge would be disposed of onsite each year (based on annual lime usage of nearly 216,000 tons). APS estimates that ash and scrubber waste disposal over a 40-year plant life would require approximately 495 acres (a square area with sides of approximately 4,642 feet). Table 7-5 shows how APS calculated ash and scrubber waste volumes. While only half this waste volume and acreage would be attributable to the 20-year license renewal period alternative, the total numbers are pertinent as a cumulative impact.

APS contends that, with proper siting coupled with current waste management and monitoring practices, waste disposal would not destabilize any resources. There would be space within the PVNGS property for this disposal. After closure of the waste site and revegetation, the land would be available for other uses. For these reasons, APS contends that waste disposal for the coal-fired alternative would have MODERATE impacts; the impacts of increased waste disposal would be noticeable, but would not destabilize any important resource, and further mitigation would be unwarranted.

Other Impacts

APS estimates that construction of the powerblock and coal storage area would affect approximately 628 acres of land and associated terrestrial habitat. Because most of this construction would be on previously disturbed land, impacts at the PVNGS site would be small to moderate but would be somewhat less than the impacts of using a greenfield site. Upgrades to an existing rail spur would be required for coal and lime deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite. APS estimates a peak construction work force of 2,580. Due to the proximity of the site to the Phoenix metropolitan area, APS thinks that the surrounding communities would experience small demands on housing and public services. APS estimates an operational workforce of 454 for the coal-fired alternative. The reduction in workforce would result in adverse socioeconomic impacts. APS contends these impacts would be SMALL, due to PVNGS' proximity to the Phoenix metropolitan area.

The additional stacks, boilers, and rail deliveries would increase the visual impact of the existing site. Impacts to cultural resources would be unlikely, due to the previously disturbed nature of the site.

APS estimates that other construction and operation impacts would be SMALL. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.3 New Nuclear Reactor

As discussed in Section 7.2.1.2, under the new nuclear reactor alternative APS would construct and operate a four-unit nuclear plant using one of the four NRC certified standard designs for nuclear power plants.

Air Quality

Air quality impacts would be minimal. Air emissions are primarily from non-facility equipment and diesel generators and are comparable to those associated with the continued operation of PVNGS. Overall, emissions and associated impacts would be considered SMALL.

Waste Management

High level radioactive wastes would be similar to those associated with the continued operation of PVNGS. Low level radioactive waste impacts from a new nuclear plant would be slightly greater but similar to the continued operation of PVNGS. The overall impacts are characterized as SMALL.

Other Impacts

APS estimates that construction of the reactors and auxiliary facilities would affect approximately 500 acres of land and associated terrestrial habitat. Because most of this construction would be on previously disturbed land, impacts at the PVNGS site would be SMALL to MODERATE. For the purposes of analysis, APS has assumed that the existing rail line would be used for reactor vessel and other deliveries under this alternative. Visual impacts would be consistent with the industrial nature of the site. As with any large construction project, some erosion and sedimentation and fugitive dust emissions could be anticipated, but would be minimized by using best management practices. Debris from clearing and grubbing could be disposed of onsite.

APS estimates a peak construction work force of approximately 3,000. Due to the proximity of the site to the Phoenix metropolitan area, APS thinks that the surrounding communities would experience small demands on housing and public services. Long-term job opportunities would be comparable to continued operation of PVNGS. Therefore, APS concludes that the socioeconomic impacts during operation would be SMALL.

APS estimates that other construction and operation impacts would be SMALL. In most cases, the impacts would be detectable, but they would not destabilize any important attribute of the resource involved. Due to the minor nature of these other impacts, mitigation would not be warranted beyond that previously mentioned.

7.2.2.4 Purchased Power

As discussed in Section 7.2.1.2, APS assumes that the generating technology used under the purchased power alternative would be one of those that NRC analyzed in the GEIS.

APS is also adopting by reference the NRC analysis of the environmental impacts from those technologies. Under the purchased power alternative, therefore, environmental impacts would still occur, but they would likely originate from a power plant located elsewhere in Arizona or other states in the southwest.

The purchased power alternative would include constructing up to 200 miles of high-voltage (i.e., 345- or 525-kilovolt) transmission lines to get power from the remote locations in the southwest to the PVNGS service area. APS thinks most of the transmission lines could be routed along existing rights-of-way. APS assumes that the environmental impacts of transmission line construction would be moderate. As indicated in the introduction to Section 7.2.1.1, the environmental impacts of construction and operation of new nuclear, coal- or gas-fired generating capacity for purchased power at a previously undisturbed greenfield site would exceed those of a new nuclear, coal- or gas-fired alternative located on the PVNGS site.

7.3 TABLES

Table 7-1. Gas-Fired Alternative.

Characteristic	Basis
Unit size = 780 MWe ISO rating net[a]	Calculated to be ≤ PVNGS net capacity – 4,020 MWe
Unit size = 813 MWe ISO rating gross[a]	Calculated based on 4 percent onsite power
Number of units = 5	Assumed
Fuel type = natural gas	Assumed
Fuel heating value = 1,021 Btu/ft^3	2004 value for gas used in Arizona (EIA 2006c)
Fuel SO_x content = 0.0034 lb/MMBtu	EPA 2000, Table 3.1-2a
NO_x control = selective catalytic reduction (SCR) with steam/water injection	Best available for minimizing NO_x emissions (EPA 2000)
Fuel NOx content = 0.0109 lb/MMBtu	Typical for large SCR-controlled gas fired units with water injection (EPA 2000)
Fuel CO content = 0.00226 lb/MMBtu	Typical for large SCR-controlled gas fired units (EPA 2000)
Fuel PM_{10} content = 0.0019 lb/MMBtu	EPA 2000, Table 3.1-2a
Heat rate = 6,290 Btu/kWh	Assumed based on performance of modern plants
Capacity factor = 0.85	Assumed based on performance of modern plants

[a.] The difference between "net" and "gross" is electricity consumed onsite.

Btu = British thermal unit
ft^3 = cubic foot
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
MM = million
MWe = megawatt
NO_x = nitrogen oxides
PM_{10} = particulates having diameter of 10 microns or less
SCR = selective catalytic reduction
≤ = less than or equal to

Table 7-2. Coal-Fired Alternative.

Characteristic	Basis
Unit size = 780 MWe ISO rating net[a]	Calculated to be ≤ PVNGS net capacity – 4,020 MWe
Unit size = 830 MWe ISO rating gross[a]	Calculated based on 6 percent onsite power
Number of units = 5	Assumed
Boiler type = tangentially fired, dry-bottom	Minimizes nitrogen oxides emissions (EPA 1998)
Fuel type = bituminous, pulverized coal	Typical for coal used in Arizona
Fuel heating value = 10,211 Btu/lb	2004 value for coal used in Arizona (EIA 2006c)
Fuel ash content by weight = 12.45 percent[b]	2004 value for coal used in Arizona (EIA 2006c)
Fuel sulfur content by weight = 0.85 percent	2004 value for coal used in Arizona (EIA 2006c)
Uncontrolled NO_x emission = 10 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998)
Uncontrolled CO emission = 0.5 lb/ton	Typical for pulverized coal, tangentially fired, dry-bottom, NSPS (EPA 1998)
Heat rate = 9,600 Btu/kWh	Assumed based on performance of modern plants
Capacity factor = 0.85	Typical for large coal-fired units
NO_x control = low NO_x burners, overfire air and selective catalytic reduction (95 percent reduction)	Best available and widely demonstrated for minimizing NO_x emissions (EPA 1998)
Particulate control = fabric filters (baghouse-99.9 percent removal efficiency)	Best available for minimizing particulate emissions (EPA 1998)
SO_x control = Wet scrubber - lime (95 percent removal efficiency)	Best available for minimizing SO_x emissions (EPA 1998)

a. The difference between "net" and "gross" is electricity consumed onsite.
b. The 2002 average percent ash for coal used in Arizona is not available.

Btu = British thermal unit
ISO rating = International Standards Organization rating at standard atmospheric conditions of 59°F, 60 percent relative humidity, and 14.696 pounds of atmospheric pressure per square inch
kWh = kilowatt hour
NSPS = New Source Performance Standard
lb = pound
MWe = megawatt
NO_x = nitrogen oxides
SO_x = oxides of sulfur
≤ = less than or equal to

Table 7-3. Air Emissions from Gas-Fired Alternative.

Parameter	Calculation	Result
Annual gas consumption	$5\text{ units} \times \frac{813\text{ MW}}{\text{unit}} \times \frac{6{,}290\text{ Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\text{ kW}}{\text{MW}} \times \frac{\text{ft}^3}{1{,}021\text{ Btu}} \times 0.85 \times \frac{8{,}760\text{ hr}}{\text{yr}}$	186,355,111,410 ft^3 of gas per year
Annual Btu input	$\frac{186{,}355{,}111{,}410\text{ ft}^3}{\text{yr}} \times \frac{1{,}021\text{ Btu}}{\text{ft}^3} \times \frac{\text{MMBtu}}{10^6\text{ Btu}}$	190,268,569 MMBtu per year
SO_x[a]	$\frac{0.0034\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{190{,}268{,}569\text{ MMBtu}}{\text{yr}}$	323 tons SO_x per year
NO_x[b]	$\frac{0.0109\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{190{,}268{,}569\text{ MMBtu}}{\text{yr}}$	1,037 tons NO_x per year
CO[b]	$\frac{0.00226\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{190{,}268{,}569\text{ MMBtu}}{\text{yr}}$	215 tons CO per year
$PM_{2.5}$[a]	$\frac{0.0019\text{ lb}}{\text{MMBtu}} \times \frac{\text{ton}}{2{,}000\text{ lb}} \times \frac{190{,}268{,}569\text{ MMBtu}}{\text{yr}}$	181 tons $PM_{2.5}$ per year

a. EPA (2000), Table 3.1-1.
b. EPA (2000), Table 3.1-2.
CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter of 10 microns or less
SO_x = oxides of sulfur
TSP = total suspended particulates

Table 7-4. Air Emissions from Coal-Fired Alternative.

Parameter	Calculation	Result
Annual coal consumption	$5\,\text{unit} \times \frac{830\,\text{MW}}{\text{unit}} \times \frac{9{,}600\,\text{Btu}}{\text{kW} \times \text{hr}} \times \frac{1{,}000\,\text{kW}}{\text{MW}} \times \frac{\text{lb}}{10{,}211\,\text{Btu}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times 0.85 \times \frac{8{,}760\,\text{hr}}{\text{yr}}$	14,522,211 tons of coal per year
SO_x[a,c]	$\frac{38 \times 0.85\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{100-95}{100} \times \frac{14{,}522{,}211\,\text{tons}}{\text{yr}}$	11,727 tons SO_x per year
NO_x[b,c]	$\frac{10\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{100-95}{100} \times \frac{14{,}522{,}211\,\text{tons}}{\text{yr}}$	3,631 tons NO_x per year
CO[c]	$\frac{0.5\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{14{,}522{,}211\,\text{tons}}{\text{yr}}$	3,631 tons CO per year
PM_{10}[d]	$\frac{2.3 \times 12.45\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{100-99.9}{100} \times \frac{14{,}522{,}211\,\text{tons}}{\text{yr}}$	208 tons PM_{10} per year
$PM_{2.5}$[d]	$\frac{0.01 \times 12.45\,\text{lb}}{\text{ton}} \times \frac{\text{ton}}{2{,}000\,\text{lb}} \times \frac{100-99.9}{100} \times \frac{14{,}522{,}211\,\text{tons}}{\text{yr}}$	0.904 tons $PM_{2.5}$ per year

a. EPA (1998), Table 1.1-1.
b. EPA (1998), Table 1.1-2.
c. EPA (1998), Table 1.1-3.
d. EPA (1998), Table 1.1-4.

CO = carbon monoxide
NO_x = oxides of nitrogen
PM_{10} = particulates having diameter less than 10 microns
SO_x = oxides of sulfur
TSP = total suspended particulates

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 $CaSO_4 \cdot 2H_2O$ 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 ft^3 + 144,496,582 ft^3	646,308,283 ft^3 of solid waste
Waste pile area (acres)	$\frac{646{,}305{,}283 \ ft^3}{30 \text{ ft}} \times \frac{\text{acre}}{43{,}560 \ ft^2}$	495 acres of solid waste
Waste pile area (ft x ft square)	$\sqrt{(646{,}308{,}283 \ ft^3/30 \text{ ft})}$	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)
$CaSO_4 \cdot 2H_2O$ = calcium sulfate dihydrate

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8.0 CHAPTER 8 - COMPARISON OF ENVIRONMENTAL IMPACTS OF LICENSE RENEWAL WITH THE ALTERNATIVES

NRC

"To the extent practicable, the environmental impacts of the proposal and the alternatives should be presented in comparative form..." 10 CFR 51.45(b)(3) as adopted by 51.53(c)(2)

Chapter 4 analyzes environmental impacts of PVNGS license renewal and Chapter 7 analyzes impacts from renewal alternatives. Table 8-1 summarizes environmental impacts of the proposed action (license renewal) and the alternatives, for comparison purposes. The environmental impacts compared in Table 8-1 are those that are either Category 2 issues for the proposed action, license renewal, or are issues that the Generic Environmental Impact Statement (GEIS) (NRC 1996) identified as major considerations in an alternatives analysis. For example, although the NRC concluded that air quality impacts from the proposed action would be small (Category 1), the GEIS identified major human health concerns associated with air emissions from alternatives (Section 7.2.2). Therefore, Table 8-1 compares air impacts among the proposed action and the alternatives. Table 8-2 is a more detailed comparison of the alternatives.

8.1 TABLES

Table 8-1. Impacts Comparison Summary.

			No Action Alternatives			
Impact	**Proposed Action (License Renewal)**	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Land Use	SMALL	SMALL	SMALL to MODERATE	SMALL	SMALL to MODERATE	MODERATE
Water Quality	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Air Quality	SMALL	SMALL	MODERATE	MODERATE	SMALL	SMALL to MODERATE
Ecological Resources	SMALL	SMALL	MODERATE	SMALL to MODERATE	SMALL	SMALL to MODERATE
Threatened or Endangered Species	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL
Human Health	SMALL	SMALL	MODERATE	SMALL	SMALL	SMALL to MODERATE
Socioeconomics	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL to MODERATE
Waste Management	SMALL	SMALL	MODERATE	SMALL	SMALL	SMALL to MODERATE
Aesthetics	SMALL	SMALL	MODERATE	SMALL	SMALL	SMALL to MODERATE
Cultural Resources	SMALL	SMALL	SMALL	SMALL	SMALL	SMALL

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource. LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Table 8-2. Impacts Comparison Detail.

		No-Action Alternatives			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Alternative Descriptions					
PVNGS license renewal for 20 years, followed by decommissioning	Decommissioning following expiration of current PVNGS license. Adopting by reference, as bounding PVNGS decommissioning, GEIS description (NRC 1996, Section 7.1)	New construction at the PVNGS site.	New construction at the PVNGS site.	New construction at the PVNGS site	Would involve construction of new generation capacity in Arizona Adopting by reference GEIS description of alternate technologies (Section 7.2.1.2)
		Use existing rail spur	Construct up to 6 miles of gas pipeline in a 50-foot-wide corridor, disturbing as much as 40 acres. May require upgrades to existing pipelines.	Use existing rail spur for delivery of reactor vessel and other large equipment during construction.	
		Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Use existing switchyard and transmission lines	Construct more than 200 miles of transmission lines
		Five 780-MW (net) tangentially-fired, dry bottom unit; capacity factor 0.85	Five 780-MW of net power (Combined-cycle turbines to be used); capacity factor 0.85	Four unit nuclear plant using one of the NRC certified standard designs.	
		Existing PVNGS cooling water intake/ discharge system	Existing PVNGS cooling water intake/discharge system	Existing PVNGS cooling water intake/ discharge system	

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
		Pulverized bituminous coal, 10,211 Btu/pound; 9,600 Btu/kWh; 12.45% ash; 0.85% sulfur; 10 lb/ton nitrogen oxides; 14,522,211 tons coal/yr	Natural gas, 1,021 Btu/ft^3; 6,290 Btu/kWh; 0.0034 lb sulfur/MMBtu; 0.0109 lb NO_x/MMBtu; 186,355,111,410 ft^3 gas/yr		
		Low NO_x burners, overfire air and selective catalytic reduction (95% NO_x reduction efficiency).	Selective catalytic reduction with steam/water injection		
		Wet scrubber – lime/limestone desulfurization system (95% SO_x removal efficiency); 216,000 tons lime/yr Fabric filters or electrostatic precipitators (99.9% particulate removal efficiency)			
2,200 permanent and 620 long-term contract workers		454 workers (Section 7.2.2.2)	131 workers (Section 7.2.2.1)	2,200 permanent and 620 long-term contract workers	

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Land Use Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 52, 53)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL to MODERATE – 628 acres required for the powerblock and associated facilities. (Section 7.2.2.2)	SMALL – 154 acres for facility at PVNGS location; 40 acres for pipeline (Section 7.2.2.1). New gas pipeline would be built to connect with existing gas pipeline corridor.	SMALL to MODERATE – 500 acres required for the powerblock and associated facilities. (Section 7.2.2.3)	MODERATE – most transmission facilities could be constructed along existing transmission corridors (Section 7.2.2.3) Adopting by reference GEIS description of land use impacts from alternate technologies (NRC 1996)
Water Quality Impacts					
SMALL – Two Category 2 groundwater issues not applicable (Section 4.7, Issue 35; and Section 4.8, Issue 39). PVNGS uses treated effluent from Phoenix-area wastewater treatment plants for all of its non-safety related cooling systems. The use of treated effluent is itself a mitigation factor against the overuse of natural water resources (Section 4.1, Issue 13; Section 4.6, Issue 34) PVNGS uses 6.8 percent of groundwater that passes through the Hassayampa sub-basin. PVNGS operations have had little to no impact on the regional aquifer's potentiometric surface. (Section 4.5, Issue 33).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 89).	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system. (Section 7.2.2.2)	SMALL – Construction impacts minimized by use of best management practices. Reduced cooling water demands, inherent in combined-cycle design. (Section 7.2.2.1)	SMALL – Construction impacts minimized by use of best management practices. Operational impacts minimized by use of the existing cooling water system. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of water quality impacts from alternate technologies (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Air Quality Impacts					
SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table A-1, Issue 51). One Category 2 issue not applicable (Section 4.11, Issue 50).	SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issue 88)	MODERATE – 11,727 tons SO_x/yr 3,631 tons NO_x/yr 3,631 tons CO/yr 208 tons PM_{10}/yr 0.904 tons $PM_{2.5}$/yr (Section 7.2.2.2)	MODERATE – 323 tons SO_x/yr 1,037 tons NO_x/yr 215 tons CO/yr 181 tons $PM_{2.5}$/yr[a] (Section 7.2.2.1)	SMALL – Air emissions would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of air quality impacts from alternate technologies (NRC 1996)
Ecological Resource Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 41, 42, 44-48). Four Category 2 issues not applicable (Section 4.2, Issue 25; Section 4.3, Issue 26; Section 4.4, Issue 27; Section 4.9, Issue 40).	SMALL – Adopting by reference Category 1 issue finding (Attachment A, Table -1, Issue 90)	MODERATE – 247.5 acres could be required for ash/sludge disposal over 20-year license renewal term. (Section 7.2.2.2)	SMALL to MODERATE – Construction of the pipeline could alter habitat. (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of ecological resource impacts from alternate technologies (NRC 1996)
Threatened or Endangered Species Impacts					
SMALL – APS is not aware of any threatened or endangered terrestrial or aquatic species that occur at PVNGS or along the associated 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. Plant operations and transmission line maintenance practices are not expected to change significantly during the license renewal term. (Section 4.10, Issue 49)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats	SMALL – Federal and state laws prohibit destroying or adversely affecting protected species and their habitats

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Human Health Impacts					
SMALL – Adopting by reference Category 1 issues (Attachment A, Table A-1, Issues 56, 58, 61, 62). One Category 2 issue not applicable (Section 4.12, Issue 57)	SMALL – Adopting by reference Category 1 issue finding. (Attachment A, Table A-1, Issue 86)	MODERATE – Adopting by reference GEIS conclusion that risks such as cancer and emphysema from emissions are likely. (NRC 1996)	SMALL – Adopting by reference GEIS conclusion that some risk of cancer and emphysema exists from emissions. (NRC 1996)	SMALL – Impacts would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of human health impacts from alternate technologies. (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Socioeconomic Impacts					
SMALL – Adopting by reference Category 1 issue findings (Attachment A, Table A-1, Issues 64, 67, 91). Two Category 2 issues are not applicable (Section 4.16, Issue 66 and Section 4.17.1, Issue 68). No additional license renewal employment increment is anticipated. Existing "surge" capabilities for routine activities, such as outages, minimizes potential for housing impacts. (Section 4.14, Issue 63). Plant property tax payment represents 1.3 percent of Maricopa County's total tax revenues (2006). License renewal is not expected to influence area land-use pattern, but would continue to have a beneficial impact on Maricopa County (Section 4.17.2, Issue 69). Capacity of public water supply and transportation infrastructure minimizes potential for related impacts. (Section 4.15, Issue 65 and Section 4.18, Issue 70)	SMALL – Adopting by reference Category 1 issue finding. (Attachment A, Table A-1, Issue 91)	<u>Construction:</u> SMALL – Peak construction workforce of 2,580 could affect housing and public services in surrounding communities. Impacts would be mitigated by site's proximity to the Phoenix metropolitan area. <u>Operation</u>: SMALL – Reduction in permanent work force to 454 could adversely affect surrounding communities. Impacts would be mitigated by site's proximity to the Phoenix metropolitan area. (Section 7.2.2.2)	<u>Construction:</u> SMALL– Peak construction workforce of 946 could affect housing and public services in surrounding communities. Impacts would be mitigated by site's proximity to the Phoenix metropolitan area. <u>Operation</u>: SMALL – Reduction in permanent work force to 131 could adversely affect surrounding communities. Impacts would be mitigated by site's proximity to the Phoenix metropolitan area. (Section 7.2.2.1)	<u>Construction:</u> SMALL – Peak construction workforce of 3,000 could affect housing and public services in surrounding communities. Impacts would be mitigated by site's proximity to the Phoenix metropolitan area. <u>Operation</u>: SMALL – Impacts would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of socioeconomic impacts from alternate technologies. (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Waste Management Impacts					
SMALL – Adopting by reference Category 1 issue findings. (Attachment A, Table A-1, Issues 77-85)	SMALL – Adopting by reference Category 1 issue finding. (Attachment A, Table A-1, Issue 87)	MODERATE – 181,000 tons of coal ash and 640,000 tons of scrubber sludge would require 247.5 acres over 20-year license renewal term. Industrial waste generated annually. (Section 7.2.2.2, Table 7-5)	SMALL – Almost no waste generation. (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of waste management impacts from alternate technologies. (NRC 1996)
Aesthetic Impacts					
SMALL – Adopting by reference Category 1 issue findings. (Table A-1, Issues 73, 74)	SMALL – Not an impact evaluated by GEIS. (NRC 1996)	SMALL – The coal-fired power blocks and the exhaust stacks would be visible from a moderate offsite distance. (Section 7.2.2.2)	SMALL – Steam turbines and stacks would create visual impacts comparable to those from existing PVNGS facilities. (Section 7.2.2.1)	SMALL – Impacts would be comparable to those associated with the continued operation of PVNGS. (Section 7.2.2.3)	SMALL to MODERATE – Adopting by reference GEIS description of aesthetic impacts from alternate technologies. (NRC 1996)

Table 8-2. Impacts Comparison Detail. (Continued)

		No Action Alternative			
Proposed Action (License Renewal)	**Base (Decommissioning)**	**With Coal-Fired Generation**	**With Gas-Fired Generation**	**With New Nuclear**	**With Purchased Power**
Cultural Resource Impacts					
SMALL – SHPO consultation minimizes potential for impact . (Section 4.19, Issue 71)	SMALL – Not an impact evaluated by GEIS (NRC 1996)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.2)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.1)	SMALL – Impacts to cultural resources would be unlikely due to developed nature of the site (Section 7.2.2.3)	SMALL – Adopting by reference GEIS description of cultural resource impacts from alternate technologies (NRC 1996)

SMALL - Environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource.
MODERATE - Environmental effects are sufficient to alter noticeably, but not to destabilize, any important attribute of the resource.
LARGE - Environmental effects are clearly noticeable and are sufficient to destabilize any important attributes of the resource. 10 CFR 51, Subpart A, Appendix B, Table B-1, Footnote 3.

Btu	=	British thermal unit	MW	=	megawatt
ft^3	=	cubic foot	NO_x	=	nitrogen oxide
gal	=	gallon	PM_{10}	=	particulates having diameter less than 10 microns
GEIS	=	Generic Environmental Impact Statement (NRC 1996)	SHPO	=	State Historic Preservation Officer
kWh	=	kilowatt-hour	SO_x	=	oxides of sulfur
lb	=	pound	yr	=	year
MM	=	million			

[a.] All particulate matter for gas-fired alternative is $PM_{2.5}$.

8.2 REFERENCES

NRC (U.S. Nuclear Regulatory Commission) 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), Volumes 1 and 2, NUREG-1437, Washington, D.C., May.

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9.0 CHAPTER 9 - STATUS OF COMPLIANCE

9.1 PROPOSED ACTION

NRC

"The environmental report shall list all Federal permits, licenses, approvals and other entitlements which must be obtained in connection with the proposed action and shall describe the status of compliance with applicable environmental quality standards and requirements including, but not limited to, applicable zoning and land-use regulations, and thermal and other water pollution limitations or requirements which have been imposed by Federal, State, regional, and local agencies having responsibility for environmental protection…." 10 CFR 51.54(d)(2) as adopted by 10 CFR 51.53(c)(2)

9.1.1 General

Table 9-1 lists environmental authorizations that APS has obtained for current PVNGS operations. In this context, APS uses "authorizations" to include any permits, licenses, approvals, or other entitlements. APS expects to continue renewing these authorizations during the current license period. Based on the new and significant information identification process described in Chapter 5, PVNGS is in compliance with applicable environmental standards and requirements.

Table 9-2 lists additional environmental authorizations and consultations that would be conditions precedent to NRC renewal of the PVNGS license to operate. As indicated, APS anticipates needing relatively few such authorizations and consultations. Sections 9.1.2 through 9.1.5 discuss some of these items in more detail.

9.1.2 Threatened or Endangered Species

Section 7 of the Endangered Species Act (16 USC 1536) requires federal agencies to ensure that agency action is not likely to jeopardize any species that is listed or proposed for listing as threatened or endangered. Depending on the action involved, the Act requires consultation with the U.S. Fish and Wildlife Service (USFWS) regarding effects on non-marine species, the National Marine Fisheries Service (NMFS) for marine species, or both. USFWS and NMFS have issued joint procedural regulations at 50 CFR 402, Subpart B, that address consultation, and USFWS maintains the joint list of threatened and endangered species at 50 CFR 17.

Although not required by federal law or NRC regulation, APS has chosen to invite comment from federal and state agencies regarding potential effects that PVNGS license renewal might have. Attachment B includes copies of APS correspondence with USFWS, the Arizona Game and Fish Department, the Arizona Department of Agriculture, and the California Department of Fish and Game. APS did not consult with NMFS because species under the auspices of NMFS are not found in the vicinity of PVNGS.

9.1.3 Coastal Zone Management Program

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone. PVNGS is located in Maricopa County, Arizona, not within a coastal zone. Coastal zone management requirements are not applicable to PVNGS license renewal.

9.1.4 Historic Preservation

Section 106 of the National Historic Preservation Act (16 USC 470f) requires federal agencies having the authority to license any undertaking to, prior to issuing the license, take into account the effect of the undertaking on historic properties and to afford the Advisory Council on Historic Preservation an opportunity to comment on the undertaking. Council regulations provide for establishing an agreement with any State Historic Preservation Officer (SHPO) to substitute state review for Committee review (35 CFR 800.7). Although not required of an applicant by federal law or NRC regulation, APS has chosen to invite comment by the Arizona and California SHPOs. Attachment C includes a copy of APS correspondence with the SHPOs regarding potential effects that PVNGS license renewal might have on cultural resources. Based on the APS submittal and other information, the Arizona SHPO concurred with APS' conclusion that continued operation of PVNGS would have no effect on cultural resources. The California SHPO did not respond.

9.1.5 Water Quality (401) Certification

Federal Clean Water Act (CWA) Section 401 requires that applicants for a federal license to conduct an activity that might result in a discharge into navigable waters to provide the licensing agency a certification from the state that the discharge will comply with applicable CWA requirements (33 USC 1341). NRC has indicated in its *Generic Environmental Impact Statement for License Renewal* (GEIS) (NRC 1996) that issuance of a National Pollution Discharge Elimination System (NPDES) permit implies certification by the state. APS is applying to NRC for license renewal to continue PVNGS operations. No water from PVNGS operations is discharged to waters of the state. Therefore, PVNGS does not have to demonstrate compliance with the CWA. The plant had an NPDES storm water multi-sector permit issued by EPA; however, the permit was rescinded by the EPA on October 28, 2005.

Palo Verde has a site Aquifer Protection Permit No. 100388, issued by the ADEQ, that requires developing a series of wells with permit limits and has required sampling frequencies. Since this permit was issued, there have been administrative violations of the permit, including failure to submit a report on the required due date or failure to collect a required sample. There have not been any violations of an Aquifer Quality Limit at any defined Point Of Compliance since the permit was issued.

Palo Verde has had instances of unauthorized discharges to waters of the US from the pipeline delivering water to the site from Phoenix. Details of the unauthorized discharges are summarized in Table 9-3. There has not been a pipeline discharge since 1997 due to significant actions taken by Palo Verde to diagnose and correct the problem. It was determined that the reinforced concrete cylinder pipe was being attacked by corrosive, high chloride groundwater. The outer mortar layer was becoming degraded, allowing the embedded steel to be attacked, corrode, and ultimately fail. The problem was corrected by a systematic analysis of each spool 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. (Order of Abatement by Consent NV-006-08-GJV). 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.

9.3 TABLES

Table 9-1. Environmental Authorizations for Current PVNGS Operations.

Agency	Authority	Requirement or Permit Type	Number	Issue or Expiration Date	Activity Covered
Arizona Department of Environmental Quality	Arizona Water Quality Control (A.R.S. 49-2); A.A.C. R-18-9 Article 7	Aquifer Protection Permit	P-3507-100388	Issued: 03/14/2008 Expires: End of facility life	Operate PVNGS facilities that have potential to impact groundwater
Arizona Department of Environmental Quality	Arizona Water Quality Control (A.R.S. 49-2); A.A.C. R-18-9 Article 7	Aquifer Protection Permit	P-105295	Issued: 02/02/2004 Expires: End of facility life	Operate the Hassayampa Pump Station Holding Pond
Arizona Department of Environmental Quality	Arizona Water Quality Control (A.R.S. 49-2); A.A.C. R-18-9 Article 7	Aquifer Protection Permit	P-105317	Issued: 04/06/2005 Expires: End of facility life	Operate the Water Reclamation Supply System (WRSS) Pipeline Temporary Chlorination Station
Arizona Department of Environmental Quality	Arizona Water Quality Control (A.R.S. 49-2); A.A.C. R-18-9 Article 7	Type 3 Reclaimed Water General Permit	R-105317	Issued: 06/22/2005 Expires: 06/22/2010	External dewatering of the Water Reclamation Supply System (WRSS) Pipeline
Arizona Department of Health Services	A.R.S. 36-401.01	WRF Laboratory License	AZ0129	Issued: annually Expires: End of April of each year	Environmental Compliance Analysis
Arizona Department of Health Services	A.R.S. 36-401.01	Central Laboratory License	AZ0555	Issued: annually Expires: End of July of each year	Environmental Compliance Analysis
Arizona Department of Water Resources	A.A.C. R-12-15-1214	Approval to Operate	Application No. 07.54	Issued: 11/27/1992	Operate Evaporation Pond 1

Agency	Authority	Requirement or Permit Type	Number	Issue or Expiration Date	Activity Covered
Arizona Department of Water Resources	A.A.C. R-12-15-1214	Approval to Operate	Application No. 07.62	Issued: 12/12/1990	Operate Evaporation Pond 2
Arizona Department of Water Resources	A.R.S. Title 45, Chapter 2	Type 1 Non-Irrigation Certificate of Grandfathered Groundwater Right	58-114051.0001	Issued: 09/13/1990	Groundwater withdrawal
Arizona Department of Water Resources	A.R.S. Title 45, Chapter 2	Irrigation Certificate of Grandfathered Groundwater Right	58-114058.0000	Issued 12/13/1983	Groundwater withdrawal for irrigation
Arizona Radiation Regulatory Agency	A.R.S. 30-672; A.A.C. R-12-1 Article 11	Notice of Registration Certificate for Ionizing Radiation Machine	7/1/3340	Issued: 02/13/2007 Expires: 04/30/2014	Industrial X-Ray
Arizona Radiation Regulatory Agency	A.R.S. 30-651 et seq.; A.A.C. R-12-1	Special Approval	7-368 (Category D18)	Issued: 09/11/2008 Expires: 04/30/2013	Disposal of Water Reclamation Facility sludge
Flood Control District of Maricopa County	A.R.S. 48-3603 and 48-3609; Floodplain Regulation for Maricopa County	Pipeline Repair & Maintenance	FA20020002	Issued: 08/18/2005 Expires: 07/31/2010	Repair work on the WRSS Pipeline
Maricopa County Air Quality Department	Arizona Air Quality (A.R.S. 49-3); MCAP Control Regulations, Rule 200, §303	Dust Control/Demolition (Annual Block Permit)	E081389	Issued: Annual Expires: 04/17/2009	Activities identified in the Dust Control Plan
Maricopa County Air Quality Department	Arizona Air Quality (A.R.S. 49-3); MCAP Control Regulations, Rule 200, §303	Non-Title V Air Permit	030132	Issued: 08/18/2005 Expires: 07/31/2010	Operate listed Non-Title V equipment
Maricopa County Environmental Services Department	Maricopa County Health Code	Chemical Toilet	TCV00144	Issued: Annually Expires: 09/30/2009	Chemical Toilets

Agency	Authority	Requirement or Permit Type	Number	Issue or Expiration Date	Activity Covered
Maricopa County Environmental Services Department	Arizona Water Quality Control (A.R.S. 49-2); A.A.C. R-18-9 Article 3, Part A	Discharge Authorization Aquifer Protection Permit/General Permit	066616	Issued: 01/25/2007 Expires: 01/18/2009	Approval to Construct a Septic Tank at the Security Firing Range
Maricopa County Environmental Services Department	Maricopa County Health Code	Landfill	00008	Issued: Annually Expires: 04/30/2009	Operated Rubbish Landfill
Maricopa County Environmental Services Department	Maricopa County Health Code	Waste Water Treatment Plant	37148	Issued: Annually Expires: 12/31/2008	Operate the package Sewage Treatment Plant
Maricopa County Environmental Services Department	Maricopa County Health Code	Water Public/Non-Community	07412	Issued: Annually Expires: 12/31/2008	Operate the site drinking water system
Maricopa County Planning and Zoning Commission	The 1969 Amended Zoning Ordinance, Article XXIV, §2401	Special Use	Zoning Case Z 76-33	Issued: 04/15/1976 Expires: 04/15/2051	Construct a nuclear power electric generation facility
Maricopa County Planning and Development Department	Maricopa County Zoning Ordinance	Special Use	Zoning Case Z2006106	Issued: 12/20/2006 Expires: 04/15/2051	Construct additional Evaporation Ponds south of the current ponds

Table 9.2. Environmental Authorizations for PVNGS License Renewal.

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License Renewal	Environmental Report submitted in support of license renewal application.
U.S. Fish and Wildlife Service (USFWS)	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with USFWS.
Arizona State Historic Preservation Office California Office of Historic Preservation	National Historic Preservation Act Section 106 (16 USC 470f)	Consultation	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO).

Table 9-3. Water Reclamation Pipeline Releases.

Date	Gallons Released	Waters of the US
August 1994	2,500,000	Luke Wash
May 2, 1995	2,000	Buckeye Irrigation Canal
January 30, 1997	735,500	Luke Wash
February 20, 1997	1,700,000	Buckeye Irrigation Canal
March 24,1997	25,000	Buckeye Irrigation Canal
Consent Orders for Last 3 Releases Listed		
Arizona Department of Environmental Quality, Docket No. P-128-97, August 27, 1997		
USEPA, Docket No. CWA-IX-FY97-16 ($42,000 Fine), September 11, 1997		

9.4 REFERENCES

NRC (U.S. Nuclear Regulatory Commission) 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS), Volumes 1 and 2, NUREG-1437, Washington, D.C., May.

Bement, R., 2008. Letter from Robert S. Bement, Palo Verde Nuclear Vice President To Maricopa County Environmental Services, Air Quality Department, Enforcement Division, “Order of Abatement by Consent- NumberNV-006-08-GJV,” February 19, 2008

ATTACHMENT A

NRC NEPA ISSUES FOR LICENSE RENEWAL OF NUCLEAR POWER PLANTS

APS has prepared this environmental report in accordance with the requirements of NRC regulation 10 CFR 51.53. NRC included in the regulation a list of National Environmental Policy Act (NEPA) issues for license renewal of nuclear power plants.

Table A-1 lists these 92 issues and identifies the section in which APS addressed each applicable issue in this environmental report. For organization and clarity, APS has assigned a number to each issue and uses the issue numbers throughout the environmental report.

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TABLES

Table A-1 PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues.

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Surface Water Quality, Hydrology, and Use (for all plants)			
1. Impacts of refurbishment on surface water quality	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
2. Impacts of refurbishment on surface water use	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
3. Altered current patterns at intake and discharge structures	1	NA	PVNGS does not take water directly from or discharge to surface water. PVNGS uses sewage effluent as source water, and discharges to lined evaporation basins.
4. Altered salinity gradients	1	NA	See explanation at #3.
5. Altered thermal stratification of lakes	1	NA	See explanation at #3.
6. Temperature effects on sediment transport capacity	1	NA	See explanation at #3.
7. Scouring caused by discharged cooling water	1	NA	See explanation at #3.
8. Eutrophication	1	NA	See explanation at #3.
9. Discharge of chlorine or other biocides	1	NA	See explanation at #3.
10. Discharge of sanitary wastes and minor chemical spills	1	NA	See explanation at #3.
11. Discharge of other metals in waste water	1	NA	See explanation at #3.
12. Water use conflicts (plants with once-through cooling systems)	1	NA	Issue applies to a plant feature, once-through cooling, that PVNGS does not have.
13. Water use conflicts (plants with cooling ponds or cooling towers using make-up water from a small river with low flow)	2	4.1	4.4.2.1/4-52
Aquatic Ecology (for all plants)			
14. Refurbishment impacts to aquatic resources	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
15. Accumulation of contaminants in sediments or biota	1	NA	See explanation at #3.
16. Entrainment of phytoplankton and zooplankton	1	NA	See explanation at #3.
17. Cold shock	1	NA	See explanation at #3.
18. Thermal plume barrier to migrating fish	1	NA	See explanation at #3.
19. Distribution of aquatic organisms	1	NA	See explanation at #3.
20. Premature emergence of aquatic insects	1	NA	See explanation at #3.
21. Gas supersaturation (gas bubble disease)	1	NA	See explanation at #3.
22. Low dissolved oxygen in the discharge	1	NA	See explanation at #3.
23. Losses from predation, parasitism, and disease among organisms exposed to sublethal stresses	1	NA	See explanation at #3.
24. Stimulation of nuisance organisms (e.g., shipworms)	1	NA	See explanation at #3.
Aquatic Ecology (for plants with once-through and cooling pond heat dissipation systems)			
25. Entrainment of fish and shellfish in early life stages for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to plant features, once-through cooling or cooling ponds, that PVNGS does not have.
26. Impingement of fish and shellfish for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to plant features, once-through cooling or cooling ponds, that PVNGS does not have.
27. Heat shock for plants with once-through and cooling pond heat dissipation systems	2	NA	Issue applies to plant features, once-through cooling or cooling ponds, that PVNGS does not have.
Aquatic Ecology (for plants with cooling-tower-based heat dissipation systems)			
28. Entrainment of fish and shellfish in early life stages for plants with cooling-tower-based heat dissipation systems	1	NA	See explanation at #3.
29. Impingement of fish and shellfish for plants with cooling-tower-based heat dissipation systems	1	NA	See explanation at #3.
30. Heat shock for plants with cooling-tower-based heat dissipation systems	1	NA	See explanation at #3.

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
Groundwater Use and Quality			
31. Impacts of refurbishment on groundwater use and quality	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
32. Groundwater use conflicts (potable and service water; plants that use < 100 gpm)	1	NA	Issue applies to a feature, use of <100 gpm of groundwater, that PVNGS does not do.
33. Groundwater use conflicts (potable, service water, and dewatering; plants that use > 100 gpm)	2	4.5	4.8.1.1/4-116 4.8.2.1/4-119
34. Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.6	4.8.1.3/4-117
35. Groundwater use conflicts (Ranney wells)	2	NA	Issue applies to a plant feature, Ranney wells, that PVNGS does not have.
36. Groundwater quality degradation (Ranney wells)	1	NA	Issue applies to a feature, Ranney wells, that PVNGS does not have.
37. Groundwater quality degradation (saltwater intrusion)	1	NA	Issue applies to a feature, location at an ocean or estuary site, that PVNGS does not have.
38. Groundwater quality degradation (cooling ponds in salt marshes)	1	NA	Issue applies to a feature, location in a salt marsh, that PVNGS does not have.
39. Groundwater quality degradation (cooling ponds at inland sites)	2	NA	Issue applies to a feature, cooling ponds, that PVNGS does not have
Terrestrial Resources			
40. Refurbishment impacts to terrestrial resources	2	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
41. Cooling tower impacts on crops and ornamental vegetation	1	4.0	4.3.4/4-34
42. Cooling tower impacts on native plants	1	NA	4.3.5/4-42
43. Bird collisions with cooling towers	1	NA	Issue applies to a feature, natural draft cooling towers, that PVNGS does not have.
44. Cooling pond impacts on terrestrial resources	1	4.0	4.4.4/4-58 (issue applied to evaporation ponds)

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
45. Power line right-of-way management (cutting and herbicide application)	1	4.0	4.5.6.1/4-71
46. Bird collisions with power lines	1	4.0	4.5.6.2/4-74
47. Impacts of electromagnetic fields on flora and fauna (plants, agricultural crops, honeybees, wildlife, livestock)	1	4.0	4.5.6.3/4-77
48. Floodplains and wetlands on power line right-of-way	1	4.0	4.5.7./4-81
Threatened or Endangered Species (for all plants)			
49. Threatened or endangered species	2	4.10	4.1/4-1
Air Quality			
50. Air quality during refurbishment (non-attainment and maintenance areas)	2	NA	Issue applies to an activity, refurbishment, that PVNGS does not plan to undertake.
51. Air quality effects of transmission lines	1	4.0	4.5.2/4-62
Land Use			
52. Onsite land use	1	4.0	3.2/3-1
53. Power line right-of-way land use impacts	1	4.0	4.5.3/4-62
Human Health			
54. Radiation exposures to the public during refurbishment	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
55. Occupational radiation exposures during refurbishment	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.
56. Microbiological organisms (occupational health)	1	4.0	4.3.6/4-48
57. Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	2	NA	Issue applies to an activity, discharge of heated cooling water to a surface water body, that PVNGS does not do.
58. Noise	1	4.0	4.3.7/4-49
59. Electromagnetic fields, acute effects	2	4.13	4.5.4.1/4-66
60. Electromagnetic fields, chronic effects	NA	4.0	4.5.4.2/4-67
61. Radiation exposures to public (license renewal term)	1	4.0	4.6.2/4-87

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
62. Occupational radiation exposures (license renewal term)	1	4.0	4.6.3/4-95
Socioeconomics			
63. Housing impacts	2	4.14	3.7.2/3-10 (refurbishment - not applicable to PVNGS) 4.7.1/4-101 (renewable term)
64. Public services: public safety, social services, and tourism and recreation	1	4.0	Refurbishment (not applicable to PVNGS) 3.7.4/3-14 (public service) 3.7.4.3/3-18 (safety) 3.7.4.4/3-19 (social) 3.7.4.6/3-20 (tour, rec) Renewal Term 4.7.3/4-104 (public safety) 4.7.3.3/4-106 (safety) 4.7.3.44-107 (social) 4.7.3.6/4-107 (tour, rec)
65. Public services: public utilities	2	4.15	3.7.4.5/3-19 (refurbishment - not applicable to PVNGS) 4.7.3.5/4-107 (renewable term)
66. Public services: education (refurbishment)	2	NA	Issue applies to an activity, refurbishment, that PVNGS does not plan to undertake.
67. Public services: education (license renewal term)	1	4.0	4.7.3.1/4-106
68. Offsite land use (refurbishment)	2	NA	Issue applies to an activity, refurbishment, that PVNGS does not plan to undertake.
69. Offsite land use (license renewal term)	2	4.17.2	4.7.4/4-107
70. Public services: transportation	2	4.18	3.7.4.2/3-17 (refurbishment - not applicable to PVNGS) 4.7.3.2/4-106 (renewal term)
71. Historic and archaeological resources	2	4.19	3.7.7/3-23 (refurbishment - not applicable to PVNGS) 4.7.7/4-114 (renewal term)
72. Aesthetic impacts (refurbishment)	1	NA	Issue applies to an activity, refurbishment, that PVNGS has no plans to undertake.

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
73. Aesthetic impacts (license renewal term)	1	4.0	4.7.6/4-111
74. Aesthetic impacts of transmission lines (license renewal term)	1	4.0	4.5.8/4-83
Postulated Accidents			
75. Design basis accidents	1	4.0	5.3.2/5-11 (design basis) 5.5.1/5-114 (summary)
76. Severe accidents	2	4.20	5.3.3/5-12 (probabilistic analysis) 5.3.3.2/5-19 (air dose) 5.3.3.3/5-49 (water) 5.3.3.4/5-65 (groundwater) 5.3.3.5/5-95 (economic) 5.4/5-106 (mitigation) 5.5.2/5-114 (summary)
Uranium Fuel Cycle and Waste Management			
77. Offsite radiological impacts (individual effects from other than the disposal of spent fuel and high-level waste)	1	4.0	6.2/6-8
78. Offsite radiological impacts (collective effects)	1	4.0	Not in GEIS.
79. Offsite radiological impacts (spent fuel and high-level waste disposal)	1	4.0	Not in GEIS.
80. Nonradiological impacts of the uranium fuel cycle	1	4.0	6.2.2.6/6-20 (land use) 6.2.2.7/6-20 (water use) 6.2.2.8/6-21 (fossil fuel) 6.2.2.9/6-21 (chemical)
81. Low-level waste storage and disposal	1	4.0	6.4.2/6-36 (low-level def) 6.4.3/6-37 (low-level volume) 6.4.4/6-48 (renewal effects)
82. Mixed waste storage and disposal	1	4.0	6.4.5/6-63
83. Onsite spent fuel	1	4.0	6.4.6/6-70
84. Nonradiological waste	1	4.0	6.5/6-86
85. Transportation	1	4.0	6.3/6-31, as revised by Addendum 1, August 1999.
Decommissioning			
86. Radiation doses (decommissioning)	1	4.0	7.3.1/7-15

Table A-1. PVNGS Environmental Report Cross-Reference of License Renewal NEPA Issues. (Continued)

Issue[a]	Category	Section of this Environmental Report	GEIS Cross Reference (Section/Page)[b]
87. Waste management (decommissioning)	1	4.0	7.3.2/7-19 (impacts) 7.4/7-25 (conclusions)
88. Air quality (decommissioning)	1	4.0	7.3.3/7-21 (air) 7.4/7-25 (conclusions)
89. Water quality (decommissioning)	1	4.0	7.3.4/7-21 (water) 7.4/7-25 (conclusions)
90. Ecological resources (decommissioning)	1	4.0	7.3.5/7-21 (ecological) 7.4/7-25 (conclusions)
91. Socioeconomic impacts (decommissioning)	1	4.0	7.3.7/7-19 (socioeconomic) 7.4/7-24 (conclusions)
Environmental Justice			
92. Environmental justice	NA	2.6.2	not in GEIS

a. Source: 10 CFR 51, Subpart A, Appendix A, Table B-1. (Issue numbers added to facilitate discussion.)
b. Source: Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437).
NA = not applicable

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ATTACHMENT B

SPECIAL STATUS SPECIES CORRESPONDENCE

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APS

THE POWER TO MAKE IT HAPPEN℠

Edward Z. Fox
Vice President
Communications,
Environment and
Safety

Tel. 602-250-2916
Fax 602-250-3002
e-mail Edward.Fox@aps.com

Mail Station 9085
PO Box 53999
Phoenix, Arizona 85072-3999

September 28, 2007

Steve Spangle
Arizona Ecological Services Field Office
U.S. Fish and Wildlife Service
2321 West Royal Palm Road, Suite 103
Phoenix, AZ 85021

SUBJECT: Palo Verde Nuclear Generating Station (PVNGS)
Request for Information on Threatened or Endangered Species

Dear Mr. Spangle:

Arizona Public Service Company (APS) is initiating the steps required to be in a position to file an application with the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PVNGS Units 1, 2 and 3. The current operating licenses expire on December 31, 2024 for Unit 1; December 9, 2025 for Unit 2; and March 25, 2027 for Unit 3. The renewal terms would be for an additional 20 years beyond each original license expiration date. The NRC review schedule dictates limited windows of opportunity to submit an application for license renewal, and a submittal window of fourth quarter 2008 is available to APS. However, the decision on whether or not to actually file an application in 2008 would need to be formally agreed upon by Palo Verde participants.

As part of the license renewal process, NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or provide any information your office may need to expedite the NRC consultation.

PVNGS is located in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area, which is the nearest population center. The town of Buckeye (year 2000 population approximately 6,500) is approximately 16 miles to the east. The nearest town, which is the mailing address for the plant, is Wintersburg. The PVNGS site boundary encloses approximately 4,250 acres (see attached Figure 2-1).

APS owns the largest share of PVNGS, and maintains and operates the facility. Other owners include Salt River Project, Southern California Edison, El Paso Electric Company, Public Service Company of New Mexico, Southern California Public Power Authority, and the Department of Water and Power of the City of Los Angeles.

Seven transmission lines connect the station to the regional grid, and are thus relevant to license renewal (see attached Figure 3-2). They include:

- Westwing #1 and #2 – These two 525-kilovolt lines extend east and north for 45 miles in a 330-foot wide corridor to the Westwing Substation northwest of Phoenix.

- Rudd – Starting in a common corridor with Westwing #1 and #2, this 525-kilovolt line runs for 37 miles to the Rudd Substation in Phoenix. After leaving the Westwing corridor, the Rudd corridor width is generally 200 feet.

- Kyrene – This line runs south to the Hassayampa substation for 3 miles, then turns to the southeast for 20 miles to the Jojoba Substation, and then runs another 52 miles to the Kyrene Generating Station south of Tempe, Arizona. The corridor width for this 525-kilovolt line varies from 75 to 200 feet, except that the 3-mile length it shares with Hassaymapa #2 (described below) is 330 feet wide.

- Hassayampa #2 – This 525-kilovolt line runs in the same corridor as Hassayampa #1 to the Hassayampa substation, a distance of 3 miles. The combined corridor width is approximately 330 feet.

- Hassayampa #3 – This 525-kilovolt line roughly parallels the Hassayampa #1 and #2 lines to the Hassaymapa substation, but in a separate corridor. The corridor width is 200 feet.

- Devers – This 235-mile line runs westward from the plant to the Devers Substation north of Palm Springs, California. The corridor width is typically 200 feet.

In total, there are approximately 390 miles and approximately 10,000 acres of transmission line corridor. The corridors pass through land that is primarily agricultural and desert. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways. Much of the land crossed is Federal property. Corridors that pass through farmlands generally continue to be used as farmland.

Based on a review of historical documents, previous on-site surveys, and information on U.S. Fish and Wildlife Service Region 2 and Arizona Game and Fish Department websites, APS believes that no federally listed species occur on the PVNGS site proper, although several species are federally listed within the Arizona counties containing the transmission lines. The PVNGS-to-Devers transmission corridor crosses a reach of the lower Colorado River that is designated critical habitat for the endangered razorback sucker (*Xyrauchen texanus*). This river reach is scheduled to be stocked with this sucker and the threatened boneytail chub (*Gila elegans*) over the next 50 years. This same transmission line crosses the Kofa National Wildlife Refuge in La Paz County, Arizona.

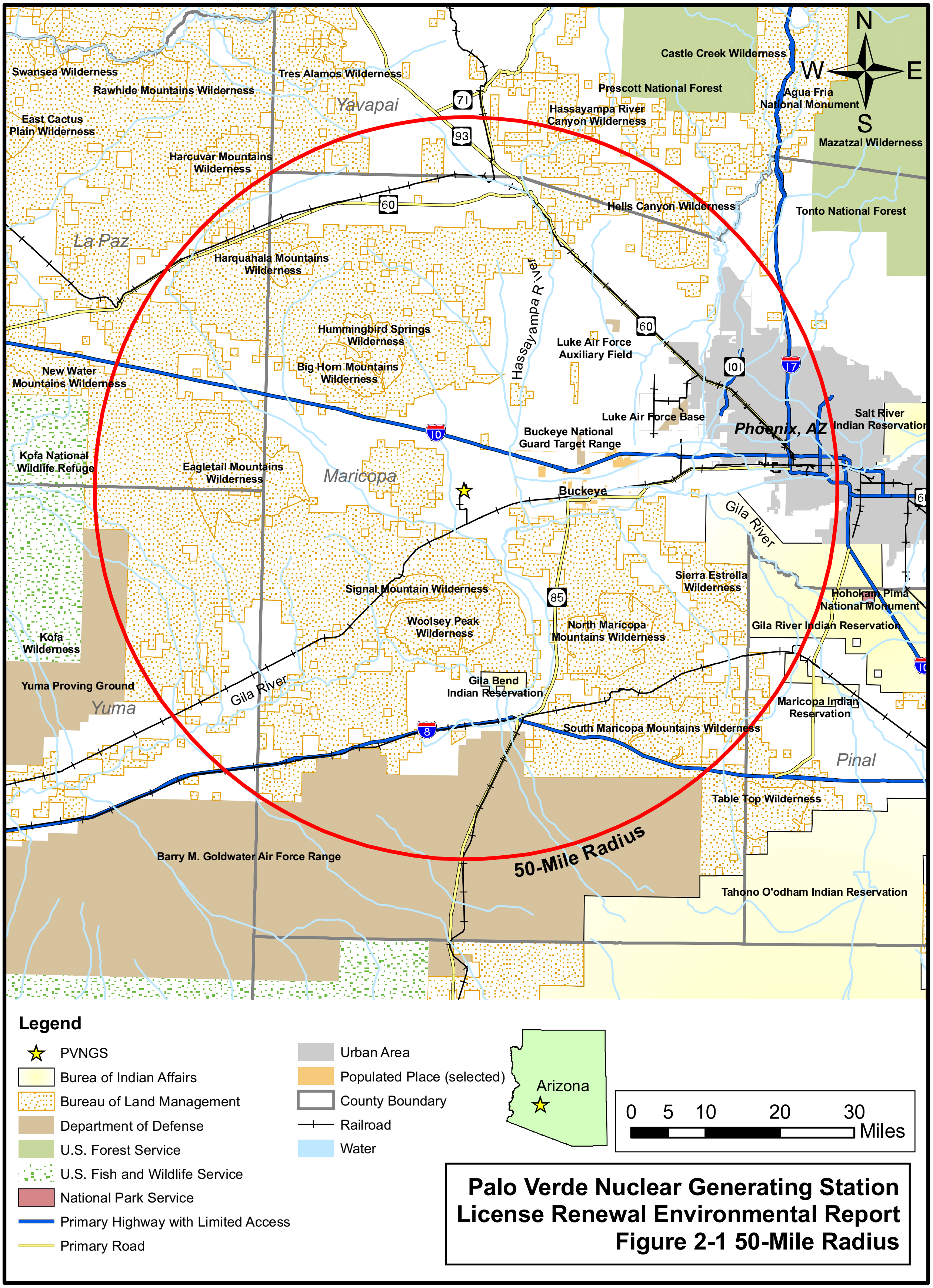
APS has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, we believe that operation of PVNGS over the license renewal term would not adversely affect any threatened or endangered species.

Please do not hesitate to call Henry Day at (623) 393-6567 if you have any questions or require any additional information. After your review, we would appreciate your office sending a letter by January 31, 2008 detailing any concerns you may have about any listed species or critical habitat in the area, or confirming APS's conclusion that operation of PVNGS over the license renewal term would have no effect on any threatened or endangered species. APS will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the PVNGS license renewal application.

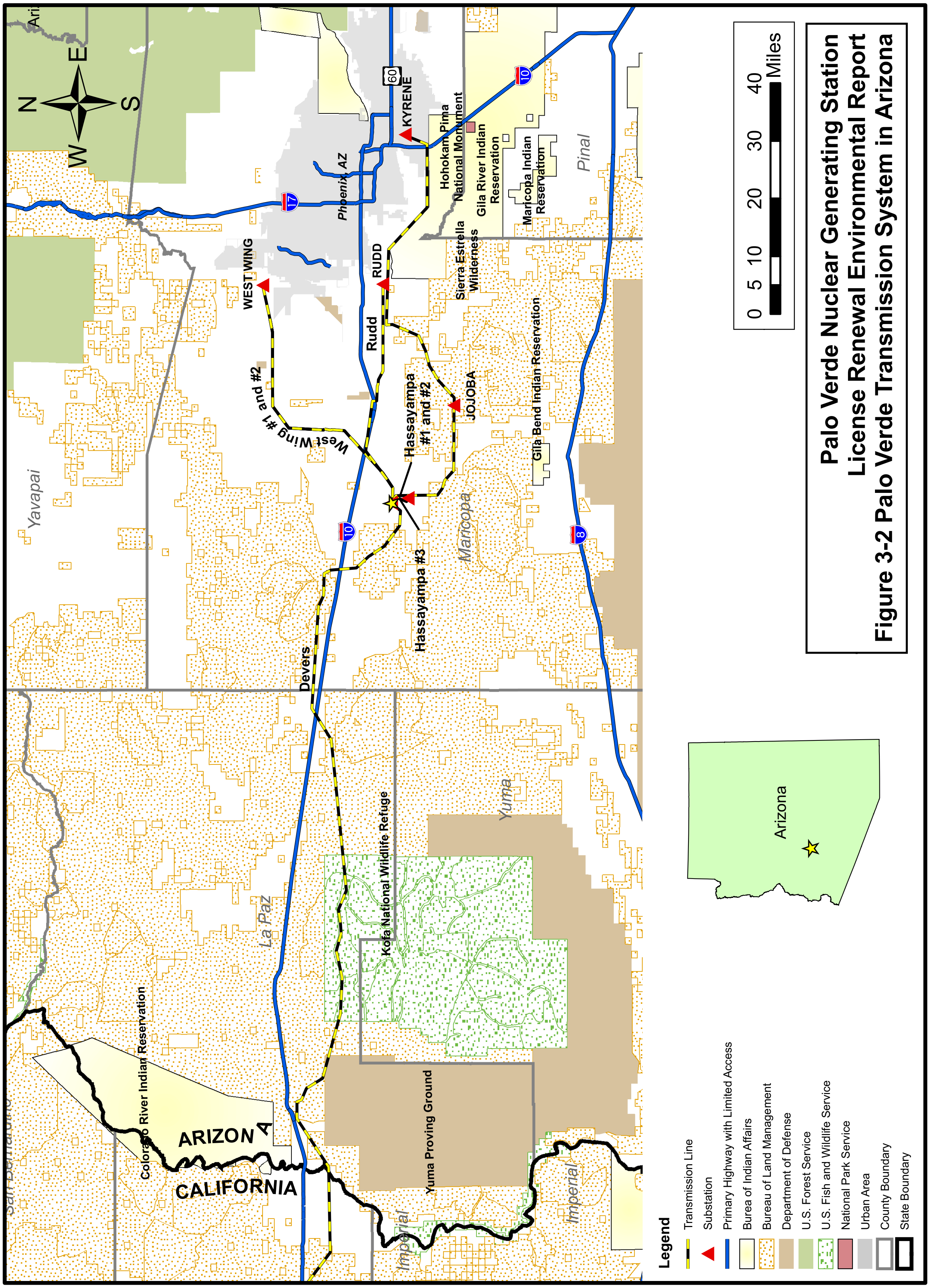
Sincerely,

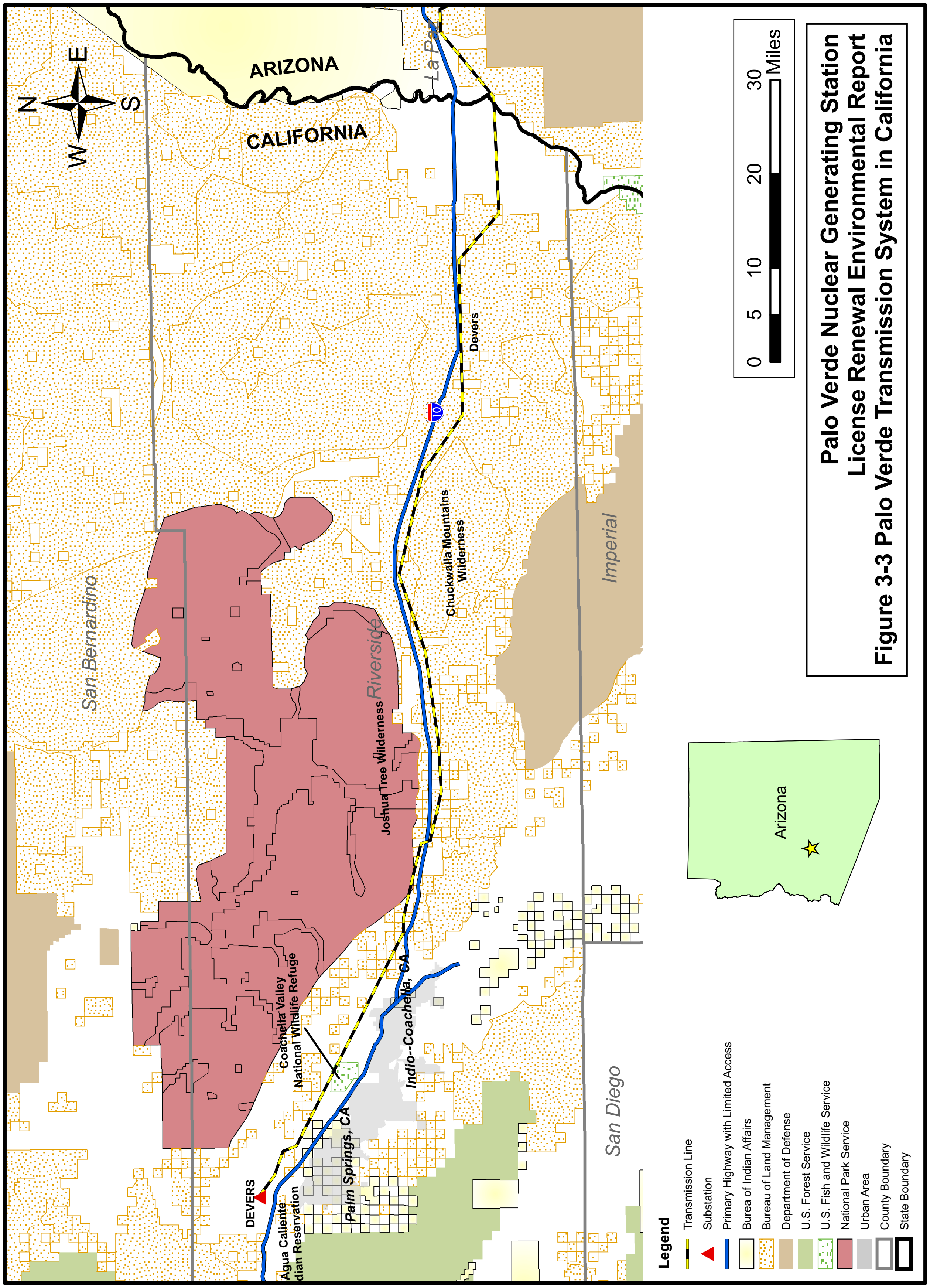
Edward Fox

EZF:bgs
Enclosures: (1) Figure 2-1 (2) Figure 3-2 (3) Figure 3-3



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 2-1 50-Mile Radius


Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-2 Palo Verde Transmission System in Arizona
0 5 10 20 30 40 Miles
Legend
Transmission Line
Substation
Primary Highway with Limited Access
Bureau of Indian Affairs
Bureau of Land Management
Department of Defense
U.S. Forest Service
U.S. Fish and Wildlife Service
National Park Service
Urban Area
County Boundary
State Boundary
Arizona
N
E
S
W
WEST WING
RUDD
KYRENE
JOJOBA
West Wing #1 and #2
Rudd
Hassayampa #1 and #2
Hassayampa #3
Devers
Phoenix, AZ
Hohokam Pima National Monument
Gila River Indian Reservation
Maricopa Indian Reservation
Sierra Estrella Wilderness
Gila Bend Indian Reservation
Kofa National Wildlife Refuge
Yuma Proving Ground
Colorado River Indian Reservation
ARIZONA
CALIFORNIA
Yavapai
Maricopa
Pinal
La Paz
Yuma
Imperial
60
17
10
8



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-3 Palo Verde Transmission System in California

United States Department of the Interior
U.S. Fish and Wildlife Service
Arizona Ecological Services Field Office
2321 West Royal Palm Road, Suite 103
Phoenix. Arizona 85021-4951
Telephone: (602) 242-0210 Fax: (602) 242-2513

RECEIVED
NOV 3 0 2007
EDWARD Z. FOX

In Reply Refer to:
AESO/SE
22410-2008-SL-0091

November 29.2007

Mr. Edward Fox
APS
P.O. Box 53999
Phoenix, Arizona 85072-3999

RE: Palo Verde Nuclear Generating Station (PVGS) Located Approximately 26 Miles West of the Phoenix Metropolitan Area, Maricopa County, Arizona (Operating License Renewal for Units 1,2 and 3)

Dear Mr. Fox:

Thank you for your recent request for infomlation on threatened or endangered species, or those that are proposed to be listed as such tmder the Endangered Species Act of 1973, as amended (Act), which may occur in your project area. The Arizona Ecological Service Field Office has posted lists of the endangered. threatened, proposed, and candidate species occurring in each of Arizona's 15 counties on the Internet. Please refer to the following web page for species information in the county where your project occurs: **http://www.fws.gov/southwest/es/arizona**

If you do not have access to the Tntemet or have difficulty obtaining a list, please contact our office and we will mail or fax you a list as soon as possible.

After opening the web page, find County Species Lists on the main page. Then click on the county of interest. The alTows on the left will guide you through information on species that are listed, proposed, candidates, or have conservation agreements. Here you will find infomlation on the species' status. a physical description. all counties where the species occurs, habitat, elevation, and some general comments. Additional infomlation can be obtained by going back to the main page. On the left side of the screen, click on Document Library, then click on Documents by Species, then click on the name of the species of interest to obtain General Species Infonnation, or other documents that may be available. Click on the "Cactus" icon to view the desired document.

Please note that your project area may not necessarily include all or any of these species. The infomlation provided includes general descriptions. habitat requirements, and other information for each species on the list. Under the General Species In[om1ation, citations for the Federal Register (FR) are included for each listed and proposed species. The FR is available at most Federal depository libraries. This information should assist you in determining which species may or may not occur within your project area. Site-specific surveys could also be helpful and may be needed to verify the presence or absence of a species or its habitat as required for the evaluation of proposed project-related impacts.

Endangered and threatened species are protected by Federal law and must be considered prior to project development. If the action agency determines that listed species or critical habitat may be adversely affected by a federally funded, permitted, or authorized activity, the action agency will need to request formal consultation with us. If the action agency determines that the planned action may jeopardize a proposed species or destroy or adversely modify proposed critical habitat, the action agency will need to enter into a section 7 conference. The county list may also contain candidate or conservation agreement species. Candidate species are those for which there is sufficient information to support a proposal for listing; conservation agreement species are those for which we have entered into an agreement to protect the species and its habitat. Although candidate and conservation agreement species have no legal protection under the Act, we recommend that they be considered in the planning process in the event that they become listed or proposed for listing prior to project completion.

If any proposed action occurs in or near areas with trees and shrubs growing along watercourses, known as riparian habitat, we recommend the protection of these areas. Riparian areas are critical to biological community diversity and provide linear corridors important to migratory species. In addition, if the project will result in the deposition of dredged or fill materials into waterways, we recommend you contact the Army Corps of Engineers which regulates these activities under Section 404 of the Clean Water Act.

The State of Arizona and some of the Native American Tribes protect some plant and animal species not protected by Federal law. We recommend you contact the Arizona Game and Fish Department and the Arizona Department of Agriculture for State-listed or sensitive species, or contact the appropriate Native American Tribe to determine if sensitive species are protected by Tribal governments in your project area. We further recommend that you invite the Arizona Game and Fish Department and any Native American Tribes in or near your project area to participate in your informal or formal Section 7 Consultation process.

For additional communications regarding this project, please refer to consultation number 22410-2008-SL-0091. We appreciate your efforts to identify and avoid impacts to listed and sensitive species in your project area. If we may be of further assistance, please feel free to contact Brenda Smith (928) 226-0614 (x101) for projects in Northern Arizona, Debra Bills (602) 242-0210 (x239) for projects in central Arizona and along the Lower Colorado River, and Sherry Barrett (520) 670-6150 (x223) for projects in southern Arizona.

Sincerely,

for

Steven L. Spangle
Field Supervisor

cc: Bob Brocheid, Chief, Habitat Branch, Arizona Game and Fish Department, Phoenix, AZ

W:\Cathy Gordon\species ltrs\complete\APS Palo Verde Nuclear Gen Station License Renewal Units 1 2 3.doc:cgg

THE POWER TO MAKE IT HAPPEN℠

Edward Z. Fox
Vice President
Communications,
Environment and
Safety

Tel. 602-250-2916
Fax 602-250-3002
e-mail Edward.Fox@aps.com

Mail Station 9085
PO Box 53999
Phoenix, Arizona 85072-3999

September 28,2007

Rebecca Davidson
Project Evaluation Supervisor
Arizona Game and Fish Department
WMHB-Project Evaluation Program
2221 W. Greenway Road
Phoenix, AZ 85023

SUBJECT: Palo Verde Nuclear Generating Station (PVNGS)
Request for Information on Threatened or Endangered Species

Dear Ms. Davidson:

Arizona Public Service Company (APS) is initiating the steps required to be in a position to file an application with the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PVNGS Units 1,2 and 3. The current operating licenses expire on December 31,2024 for Unit 1; December 9, 2025 for Unit 2; and March 25, 2027 for Unit 3. The renewal terms would be for an additional 20 years beyond each original license expiration date. The NRC review schedule dictates limited windows of opportunity to submit an application for license renewal, and a submittal window of fourth quarter 2008 is available to APS. However, the decision on whether or not to actually file an application in 2008 would need to be formally agreed upon by the Palo Verde participants.

As part of the license renewal process, NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or provide any information your office may need to expedite the NRC consultation.

PVNGS is located in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area, which is the nearest population center. The town of Buckeye (year 2000 population approximately 6,500) is approximately 16 miles to the east. The nearest town, which is the mailing address for the plant, is Wintersburg. The PVNGS site boundary encloses approximately 4,250 acres (see attached Figure 2-1).

APS owns the largest share of PVNGS, and maintains and operates the facility. Other owners include Salt River Project, Southern California Edison, El Paso Electric Company, Public Service Company of New Mexico, Southern California Public Power Authority, and the Department of Water and Power of the City of Los Angeles.

Seven transmission lines connect the station to the regional grid, and are thus relevant to license renewal (see attached Figure 3-2). They include:

- Westwing #I and #2 – These two 525-kilovolt lines extend east and north for 45 miles in a 330-foot wide corridor to the Westwing Substation northwest of Phoenix.

- Rudd – Starting in a common corridor with Westwing #1 and #2, this 525-kilovolt line runs for 37 miles to the Rudd Substation in Phoenix. After leaving the Westwing corridor, the Rudd corridor width is generally 200 feet.

- Kyrene – This line runs south to the Hassayampa substation for 3 miles, then turns to the southeast for 20 miles to the Jojoba Substation, and then runs another 52 miles to the Kyrene Generating Station south of Tempe, Arizona. The corridor width for this 525-kilovolt line varies from 75 to 200 feet, except that the 3-mile length it shares with Hassaymapa #2 (described below) is 330 feet wide.

- Hassayampa #2 – This 525-kilovolt line runs in the same corridor as Hassayampa #1 to the Hassayampa substation, a distance of 3 miles. The combined corridor width is approximately 330 feet.

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In total, there are approximately 390 miles and approximately 10,000 acres of transmission line corridor. The corridors pass through land that is primarily agricultural and desert. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways. Much of the land crossed is Federal property. Corridors that pass through farmlands generally continue to be used as farmland.

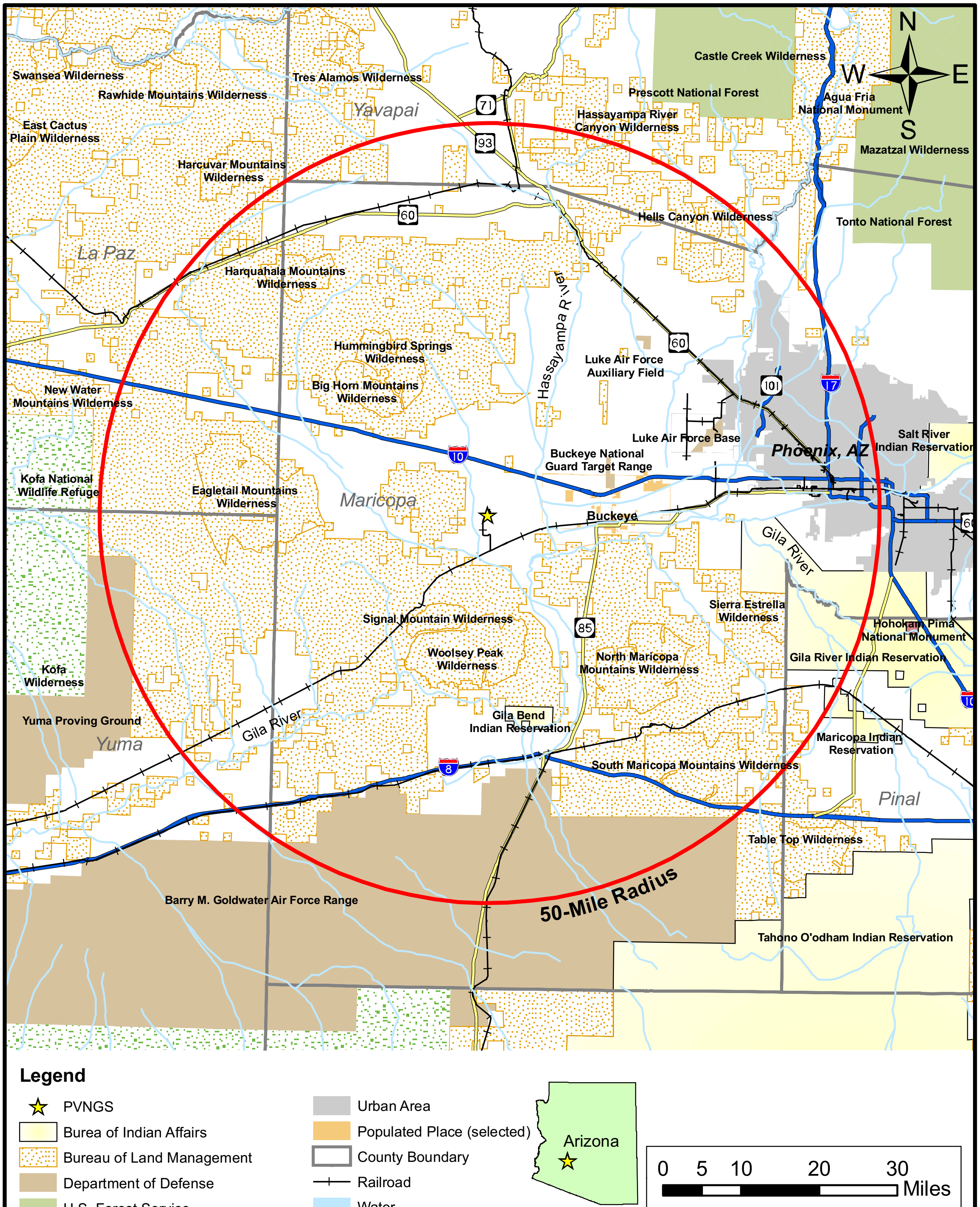
APS has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, we believe that operation of PVNGS over the license renewal term would not adversely affect any threatened or endangered species.

Please do not hesitate to call Henry Day at (623) 393-6567 if you have any questions or require any additional information. After your review, we would appreciate your office sending a letter by January 31,2008 detailing any concerns you may have about any listed species or critical habitat in the area or confirming APS's conclusion that operation of PVNGS over the license renewal term would have no effect on any threatened or endangered species. APS will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the PVNGS license renewal application.

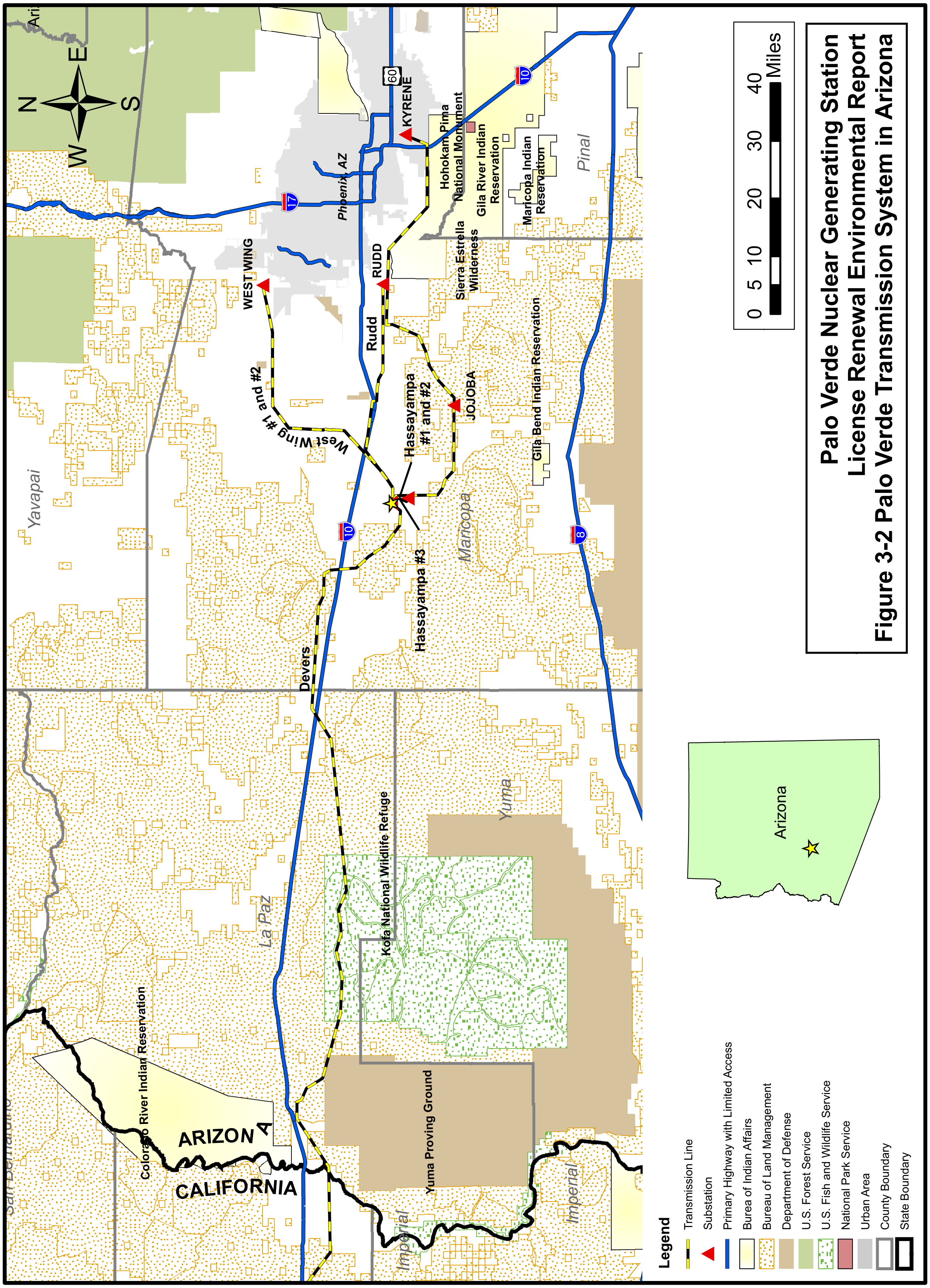
Sincerely,

Edward Fox

EZF:bgs
Enclosures: (1) Figure 2-1
(2) Figure 3-2



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 2-1 50-Mile Radius



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-2 Palo Verde Transmission System in Arizona

THE STATE OF ARIZONA
GAME AND FISH DEPARTMENT
5000 W. CAREFREE HIGHWAY
PHOENIX, AZ 85086-5000
(602) 942-3000 • WWW.AZGFD.GOV

RECEIVED

DEC 12 2007

EDWARD Z. FOX

December 11,2007

Mr. Edward Fox
APS
Mail Station 9085
PO Box 53999
Phoenix, AZ 85072

Re: Special Status Species Information for **Palo Verde Nuclear Generation Station Transmission Lines and Substations.**

Dear Mr. Fox:

The Arizona Game and Fish Department (Department) has reviewed your request, dated September 28, 2007, regarding special status species information associated with the above-referenced project area. The Department's Heritage Data Management System (HDMS) has been accessed and current records show that the special status species listed on the attachment have been documented as occurring in the project vicinity (5-mile buffer). In addition, this project occurs in the vicinity of Designated Critical Habitat for razorback sucker (Xyrauchen texanus).

The Department's HDMS data are not intended to include potential distribution of special status species. Arizona is large and diverse with plants, animals, and environmental conditions that are ever changing. Consequently, many areas may contain species that biologists do not know about or species previously noted in a particular area may no longer occur there. Not all of Arizona has been surveyed for special status species, and surveys that have been conducted have varied greatly in scope and intensity.

If you have any questions regarding this letter, please contact me at (623) 236-7606. General status information, county and watershed distribution lists and abstracts for some special status species are also available on our web site at http://www.azgfd.gov/hdms.

Sincerely,

Ginger Ritter

Ginger L. Ritter
Project Evaluation Program Specialist

cc: Rebecca Davidson, Project Evaluation Program Supervisor
Russ Engel, Habitat Program Manager, Region IV
Russ Haughey, Habitat Program Manager, Region VI

AGFD #M07-10214617

Special Status Species within 5 Miles of Palo Verde Transmission Lines

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Ardea alba	Great Egret				WSC
Athene cunicularia hypugaea	Western Burrowing Owl	SC		S	
Bat Colony					
CH for Xyrauchen texanus	Designated Critical Habitat for razorback sucker				
Charina trivirgata gracia	Desert Rosy Boa	SC	S	S	
Coccyzus americanus occidentalis	Western Yellow-billed Cuckoo	C	S		WSC
Colorado River Indian Reservation	Colorado River Indian Reservation				
Dendrocygna autumnalis	Black-bellied Whistling-Duck				WSC
Empidonax traillii extimus	Southwestern Willow Flycatcher	LE	S		WSC
Eumops perotis californicus	Greater Western Bonneted Bat	SC			
Ferocactus cylindraceus var. cylindraceus	California Barrel Cactus				SR
Gila River Indian Reservation	Gila River Indian Reservation				
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Heloderma suspectum cinctum	Banded Gila Monster	SC		S	
Ixobrychus exilis	Least Bittern				WSC
Lasiurus blossevillii	Western Red Bat				WSC
Lasiurus xanthinus	Western Yellow Bat				WSC
Macrotus californicus	California Leaf-nosed Bat	SC			WSC
Myotis velifer	Cave Myotis	SC		S	
Opuntia echinocarpa	Straw-top Cholla				SR
Opuntia engelmannii var. flavispina					SR
Rallus longirostris yumanensis	Yuma Clapper Rail	LE			WSC
Sauromalus ater (Arizona Population)	Arizona Chuckwalla	SC		S	
Uma scoparia	Mojave Fringe-toed Lizard				WSC
Xyrauchen texanus	Razorback Sucker	LE	S		WSC

AGFD #M07-10214617

Arizona Game and Fish Department, Heritage Data Management System, December 11, 2007
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 1 South, Range 5 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Bat Colony					

Township 1 South. Range 4 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Lasiurus blossevillii	Western Red Bat				WSC

Township 1 North, Range 4 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Bat Colony					
Lasiurus xanthinus	Western Yellow Bat				WSC

Township 1 South, Range 3 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii *(Sonoran* Population)	Sonoran Desert Tortoise	SC			WSC
Sauromalus ater (Arizona Population)	Arizona Chuckwalla	SC		S	

Township 1 North, Range 2 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Athene cunicularia hypugaea	Western Burrowing Owl	SC		S	

Township 1 North, Range 1 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Athene *cunicularia* hypugaea	Western Burrowing Owl	SC		S	
Coccyzus americanus occidentalis	Western Yellow-billed Cuckoo	C	S		WSC
Dendrocygna autumnalis	Black-bellied Whistling-Duck				WSC

Township 4 North, Range 1 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Eumops perotis californicus	Greater Western Bonneted Bat	SC			

Township 5 North, Range 1 East

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii *(Sonoran* Population)	Sonoran Desert Tortoise	SC			WSC

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11,2007
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 1 South, Range 1 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Bat Colony					
Macrotus californicus	California Leaf-nosed Bat	SC			WSC

Township 1 North, Range 1 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Coccyzus americanus occidentalis	Western Yellow-billed Cuckoo	C	S		WSC
Empidonax traillii extimus	Southwestern Willow Flycatcher	LE	S		WSC
Ixobrychus exilis	Least Bittern				WSC
Rallus longirostris yumanensis	Yuma Clapper Rail	LE			WSC

Township 5 North, Range [illegible] West

NAMt	COMMON	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 South, Range 2 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Athene cunicularia hypugaea	Western Burrowing Owl	SC		S	

Township 1 South, Range 2 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Coccyzus americanus occidentalis	Western Yellow-billed Cuckoo	C	S		WSC
Rallus longirostris yumanensis	Yuma Clapper Rail	LE			WSC

Township 1 North, Range 2 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Athene cunicularia hypugaea	Western Burrowing Owl	SC		S	

Township 3 North, Range 2 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Athene cunicularia hypugaea	Western Burrowing Owl	SC		S	
Opuntia engelmannii var. flavispina					SR

Township 3 South, Range 3 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11,2007.
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 1 South, Range 3 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Coccyzus *americanus occidentalis*	Western Yellow-billed Cuckoo	C	S		WSC
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Ixobrychus exilis	Least Bittern				WSC
Rallus *longirostris* yumanensis	Yuma Clapper Rail	LE			WSC

Township 2 North, Range 3 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 3 North, Range 3 West

NAME	**COMMON NAME**	**ESA**	**USFS**	BLM	STAT
Bat Colony					
Macrotus *californicus*	California Leaf-nosed Bat	SC			WSC

Township 4 North, Range 3 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Opuntia engelmannii var. *flavispina*					SR

Township 3 South, Range 4 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 1 South, Range 4 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Ferocactus cylindraceus var. cylindraceus	California Barrel Cactus				SR

Township 4 North, Range 4 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Opuntia *echinocarpa*	Straw-top Cholla				SR

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11, 2007.
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

<u>Township 2 South, Range 5 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Rallus longirostris yumanensis	Yuma Clapper Rail	LE			WSC

<u>Township 1 South. Range 5 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Rallus longirostris yumanensis	Yuma Clapper Rail	LE			WSC

<u>Township 4 North, Range 5 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

<u>Township 3 South, Range 6 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

<u>Township 2 South, Range 6 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Bat Colony					
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Macrotus californicus	California Leaf-nosed Bat	SC			WSC
Myotis velifer	Cave Myotis	SC		S	

<u>Township 1 South, Range 6 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Opuntia echinocarpa	Straw-top Cholla				SR

<u>Township 1 North, Range 8 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

<u>Township 3 North, Range 8 West</u>

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11,2007
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 3 North, Range 9 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 North, Range 11 West

NAME	COMMON NAME	ESA	USFS	ELM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 North, Range 12 West

NAME	COMMON NAME	ESA	USFS	ELM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 North, Range 14 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 North, Range **16** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 3 North, Range 16 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 3 North, Range 17 West

NAME	COMMON NAME	ESA	USFS	ELM	STATE
Charina trivirgata gracia	Desert Rosy Boa	SC	S	S	
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 2 North, **Range** 18 West

NAME	COMMON NAME	ESA	USFS	ELM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Heloderma suspectum cinctum	Banded Gila Monster	SC		S	

Township 3 North, Range 18 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Charina trivirgata gracia	Desert Rosy Boa	SC	*S*	S	

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11,2007
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 3 North, Range **19** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township **2** North, Range **20** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 3 North, Range **20** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Bat Colony					
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Macrotus californicus	California Leaf-nosed Bat	SC			WSC

Township 4 North, Range **20** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC
Macrotus californicus	California Leaf-nosed Bat	SC			WSC
Myotis velifer	Cave Myotis	SC		S	

Township 2 North, Range **21** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Uma scoparia	Mojave Fringe-toed Lizard				WSC

Township 3 North, Range **21** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township 4 North, Range **21** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Gopherus agassizii (Sonoran Population)	Sonoran Desert Tortoise	SC			WSC

Township **2** North, Range **22** West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
CH *for Xyrauchen texanus*	Designated Critical Habitat for razorback sucker				

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11, 2007
Project Evaluation Program.

Speical Status Species within 5 Miles of Palo Verde Transmission Lines

Township 3 North, Range 22 West

NAME	COMMON NAME	ESA	USFS	BLM	STATE
Ardea alba	Great Egret				WSC
CH for Xyrauchen texanus	Designated Critical Habitat for razorback sucker				
Empidonax traillii extimus	Southwestern Willow Flycatcher	LE	S		WSC
Myotis velifer	Cave Myotis	SC		S	
Xyrauchen texanus	Razorback Sucker	LE	S		WSC

AGFD #M07-03230421. Proposed Construction of 69kV Transmission Line.

Arizona Game and Fish Department, Heritage Data Management System, December 11, 2007.
Project Evaluation Program.

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Edward Z. Fox
Vice President
Communications, Environment and Safety

Tel. 602-250-2916
Fax 602-250-3002
e-mail Edward.Fox@aps.com

Mail Station 9085
PO Box 53999
Phoenix, Arizona 85072-3999

September 28,2007

Ms. Gabbi Gatchel
California Department of Fish and Game - Regional Office
3602 Inland Empire Boulevard,
Suite C-220
Ontario, CA 91764

SUBJECT: Palo Verde Nuclear Generating Station (PVNGS)
Request for Information on Threatened or Endangered Species

Dear Ms. Gatchel:

Arizona Public Service Company (APS) is initiating the steps required to be in a position to file an application with the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PVNGS Units 1,2 and 3. The current operating licenses expire on December 31,2024 for Unit 1; December 9,2025 for Unit 2; and March 25, 2027 for Unit 3. The renewal terms would be for an additional 20 years beyond each original license expiration date. The NRC review schedule dictates limited windows of opportunity to submit an application for license renewal, and a submittal window of fourth quarter 2008 is available to APS. However, the decision on whether or not to actually file an application in 2008 would need to be formally agreed upon by the Palo Verde participants.

As part of the license renewal process, NRC requires license applicants to "assess the impact of the proposed action on threatened or endangered species in accordance with the Endangered Species Act" (10 CFR 51.53). The NRC will request an informal consultation with your office at a later date under Section 7 of the Endangered Species Act. By contacting you early in the application process, we hope to identify any issues that need to be addressed or provide any information your office may need to expedite the NRC consultation.

PVNGS is located in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area, which is the nearest population center. The town of Buckeye (year 2000 population approximately 6,500) is approximately 16 miles to the east. The nearest town, which is the mailing address for the plant, is Wintersburg. The PVNGS site boundary encloses approximately 4,250 acres (see attached Figure 2-1).

APS owns the largest share of PVNGS, and maintains and operates the facility. Other owners include Salt River Project, Southern California Edison (SCE), El Paso Electric Company, Public Service Company of New Mexico, Southern California Public Power Authority, and the Department of Water and Power of the City of Los Angeles. Seven 525-kV transmission lines connect PVNGS to the regional grid, but six of the transmission lines are contained within Arizona. The PVNGS-to-Devers transmission line is the only line that crosses into California. SCE owns and operates the PVNGS-to-Devers transmission line, which crosses into Riverside County, California, and terminates near Palm Springs (see attached Figure 3-3).

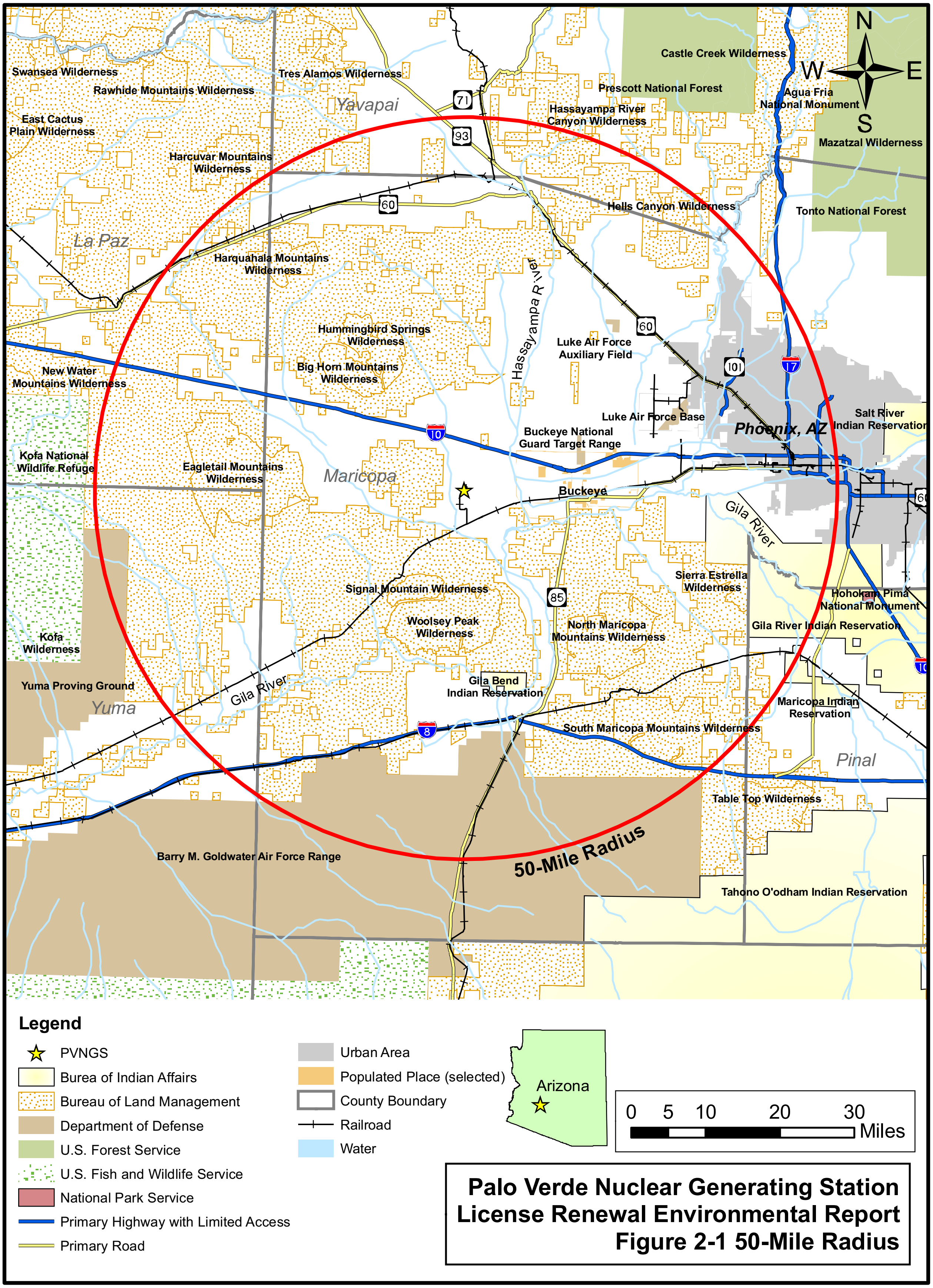
APS has no plans to alter current operations over the license renewal period. Any maintenance activities necessary to support license renewal would be limited to previously disturbed areas. No expansion of existing facilities is planned, and no additional land disturbance is anticipated in support of license renewal. As a consequence, we believe that operation of PVNGS over the license renewal term would not adversely affect any threatened or endangered species.

Please do not hesitate to call Henry Day at **(623) 393-6567** if you have any questions or require any additional information. After your review, we would appreciate your office sending a letter by January **31,2008** detailing any concerns you may have about any listed species or critical habitat in the area or confirming **APS's** conclusion that operation of PVNGS over the license renewal term would have no effect on any threatened or endangered species. APS will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the PVNGS license renewal application.

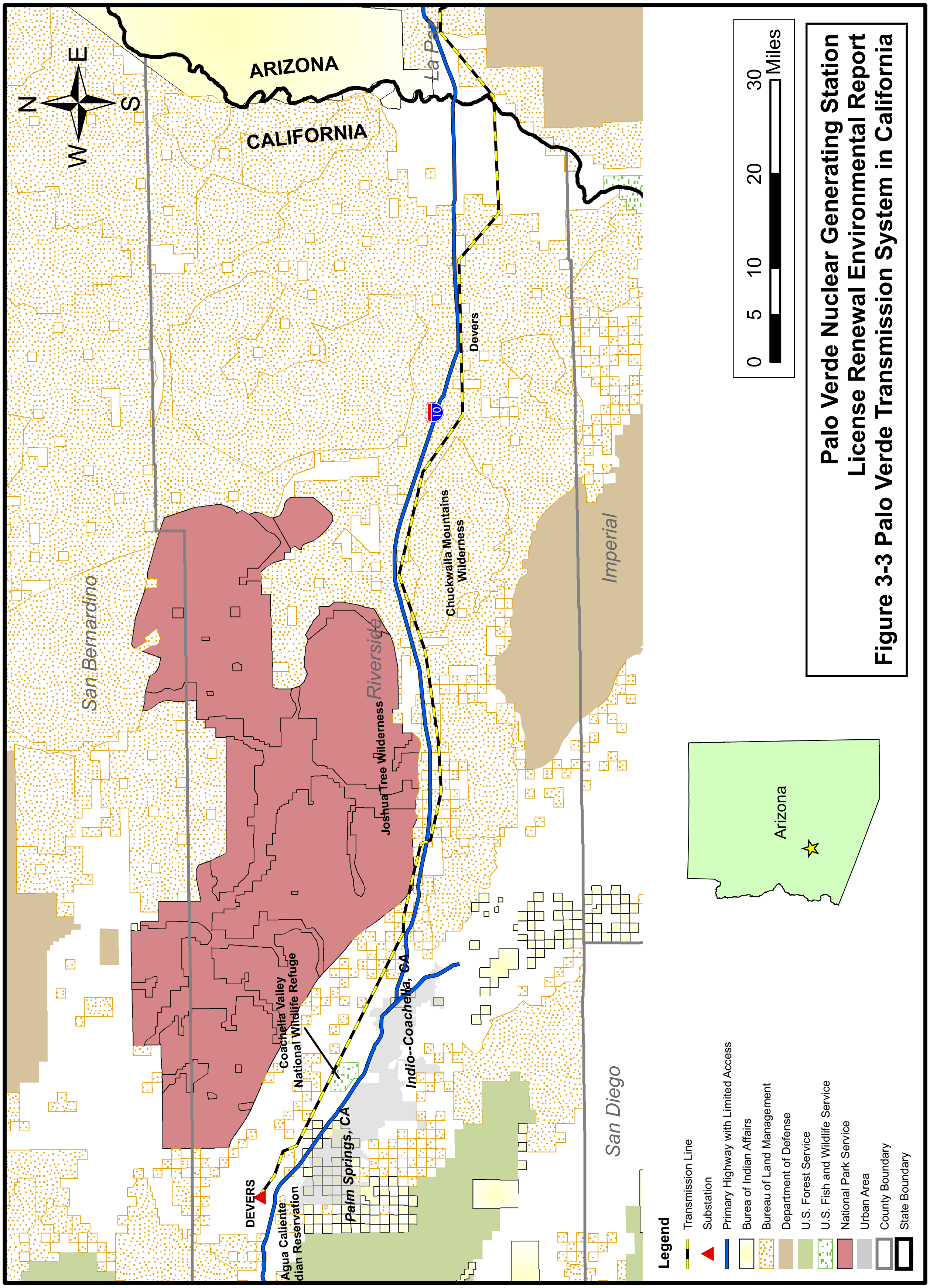
Sincerely,

Edward Fox

EZF:bgs
Enclosures: (1) Figure 2-1
(2) Figure **3-3**



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 2-1 50-Mile Radius



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-3 Palo Verde Transmission System in California

ATTACHMENT C

STATE HISTORIC PRESERVATION OFFICE CORRESPONDENCE

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APS
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Edward Z. Fox
Vice President
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e-mail Edward.Fox@aps.com

Mail Station 9085
PO Box 53999
Phoenix, Arizona 85072-3999

September 28,2007

Milford Wayne Donaldson, State Historic Preservation Officer
Office of Historic Preservation
California Department of Parks and Recreation
1416 9th Street, Room 1442-7
Sacramento, CA 95814

SUBJECT: Palo Verde Nuclear Generating Station (PVNGS)
Request for Information on Historic and Archaeological Resources

Dear Mr. Donaldson:

Arizona Public Service Company (APS) is initiating the steps required to be in a position to file an application with the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PVNGS Units 1,2 and 3. The current operating licenses expire on December 31,2024 for Unit 1; December 9,2025 for Unit 2; and March 25,2027 for Unit 3. The renewal terms would be for an additional 20 years beyond each original license expiration date. The NRC review schedule dictates limited windows of opportunity to submit an application for license renewal, and a submittal window of fourth quarter 2008 is available to APS. However, the decision on whether or not to actually file an application in 2008 would need to be formally agreed upon by the Palo Verde participants.

As part of the license renewal process, NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project." NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and under Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or provide any information your office may need to expedite the NRC consultation.

PVNGS is located in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area. Seven transmission lines connect the station to the regional grid, and are thus relevant to license renewal. However, only one of them traverses California (see attached Figure 3-3). The 235-mile PVNGS-Devers line runs westward from the plant to the Devers Substation north of Palm Springs, California. The corridor width is typically 200 feet.

Using the National Register Information System on-line database, we have compiled a list of sites on the National Register of Historic Places (NRHP) within Riverside County, which contains the Devers transmission line. As of April 18, 2007, there were 53 sites on the NRHP and six sites that were determined to be eligible for listing on the NRHP (DOI 2007).

APS does not expect PVNGS operations through the license renewal term to adversely affect cultural resources in the area, as APS has no plans to alter current operations for license renewal. No construction along the Devers transmission line is planned. Maintenance on the transmission line would continue as currently performed. No additional land-disturbance is anticipated in support of license renewal.

Please do not hesitate to call Henry Day at **(623) 393-6567** if you have any questions or require any additional information. After your review, we would appreciate receiving your input by January **31**, **2008,** detailing any concerns you may have about cultural resources in the area or confirming APS' conclusion that operation of PVNGS over the license renewal term would have no effect on cultural resources. This will enable us to meet our application preparation schedule. APS will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the PVNGS license renewal application.

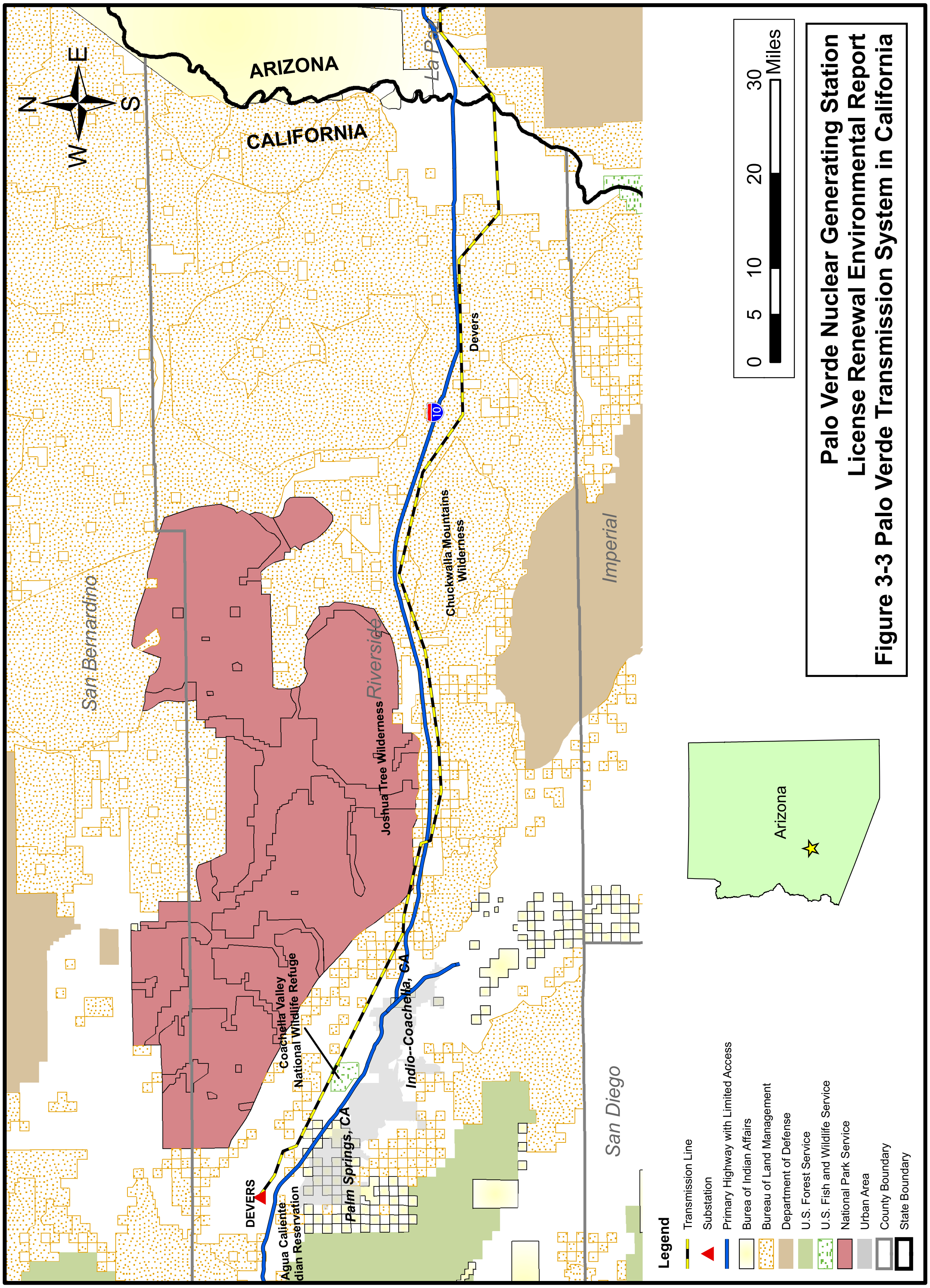
Sincerely,

Edward Fox

EZF:bgs
Enclosure: Figure **3-3**

Reference:

DOI (U.S. Department of the Interior) **2007.** National Register of Historic'Places. Available online at http://www.nr.nps.gov/. Accessed April **18, 2007.**



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-3 Palo Verde Transmission System in California

THE POWER TO MAKE IT HAPPEN℠

Edward Z. Fox
Vice President
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PO Box 53999
Phoenix, Arizona 85072-3999

September 28,2007

James Garrison, State Historic Preservation Officer
Arizona State Parks
State Historic Preservation Office
1300 West Washington
Phoenix, Arizona 85007

SUBJECT: Palo Verde Nuclear Generating Station (PVNGS)
Request for Information on Historic and Archaeological Resources

Dear Mr. Garrison:

Arizona Public Service Company (APS) is initiating the steps required to be in a position to file an application with the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for PVNGS Units 1, 2 and 3. The current operating licenses expire on December 31,2024 for Unit 1; December 9,2025 for Unit 2; and March 25,2027 for Unit 3. The renewal terms would be for an additional 20 years beyond each original license expiration date. The NRC review schedule dictates limited windows of opportunity to submit an application for license renewal, and a submittal window of fourth quarter 2008 is available to APS. However, the decision on whether or not to actually file an application in 2008 would need to be formally agreed upon by the Palo Verde participants.

As part of the license renewal process, NRC requires license applicants to "assess whether any historic or archaeological properties will be affected by the proposed project". The NRC may also request an informal consultation with your office at a later date under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and under Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or provide any information your office may need to expedite the NRC consultation.

PVNGS is located in Maricopa County, Arizona, approximately 26 miles west of the nearest boundary of the Phoenix metropolitan area, which is the nearest population center. The town of Buckeye (year 2000 population approximately 6,500) is approximately 16 miles to the east. The nearest town, which is the mailing address for the plant, is Wintersburg. The PVNGS site boundary encloses approximately 4,250 acres (see attached Figure 2-1).

Seven transmission lines connect the station to the regional grid, and are thus relevant to license renewal (see attached Figure 3-2). They include:

- Westwing #1 and #2 – These two 525-kilovolt lines extend east and north for 45 miles in a 330-foot wide corridor to the Westwing Substation northwest of Phoenix.

- Rudd – Starting in a common corridor with Westwing #1 and #2, this 525-kilovolt line runs for 37 miles to the Rudd Substation in Phoenix. After leaving the Westwing corridor, the Rudd corridor width is generally 200 feet.

- Kyrene – This line runs south to the Hassayampa substation for 3 miles, then turns to the southeast for 20 miles to the Jojoba Substation, and then runs another 52 miles to the Kyrene Generating Station south of Tempe, Arizona. The corridor width for this 525-kilovolt line varies from 75 to 200 feet, except that the 3-mile length it shares with Hassaymapa #2 (described below) is 330 feet wide.

- Hassayampa #2 – This 525-kilovolt line runs in the same corridor as Hassayampa #1 to the Hassayampa substation, a distance of 3 miles. The combined corridor width is approximately 330 feet.

- Hassayampa #3 – This 525-kilovolt line roughly parallels the Hassayampa #1 and #2 lines to the Hassaymapa substation, but in a separate corridor. The corridor width is 200 feet.

- Devers – This 235-mile line runs westward from the plant to the Devers Substation north of Palm Springs, California. The corridor width is typically 200 feet.

In total, there are approximately 390 miles and approximately 10,000 acres of transmission line corridor. The corridors pass through land that is primarily agricultural and desert. The areas are mostly remote, with low population densities. The lines cross numerous county, state and U.S. highways. Much of the land crossed is Federal property. Corridors that pass through farmlands generally continue to be used as farmland.

Using the National Register Information System (NRIS) on-line database, we have compiled a lsot of sites on the National Register of Historic Places (NRHP) within Maricopa County. As of 2006, the NRHP listed 317 locations in Maricopa County (DOI 2006). Of these 317 locations, one (the Hassayampa River Bridge) falls within 6 miles of PVNGS property. The Hassayampa River Bridge was added to the list in 1988 and is located on Old U.S. Highway 80, spanning the Hassayampa River. As of 2006, the NRHP listed 55 locations that have been determined eligible in Maricopa County for inclusion in the NRHP (DOI 2006). Of these 55 locations, none falls within 6 miles of PVNGS property.

APS does not expect PVNGS operations through the license renewal term to adversely affect cultural resources in the area, as APS has no plans to alter current operations for license renewal. No expansion of existing facilities is planned, and no structural modifications have been identified for the purpose of supporting license renewal. Maintenance on the transmission line would continue as currently performed. No additional land-disturbance is anticipated in support of license renewal.

Please do not hesitate to call Henry Day at (623) 393-6567 if you have any questions or require any additional information. After your review, we would appreciate your input by January 31, 2008 detailing any concerns you may have about cultural resources in the area or confirming APS's conclusion that operation of PVNGS over the license renewal term would have no effect on any threatened or endangered species. This will enable us to meet our application preparation schedule. APS will include a copy of this letter and your response in the Environmental Report that will be submitted to the NRC as part of the PVNGS license renewal application.

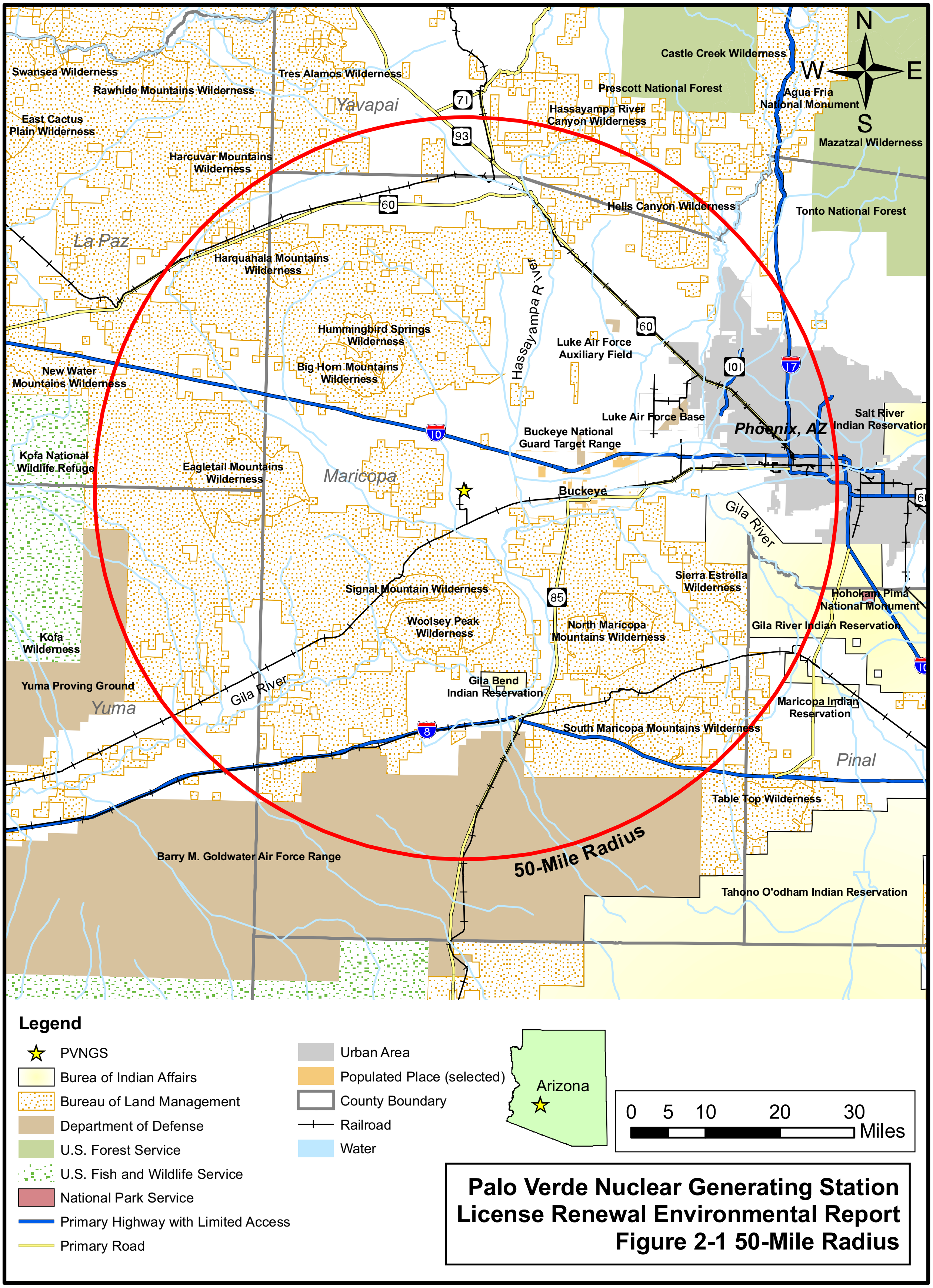
Sincerely,

Edward Fox

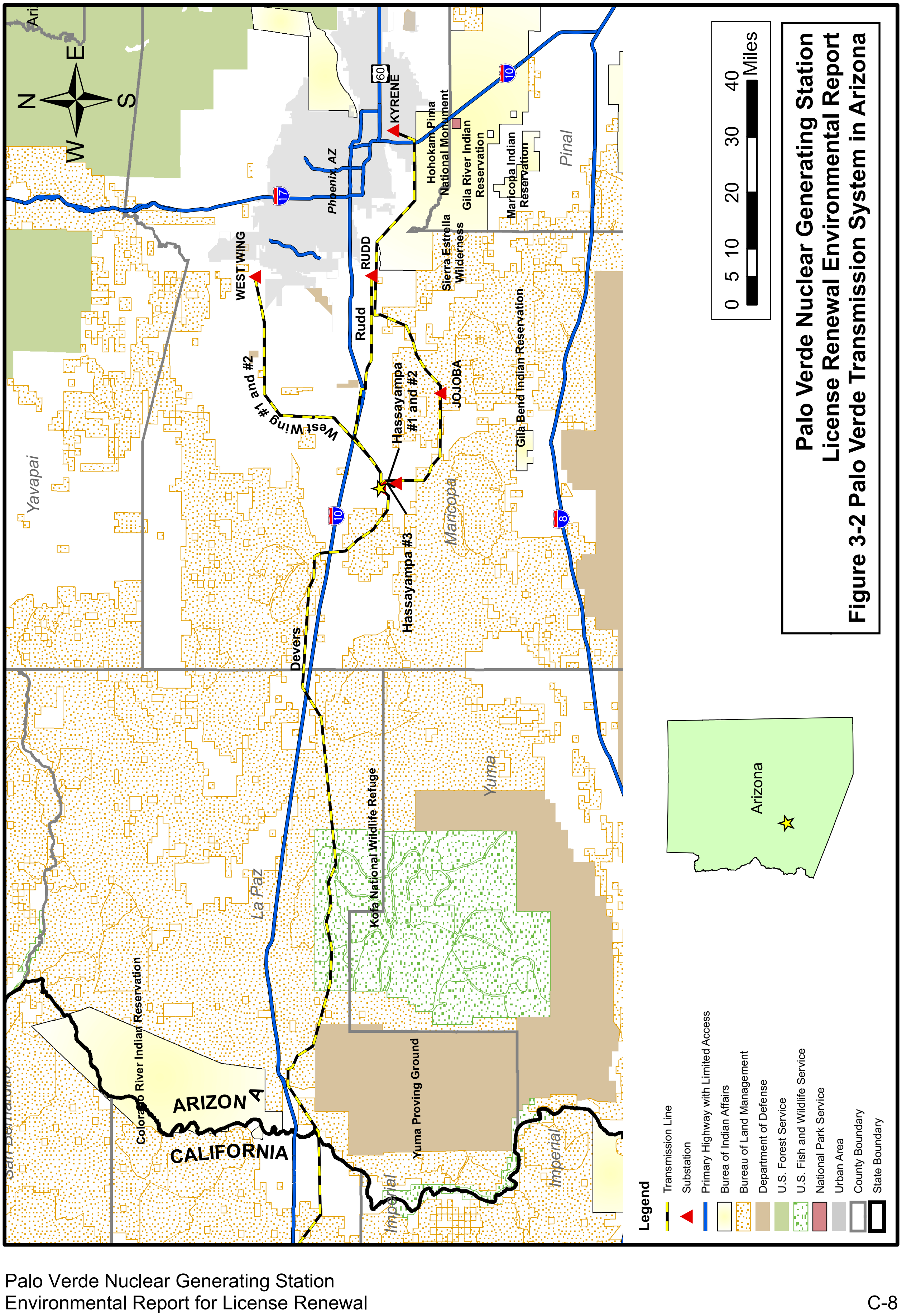
EZF:bgs
Enclosures: (1) Figure 2-1
(2) Figure 3-2

Reference:

DOI (U.S. Department of the Interior) 2006. National Register of Historic Places. Available online at httv://www.nr.nps.gov. Accessed 12/8/2006.



Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 2-1 50-Mile Radius


Palo Verde Nuclear Generating Station
License Renewal Environmental Report
Figure 3-2 Palo Verde Transmission System in Arizona
0 5 10 20 30 40 Miles
N
S
E
W
Legend
Transmission Line
Substation
Primary Highway with Limited Access
Bureau of Indian Affairs
Bureau of Land Management
Department of Defense
U.S. Forest Service
U.S. Fish and Wildlife Service
National Park Service
Urban Area
County Boundary
State Boundary
Arizona
ARIZONA
CALIFORNIA
WEST WING
RUDD
KYRENE
JOJOBA
Rudd
Devers
West Wing #1 and #2
Hassayampa #1 and #2
Hassayampa #3
Phoenix, AZ
Hohokam Pima National Monument
Gila River Indian Reservation
Maricopa Indian Reservation
Sierra Estrella Wilderness
Gila Bend Indian Reservation
Kofa National Wildlife Refuge
Yuma Proving Ground
Colorado River Indian Reservation
Yavapai
Maricopa
Pinal
Yuma
La Paz
Imperial
17
10
60
8

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ATTACHMENT D

SEVERE ACCIDENT MITIGATION ALTERNATIVES ANALYSIS

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Attachment D
Severe Accident Mitigation Alternatives

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Acronyms Used in Attachment D

AFW	auxiliary feedwater
APS	Arizona Public Service Company
ATWS	anticipated transient without scram
B&WOC	Babcock and Wilcox Owner’s Group
BWR	boiling water reactor
CCF	common cause failure
CCW	component cooling water
CDF	core damage frequency
CEOG	Combustion Engineering Owners Group
CM	core melt
Cs	cesium
CST	condensate storage tank
DC	direct current
DG	diesel generator
DHR	decay heat removal
DWS	demineralized water system
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
EPZ	emergency planning zone
ESF	engineered safeguard feature
ESFAS	engineered safety features activation system
EW	essential cooling water
F&O	facts and observations
FDS	fire damage states
FIVE	EPRI fire induced vulnerability evaluation
FP	fire protection
FZ	fire zone
GTG	gas turbine generators
HEP	human error probability
HPSI	high pressure safety injection
HRA	human reliability analysis
HVAC	heating ventilation and air-conditioning

Acronyms Used in Attachment D

INPO	Institute of Nuclear Power Operations
IA	instrument air
IPE	individual plant examination
IPEEE	individual plant examination – external events
ISFSI	independent spent fuel storage installation
ISLOCA	interfacing systems LOCA
LERF	large early release frequency
LOCA	loss-of-coolant accident
LOOP	loss of off-site power
MAAP	modular accident analysis program
MACCS	MELCOR accident consequences code system
MACCS2	MELCOR accident consequences code system, version 2
MACR	maximum averted cost-risk
MCR	main control room
MFW	main feedwater
MSIV	main steam isolation valve
MWt	megawatts thermal
NRC	U.S. Nuclear Regulatory Commission
OECR	off-site economic cost-risk
PORV	power operated relief valve
PDS	plant damage state
PRA	probabilistic risk assessment
PSA	probabilistic safety assessment
PVNGS	Palo Verde Nuclear Generating Station
PWR	pressurized water reactor
RCP	reactor coolant pump
RCS	reactor coolant system
RDR	real discount rate
RHR	residual heat removal
RLE	review level earthquake
RMWT	reactor makeup water tank
RRW	risk reduction worth
RSP	remote shutdown panel
SAMA	severe accident mitigation alternative

Acronyms Used in Attachment D

SBO	station blackout
SDC	shutdown cooling
SERF	small early release frequency
SG	steam generator
SGTR	steam generator tube rupture
SI	safety injection
SRO	senior reactor operator
SRP	standard review plan
TC	turbine cooling water
Te	tellurium
TD AFW	turbine driven auxiliary feedwater
TI SGTR	temperature-induced steam generator tube rupture
UFSAR	updated final safety analysis report
UHS	ultimate heat sink
VCC	vertical concrete cask
WOG	Westinghouse Owner’s Group

Attachment D
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in Section 4.20 of the Environmental Report is presented below.

D.1 METHODOLOGY

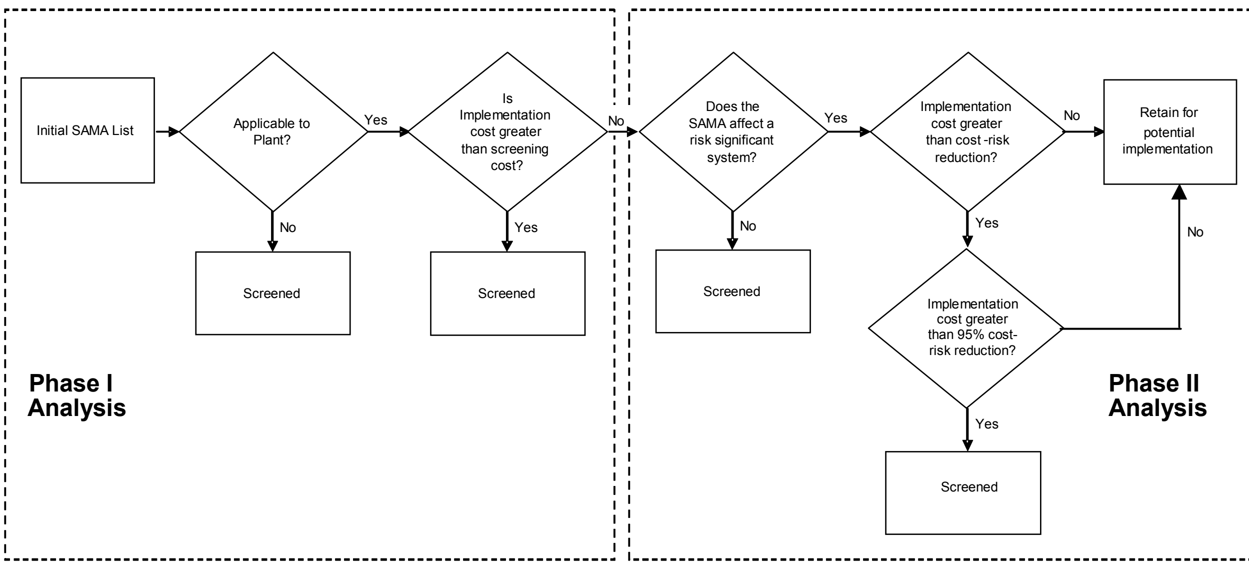
The methodology selected for this analysis, which is based on the NEI 05-01 guidance, involves identifying SAMA candidates that have the highest potential for reducing plant risk and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. The metrics chosen to represent plant risk include the core damage frequency (CDF), the dose-risk, and the off-site economic cost-risk (OECR). These values provide a measure of both the likelihood and consequences of a core damage event. The SAMA process consists of the following steps:

- Baseline Risk Monetization – Use U.S. Nuclear Regulatory Commission (NRC) regulatory analysis techniques to calculate the monetary value of the unmitigated PVNGS severe accident risk. This becomes the maximum averted cost-risk (MACR) that is possible (Section D.4). The following plant specific risk analyses are used to support this process:
    - The PVNGS Level 1 and 2 Probabilistic Risk Assessment (PRA) models (Section D.2) provide estimates of the risk related to core melt scenarios. These models evaluate the likelihood of a core melt and the performance of the containment structures after core melt has occurred. The external events contributions, which have historically been evaluated separately from the internal events contributors, are incorporated as described in Section D.6.
    - The Level 1 and 2 PRA output, site-specific meteorology, demographic, land use, and emergency response data are used as input in performing a Level 3 PRA using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section D.3). The results of the Level 3 PRA provide estimates of the consequences of core melt scenarios.
- Develop an initial plant specific SAMA list based on the PVNGS PRA, Individual Plant Examination (IPE), Individual Plant Examination – External Events (IPEEE), and documentation from the industry and NRC. This process is defined in more detail in Section D.5 and the resulting 23 candidate Phase I SAMA list is provided as Table D.5-3.
- Phase I SAMA Analysis – Screen out SAMA candidates that are not applicable to the PVNGS design or are of low benefit in pressurized water reactors (PWRs) such as PVNGS, candidates that have already been implemented at PVNGS or whose benefits have been achieved at PVNGS

using other means, and candidates whose estimated cost exceeds the possible MACR (Section D.5). The result of this process is the Phase II SAMA list, which is provided as Table D.5-4.

- Phase II SAMA Analysis – Calculate the monetary value of the risk reduction attributable to each remaining SAMA candidate and compare it to the SAMA's implementation cost to identify the net cost-benefit. PRA insights are also used to screen SAMA candidates in this phase (Section D.6).
- Uncertainty Analysis – Evaluate how changes in the SAMA analysis assumptions might affect the cost-benefit evaluation (Section D.7).
- Conclusions – Summarize results and identify conclusions (Section D.8).

The steps outlined above are described in more detail in the subsections of this attachment. The graphic below summarizes the high-level steps of the SAMA process.



D.2 PVNGS PRA MODEL

D.2.1 PALO VERDE PRA QUALITY OVERVIEW

- Formal qualification program for the PRA staff
- Use of procedures to control PRA processes
- Independent reviews (checks) of PRA documents
- Comprehensive PRA Configuration Control Program
  - Quarterly plant change monitoring program
  - Process to control PRA quantification software
  - Active open items list (Impact Review database)
  - Interface with the site's corrective action program
  - Process to maintain configuration of previous risk-informed decisions
- Peer reviews
- Participation in the Combustion Engineering Owner's Group (CEOG) cross comparison process
- Incorporation, where applicable, of CEOG PRA Technical Positions
- Commitment to continuous quality improvement

These elements are used to achieve a quality PRA and are described in the remainder of Section D.2.1. Section D.2.2 provides an overview of the development history of the PRA since the IPE submittal in April of 1992. Section D.2.3 describes the significant PRA open items. Section D.2.4 lists the CEOG Technical Positions and describes the PVNGS position on each of these documents. Section D.2.5 discusses the independent (external) reviews that have been performed on PRA. A summary of the significant issues and their status is provided. The remainder of Section D.2 summarizes the current PRA results.

D.2.1.1 QUALIFICATION OF PRA STAFF

Risk analysts are qualified in accordance with the PVNGS Engineering Training Program, which meets the Institute of Nuclear Power Operations (INPO) requirements for a Systematic Approach to Training and 10 CFR 50.120.

D.2.1.2 PRA PROCEDURES

The PRA model is controlled by procedure 70DP-0RA03, *PRA Model Control* (APS 2007b). The PRA model is documented by way of Engineering Studies, which are controlled by station procedure 81DP-4CC03, *Engineering Studies* (APS 2002b). PRA model documentation is maintained by the Nuclear Information Records Management Department in accordance with administrative controls meeting the requirements of NRC Reg. Guide 1.33, *Quality Assurance Program Requirements*.

D.2.1.3 INDEPENDENT REVIEWS

The Engineering Studies, which document the PRA, receive independent technical review, as required by station procedure 81DP-0CC05, Design and Technical Document Control (APS 2007c).

D.2.1.4 PRA CONFIGURATION CONTROL PROGRAM

The three Palo Verde units are nearly identical. Differences among the units are primarily due to the fact that plant modifications cannot be introduced simultaneously in all three units; typically they are introduced in succeeding outages. Any one of the units could be the lead unit. The model is intended to represent Unit 1. Unit One's drawings, calculations and procedures (where unitized) are the ones referenced within the model. The one exception to this is the static transfer switches for the Vital AC. Unit 1 was originally scheduled to receive this change, but did not; Units 2 and 3 did. Were the model to reflect Unit 1, the static transfer switch failure would be replaced by a human error probability of the same order of magnitude. Thus, there is no material impact resulting from this plant difference.

Referenced drawing changes are reviewed by PRA Department personnel. Differences in unit applicability can be ascertained in the review. The PVNGS PRA model Revision 15 was used to support the SAMA analysis. As of August 2008, there were no significant findings that required model changes. Review of procedure changes and drawing changes affected only the revision numbers quoted in the PRA model reference section.

Noteworthy connections between the 3 units are as follows:

1. In normal line-up, the three Startup-up Transformers each supply one source of off-site power to two units through separate secondary windings. Thus, loss of one Start-up Transformer would cause a single train of Engineered Safety Features (ESF) equipment on two units to lose off-site power. Although loss of off-site power to one ESF bus is not by itself an initiating event, it can be a precursor and is captured by initiating events IELOP-TRAIN-A and IELOP-TRAIN-B.
2. The units are also connected via the Auxiliary Steam System, which supplies process steam for water processing and turbine gland seals during start-up. The normal line-up of this system is one unit supplying auxiliary steam for all three units. This sharing is done primarily to keep the lines warm and the water within them in good condition. Malfunctions of the system are not significant enough perturbators to cause a trip or shutdown; nor is the system credited in the PRA for mitigating any transients or accidents. Procedures do exist, however, to transfer condensate from one unit to another, if needed.

3. Another common electrical connection is to the Station Blackout Gas Turbine Generators. It is not expected that more than one unit would ever be lined up to receive power concurrently from the gas turbine generators (GTGs), although procedures exist to provide limited power to two units (not modeled in the PRA). The likelihood of two units experiencing a simultaneous station blackout is remote.
4. The Tower Make-up and Blowdown system supplies condenser cooling water to all three units to make up for evaporation and blowdown. Its failure would lead to shutdown of all three units. It has redundant pumps powered from redundant power supplies, making it highly reliable. Should it ever fail, it would most likely be manifest as a normal shutdown for all three units. At worst, it could lead to loss of condenser vacuum and loss of Plant Cooling Water. The list of identified PVNGS initiators includes loss of condenser vacuum, loss of plant cooling water, and unplanned reactor trips (as IEMISC). The Tower Make-up and Blowdown system is not required for safe shutdown.

D.2.1.5 PRA OPEN ITEMS (IMPACTS)

To evaluate and track items that may lead to a change to the model or its documentation, an "impact review database" is maintained. Dispositions and change records are sent to Nuclear Information Records Management and maintained per the above-mentioned requirements.

D.2.1.6 MONITORING PLANT CHANGES

Documents used in the development of the PRA are periodically compared to the station document database to identify revisions to referenced documents.

Documents that have been revised are then reviewed to determine if there is any impact to the model. Changes are identified and evaluated using the impact database and process described above.

D.2.1.7 PRA UPDATES

Updates to the PRA model to incorporate changes required due to plant changes are typically made every 2 years.

D.2.1.8 SOFTWARE QUALITY CONTROL

Software, including Risk Spectrum™, MAAP, etc. is verified and controlled in accordance with the *PVNGS Non-process Software QA Program*. Electronic data and databases are controlled by the same guidance. The databases are stored in a controlled, limited access location. Copies for use are required to be verified against the controlled version.

D.2.1.9 PEER REVIEWS

The nuclear industry has adopted a PSA Peer Review Process originally developed by the Boiling Water Reactor Owners Group (BWROG). This original BWROG Process was provided to the other owners groups. In a cooperative undertaking, this process was modified by the Westinghouse Owner's Group (WOG), the Babcock and Wilcox Owner's Group (B&WOG), and the CEOG to be applicable to both BWRs and PWRs. The result is a common, consistent PRA peer review process that is applicable to any commercial nuclear power plant in the U.S. At the same time, it is flexible enough to incorporate individual owners' group programs to enhance the technical quality and adequacy of the plant PRAs.
Combustion Engineering Owners Group performed a review of the Palo Verde PRA as part of the industry-wide PRA quality initiative in November 1999.

D.2.1.10 CEOG CROSS-COMPARISON PROCESS

In 1995, the CEOG PSA Working Group funded the first in a series of five cross-comparison review tasks to identify similarities and differences among CEOG member PRAs and, where the results are perceived to be different, to investigate the potential causes for differences. In general, differences in PRA results were attributed to one of the following:

a) Plant specific design or operational differences.
b) Data selection.
c) Selection of success criteria.
d) PRA modeling assumptions and modeling philosophy.

The primary interest of this effort was to highlight areas where additional attention may be desirable as the PRA evolves. Besides the knowledge and insights gained through participation in this activity, the primary product was the identification of areas where additional guidance is required.

Since that time, the PWR Owners Group has expanded the original Westinghouse database to provide model information on all PWRs to facilitate members' ability to query other facilities' results and modeling methods.

D.2.1.11 CEOG PSA TECHNICAL POSITIONS

CEOG PSA Technical Positions (Standards) and Guidelines were developed to either address a specific application need or were an outgrowth of the results of quality-related tasks, such as the CEOG plant cross-comparison, CEOG risk-informed joint applications, and resolution of PRA issues raised by individual member utilities. Section D.2.4 lists the CEOG Technical Positions and describes the Palo Verde position on each of these documents. The PWR Owners Group is continually addressing model quality issues.

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. 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, 10CFR50.46. 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

quarterly for the relays associated with Auxiliary Feedwater injection valves. This reduced CDF and LERF by about 10%.

- Credited an additional check valve in the charging line to remove conservatism in the containment penetration model. This change significantly reduced LERF.
- Removed Loss of Control Room Heating, Ventilation, and Air Conditioning (HVAC) as an initiating event. This event had been modeled in a highly conservative and unrealistic manner. Since the Control Room is continuously manned, and since at least twelve hours are available before equipment failure temperatures would be reached, it would be virtually certain that either equipment could be repaired or temporary cooling could be established.
- Updated Initiating Event Frequencies in 2001 resulting in significant decreases to Uncomplicated Reactor Trip and Turbine Trip frequencies. The definition of Uncomplicated Reactor Trip (called Miscellaneous Trip in the model) was narrowed to be consistent with the rest of the industry. Previously, all manual shutdowns, including for planned outages, were counted as initiators. This in turn resulted in much lower CDF and LERF, and significantly affected importance measures.
- Addition of the alternate off-site power supply to each ESF bus. This plant feature had not been procedurally allowed due to Technical Specification interpretation.
- Physical plant change adding a redundant power supply to the balance of plant (BOP) ESFAS cabinet cooling fans. This change makes spurious load shed actuation much less likely.
- Added alignment of the Gas Turbine Generators to the initiating event trees for loss of off-site power to Train A or B ESF Bus. This provides a more realistic treatment of these initiators.
- Changed the treatment of the Loss of Instrument Air initiating event to allow use of low-pressure condensate (Alternate Feedwater) in its mitigation. This was possible due to removal of an incorrect dependence of the Condensate system on Instrument Air.
- Corrected modeling of spurious load shed. Certain failures had been incorrectly modeled as preventing closure of the Emergency Diesel Generator output breaker.
- Adopted “Alpha factor” common-cause methodology and used NRC Common-Cause database to update common-cause failure probabilities in 2006.
- Updated failure data in 2006.

- Revision 15 (the most recent), made the following changes: 1) Upon a steam generator tube rupture (SGTR) event, credited the feed to either steam generator until the affected SG is identified. 2) Credited the removal of ESF pump room dependency on HVAC. 3) Credited the continued flow of Main Feedwater for up to 7 hours after reactor trip. Those credits lowered the LERF and CDF values. The dominant LERF contributor remained the SGTR events.
- Westinghouse guideline (WCAP 16341-P (WEST 2005)) developed an approach to bin all level 1 core damage sequences in several plant damage states (PDS). The plant damage states are classified in terms of: station blackout (SBO), non-SBO, Containment bypasss, reactor coolant system (RCS) at High pressure during vessel breach, and RCS at low pressure during vessel breach. Each of the 155 level 1 sequences was binned into the appropriate PDS.
- Similarly, Westinghouse guideline (WCAP 16341-P) developed a containment event tree structure used in developing the level 2 fault tree structures for SBO and non-SBO cases. Each plant damage state sequence through the containment event tree results in a unique endstate: LERF, small early release (SERF), or LATE release.

Internal Events CDF and LERF have varied significantly as the above changes were implemented. Compared to the IPE, CDF has decreased significantly. Similarly, LERF cannot be compared to the overall Level 2 value presented in the IPE, but compared to when it was first determined in 1998, it has decreased significantly. The LERF results are dominated by Steam Generator Tube Rupture events. When internal events and fire are quantified to the same truncation level, fire contributes about 35% to total CDF and 30% to total LERF.

D.2.4 COMBUSTION ENGINEERING OWNERS GROUP TECHNICAL POSITIONS

D.2.4.1 CEOG PSA STANDARD: EVALUATION OF THE INITIATING EVENT FREQUENCY FOR THE LOSS OF COOLANT ACCIDENT

This CEOG PSA Standard is no longer used; LOCA frequencies are based on NUREG/CR-5750 (NRC 1998b). The NUREG values were used in lieu of the CEOG standard because the NUREG is a more recent document and more publicly available.

D.2.4.2 CEOG PSA STANDARD: EVALUATION OF THE INITIATING EVENT FREQUENCY FOR MAIN STEAM LINE BREAK EVENTS

The CEOG standard is used as the basis for developing large steam and feedwater line break IE frequencies.

D.2.4.3 CEOG PSA STANDARD: EVALUATION OF THE INITIATING EVENT FREQUENCY FOR STEAM GENERATOR TUBE RUPTURE

The CEOG standard is used as the basis for calculating the PVNGS SGTR frequency.

D.2.4.4 CEOG PSA STANDARD: SUCCESS CRITERIA FOR THE MINIMUM NUMBER OF SAFETY INJECTION (SI) PATHWAYS FOLLOWING LARGE AND SMALL BREAK LOCAS FOR COMBUSION ENGINEERING PWRS

The CEOG standard is used.

D.2.4.5 CEOG PSA STANDARD: BEST ESTIMATE ATWS SCENARIOS AND SUCCESS CRITERIA

The CEOG standard is used.

D.2.4.6 CEOG PSA STANDARD: EVALUATION OF THE MECHANICAL SCRAM FAILURE FOR ATWS OCCURRENCE FREQUENCY

The CEOG standard is used.

D.2.4.7 CEOG PSA STANDARD: REACTOR COOLANT PUMP (RCP) SEAL FAILURE PROBABILITY GIVEN A LOSS OF SEAL INJECTION

The CEOG standard was used in the development of reactor coolant pump (RCP) seal failure probability. Modeling showed that RCP seal failure is not a significant contributor to CDF or LERF under any circumstances. It was subsequently removed from the model

D.2.4.8 CEOG PSA STANDARD: EVALUATION OF THE INITIATING EVENT FREQUENCY FOR REACTOR VESSEL RUPTURE

Reactor vessel rupture is not explicitly modeled in the PVNGS PRA. Its frequency is less that 1E-7 per year allowing it to be screened. It is not possible to mitigate the event, so modeling it provides no insight. Palo Verde's reactor vessel is less susceptible to brittle fracture due to a lower than typical copper content in the steel alloy used for the vessel.

D.2.5 INDEPENDENT EXTERNAL REVIEWS

- Combustion Engineering Owners Group performed a review of the overall PRA modeling as part of the industry-wide PRA quality initiative in November 1999. All F&Os are addressed in PRA's Impact Database, as well as by the station's Corrective Action Program (CRDR 113787).
- Erin Engineering performed a review of Large Early Release Frequency methodology and results in December 2000.
- In early 2001 Erin Engineering reviewed all Category A and B Facts and Observations (F&Os) from the CEOG peer review. The results are as follows:
    - Category A – 8 F&Os. 4 were closed and the responses deemed satisfactory. The remaining 4 were later closed.
    - Category B – 26 F&Os. The one remaining open item is lack of flooding analysis. This is addressed in Section D.5.1.6.7 for the SAMA analysis.

D.2.6 INTERNAL EVENTS CDF RESULTS

Figure D.2-1 provides a graphic display of the CDF contributors by initiator for the PVNGS Rev 15 PRA model (CDF = 5.07E-06/yr).

Table D.2-1 provides a list of the top 40 events by Fussell-Vesely ranking (based on CDF).

D.2.7 PRA LEVEL 2 SUMMARY

The quantification results show that the total frequency for all Level 2 endstates is 5.24-06/yr, which is slightly larger than the Level 1 CDF. The small increase in the

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.

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 the SECPOP2000 code and, therefore, the problems recently identified with that portion of the code have no impact on this analysis.

In addition, generic economic data that apply to the region as a whole were revised from the MACCS2 sample problem input in order to account for cost escalation since 1986, the year that input was first specified. A factor of 1.86 (USDL 2007), representing cost escalation from 1986 to March 2007, was applied to parameters describing cost of evacuating and relocating people, land decontamination, and property condemnation. Region-wide wealth data (i.e., farm wealth and non-farm wealth) was calculated for the 50 miles surrounding the site. Farm wealth was determined from the 2002 National Census of Agriculture county data describing the value of farm lands, buildings and machinery (USDA 2004); the portion of each county within 50 miles of the site was considered. Non-farm wealth was derived from 2002 property tax valuations (Arizona 2003, GPEC 2005). Both of the region-wide wealth descriptors were escalated to March 2007. Those escalated values are $1,320.97 per hectare (farm wealth) and $70,099.67 per person (non-farm wealth).

D.3.3 NUCLIDE RELEASE

The core inventory is that used in Chapter 15 of the Updated Final Safety Analysis Report (UFSAR) (APS 2005). All core nuclides included there but not included in the extensive (825 nuclide) MACCS2 decay data base have half-lives less than 4 minutes and were not modeled. Table D.3-1 gives the estimated PVNGS core inventory at a core thermal power of 3990 megawatts thermal (MWt) (APS 2007a) as used in the present analysis.

Release frequencies, nuclide release fractions (of the core inventory), shown in Table D.3-2, and the time distribution of the release (described in the table for noble gases and cesium [Cs]) were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from 11 accident sequences (also given in Table D.3-2). Each accident frequency was chosen to represent the set of similar accidents. PVNGS nuclide source term categories, as determined by the MAAP computer code, were related to the MACCS categories as shown in Table D.3-3. Multiple release duration periods were defined which represented the time distribution of each category's releases. Release inventories of each of the multiple chemical forms of the Cs and tellurium (Te) releases, as given by the MAAP code output, were incorporated into the nuclide release fractions.

The containment building dimensions, 47 meters in diameter and 64 meters high (APS 2007a), were used to specify building wake parameters. Releases were modeled as occurring at ground level except that sequence LERF-SGTR, a steam generator tube rupture event, release was modeled from the top of the 42-meter-wide, 17-meter-high auxiliary building (APS 2007a). The thermal content of each of the releases was assumed to be the same as ambient thermal content, i.e., buoyant plume rise was not modeled. Each of these assumptions was considered in sensitivity analyses, presented in Section D.7.2.

D.3.4 EVACUATION

Reactor trip for each sequence was taken as time zero relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public; it was assumed here that the declaration would coincide with the onset of core damage. Table D.3-4 shows the resulting declaration times.

The MACCS2 User's Guide input parameters of 95% of the population within 10 miles of the plant (the Emergency Planning Zone, [EPZ]) evacuating and 5% not evacuating were employed. These values are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5% of the population within the EPZ (NRC 1989). The evacuees are assumed to begin evacuation 75 minutes after a general emergency has been declared (Maricopa 2005) at a base evacuation radial speed of 3.40 m/sec (7.6 mph). This base speed is derived from the time to evacuate the entire EPZ for 2005, the year of the evacuation study (Maricopa 2005). The base evacuation speed was projected to year 2040 conditions by conservatively assuming that all of the roads in 2005 transported traffic at their maximum throughput and that no new roads would be constructed (although the roads would be maintained at 2005 conditions). The 2040 evacuation speed was then the 2005 speed multiplied by the ratio of 2005 EPZ population (Maricopa 2005) to 2040 EPZ population. That estimated 2040 evacuation speed, 2.93 m/sec (6.6 mph), was used in the risk analysis. The evacuation speed was considered further in the sensitivity analyses presented in the last subheading in this section.

D.3.5 METEOROLOGY

Annual, sequential, hourly, meteorology on-site data sets from 2003 through 2005 were investigated for use in MACCS2. Of the hourly data points of interest, 0.03% of 10-meter wind speed, 0.02% of 10-meter wind direction, and 0.006% of multi-level temperatures used to simulate stability class and precipitation were missing for 2003-2005. Data gaps were filled in by (in order of preference): using corresponding data from another level (taking the relationship between the levels as determined from immediately preceding hours), interpolation (if the data gap was less than 4 hours), or using data from the same hour and a nearby day of a previous year.

The 2003 data set was found to result in the maximum economic cost and dose risks (see subsequent discussion of sensitivity analysis in Section D.7.2). The 2003 hourly sequential meteorology was used to create the one-year sequential hourly data set used in the baseline MACCS2 runs. Data for 10-meter wind speed and direction were combined with precipitation and atmospheric stability data (specified according to the vertical temperature gradient as measured between the 60- and 10-meter levels) to create the hourly data. Hourly stability was classified according to the scheme used by the NRC (NRC 1983).

Atmospheric mixing heights were specified for AM and PM hours for each season of the year. These values ranged from 250-300 meters throughout the year for AM hours to 3000 meters for Summer PM (EPA 1972).

D.3.6 MACCS2 RESULTS

The resulting annual risk from the analyzed PVNGS releases is provided in Table D.3-5.

Almost one-half of the total baseline dose risk and two-thirds of the cost risk is from the LATE-CHR-NOAFW release category. Most of that category's risk is a result of its cesium release.

The largest consequences (i.e., assuming the event takes place) are from the LERF-ISO (dose) and LERF-BYPASS (cost) categories. All of the noble gases and a significant fraction (almost all for the latter sequence) of the iodine and cesium are released shortly after a general emergency is declared for these categories. As such, they represent close to bounding accident scenarios. Any scenario (e.g., beyond design basis external event initiators) not encompassed by the categories analyzed here would be expected to have dose and cost impacts not significantly greater than these. Although the risk from these categories is ameliorated by their small frequency of occurrence, beyond design basis external events will likely have similar frequencies. The annual baseline population dose risk within 50 miles of PVNGS is calculated to be 13.62 person-rem. The total annual economic risk was calculated to be $14,929.

D.4 BASELINE RISK MONETIZATION

This section explains how PVNGS calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). PVNGS also used this analysis to establish the maximum benefit that could be achieved if all risk for reactor operation were eliminated.

D.4.1 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using NRC's conversion factor of $2,000 per person-rem, and discounted to present value using NRC standard formula (NRC 1997):

$$W_{pha} = C \times Z_{pha}$$

Where:

W_{pha}	=	monetary value of public health risk after discounting
C	=	$[1-\exp(-rt_f)]/r$
t_f	=	years remaining until end of facility life = 20 years
r	=	real discount rate (RDR) (as fraction) = 0.03 per year
Z_{pha}	=	monetary value of public health (accident) risk per year before discounting ($ per year)

The Level 3 analysis showed an annual off-site population dose risk of 13.62 person-rem, as documented in Table D.3-5. The calculated value for C using 20 years and a 3% discount rate is 15.0396. Therefore, calculating the discounted monetary equivalent of accident dose-risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (15.0396). The calculated off-site exposure cost is estimated to be $409,679 (13.62 * 15.0396 * $2000 = $409,679).

D.4.2 OFF-SITE ECONOMIC COST RISK

The Level 3 analysis showed an annual Off-site Economic Cost Risk (OECR) of $14,929, as documented in Table D.3-5. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $224,526 (15.0396 * $14,929 = $224,526).

D.4.3 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using NRC methodology that involves separately evaluating immediate and long-term doses (NRC 1997).
For immediate dose, NRC recommends using the following equation:
Equation 1:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

Where:

W_{IO}	=	monetary value of accident risk avoided due to immediate doses, after discounting

R	=	monetary equivalent of unit dose ($2,000 per person-rem)
F	=	accident frequency (5.07E-06 events per year)
D_{IO}	=	immediate occupational dose [3,300 person-rem per accident (NRC estimate)]
$_S$	=	subscript denoting status quo (current conditions)
$_A$	=	subscript denoting after implementation of proposed action
r	=	RDR (0.03 per year)
t_f	=	years remaining until end of facility life (20 years).

Assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\,\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000*5.07\text{E-}06*3{,}300*\{[1 - \exp(-0.03*20)]/0.03\}$$

$$= \$503$$

For long-term dose, NRC recommends using the following equation:
Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\,\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

W_{LTO}	=	monetary value of accident risk avoided long-term doses, after discounting, ($)
D_{LTO}	=	long-term dose [20,000 person-rem per accident (NRC estimate)]
m	=	years over which long-term doses accrue (as long as 10 years)

Using values defined for immediate dose and assuming F_A is zero, the best estimate of the long-term dose is:

$$W_{LTO} = R\,(FD_{LTO})_S\,\{[1 - \exp(-rt_f)]/r\}\,\{[1 - \exp(-rm)]/rm\}$$

$$= 2{,}000*5.07\text{E-}06*20{,}000*\{[1 - \exp(-0.03*20)]/0.03\}\,\{[1 - \exp(-0.03*10)]/0.03*10\}$$

$$= \$2{,}635$$

The total occupational exposure is then calculated by combining Equations 1 and 2 above. The total accident related on-site (occupational) exposure risk (W_O) is:

$$W_O = W_{IO} + W_{LTO} = (\$503 + \$2{,}635) = \$3{,}138$$

D.4.4 ON-SITE CLEANUP AND DECONTAMINATION COST

The total undiscounted cost of a single event in constant year dollars (C_{CD}) that NRC provides for cleanup and decontamination is $1.5 billion (NRC 1997). The net present value of a single event is calculated as follows. NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$PV_{CD} = [C_{CD}/mr][1-\exp(-rm)]$$

Where:

PV_{CD} = net present value of a single event
C_{CD} = total undiscounted cost for a single accident in constant dollar years
r = RDR (0.03)
m = years required to return site to a pre-accident state

The resulting net present value of a single event is $1.3E+09. The NRC uses the following equation to integrate the net present value over the average number of remaining service years:

$$U_{CD} = [PV_{CD}/r][1-\exp(-rt_f)]$$

Where:

PV_{CD} = net present value of a single event ($1.3E+09)

r = RDR (0.03)

t_f = 20 years (license renewal period)

The resulting net present value of cleanup integrated over the license renewal term, $1.95E+10, must be multiplied by the total CDF (5.07E-06) to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is $98,814.

D.4.5 REPLACEMENT POWER COST

Long-term replacement power costs were determined following NRC methodology in NUREG/BR-0184 (NRC 1997). The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^8/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, ($)

r = RDR (0.03)

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP}/r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for PVNGS size relative to the generic reactor described in NUREG/BR-0184 (i.e., 1338 megawatt electric/910 megawatt electric) the replacement power costs are determined to be 8.12E+09 ($-year). Multiplying this value by the CDF (5.07E-06) results in a replacement power cost of $41,190.

D.4.6 MAXIMUM AVERTED COST-RISK

The PVNGS MACR is the total averted cost-risk if all internal and external events risk associated with on-line operation were eliminated. This is calculated by summing the following components for all units:

- Maximum Internal Events Averted Cost-Risk
- Maximum External Events Averted Cost-Risk

As described in Section D.5.1, the MACR is used in the SAMA identification process to determine the depth of the importance list review. In addition, the MACR is used in the Phase I analysis as a means of screening SAMAs.
The following subsections provide a description of how each of these components are calculated and used together to obtain the PVNGS MACR.

D.4.6.1 INTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum internal events averted cost-risk is the sum of the contributors calculated in Sections D.4.1 through D.4.5:

Maximum Averted Internal Events Cost-Risk

Off-site exposure cost	=	$409,679
Off-site economic cost	=	$224,526
On-site exposure cost	=	$3,138
On-site cleanup cost	=	$98,814
Replacement Power cost	=	$41,190
Total cost	=	$777,347

This total represents the monetary equivalent of the risk that could be eliminated if all on-line internal events based events could be eliminated for a single PVNGS unit. The internal events MACR is rounded to next highest thousand ($778,000) for SAMA calculations. It should be noted that the Phase II cost benefit calculations account for the difference between the rounded MACR and the actual MACR by adding the difference to the averted cost-risk calculated for each SAMA.

D.4.6.2 EXTERNAL EVENTS MAXIMUM AVERTED COST-RISK

The maximum averted cost-risk for external events must be quantified for the cost benefit calculations; however, this cost-risk must be estimated based on information in the IPEEE given that complete, current, quantifiable external events models are not available. As described in Sections D.5.1.5 and D.5.1.6, these models have not been updated to reflect recent plant changes or current PRA techniques. Therefore, the absolute CDF values that are included in the IPEEE are not considered to be directly comparable to the results of the internal events PRA model. As a result, an alternate method of accounting for the external events contributions must be established.

The method chosen to account for external events contributions in the SAMA analysis is to use a multiplier on the internal events results. In previous SAMA analyses, it has been assumed that the risk posed by external events and internal events is approximately equal. This assumption is not unreasonable unless available analyses indicate that there are external events contributors that present a disproportionate risk to the site. Based on a review of the PVNGS external events results, no such contributors have been identified.
The contributions of the external events initiators are summarized in the following table:

IPEEE Contributor Summary

External Event Initiator Group	CDF
Seismic	Not Applicable (seismic margins analysis performed)
Internal Fire (current model)	2.72E-06 per yr
High Winds	4.10E-10/yr (quantitative screening information used to develop a CDF for SAMA; refer to section D.5.1.6.3.)
External Floods	Not Applicable (progressive screening method used)
Accidental Aircraft	< 3.00E-08 per yr Impact (refer to section D.5.1.6.5)
Others	Not Applicable (progressive screening method used)
Total (for initiators with CDF available)	2.75E-06 per yr

The lack of detailed quantitative analyses makes it difficult to establish a meaningful CDF for many of these initiator groups; however, some assumptions can be made about the non-quantified initiator groups that could be used to further develop a total external events CDF.

The PVNGS IPEEE methodology implies that if the plant licensing bases are met, the plant and facilities design meets the 1975 Standard Review Plan (SRP) criteria, and the site walkdown does not reveal any potential vulnerabilities not already considered in the design basis analysis, then the CDF posed by an initiator is less than the 1.0E-06 per yr screening criterion. As described in Section D.5.1.6, these conditions are met for PVNGS and no contributions of greater than 1.0E-06 per yr are expected for any of the non-fire external events. Given that, a CDF of 1.0E-06 per yr could be assumed for each of the contributors for which no quantitative basis exists to obtain a more complete estimate of the external events CDF. If this is done, the external events contributions could be summarized as follows:

Modified IPEEE Contributor Summary

External Event Initiator Group	CDF Per year
Seismic	1.0E-06
Internal Fire (current model)	2.72E-06
High Winds	4.1E-10
External Floods	1.0E-06
Transportation and Nearby Facility Accidents (including accidental aircraft impact)	1.0E-06
Others	1.0E-06
Total	6.72E-06

Even when the screening threshold of 1.0E-06 is used for the non-quantified external event initiator groups, the total is 6.72E-06 per yr, which is comparable to the current internal events CDF of 5.07E-06 per yr. No conditions exist that would indicate an external events multiplier of greater than two should be used.
While it is possible to assume larger external events multipliers to compensate for the uncertainty associated with undeveloped external events models, overemphasizing external events contributions can be detrimental to the SAMA process in that:

- Over predicting the averted cost-risk of internal events based SAMAs through the use of an inflated multiplier could divert site resources to issues that are not important to the plant.
- Over predicting the averted cost-risk of an external events based SAMA could change the prioritization of addressing cost effective SAMAs away from important issues identified by the internal events model to highly uncertain issues identified by the external events analyses.
- Use of a larger multiplier impacts the MACR, which forces the identification of internal events based SAMAs that are not important to plant risk (refer to Sections D.5.1.1 and D.5.1.2) and consequentially reduces the credibility of the analysis.

For these reasons, a multiplier of two has been chosen to account for the PVNGS external events contributions. This implies that the contribution to the MACR from the external events is the same as the contribution from the internal events model ($778,000).

D.4.6.3 PVNGS MAXIMUM AVERTED COST-RISK

As stated in Section D.4.6, the MACR is the total of these two components:

Internal Events	=	$778,000
External Events	=	$778,000
Single Unit Maximum Averted Cost-Risk	=	$1,556,000

Finally, the single unit MACR is multiplied by three to obtain the site MACR of $4,668,000 ($1,556,000*3=$4,668,000). The MACR and implementation costs are considered on a site scale for consistency and to clearly account for any "economy of scale" that may exist in the implementation costs.

D.5 PHASE I SAMA ANALYSIS

The Phase I SAMA analysis, as discussed in Section D.1, includes the development of the initial SAMA list and a coarse screening process. This screening process eliminates those candidates that are not applicable to the plant's design, have already been implemented at APS, would achieve results that APS has already achieved by other means, or are too expensive to be cost beneficial even if the risk of on-line operations were completely eliminated. The following subsections provide additional details of the Phase I process.

D.5.1 SAMA IDENTIFICATION

The initial list of SAMA candidates for PVNGS was developed from a combination of resources including:

PVNGS PRA results
Industry Phase II SAMAs
PVNGS IPE (APS 1992)
PVNGS IPEEE (APS 1995)

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for PVNGS.
In addition to the "Industry Phase II SAMA" review identified above, an industry based SAMA list was used in a different way to aid in the development of the PVNGS plant-specific SAMA list. While the industry SAMA review cited above was used to identify SAMAs that might have been overlooked in the development of the PVNGS SAMA list due to PRA modeling issues, a generic SAMA list was used as an idea source to identify the types of changes that could be used to address the areas of concern identified through the PVNGS importance list review. For example, if long term direct current (DC) power availability was determined to be an important issue for PVNGS, the industry list would be reviewed to determine if a plant enhancement had already been conceived that would address PVNGS's needs. If an appropriate SAMA was found to exist, it would be used in the PVNGS list to address the DC power issue; otherwise, a new SAMA would be developed that would meet the site's needs. This generic list was compiled as part of the development of several industry SAMA analyses and is available in NEI 05-01 (NEI 2005).

D.5.1.1 LEVEL 1 PVNGS IMPORTANCE LIST REVIEW

The importance list review was performed to identify the failure scenarios most important to PVNGS risk and to develop methods to mitigate those scenarios. For each event on the importance list, the reasons for the event's importance are determined through cutest and systems analysis. Strategies to mitigate the relevant failures are developed based on accident sequence analysis, plant knowledge, and industry insights.

The importance list itself is developed from the PVNGS PRA cutest file and is comprised of the model's basic events sorted according to their risk reduction worth (RRW) values. The top events in this list are those events that would provide the greatest reduction in the CDF if the failure probability were set to zero. The events were reviewed down to the 1.010 level, which was chosen because it corresponds to the definition of a risk significant event, as defined in the PRA Applications Guide. (EPRI 1995)

An alternate method of establishing the lower review threshold would be to correlate the minimum expected SAMA implementation cost to an RRW value. For PVNGS, the minimum expected cost of implementation is believed to be a procedure change. The cost of procedure changes can vary depending on the type of procedure being modified and the scope of the changes, but previous industry analyses have estimated $50,000 to $100,000 for minor procedure modifications (CPL 2004). This estimate was provided for changes to system level, abnormal operating procedures at a dual unit site. While there may be a minimal cost associated with expanding the actual procedure changes to a third unit, the upper bound of this cost range ($100,000) is used for PVNGS to account for the additional training resources that would be required for implementation at a third unit. It should be noted that the scope of the procedure based improvements identified as SAMAs for PVNGS is greater than the scope corresponding to the types of changes used to establish the minimum expected cost of implementation. This is the reason that the PVNGS implementation costs for the procedure based SAMAs are larger than the estimates cited above.

For PVNGS, the RRW value corresponding to $100,000 is slightly over 1.02. This can be demonstrated by reducing the CDF, dose-risk and OECR by a factor of 1.02, which corresponds to an event with Level 1- and Level 2-based RRW values of 1.02. The corresponding internal events based averted cost-risk would be $15,242. Applying a factor of 2 to estimate the potential impact of external events (refer to Section D.4.6) results in a cost-risk of $30,484 and multiplying this product by 3 to account for 3 units results in a cost-risk of $91,452. This is approximately equal to the assumed minimum expected cost of implementation of $100,000. While the RRW value of 1.02 is not exactly equal to the 1.010 established by the PSA Applications Guide definition of risk significance, the RRW threshold values are consistent and the use of 1.010 is considered to be conservative for this analysis.

Table D.5-1 documents the disposition of each event in the Level 1 PVNGS RRW list with RRW values of 1.010 or greater. Note that the review of each event involves a detailed evaluation of the cutsets including the event to identify the factors that make the event important.

D.5.1.2 LEVEL 2 PVNGS IMPORTANCE LIST REVIEW

A similar review was performed on the importance listings from the Level 2 results. In this case, a composite importance file based on the following release categories was used to identify potential SAMAs:

- LATE-BMMT-NOAFW
- LATE-CHR-AFW
- LATE-CHR-NOAFW
- LATE-CHR-PDS2
- LERF-SGTR

This method was chosen to prevent high frequency-low consequence events from biasing the importance listing. While the remaining release categories contribute about 2.6% of the dose-risk, that small contribution depends on over 22% of the Level 2 frequency. For PVNGS, this is not a highly important factor because the consequences are largely driven by the LATE-CHR-NOAFW release category, but this strategy was implemented for completeness.

The Level 2 RRW values were also reviewed down to the 1.010 level. As described for the Level 1 RRW list, events below the 1.010 threshold value are not “risk significant” and are not expected to yield cost beneficial SAMAs.

Table D.5-2 documents the disposition of each event in the Level 2 RRW list with RRW values greater than 1.010.

D.5.1.3 INDUSTRY SAMA ANALYSIS REVIEW

The SAMA identification process for PVNGS is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant-specific sources, selected industry SAMA submittals were reviewed to identify any Phase II SAMAs that were determined to be potentially cost beneficial at other plants. These SAMAs were further analyzed and included in the PVNGS SAMA list if they were considered to address potential risks not identified by the PVNGS importance list review.

While many of the industry SAMAs reviewed are ultimately shown not to be cost beneficial, some are close contenders and a small number have been estimated to be cost beneficial at other plants. Use of the PVNGS importance ranking should identify the types of changes that would most likely be cost beneficial for PVNGS, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for PVNGS due to PRA modeling differences or SAMAs that represent alternate methods of addressing risk. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the PVNGS SAMA identification process.

Phase II SAMAs from the following United States nuclear power sites have been reviewed:

- Calvert Cliffs (BGE 1998)
- Fort Calhoun (OPPD 2002)
- ANO, Unit 2 (Entergy 2003)

- Millstone Unit 2 (Dominion 2004)
- Palisades (NMC 2005)
- Wolf Creek (WCNOC 2006)

One Westinghouse PWR and five Combustion Engineering PWR sites were chosen from available documentation to serve as the Phase II SAMA sources. Only one of the Phase II SAMAs from these sources was included in the initial PVNGS SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the PVNGS list, were known not to impact important plant systems, or were judged not to have the potential to be close contenders for PVNGS. These SAMAs were not considered further. The following provides a summary of some of the issues considered during the review of the industry SAMAs.

D.5.1.3.1 Calvert Cliffs

- Phase II SAMA 05 - Improve Ability to Cool residual heat removal (RHR) Heat Exchangers: Because the PVNGS design does not provide for the feed and bleed capability, the use of RHR is limited in accident sequences and has a low potential for risk reduction. This SAMA is not included on the PVNGS SAMA list.
- Phase II SAMA 34 - Incorporate an Alternate Battery Charging Capability: PVNGS can currently prevent core damage for up to 16 hours in an SBO with at least one gas turbine generator (GTG) available. For complete loss of AC cases, improvements to only secondary side cooling operation would be of limited benefit without providing makeup to the primary side to address inventory losses due to RCP seal LOCA issues. PVNGS SAMA 4 addresses the need to provide power to both the battery chargers and the charging pumps for long term SBO coping. No additional SAMAs are required.
- Phase II SAMA 48a - Change UV, AFAS Block, and Reactor Protective System Actuation Signals to 3-out-of-4 Logic, instead of 2-out-of-4: Loss of an entire division of power does not prevent signal actuation at PVNGS nor does it actuate a signal. The logic design is such that loss of a single division of power causes the leg of the logic to trip, but not to actuate and the remaining division of logic is used to govern the actuation signals. This SAMA is not applicable to PVNGS.

D.5.1.3.2 Fort Calhoun

- SAMA 4 - Implement Procedures and Operator Training Enhancements for Support System Failure Sequences, with Emphasis on Anticipating Problems and Coping with Events that Could Lead to Loss of Cooling to the RCP Seals: Due to the current RCP seal design, the PVNGS charging pumps are capable of providing makeup for any inventory loss and HPSI is not required. This greatly reduces the importance of RCP seal LOCAs and no additional SAMAs are required for non-SBO conditions. SBO cases are addressed by PVNGS SAMA 4.

- SAMA 92 - Conserve/Makeup Borated Water Storage Tank Inventory Post Accident: PVNGS has several means of refilling the RWT, the fastest being the use of the boric acid makeup pumps to transfer water to the RWT from the spent fuel pool. No SAMA required.
- SAMA 181 - Add Accumulators or Implement Training on SIRWT Bubblers and Recirculation Valves: For Fort Calhoun, loss of instrument air results in depletion of the SIRWT bubblers. This causes a failure of SIRWT level indication, which may generate a recirculation signal when adequate inventory does not exist in the sump. This failure mechanism does not exist for PVNGS; no SAMA required.
- SAMA 184 - Add Capability to Flash the Field on an emergency diesel generator (EDG) to Enhance SBO Recovery: Some EDG start failures are related to a loss of magnetism in the generator electromagnets such that no electricity is delivered from the generator even if the engine is running. If a DC current is passed through the electromagnet coils, the system can be re-magnetized and a field will be present to allow for power generation. A small DC power supply and procedures would be required to provide PVNGS with this capability; however, this enhancement would only address a fraction of the EDG start failures. Because the EDG start failures have RRW values below the review threshold of 1.010 at PVNGS, this SAMA is not included on the SAMA list.
- SAMA 186 - Add Manual Steam Relief Capability and Associated Procedures: PVNGS has the capability to use local, manual action to open the atmospheric dump valves and depressurize the steam generators. No SAMAs required.

D.5.1.3.3 ANO Unit 2

No SAMAs appear to have been identified as potentially cost beneficial for ANO Unit 2 based on the Environmental Report submittal (Entergy 2003); however, some candidates were close contenders and were considered for PVNGS:

- SAMA AC/DC-16 – Emphasize steps in plant recovery following a station blackout event: Based on some of the sensitivity cases performed for ANO-2, this SAMA would have been considered cost effective, however, the calculations assumed instantaneous recovery of AC power after onset of an SBO. Such an assumption is not consistent with actual LOOP events. Attempts could be made to enhance on-site AC power recovery procedures for PVNGS, but no reliable means of measuring the benefit of such changes has been identified. No additional SAMAs are suggested related to loss-of-coolant (LOOP) LOOP/SBO sequences based on ANO-2 SAMA AC/DC-16.

- SAMA CB-10 – Direct steam generator flooding after a steam generator tube rupture, prior to core damage: PVNGS procedures do not direct SG flooding prior to core damage in SGTR scenarios with the specific intent of ensuring any radionuclide releases are scrubbed. While scrubbing may occur as a consequence of the existing guidance that directs SG level to be maintained for heat removal, no credit is taken in the PRA for this evolution. A potential enhancement would be to expand the existing guidance to explicitly direct SG flooding to ensure that water level remains high in the SGs even after core damage such that all releases would be scrubbed when an injection source is available. This enhancement has been included on the SAMA list (SAMA 23).

- SAMA CC-20 – Make containment sump recirculation outlet valve motor operated valves 2CV-5649-1 and 2CV-5650-2 diverse from one another: For PVNGS, failures of the sump suction valves are not large contributors to sump failure and this change would not provide a significant benefit to the plant. No additional SAMAs are suggested.

D.5.1.3.4 Millstone Unit 2

Based on the cost estimates provided in the Millstone SAMA analysis, only Millstone Unit 2 SAMA 3 appeared to be potentially cost beneficial. This SAMA suggested modifying plant procedures so that they directed RCS cooldown on loss of RCP seal cooling in order to preclude an RCP seal LOCA. The current PVNGS RCP seal design and charging pump makeup capabilities make RCP seal LOCAs low contributors to the plant risk profile and no RCP seal based SAMAs would be cost effective for PVNGS for non-SBO conditions. PVNGS SAMA 4 addresses RCP seal LOCA concerns for SBO evolutions. No additional SAMAs are suggested.

D.5.1.3.5 Palisades

- SAMA 10 – Power independent Turbine driven AFW operation: This SAMA allows for long term AFW operation in SBO evolutions. Improvements to only secondary side cooling operation would be of limited benefit without providing makeup to the primary side to address inventory losses due to RCP seal LOCA issues. PVNGS SAMA 4 addresses the need to provide power to both the battery chargers and the charging pumps for long term SBO coping. No additional SAMAs are required.
- SAMA 13 – Nitrogen Station for Automatic backup to CV-2010 Air Supply: The Condensate Storage Tank (CST) makeup configuration for PVNGS is different than Palisades and the importance of the action to transfer to the alternate suction source is not a highly important action for the site. No additional SAMAs are required.
- SAMA 16 – Insulate EDG Exhaust Ducts: The Palisades EDG design includes uninsulated EDG exhaust ducts that result in rapid EDG room heatup after start. The PVNGS EDGs do not require room cooling for success and no SAMAs are required.

D.5.1.3.6 Wolf Creek (WCGS)

- SAMA 4 – ISLOCA isolation: Providing procedures to improve interfacing system LOCA (ISLOCA) recovery actions could potentially be implemented at PVNGS, but ISLOCA is a low contributor for PVNGS and no SAMAs are suggested. The long time available for diagnosis of the dominant ISLOCA event results in a very low human error probability (HEP) (8.0E-05) for isolation of the ISLOCA and procedure enhancements would not result in any measurable improvement in reliability. No SAMAs suggested.

- SAMA 3: AC Cross-tie Capability - The major issue related to loss of an AC division for PVNGS is the loss of the AFN-P01 pump, which is addressed with an automatic power transfer switch (PVNGS SAMA 5). No additional SAMAs are suggested.
- SAMA 1: Permanent, Dedicated Generator for the NCP with Local Operation of the turbine-driven auxiliary feedwater (TD AFW) after 125V Battery Depletion - For PVNGS, the function addressed by this SAMA is covered by PVNGS SAMA 4. The use of a dedicated diesel generator (DG) was suggested for WCGS in order to preclude RCP seal LOCAs on loss of cooling. For PVNGS, this is not as important an issue and the expense of a permanent DG that can be quickly aligned from the main control room (MCR) is not required. No additional SAMAs suggested.

D.5.1.3.7 Industry SAMA Identification Summary

The important issues for PVNGS are considered to be addressed by the SAMAs developed through the PRA importance list review. Further, the plant changes suggested as part of that review were developed to meet the specific needs of the plant such that those SAMAs are more likely to provide effective means of risk reduction than SAMAs taken from other sites. However, effort was made to review other industry SAMA analyses to determine if other sites identified plant changes that could be cost beneficial for PVNGS. While it was found that other plants had developed SAMAs that addressed areas of concern for PVNGS, the SAMAs developed based on the plant specific PRA results were considered to represent the most appropriate risk reducing strategies for PVNGS and only one additional industry SAMA was added to the list based on this review (SAMA 23).

D.5.1.4 PVNGS IPE

The PVNGS IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out; however, there are some items that are not completed within the industry due to high projected costs or other criteria. Because the criteria for implementation of a SAMA may be different than what was used in the post-IPE decision-making process, these recommended improvements are re-examined in this analysis.

As a result of the IPE, three potential plant improvements were identified and considered for implementation at the plant. The following table summarizes the status of these plant improvements.

Description of Potential Enhancement	Status of Implementation	Disposition

Description of Potential Enhancement	Status of Implementation	Disposition
Change the source of power for the Main Steam and Feedwater Isolation Valve Logic Cabinets	Implemented.	No further review required.
Change the loss of power failure mode of the Train A Steam Generator Downcomer Containment Isolation Valves to Fail Open	Implemented.	No further review required.
Provide a backup source of control power for the Train N aux FW pump circuit breaker	Implemented.	No further review required.
Install temp detectors in the DC Equipment Rooms, with an alarm in the MCR	Implemented.	No further review required.

All of the plant changes suggested in the IPE have been implemented at PVNGS and no further review of these items is required.

D.5.1.5 PVNGS IPEEE

Similar to the IPE, any proposed plant changes that were previously rejected based on non-SAMA criteria should be re-examined as part of this analysis. In addition, any issues that are in the process of being resolved should be examined because their resolutions could be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

The following table summarizes the status of the potential plant enhancements resulting from the IPEEE processes and their treatment in the SAMA analysis. As can be seen, no outstanding changes have been identified:

Description of Potential Enhancement	Status of Implementation	Disposition
Improve anchorage on bookshelves behind U3 control cabinets	Implemented.	No further review required.
Add remote disconnect switch to allow removal of control of the Train B DC Essential Air Cooling Unit from the MCR	Implemented.	No further review required.
Modify the fire damper control panels for the essential Switchgear rooms so that the Train A and B circuits are separated	Implemented.	No further review required.
Eliminate use of common fuses for the control circuits of safe shutdown and non-safe shutdown equipment	Implemented.	No further review required.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, other than the fire model, the PVNGS IPEEE was not maintained as a “living” analysis. This limits the capability of the models that make up the IPEEE as they do not include the latest PRA practices nor do they necessarily represent the current plant configuration or operating characteristics. The fact that the models, other than fire, cannot be “quantified” presents further difficulty because the results are limited to what has been retained from the original analysis. These factors limit the qualitative insights and quantitative estimates that can be made with regard to external events contributors. Therefore, the external events models are considered to be useful tools for identifying important accident sequences and mitigating equipment, but any quantitative results should not be directly combined with those from the internal events models due to the differences in the modeling characteristics. In this analysis, external events contributions are estimated for the reasons described above.

D.5.1.5.1 Post IPEEE Site Changes

In addition to performing a review of the IPEEE results, it was necessary to review the changes to the site and surrounding area that were implemented after the completion of the IPEEE to determine if the changes could impact the conclusions of the external events analyses. The PVNGS staff identified three major changes with the potential to impact the IPEEE results:

- Installation of two GTGs,
- Addition of dry cask storage units for spent fuel (Independent Spent Fuel Storage Installation [ISFSI]),
- Installation of security enhancements.

These changes are discussed in further detail below.

D.5.1.5.1.1 Gas Turbine Generators

The two GTGs that were installed on the site were deliberately located over a half a mile from the plant to greatly reduce the likelihood that one tornado would eliminate the offsite power supply, the EDGs, and the GTGs. The remote location of the GTGs also precludes it from negatively impacting the internal fire, external flooding, or seismic risk. It is likely that that the additional AC power generating capacity from the GTGs would reduce plant risk, but no credit is taken for such reductions in the SAMA analysis beyond what is reflected through the use of the external events multiplier on the internal events results. In summary, the presence of the GTGs does not impact the conclusions of the IPEEE.

D.5.1.5.1.2 Independent Spent Fuel Storage Installation

Palo Verde evaluated the potential external events impacts of the ISFSI and identified only minimal concerns related to the addition of the facility (APS 2002a).
External flooding is not an issue for PVNGS, in general. With respect to the addition of the cask storage area, the PVNGS flooding characteristics were reviewed as part of the

cask storage site selection criteria. Consequently, the cask storage area does not negatively impact the PVNGS external flood risk.

The IPEEE demonstrated that the seismic risk for PVNGS is low. The plant was designed for 0.25g peak ground acceleration and the systems on the safe shutdown list are robust enough to withstand the site's 0.3g Review Level Earthquake. As a result, the potential improvements identified in the study were limited to minor issues such as improving anchorages on bookshelves to prevent seismically-induced equipment interaction. The risk related to the ISFSI is also expected to be low; however, study 13-NS-C062 indicates that the addition of the ISFSI and the related activities did introduce some un-analyzed conditions. These conditions include:

- Seismic events during transfer of a Vertical Concrete Cask (VCC) with the cask handling crane
- Seismic events during periods when a VCC is near the spent fuel pool for fuel loading
- Seismic events when a VCC is being transported on a rail car in the Rail Bay Area

While there is a small probability that one of these events could occur and result in the failure of a VCC or damage the spent fuel pool, neither of these endstates are considered in the SAMA analysis. The focus of the SAMA analysis is on damage to the operating core and the corresponding consequences; therefore, because these scenarios are outside the scope of the analysis, they are screened from further review. With respect to high wind events, the wind loading design basis for the ISFSI bounds the PVNGS site design basis and no SAMAs are required to address wind loading effects for the ISFSI. Study 13-NS-C062 states that it should be confirmed that the design basis tornado-generated missile spectrum from the PVNGS site bounds the ISFSI missile spectrum. The implication is that the ISFSI could be vulnerable to tornado-generated missiles that would not pose a threat to other site structures that contain safety equipment; however, as with the seismic issues, the probabilities of these events are small and the related endstates are not included in the scope of the SAMA analysis.

No ISFSI fire-related issues have been identified that would impact the internal fire analysis for PVNGS.

D.5.1.5.1.3 Security Changes

Discussions with site personnel indicate that the security additions do not have a significant impact on access to critical plant components and that the site is evaluated for potential tornado-generated missiles quarterly. Based on these factors, the security changes are considered to have a negligible impact on the conclusions of the IPEEE.

D.5.1.6 USE OF EXTERNAL EVENTS AND INTERNAL FLOODING IN THE PVNGS SAMA ANALYSIS

The IPEEE was used in the PVNGS SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The types of events considered in the PVNGS external events analysis were identified by Supplement 4 of Generic Letter 88-20 (NRC 1991a) and included:

- Internal Fires (Section D.5.1.6.1)
- Seismic Events (Section D.5.1.6.2)
- High Wind Events (Section D.5.1.6.3)
- External Flooding and Probable Maximum Precipitation (Section D.5.1.6.4)
- Transportation and Nearby Facility Accidents (Section D.5.1.6.5)

The generic letter also required that a review be performed to identify other types of potential hazards that could impact the plant to confirm that no plant specific issues were excluded by the IPEEE that could initiate severe accidents at PVNGS. The PVNGS IPEEE indicates that the guidance in NUREG-1407 and NUREG/CR-5042 was used to identify other potential IE types that could impact safe operation of site, which included:

Avalanche
Biological Events
Coastal Erosion
Drought
Fire
Fog
Forest Fire
Frost
High Tide/High Lake
Ice Cover
Landslide
Low Lake or River Water Level
Pipeline Accident
River Diversion
Seich Flooding
Storm Surge
Tsunami
Toxic Gas
Turbine-Generated missiles
Waves
Severe temperature transients (extreme heat, extreme cold)
Severe storm (ice, hail, snow, dust, and sand storms)

Lightning
External Fires
Extraterrestrial Activity (meteor strikes, satellite falls)
Volcanic activity
Soil Shrink-Swell Consolidation

Based on the PVNGS review, three additional IE types were included in the IPEEE analysis: Sand Storms, Lightning, and Extreme Heat. Section D.5.1.6.6 describes how these analyses were included in the SAMA identification process for PVNGS.

The type of information available for the initiators that were evaluated by PVNGS varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis used an approach that combined the deterministic evaluation techniques from the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology with classical PRA techniques. The PVNGS seismic analysis was performed using the EPRI Seismic Margins Assessment methodology (NP-6041-SL) and no CDF information was produced as part of that evaluation. Due to limitations of the Fire and Seismic modeling processes, the results of these kinds of analyses are not necessarily compatible with those of the internal events analysis. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process used to identify SAMAs is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

In addition, Section D.5.1.6.7 discusses the treatment of Internal Flooding for the SAMA analysis.

D.5.1.6.1 Internal Fires

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The PVNGS Fire Model shares many of the same characteristics as the internal events model and for PVNGS, it is integrated with the internal events Level 1 model. While this is true, limitations on the state of technology produce results that are potentially more conservative than the internal events model.

The following summarizes the fire PRA topics where quantification of the CDF may introduce different levels of modeling uncertainty than the internal events PRA.
The PVNGS modeling strategy makes use of the most recent level 1 internal events model and PRA techniques. As a result, the pedigree of the fire result is more consistent with the current internal events results that the fire analyses that were performed to support the IPEEE programs. However, there are some factors that make it undesirable to quantify the PVNGS fire model with the internal events model. The first is that that the fire model is not integrated with the most recent Level 2 analysis that was developed to support the SAMA analysis. The only post-core damage fire evaluation is a LERF model that does not address release categories that have been shown to be large contributors to PVNGS risk. In addition, there are still some areas where the PVNGS modeling may yield overly conservative results such that a direct comparison

with the internal events results may not be appropriate. These areas are identified as follows:

PRA Topic	Comment
Initiating Events:	The frequency of fires and their severity are likely conservatively overestimated. While PVNGS performs Bayesian updates on the EPRI fire events database to obtain the fire initiating event frequencies used in the PRA, it is an area of continuing improvement. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection (FP) steps at plants.
System Response:	While credit is taken for automatic fire suppression systems when they can prevent the spread of a fire to safety equipment, manual fire suppression is credited in limited ways outside the MCR.
Sequences:	Sequences in the PVNGS fire model are defined in detail. The consequences of any sequence collapsing is likely minor.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., failure of suppression results in the loss of all equipment in the fire compartment) and fire propagation.
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has generally led to conservative characterization of crew actions in fire PRAs. For PVNGS, a detailed assessment of the impact of fires on the HEPs was performed. Loss of instrumentation, crew loading factors, action location, confusion from additional alarms/indications, and environmental factors were included in the assessments. The effects of fire events on the operators were typically incorporated into the HEP calculations through the use of multipliers. Such detailed treatment is an indication that an effort has been made to remove unnecessary conservatism; however, the methods for assessing the impact of fire events on HRA is less developed and detailed than other factors in HRA and the pedigree of results may not be comparable to evaluations that are only used in the internal events model. Finally, a fire HRA standard has not yet been finalized for the industry and it is not clear how the PVNGS methodology will compare to the forthcoming industry standard.
Level of Detail:	Many fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage; however, the PVNGS model includes a detailed assessment of the impacts of the initiating events, consequential fire damage, and the subsequent response of the plant.
Quality of Model:	The peer review process for fire PRAs is not as developed as internal events PRAs. For example, no industry standard, such as NEI 00-02, exists for the structured peer review of a fire PRA. This may lead to less assurance of the realism of the model.

The approach taken to identify potential fire-related SAMAs was to review the top 10 contributing fire compartments, which represent over 92% of the Fire CDF (2.51E-06 out of a total of 2.72E-06). Review of additional fire compartments is possible, but it is unlikely that any potentially cost beneficial SAMAs would be identified. As a point of reference, the eleventh largest contributing fire compartment has a CDF of only 2.53E-08, which is less than 1% of the total Fire CDF. If this compartment's CDF were converted to a fire-based RRW value, it would be 1.009 (2.72E-06 / (2.72E-06 - 2.53E-08 = 1.009), which is below the RRW threshold used for the internal events model, which has a larger base CDF. The implication is that no SAMA impacting the risk of a single fire compartment below the top 10 would be cost effective. There is some potential that a single, low-cost change could impact multiple fire compartments, but even if such a SAMA were found, the benefit would be very low. Consequently, the review effort for this analysis is limited to the top 10 contributing fire compartments.

For each fire compartment, the list of equipment lost due to fire was reviewed to determine how the loss of equipment impacted accident progression. These cases were then analyzed to determine what measures could be taken to mitigate the fire event and the corresponding core damage sequences. The following table summarizes the top fire compartment CDF contributions and the equipment that could be failed for each fire compartment. For each compartment, all of the fire scenarios were reviewed and the worst case fire damage states (FDS) were identified. Other FDSs were also identified if they provided unique consequences.

Fire Compartment/Initiator	CDF (per year)	Major Equipment Failed (multiple damage states possible depending on scenario)
FZ 17/IEFIRE-17: Main Control Room - 140 ft Control Building	7.21E-07	MCR evacuation. FDS-AFA-1 and FDS-AFB-1 are possible worst case scenarios. AFA-1: Loss of AFA-P01 control power or feed control (local operation possible). AFB-1: Loss of control power to AFB-P01 or the pump's feed valves.
FZ TB9/IEFIRE-TB09: Main Turbine Bearings Areas - 176 ft	5.74E-07	Worst case is FDS TB-2: Loss of MFW, normal HVAC, AFN-P01, reactor instrumentation.
FZ 5A/IEFIRE-05A: Train A Essential Switchgear Room - 100 ft Control Building	3.53E-07	Worst case is F-TRNA-2: All train A safety equipment and ALT FW main steam isolation valve (main steam isolation valve (MSIV and FISV close)). This includes both AFA-P01 and AFN-P01.
FZ COR2A/IEFIRE-COR2A: Corridor Building - 120 ft	2.53E-07	Worst case is FDS F-LOP-2: LOOP with normal OSP recoveries not available. Also AFN-P01 is not available due to loss of downcomer feedwater regulator valve bypass and isolation valves. (Loss of control breakers for NAN-S01-6)
FZ TB1/IEFIRE-TB01: Turbine Building - 100 ft West	2.26E-07	Worst case is FDS TB-2: Loss of MFW, normal HVAC, AFN-P01, reactor instrumentation.
FZ TB5/IEFIRE-TB05: Turbine Building: West 140 ft	1.80E-07	Worst case is FDS TB-2: Loss of MFW, normal HVAC, AFN-P01, reactor instrumentation.

Fire Compartment/Initiator	CDF (per year)	Major Equipment Failed (multiple damage states possible depending on scenario)
FZ TB3B/IEFIRE-TB03: Feedwater Pumps Area - 100 ft Turbine Building	1.10E-07	Worst case is FDS TB-2: Loss of MFW, normal HVAC, AFN-P01, reactor instrumentation.
FZ TB4B/IEFIRE-TB04B: Fire in Station DC Equipment Room - 110 ft Turb Bldg	3.28E-08	Multiple fire damage states are possible, including: - F-NBA: Loss of Train A engineered safeguard feature (ESF) service transformer due to fire, - F-LOP-1: Loss of off-site power and switchyard due to fire, - F-NK-1: Loss of station battery F17 or DCCC M45 due to fire
FZ 5B/IEFIRE-05B: Train B Essential Switchgear Room - 100 ft Control Building	3.28E-08	Multiple fire damage states are possible, including: -FDS-TRNB-2: complete loss of train B. -FDS-AFB-1: fails AFA-P01 and/or its steam supply valves. -FDS-PBB-1: fails B ESF bus.
FZ 42A/IEFIRE-042A: Electrical Penetration Room - Train A, Channel A - Aux Bldg 100 ft	2.93E-08	The worst case is F-BOP-3: Loss of SG feed regulator valve bypass and isolation valves, L25, MFW, Normal HVAC, Nonclass instrument AC, and Seal Injection.

The table above demonstrates that the total fire CDF of 2.72E-6 is not dominated by any one fire compartment; the largest contributor is only about 27% of the total CDF. In addition, while fires in each of these areas can result in the loss of a wide range of equipment, the losses are typically limited to a single division. As a result, redundant equipment is often available to mitigate the fire events. Further discussion is provided for each of the fire area/scenarios below.

FZ 17: Main Control Room - 140 ft Control Building

There are many ignition sources in the MCR and the consequences of a fire in this compartment are diverse. Many of the top contributors to the fire CDF include MCR fires in which manual suppression fails and fire propagation occurs. Fires that propagate from the source are all considered to result in a control room evacuation. No plant enhancements have been identified that could improve the operators' abilities to manually suppress MCR fires or perform a shutdown from the remote shutdown panel (RSP) in a measurable way. Automatic suppression systems are not viable in areas that are frequented by plant personnel and the installation of these types of systems is not a practical means of improving suppression ability. Also, potential changes to include the opposite division's controls on the RSP to improve functionality are not suggested given that it would provide an area where a single fire could damage two divisions of equipment. No SAMAs have been identified for this fire compartment.

FZ TB9: Main Turbine Bearings Areas - 176 ft

The fire initiator of concern in this area is a lube oil fire. Fire suppression in this compartment is of the “wet pipe pre-action” type actuated by heat detectors at the turbine and bearings. Automatic suppression is credited for this compartment and no enhancements to the suppression system have been identified. For the lube oil fires that do propagate, the entire building is assumed to be affected, which includes AFN-P01. The PVNGS fire analysis indicates that this treatment is conservative as it is very unlikely that AFN-P01 would be impacted by such a fire evolution. While damage to AFN-P01 would be rare for these fires, precautions could be taken by installing protective wrap on all cables required to support AFN-P01 operation (SAMA 18).

FZ 5A: Train A Essential Switchgear Room - 100 ft Control Building

This fire compartment includes an automatic fire suppression system, but the heat sensors responsible for system initiation are located on the ceiling. Because of the large distance between the heat sensors and the potential fire ignition sources, the current fire analysis assumes that the heat load at the sensors would not be large enough to actuate the suppression system until after the fire has propagated from the ignition source. While the fire suppression system may, in reality, be capable of preventing propagation in some cases, moving the existing sensors or installing additional heat sensors near the potential ignition sources would be required to ensure the suppression system could actuate in time to prevent the spread of fires away from their ignition sources (SAMA 19). Given that most of the more severe fire consequences for this compartment are the result of damage to non-initiator targets, enhancing the automatic suppression system could provide a large risk reduction for this compartment.

FZ COR2A: Corridor Building - 120 ft

No fixed initiators were identified for this compartment; therefore, the entire frequency is associated with transient sources. In this case, the only transient source considered to be credible was an extension cord. While there is a large uncertainty associated with the fire scenarios including extension cord fires that damage the target cables in this compartment, the consequences are non-negligible. A potential enhancement would be to protect the most important equipment in the area. In this case, the potential targets in this area include cables that allow operation of the high voltage switchgear breakers and AFN-P01. These cables could be protected to increase the post-fire availability of AFN-P01 (SAMA 18). Control cables for the high voltage switchyard breakers could also be protected to facilitate re-alignment of off-site power, but manual operation of these breakers is possible and currently not credited in the model. No additional SAMAs are considered to be required.

FZ TB1: Turbine Building - 100 ft West

Most fires in this compartment result in limited equipment damage, with the loss of AFN-P01 being one of the most significant consequences. The openness of the areas containing the equipment and the enclosed nature of the electrical cabinets preclude the propagation of most of the initiating fires. Automatic suppression systems are located throughout the building, but they are not credited for individual component fires or for transient fires given that equipment damage would have occurred by the time of actuation. Similar to other fire compartments including AFN-P01 cables/equipment, a potential means of reducing the fire risk is to install protective wrap on all cables required for AFN-P01 operation (SAMA 18).

FZ TB5: Turbine Building: West 140 ft

This compartment is located above FZ TB1 and fires can propagate to that compartment and damage to AFN-P01, Load Center L01, or Load Center L25. In addition, actuation of the fire suppression system could cause damage to the equipment in FZ TB1 because the floor is an open grate design that would allow water to pass through it to FZ TB1. A potential enhancement would be to provide barriers between FZ TB5 and FZ TB1 that would prevent fire propagation and water damage after suppression actuation in FZ TB5 (SAMA 20).

FZ TB3B: Feedwater Pumps Area - 100 ft Turbine Building

Most fires in this compartment result in limited equipment damage, with the loss of AFN-P01 being one of the most significant consequences. The openness of the areas containing the equipment precludes the propagation of most of the initiating fires. Automatic suppression systems are located throughout the building, but they are not credited for individual component fires or for transient fires given that equipment damage would have occurred by the time of actuation. Similar to other fire compartments including AFN-P01 cables/equipment, a potential means of reducing the fire risk is to install protective wrap on all cables required for ANF-P01 operation (SAMA 18).

FZ TB4B: Station DC Equipment Room - 110 ft Turb Bldg

The equipment of concern in this compartment includes non-essential DC control center NKNM45 along with the cables to the distribution panels it feeds, battery chargers NKNH17 and H21, breaker control cables for NANS03 and NANS04, and the power cable from NBNX03.

Other than a fire in NKNM45, fixed source fires that fail to propagate do not have a direct impact on plant operation because loss of a single battery charger does not cause a loss of non-essential DC power. In the case of a fire in NKNM45, a plant shutdown will be required as a significant amount of required BOP equipment is fed from this DC panel. Other than causing a trip, the impact of losing non-essential DC power in the PRA is limited to potentially impacting the Normal Chillers and the control breakers that are required to align off-site power to the plant. While local breaker operation is typically not required to align off-site power at PVNGS, the site has procedures to manually restore off-site power to the Units in the event that non-essential DC is unavailable. With respect to the Normal Chillers, they are responsible in the PRA for providing cooling flow to the HVAC system for the MCR and ESF Switchgear Rooms. In the event that a fire fails NKNM45, DC control power will be lost to the Normal Chillers; however, DC control power is not required if the Normal Chillers are already running. Given that the Normal Chillers are normally running and would only be tripped off with a LOOP or a SI signal, the Normal Chillers would not be impacted by TB4B fire scenarios as they would not result in an SI signal and induced LOOPs are low frequency contributors. No SAMAs are required to address loss of NKNM45.

Fires that propagate from fixed or transient sources have the potential to impact multiple components and/or components that are not themselves ignition sources. The only components that were identified as potentially vulnerable to a common fire were the NKNH17 and H21 battery chargers. The loss of these chargers has a similar impact to the loss of NKNM45 and no SAMAs are required to mitigate fires that fail the chargers. In addition, a swing charger is available in the event that NKNH17 and H21 are destroyed; it is currently not credited because the alignment action was not developed for the PRA and because environmental conditions may complicate the action. There are two specific cases in which transient fires could propagate to overhead cable trays:

- Case 1: Fire impacts trays carrying cables for the NAN-S03 and NAN-S04 buses, which results in loss of the switchyard.
- Case 2: Fire impact trays carrying cables from NBNX03, which results in loss of the Train A ESF service transformer.

These scenarios could potentially be mitigated by installing protective wrap on these cables (SAMA 21).

FZ 5B: Train B Essential Switchgear Room - 100 ft Control Building

This fire compartment includes an automatic fire suppression system, but the heat sensors responsible for system initiation are located on the ceiling. Because of the large distance between the heat sensor and the potential fire ignition sources, the current fire analysis assumes that the heat load at the sensors would not be large enough to actuate the suppression system until after the fire has propagated from the ignition source. While the fire suppression system may, in reality, be capable of preventing propagation in some cases, moving the existing sensors or installing additional heat sensors near the potential ignition sources would be required to ensure the suppression system could actuate in time to prevent the spread of fires away from their ignition sources (SAMA 19). Given that most of the more severe fire consequences for this compartment are the result of damage to non-initiator targets, enhancing the automatic suppression system could provide a large risk reduction for this compartment.

FZ 42A: Electrical Penetration Room - Train A, Channel A - Aux Bldg 100 ft

There are several fire scenarios for this compartment, but only the transient fires have potentially serious consequences. In the event that a transient fire does not self-extinguish, it may actuate the fire suppression system in the compartment. This is assumed to result in a reactor trip 10% of the time if the fire does not propagate. No SAMAs are suggested for these cases.

If the fire does propagate, however, MCC M71 is assumed to be failed. This results in the loss of the SG feed regulator valve bypass and isolation valves, which fails AFN-P01. While the risk from this fire compartment is relatively low and the cost of installing fire barriers can be high, a potential means of preventing the loss of MCC M71 would be to improve the MCC's fire barriers so that it could better withstand transient fires (SAMA 22).

If the suppression system fails, MCC M71 is failed along with LC L25, MFW, Normal HVAC, Non-class instrument AC, and Seal Injection. The consequences of fire suppression failures are diverse and while all of the targets could be protected with better fire barriers, protecting MCC M71 would impact cases with both fire suppression success and failure and is considered to be a better choice for this fire compartment (SAMA 22).

Fire SAMA Identification Summary

Based on the review of the PVNGS fire area results, five SAMAs have been identified as potentially cost beneficial methods of reducing fire risk:

- Fire Proof All Cables and Equipment Required for AFN-P01 Operation in the Four Fire Areas Important to Pump Operation (SAMA 18)
- Install Heat Sensors Near Potential Fire Ignition Sources to Allow Activation of Automatic Fire Suppression in Time to Prevent Fire Propagation (SAMA 19)
- Install Fire Barriers Between Fire Zone TB01 and TB05 (SAMA 20)
- Install Fire Resistant Cable Wrap on Selected Cables in Fire Compartment TB4B (SAMA 21)
- Enhance the MCC M71 fire barriers (SAMA 22)

D.5.1.6.2 Seismic Events

The IPEEE (APS 1995) indicates that the EPRI seismic margins methodology was used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). Equipment that is not capable of withstanding the RLE is identified and required to be addressed. While methods exist for using this information to develop a seismically induced core damage frequency, this was not performed as part of the PVNGS IPEEE.

It should also be noted that even in a seismic analysis developed to yield a CDF, the pedigree of information is not equivalent to what is used in the internal events models. Given that there is a limited amount of seismic response information available for nuclear power plants, analysis techniques developed to model the plant response often compensate by ingraining a conservative bias in their methodologies to prevent overestimating the capabilities of the plants. While seismic risk evaluations are helpful in the identification of potential plant weaknesses, the methodologies have not evolved to a point where the results can be directly compared with the internal events models. With these limitations in mind, the PVNGS IPEEE seismic results and history were reviewed in order to determine if there were any unresolved issues that could impact PVNGS risk. The issues of potential interest included:

- Unfinished plant enhancements that were determined to be required to ensure the equipment on the Safe Shutdown List would be capable of withstanding the RLE.
- Additional plant enhancements that were identified as means of reducing seismic risk but were not implemented at the plant.

An effort was also made to use the results of the equipment and structural screening documentation to determine if any outlier issues that were screened in the IPEEE could impact seismic risk at PVNGS. In this case, all of the equipment on the safe shutdown equipment list, including relays and equipment associated with containment performance, were seismically qualified for a level exceeding the RLE. Therefore, there were no seismic plant enhancements suggested in the IPEEE that could have been left unresolved or unimplemented and no additional enhancements have been identified that could be included on the SAMA list.

D.5.1.6.3 High Wind Events

The approach taken to analyze the high wind, flood, and “other” external event risk in the PVNGS IPEEE was to implement a progressive screening approach. The first three steps included 1) a review of PVNGS specific hazard data and licensing basis, 2) identification of significant changes since Operating License issuance, and 3) verification that the PVNGS design met the 1975 SRP criteria. The next three steps consisted of determining the hazard frequency and consequences. These steps were optional and could be bypassed provided that the first three steps were satisfied and any identified vulnerabilities were demonstrated to be insignificant. The last step was to document the process.

For the SAMA analysis, this process is considered adequate for screening events that do not pose a credible threat to plant operations. However, any issues that could impact plant safety are reconsidered to determine if the development of a SAMA is appropriate to address the vulnerability.

The PVNGS licensing bases and plant specific hazard data were reviewed as part of the IPEEE High Wind analysis. The IPEEE stated that because the PVNGS Seismic Category I structures were designed for the Design Basis Tornado’s 360 mph wind speed (300 mph rotational speed, 60 mph translational speed), these buildings and the equipment housed within were screened from further consideration for tornado threats. This would be considered adequate to screen tornado risk for the SAMA analysis; however, it was determined that the Design Basis Tornado identified in the IPEEE is not consistent with what is documented in the PVNGS UFSAR. In that document, the Design Basis Tornado is described as having a maximum wind speed of 300 m.p.h. (240 mph rotational speed, 60 mph translational speed).

The implication of this discrepancy is that PVNGS was assumed to be protected against higher wind speeds than dictated by the actual plant design. While the conclusion of the IPEEE that tornadoes do not pose a threat to the structural integrity of the Seismic Category I structures at the site is not expected to be impacted, an additional review of the PVNGS high wind risk has been performed for the SAMA analysis using information from an existing PVNGS evaluation and the SAMA cost benefit methodology.

In order to address high wind events for the SAMA analysis, the total cost-risk associated with tornadoes was calculated and compared to the minimum expected SAMA implementation cost (established as $100,000 in Section D.5.1.1) to determine if any cost beneficial SAMAs might exist. Based on the information provided in Table 6-3 of the PVNGS Equipment Hatch Missile Shield analysis (WEST 2004), which is taken from the NRC Standard Review Plan, the frequency of an F5 tornado in the region in which PVNGS is located is 7.32E-9 per square mile per year. Tornadoes of this magnitude have winds in the range of 260 to 318 mph, which includes wind speeds that exceed the PVNGS design basis. For this analysis, it is assumed that all F5 tornadoes that strike the site cause core damage and result in a release equivalent to those defined for the “LERF ISO” release category.

While table 6-3 does not provide information about tornadoes with wind speeds above 318 mph, the F5 tornado frequency it is treated as an exceedence frequency such that it accounts for those tornadoes with winds above 318 mph, as well. While this may appear to be potentially non-conservative, note that the majority of the F5 tornado wind spectrum is below the 300 m.p.h. design limit of the PVNGS Seismic Category I structures and that use of the F5 tornado frequency counts a large part of the wind spectrum that would not pose a threat to those structures.

Consistent with the PVNGS Equipment Hatch Missile Shield analysis, a tornado is only considered to be a threat to the plant when it passes within 0.5 miles of the plant. Using this assumption and the regional F5 tornado frequency, a tornado strike frequency for PVNGS can be obtained:

Site Strike Frequency = Regional F5 Tornado Frequency * PVNGS Threat Area
Site Strike Frequency = 7.32E-9 per square mile per year * 3.14 * 0.5^2 = 5.75E-09 per year.

If, as discussed above, all of these tornado strikes are assumed to cause core damage and containment bypass, a tornado based cost-risk can be developed using the methodology described in Section D.4. In summary, the input to the cost benefit calculation is:

- CDF = 5.75E-09/yr
- LERF-ISO = 5.75E-09/yr
    - 0.10 person-rem/yr (50-mile Population Dose-Risk)
    - $142/yr (50-mile Economic Cost-Risk)

In this case, no "external events" multipliers are used given that this is an external event itself. The resulting cost-risk is $15,921:

Maximum Tornado Cost-Risk

Off-site exposure cost	=	$3,008
Off-site economic cost	=	$2,136
On-site exposure cost	=	$4
On-site cleanup cost	=	$112
Replacement Power cost	=	$47
Total single unit cost	=	$5,307
Total site cost (single unit * 3)	=	$15,921

Based on the costs APS developed for procedure changes for other SAMAs ($350,000 - $400,000), a procedure update that eliminated all tornado risk would not be cost effective even if the averted cost-risk was many times greater. Even with the low end procedure change estimates of $50,000 to $100,000 that have been used in other SAMA analyses (CPL 2002), credible procedure changes would not be cost effective. As a result, no SAMAs designed to mitigate tornado risk on Seismic Category I structures were pursued for this analysis.

The effects of extreme wind loads (other than tornadoes) on structures, systems, and components important to safety are bound by those generated by the Design Basis Tornado and were not considered separately in the analysis.

The only safety-related structure which was found to be not protected from the possible effects of a tornado was the ultimate heat sink (UHS). By the nature of its design, the spray pond nozzles were found to be susceptible to tornado missile strikes and a quantitative screening method was required to eliminate them from consideration in the IPEEE. The analysis estimated that the upper-bound 95% confidence level estimate for high wind-induced loss of the UHS was 1.9E-07 per year for Unit 1, 4.0E-07 per year for Unit 2, and 2.9E-09 per year for Unit 3. Because these frequencies were well below the 1.0E-06 per year IPEEE screening frequency, high wind-induced loss of the UHS was screened from further review. For the SAMA analysis, the PRA can be used in conjunction with these frequencies to preclude the inclusion of High Wind-based SAMAs on the SAMA list. The Risk Increase Factor value for the CCF of the spray pond pumps (1SP-CC1MPCFS-ALL) is 136.4, which implies that the CDF would be

6.92E-04/year if the spray pond were lost (5.07E-06 per yr*136.4=6.92E-04). If this "conditional" CDF is used in conjunction with the wind-based loss of UHS frequencies and a plant trip is assumed to occur with the high wind event, the CDF contribution would only be 4.1E-10 per yr (6.92E-04 per yr*(1.9E-07 per yr+4.0E-07 per yr+2.9E-09 per yr)=4.1E-10 per yr). This is over 6600 times smaller than the current internal fire CDF of 2.72E-06 per yr and 14 times smaller than the CDF estimated above for tornadoes strikes on Seismic Category I structures, which implies that there are no potentially cost effective SAMAs to address this specific area of risk.
It should also be noted that PVNGS performs an annual evaluation of the UHS damage frequency to confirm that it is within the parameters established in section 2.2.3 supplement #5, section 9.2.5 of the SRP.

Given the relatively low risk of a high wind-induced core damage event, no further efforts were made in the SAMA analysis to develop plant enhancements related to high wind protection.

D.5.1.6.4 External Flooding and Probable Maximum Precipitation

Site flooding at PVNGS is addressed by the probable maximum precipitation event, which was determined not to be a threat to safe plant operations in the IPEEE. Roof ponding was also examined for the PVNGS and found to be not applicable to the site due to the pitched roofs and drain designs.
Given the low potential for identifying cost beneficial SAMAs to mitigate risk posed by external flooding, no further efforts were made in the SAMA analysis to develop SAMAs related to external flooding events.

D.5.1.6.5 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the PVNGS IPEEE to account for human errors or equipment failures that may occur in events not directly related to the power generation process at the plant. The types of hazards identified for analysis included:

Transportation Accidents
- Aircraft Activity
- Road and Rail

Fixed Facility Accidents
- Industrial Facilities
- Military Facilities
- Pipeline Accidents

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, aircraft impact events are considered to be out of the scope of the SAMA analysis. Accidental aircraft impact was reviewed in the IPEEE and the likelihood of impact was estimated to be 3.0E-08 per yr. Even if the conditional CDF is assumed to be 1.0 after an aircraft impact, the CDF is over 90 times less than the current internal fire CDF of 2.72E-06 per yr. Given the relatively low risk of aircraft impact compared with fire risk, no further efforts were made in the SAMA analysis to develop plant enhancements related to accidental aircraft protection.

The roadway loading around PVNGS was analyzed for the IPEEE and it was determined that transportation accidents on the roadways did not pose a threat to safe operation of the plant. Given that the transportation route for any hazardous material with 10 miles of the site is Interstate 10 and that distance between the site and Interstate 10 is greater than 5 miles, no credible hazardous material accidents on the route could impact safety related structures at PVNGS. No SAMAs are required to address this type of event.

The railway system near PVNGS was also examined in the IPEEE to identify potential threats to plant safety. Comparison of the contemporary configuration to that of the design basis showed that no additional rail systems had been built near the plant, no additional hazardous chemicals have been identified on the rail line, and that the frequency of hazardous material shipments had gone down from 12,562 cars per year in 1978 to 1497 cars per year in 1992. Given the low potential for identifying cost beneficial SAMAs to mitigate risk posed by the railway system, no further efforts were made in the SAMA analysis to develop SAMAs related to these hazards.

The fixed facility accidents, including pipeline breaks, industrial accidents, and aircraft accidents from nearby military bases, were reviewed in the IPEEE and it was determined that none of these elements posed credible threats to safe plant operation. There were no industrial facilities located within a 10-mile-radius of the site, no pipeline breaks that could negatively impact plant operations, and the military aircraft movements were all below the limits included in the design basis. Given the low potential for identifying cost beneficial SAMAs to mitigate risk posed by the fixed facility accidents, no further efforts were made in the SAMA analysis to develop SAMAs related to these hazards.

D.5.1.6.6 “Other” Events

Based on the external events review performed by APS using the guidance in NUREG-1407 and NUREG/CR-5042, it was concluded that lightning strikes, sand storms, and periods of extreme heat were potentially relevant IEs for the PVNGS site. It was determined in the IPEEE that these initiators posed no credible threat to plant operations other than those already addressed by the internal events model (i.e., Loss of off-site Power due to lightning strike). Given that the internal events LOOP frequency already quantitatively accounted for the lightning-initiated LOOP events, no additional modeling was required. In addition, none of these potential IEs were found to present an undue threat to the operation of any risk-significant equipment. As a result, no additional SAMAs are considered to be required to address lightning strikes, sand storms, or periods of extreme heat.

D.5.1.6.7 Internal Flooding

The current PVNGS PRA does not include an Internal Flooding analysis. The IPE included a screening assessment and the results showed that this IE posed very little risk for the site. As such, the integration of other initiators into the PRA was assigned a higher priority (for example, internal fires). In order to address Internal Flooding events for the SAMA analysis, the screening analysis from the IPE was reviewed to determine if any Internal Flooding related SAMAs could be cost beneficial for the site.

The IPE Internal Flooding analysis was performed in stages of increasing detail. For example, the first stage was based on reviewing flood sources, critical component locations, and flood/spray paths. Those flood zones that posed no risk to the site due to lack of flood sources, critical equipment, or inter-flood zone interactions could be screened. Flood zones that could not be screened were examined to determine if equipment losses would impact plant operation and then those cases that could impact plant operation were quantitatively analyzed. Most flood zones were eliminated in the most general screening phase. Only a few flooding scenarios required a frequency analysis and those that were evaluated showed CDF contributions below 1.00E-08 per yr. Contributions of this magnitude are well below the threshold of review for PVNGS. For PVNGS, it can be shown that even a SAMA capable of eliminating all Internal Flooding risk would not be cost effective. If it is assumed that Internal Flooding events contribute a CDF as high as 1.00E-07 per yr and that the frequency is distributed among the Level 2 release categories in the same proportion as for the existing internal events initiators, elimination of this contribution would correlate to only $67,791. This estimate includes the effect of applying the “external events multiplier” to the averted cost-risk, which results in an increase by a factor of 2 over the Internal Flooding results alone. Based on the costs APS developed for procedure changes for other SAMAs ($350,000 - $400,000), a procedure update that eliminated all Internal Flooding risk would not be cost effective even if the averted cost-risk was 5 times greater. Even with the low end procedure change estimates of $50,000 to $100,000 that have been used in other SAMA analyses (CPL 2002), credible flooding procedure changes would not be cost effective. As a result, no Internal Flooding SAMAs were pursued for this analysis.

D.5.2 PHASE I SCREENING

The initial list of SAMA candidates is presented in Table D.5-3. The process used to develop the initial list is described in Section D.5.1.
The purpose of the Phase 1 analysis is to use high-level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following screening criteria were used:

- Applicability to the Plant: If a proposed SAMA does not apply to the PVNGS design, it is not retained. Similarly, any SAMAs that have already been implemented by APS or achieve results that APS has achieved by other means can be screened as they are not applicable to the current plant design. The use of this criterion is not often explicitly used in the Phase I analysis because the

SAMA methodology generally precludes inclusion of such SAMAs; however, this criterion is listed as a possible screening method given that there may be circumstances in which a SAMA would be included in the list even if it is not relevant to the site. An example may be the inclusion of a high profile SAMA that is well known in the industry, but not applicable to the specific site design. Such a SAMA may be included for documentation purposes. Another example may be an unimplemented SAMA from the IPE that has been superceeded by another plant enhancement.

- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the modified MACR (refer to Section D.4.6), the SAMA cannot be cost beneficial and is screened from further analysis.

Table D.5-3 provides a description of how each SAMA was dispositioned in Phase 1. Those SAMAs that required a more detailed cost-benefit analysis are passed to the Phase 2 analysis and evaluated in Section D.6. Table D.5-4 contains the Phase 2 SAMAs.

D.6 PHASE II SAMA ANALYSIS

Not all of the Phase 2 SAMA candidates, which are listed in Table D.5-4, require detailed analysis. The Phase 2 process allows for the screening of SAMAs known to be related to non-risk significant systems or to components/functions with low importance rankings. Due to the nature of the PRA-based process used to develop the PVNGS SAMA list, there are limited avenues for SAMAs of this type to be included in the list. However, potential pathways do exist:

- Inclusion of unresolved proposed plant changes from previous PVNGS risk analyses
- Inclusion of SAMAs based on the results of conservative modeling methods.

While no calculations are required for eliminating a SAMA that is linked to a non-risk significant system or components, some quantitative efforts are usually required to screen SAMAs that are developed to address risk contributors based on conservative modeling techniques. For PVNGS, no cases were identified in which a SAMA was derived due to conservative modeling techniques.

For the SAMAs requiring detailed analysis, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidates' changes upon the plant safety model.
The final cost-risk based screening method is defined by the following equation:

Net Value = Averted cost-risk – Cost of implementation

Where:

Averted cost-risk = (baseline cost-risk of site operation (MACR) – cost-risk of site operation with SAMA implemented)

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section D.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the revised PRA results reflect implementation of the SAMA.

The quantitative methods available to evaluate external events risk at PVNGS are limited, as discussed in Section D.5.1.6. In order to account for the external events contributions in the SAMA analysis, a multi-faceted process has been implemented to provide estimates of the benefits related to reducing external events risk.

The primary basis of the external events quantification strategy is the assumption that the risk posed by external and internal events is approximately equal. As described in Section D.4.6.2, if the IPEEE CDF quantification screening threshold of 1.0E-06 per yr is assigned to the non-quantified external event initiator groups for which no quantitative basis has been developed, the total external events CDF would be 6.72E-06 per year. Given that this conservative estimate of the external events CDF is comparable to internal events CDF and that no specific external events vulnerabilities have been identified at PVNGS, the assumption that the external events risk is equal to (but not more than) the internal events risk appears to be reasonable.

The assumption that the internal and external events risks are equal is often used in SAMA analyses as a basis for doubling the internal events averted cost-risk to account for external events contributions (WCNOC 2006) (CPL 2004) (CPL 2006). The same approach could be used for PVNGS, but because a quantifiable fire model exists, additional steps have been taken to integrate the fire model's capabilities into the quantification process. In this case, the fire model quantification is used to evaluate fire risk while a constant multiplier on the internal events results is used to account for the non-fire external events contributors. To accommodate this strategy, the external events contributions to each SAMA specific cost-risk are calculated in two parts, one for fire and one for non-fire:

- The fire contribution is equal to the base fire contribution multiplied by the ratio of the SAMA-specific fire CDF to the base fire CDF, which takes advantage of the quantifiable Level 1 fire model.
- The non-fire contribution would be equal to the SAMA-specific internal events cost-risk multiplied by the fraction of the external events risk attributed to non-fire external events.

In order to implement this quantification strategy, it is necessary to define how the external events risk is distributed between fire and non-fire external events for PVNGS. In this case, two viable approaches have been identified, which are described below. For the first approach, the initial step would be to translate the assumption that the external and internal events risks are equal into its monetary equivalent. For PVNGS, the internal events cost-risk is $2,334,000 (site). It follows that if the internal and external events risks are equal, the external events cost-risk is also $2,334,000. In order to determine the fire and non-fire contributions, this quantity could then be assumed to be distributed among the external events initiator groups in proportion to CDF. The external events CDF distribution developed in Section D.4.6.2, which is reproduced below, could be used for this task:

Modified IPEEE Contributor Summary

External Event Initiator Group	CDF (per year)
Seismic	1.00E-06
Internal Fire	2.72E-06
High Winds	4.10E-10

External Floods (progressive screening method used)	1.00E-06
Transportation and Nearby Facility Accidents (including accidental aircraft impact)	1.00E-06
Others	1.00E-06
Total	6.72E-06

Based on this distribution, internal fires account for 40.5% of the external events CDF. The non-fire external events contributors would, therefore, account for the balance of the risk (59.5%).

A second approach is available that places more emphasis on the internal fire CDF. The initial assumption for this approach is the same as that for the approach described above, which is that the internal events and external events risks are equal. The assumption that the external events cost-risk is proportional to CDF is also shared with the previous approach, but in this case, the percent contribution from fire initiators is based on the ratio of the fire CDF to the internal events CDF. The complement is assumed to represent the contributions from the remainder of the external events.

Specifically, the fire CDF of 2.72E-06 per yr is 53.6% of the internal events CDF (2.72E-06 per yr / 5.07E-06 per yr * 100 = 53.6%), so the fire-based cost-risk is assumed to be equal to 53.6% of the internal events cost-risk and the balance is attributed to the non-fire external events contributors. In this case, the baseline fire cost-risk is $1,251,024 (0.536 * $2,334,000 = $1,251,024). The non-fire external events would, therefore, be $1,082,976 (0.464 * $2,334,000 = $1,082,976).
While either of the approaches above could be used, the latter is considered to be better suited to PVNGS because:

- It emphasizes the importance of the fire risk, which appears to be the dominant external events contributor based on the results of the IPEEE.
- The fire model is fully developed and integrated with the Level 1 internal events model, which implies that the relative risk of the fire and internal events initiators is better defined by a comparison of the PRA CDFs than by a comparison of the fire CDF to a set of assumed CDFs for the non-quantified external events.

It should be noted that while the PVNGS fire model can be quantified, this approach to estimating the fire based cost-risk is required due to the fact that the recent Level 2 PRA update did not extend to the fire model and a full spectrum of release category results is not available for the fire model.

For the non-fire external events initiator groups, no quantifiable models are available and a multiplier on the internal events cost-risk is used to approximate the external events cost-risk for a given SAMA.

In order to clarify how the above process is used to support a SAMA's net value calculation, consider the following simplified example:

The cost of implementation for SAMA "A" is $500,000. After implementation of SAMA "A", the internal events cost-risk for the site was determined to be $2,000,000 (using the process defined in Section D.4) and the fire CDF was determined to be 2.00E-06 per yr. The net value for SAMA "A" can be calculated from this information.

The fire cost-risk for the site, given SAMA implementation, is the product of the baseline fire cost-risk and the ratio of the SAMA specific fire CDF to the base fire CDF:

$$\text{Cost-Risk}_{fire} = (0.536 * \$2,334,000) * (2.00\text{E-}6 \text{ per yr} / 2.72\text{E-}06 \text{ per yr})$$

$$\text{Cost-Risk}_{fire} = \$1,251,024 * 0.735 = \$919,503$$

The non-fire external events contribution is the product of the SAMA specific internal events cost-risk and the fraction of external events risk attributed to non-fire external events (the non-fire external events multiplier). The non-fire external events multiplier of 0.464 was developed above and is a constant for all SAMA quantifications:

$$\text{Cost-Risk}_{EE,\ non\text{-}fire} = 0.464 * \$2,000,000 = \$928,000$$

The cost-risk of site operation with the SAMA implemented is the sum of the internal events, fire events, and non-fire external events cost-risks:

$$\text{Total Cost-Risk}_{SAMA} = \$2,000,000 + \$919,503 + \$928,000$$

$$\text{Total Cost-Risk}_{SAMA} = \$3,847,503$$

The averted cost-risk for SAMA "A" is the difference between the baseline MACR and the total cost-risk with the SAMA implemented:

$$\text{Averted Cost-Risk} = \$4,668,000 - \$3,847,503 = \$820,497$$

Finally, the net value can be obtained by subtracting the cost of implementation from the averted cost-risk:

$$\text{Net Value} = \$820,497 - \$500,000 = \$320,497$$

For this example, the net value is positive.

Finally, a unique situation exists for SAMAs that are developed to specifically address external events risk. For these cases, IPEEE insights, the fire PRA, and the internal events PRA are used, as appropriate, to estimate the total benefit associated with SAMA implementation. The internal events modeling approach is the same as for SAMAs identified in the internal events models with the caveat that there may be no measurable impact on the internal events model for SAMAs specifically addressing external events risk. For PVNGS, the fire SAMAs that were quantified had no impact on internal events CDF and all of the assessments were made based on fire area CDF information. The changes in fire CDF were assumed to result in proportionate changes to the fire cost-risk. The reduction in the fire cost-risk is the averted cost-risk for these SAMAs.

Given that no non-fire external events SAMAs were identified for PVNGS, quantification strategies were not developed for those cases.

The implementation costs used in the Phase 2 analysis include both PVNGS-specific estimates developed by plant personnel and estimates taken from other SAMA submittals for those SAMAs that were determined to be similar. It should be noted that the PVNGS-specific implementation costs do include margin to account for unforeseen difficulties, but they do not account for any replacement power costs that may be incurred due to consequential shutdown time.

Sections D.6.1 – D.6.13 describe the detailed cost-benefit analysis that was used for each of the remaining candidates.

D.6.1 SAMA NUMBER 4: SBO MITIGATION (GTGS NOT AVAILABLE)

SBO scenarios lead to core damage once the station batteries deplete at three hours. In the event that AC power is not recovered, a 480V AC generator could be used to power the division 1 station batteries to support continued use of the turbine-driven AFW pump from the MCR. Given that the 480V AC generator is sized appropriately, it could also be used to power at least two charging pumps such that a primary side makeup source is available to mitigate any RCP seal LOCAs or leakage. The RCP seals at PVNGS are not highly susceptible to seal LOCAs, but primary side injection is assumed to be required for long term makeup for the expected inventory loss through the RCP seals after an SBO event. As a result, a primary side makeup capability has been included in the design.

In order to represent this SAMA, the GTG system logic was modified to include logic that would credit the 480V AC generator. While the 480V AC system would not be physically connected to the GTG system, the SAMA 4 logic can be included with the GTG system logic given that both systems would primarily be used in SBO cases. As a result, the SAMA 4 logic was “ANDed” with the failure of the GTGs to supply power to an ESF bus so that whenever the GTGs fail to supply power to the ESF buses, credit is also given to SAMA 4. The primary contributors to the SAMA 4 failures were considered to be:

- Operator action to align the portable generator
- Hardware failure of the generator
- Charging pump and failures
- Charging pump discharge pulsation dampener failure
- AFW pump A failure

A lumped event for the operator action to align the portable generator and for the generator to start and run has been assigned a value of 5.0E-2. Given that a standard PVNGS EDG has a failure-to-run probability of about 3.70E-02 for a 24-hour mission time and the start failure contributes another 3.8E-03, 5.0E-02 may be optimistic given that the alignment HEP would also have to be included. This action would likely have to be completed within 1 hour and requires local, manual actions in SBO conditions. The remaining failure contributors were represented by existing events from the PVNGS PRA. The following table summarizes the changes that were made:

SAMA 4 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GGTG-1GTG: Power to ESF Bus from Either GTG Unavail; i.e. Both GTGs Fail Modified for SAMA 4	Changed gate type from "OR" to "AND". Deleted following transfer gates: • GGTG-2 • GGTG-2-1GTG-OOS Added new OR gates: • SAMA4 • GGTG-1GTG-1A
SAMA4: Failure of Port Gen or Major Hardware Failures for AFW and Charging	New "OR" gate including the following events: • SAMA4-OP-PORTGEN • 1CHAP01----MP-FR • 1CHAX07----PDDEL • 1CHEP01----MP-FR • 1CHEX07----PDDEL • 1AFAP01----TPAFR
SAMA4-OP-PORTGEN: Lumped Event for Generator Hardware Failure and Op Error	New basic event. Assigned failure probability of 5.00E-02.
GGTG-1GTG-1A: Power to ESF Bus from Either GTG Unavail; i.e. Both GTGs Fail	New "OR" gate including the following events: • GGTG-2 • GGTG-2-1GTG-OOS

D.6.1.1 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 4 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	4.04E-06	8.94	$11,204	2.67E-06
Percent Change	-20.3%	-34.4%	-25.0%	-1.8%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 4 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.720E-07	4.40E-07	1.84E-06	5.010E-07	4.88E-07	3.78E-07	1.21E-07	1.49E-08	6.17E-09	0.00E+00	2.25E-07	**4.19E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.45	0.06	1.51	4.35	0.30	0.14	0.11	0.00	2.02	**8.94**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3,947	**$14,929**
OECR$_{SAMA}$	$0	$0	$9	$1	$49	$7,031	$11	$441	$152	$0	$3,510	**$11,204**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $552,127
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 4 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$552,127	0.464	$256,187

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 4 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.67E-06	$409,342

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 4 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)
$552,127	$256,187	$409,342	3	$3,652,968

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 4 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$3,652,968	$1,015,032

D.6.1.2 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $1,832,954 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $5,498,862. While this cost of implementation exceeds the MACR of $4.67 million, it has been retained for analysis due to the high profile nature of the case.

D.6.1.3 NET VALUE

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

SAMA 4 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$1,015,032	$5,498,862	-$4,483,830

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

D.6.2 SAMA NUMBER 6: DEVELOP PROCEDURES TO GUIDE RECOVERY ACTIONS FOR SPURIOUS ELECTRICAL PROTECTION FAULTS

Loss of bus initiators are potentially recoverable in accident scenarios, but procedures are not currently available to provide guidance for those evolutions. The recovery process may be enhanced if guidance is developed for the site. Recovery of the initially locked out bus will restore power to an entire division of equipment and provide significant recovery options.

The spurious bus lockout events are represented in the PRA model by two basic events, one for the “A” division and one for the “B” division. Procedure improvements that would allow credit for recovery of the spurious bus lockout events can be modeled through manipulation of the basic event probabilities of these events. While it is difficult to assess the potential reliability of the recovery actions, the averted cost-risk for the SAMA is not particularly sensitive to the credit taken for the action. Even if the failure probability for the action was assumed to be as high as 0.1, this recovery would eliminate 90% of the bus lockout risk. For this evaluation, it was assumed that the recovery action is always successful, which maximizes the averted cost-risk for the SAMA. The following table summarizes the changes that were made:

SAMA 6 Model Changes

Gate and/or Basic Event ID and Description	Description of Change
1PBAS03LBKXCXAXX: spur Elect Prot on Train A ESF Bus Locks Out All Power Sources	BE probability changed from 6.50E-06 to 0.0.
1PBBS04KBLXCXAXX: spur Elect Prot on Train B ESF Bus Locks Out All Power Sources	BE probability changed from 6.50E-06 to 0.0.

D.6.2.1 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 6 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF (per year)
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	4.56E-06	12.38	$13,025	2.72E-06
Percent Change	-10.1%	-9.1%	-12.8%	0.0%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 6 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk

Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.35E-07	4.91E-07	1.47E-06	5.01E-07	1.28E-06	4.70E-07	1.21E-07	1.51E-08	7.89E-09	0.00E+00	2.24E-07	**4.56E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.36	0.06	3.96	5.41	0.30	0.14	0.14	0.00	2.01	**12.38**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$7	$1	$128	$8742	$11	$447	$195	$0	$3494	**$13,025**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $697,669.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 6 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$697,669	0.464	$323,718

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 6 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.72E-06	$417,008

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 6 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)
$697,669	$323,718	$417,008	3	$4,315,185

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.

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

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
Percent Change	-7.7%	-22.2%	-30.1%	-7.4%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 8 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.71E-07	4.35E-07	1.83E-06	5.01E-07	1.20E-06	3.29E-07	1.21E-07	1.50E-08	8.61E-09	0.00E+00	2.26E-07	**4.84E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.44	0.06	3.71	3.78	0.30	0.14	0.15	0.00	2.02	**10.60**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$8	$1	$120	$6119	$11	$444	$213	$0	$3526	**$10,442**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $608,669.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 8 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$608,669	0.464	$282,4222

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 8 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.52E-06	$386,346

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 8 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)
$608,669	$282,422	$386,346	3	$3,832,311

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 8 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$3,832,311	$835,689

D.6.3.2 COST OF IMPLEMENTATION

TMI-1 estimated the cost of modifying the SBO EDG so that it could auto-start and load to be $3,125,000 (Exelon 2008). It is assumed that the cost of this type of modification for a GTG is about the same. For PVNGS, only one GTG is required for SBO loads and it is assumed that all three units can be addressed through the enhancement of one GTG. The cost for implementing this SAMA for three units is $3,125,000.

D.6.3.3 NET VALUE

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

SAMA 8 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$835,689	$3,125,000	-$2,289,311

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

D.6.4 SAMA NUMBER 10: PROVIDE A BACKUP AFW START SIGNAL ON A LOWER SG LEVEL AND USE IT FOR ALL THREE AFW PUMPS

This enhancement would provide a diverse backup to the auto-start logic currently used for safety related AFW pumps AFA-P01 and AFB-P01 and provide a primary start signal for non-safety AFW pump AFN-P01. This enhancement improves the reliability of a function that is critical to the mitigation of almost all accident scenarios.

This SAMA has two major modeling components, one for the AFN pump and one for the AFW pumps. Given that the only start function for AFN-P01 is provided by operator action, the basic events representing the operator actions can be manipulated to model the installation of the automatic start function. Based on a review of the major contributors to the EDG start logic, which is considered to adequately represent the reliability of an automated start signal, a failure probability of 5.0E-04 was applied to the two relevant basic events for AFN-P01 operator start failures. Additional credit could be taken for backup manual starts, but the results would not change in a meaningful way, so only the automated function is credited.

More complex model changes are required to credit a secondary start signal for the class AFW pumps (1AFA-P01 and 1AFB-P01). For train “B”, the automatic actuation logic was “AND”ed with the modified basic events representing the automatic actuation of AFN-P01. Train “A” does not have a similar structure for pump actuation; the only ASFAS actuation signal used is linked to the valves that are required to realign on AFW A start. The logic that governs these valve movements was “AND”ed with the same modified basic events representing the automatic actuation of AFN-P01.
The following table summarizes the changes that were made:

SAMA 10 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GAF1A2: Train A Isol MOV UV36 Fails to Open (no flow to SG 1)	Deleted following transfer gate: • GAF-ACT-A1R2 Added new "AND" gate: • SAMA10-AFWA1
SAMA10-AFWA1: Actuation for AFW A	New "AND" gate including the following events: • AFN-ACTUATION-A (new "OR" gate) • GAF-ACT-A1R2 (existing gate)
AFN-ACTUATION-A: Op Actions from AFN Modified to Serve as Independent Actuation for AFW	New "OR" gate including the following events: • 1AFN-NOMFW----HR (existing BE modified for SAMA 10) • 1AFN-NOMFW-ND-HR (existing BE modified for SAMA 10)
1AFN-NOMFW----HR: CR Operator Fails to Align AFN (MFW Lost)	Changed BE value from 3.20E-03 to 5.00E-04.
1AFN-NOMFW-ND-HR: CR Operator Fails to Align AFN (MFW Lost) - No Diagnosis	Changed BE value from 2.20E-01 to 5.00E-04.
GAF1A30: Train A Regulator HV32 Fails to Open (no flow to SG 1)	Deleted following transfer gate: • GAF-ACT-A1R3 Added new "AND" gate: • SAMA10-AFWA2
SAMA10-AFWA2: Actuation for AFW A	New "AND" gate including the following events: • AFN-ACTUATION (new "OR" gate) • GAF-ACT-A1R3 (existing gate)
AFN-ACTUATION: Op Actions from AFN Modified to Serve as Independent Actuation for AFW	New "OR" gate including the following events: • 1AFN-NOMFW----HR (existing BE modified for SAMA 10) • 1AFN-NOMFW-ND-HR (existing BE modified for SAMA 10)
1AFN-NOMFW---FHR: XE CR Operator Fails to Align AFN (MFW Lost) - Post Fire	Changed BE value from 6.40E-03 to 5.00E-04.
GAFBP01FS: AFW B Pump Fails to Start	Deleted following transfer gate: • GAF2B18 Added new "AND" gate: • SAMA10-AFWB

SAMA 10 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
SAMA10-AFWB: Actuation for AFW B	New "AND" gate including the following events: • AFB-ACTUATIONB1 (new "OR" gate) • GAF2B18 (existing gate for B actuation)
AFB-ACTUATIONB1: Op Actions for AFW B Modified to Serve as Independent Actuation for AFW	New "OR" gate including the following events: • 1AFN-NOMFW----HR (existing BE modified for SAMA 10) • 1AFN-NOMFW-ND-HR (existing BE modified for SAMA 10)

D.6.4.1 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 10 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	4.60E-06	12.95	$13,915	2.58E-06
Percent Change	-9.3%	-4.9%	-6.8%	-5.2%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 10 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.50E-07	3.20E-07	1.61E-06	5.01E-07	1.28E-06	5.10E-07	1.21E-07	1.51E-08	8.74E-09	0.00E+00	2.32E-07	**4.75E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.39	0.06	3.96	5.87	0.30	0.14	0.15	0.00	2.08	**12.95**

SAMA 10 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
$OECR_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
$OECR_{SAMA}$	$0	$0	$7	$1	$128	$9486	$11	$447	$216	$0	$3619	**$13,915**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $729,329.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 10 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$729,329	0.464	$338,409

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 10 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.58E-06	$395,544

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 10 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)
$729,329	$338,409	$395,544	3	$4,389,846

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 10 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,389,846	$278,154

D.6.4.2 COST OF IMPLEMENTATION

The Farley SAMA analysis (SNC 2003) provides a cost of implementation of $1,000,000 to provide backup start signals for the standby CCW trains on loss of the running train. A CCW system is different than a feedwater system, but the installation of sensors to provide a start signal to a pump is common to both SAMAs and the changes are considered to be similar. The Farley estimate of $1,000,000 per unit is used for this SAMA. For three units, the cost of implementation is $3,000,000.

D.6.4.3 NET VALUE

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

SAMA 10 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$278,154	$3,000,000	-$2,721,846

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

D.6.5 SAMA NUMBER 11: ALTERNATE COOLING FLOW TO SDC HEAT EXCHANGERS

For scenarios that require recirculation mode, if essential cooling water (EW) flow is lost to the shutdown cooling (SDC) heat exchangers, there is no other means of removing heat from the core/containment. Providing an alternate means of cooling the SDC heat exchangers could address EW system failures. The existing Fire Protection system may not be able to provide the required cooling flows, but if significant enhancements were made (including an alternate suction alignment to the spray pond), it could be connected to the SDC heat exchangers with a hard-piped connection and provide backup cooling. This would also address some Emergency Spray Pond failures.

The approach taken to represent this SAMA in the PRA model was to modify the SDC heat exchanger cooling logic to include additional logic for the alternate cooling connection. The major failure contributors for this SAMA are considered to be the alignment and hardware failure for the alternate cooling connection and failure of the fire protection system itself. The alignment and hardware connection is represented by a single event with a failure probability of 5.00E-02. This probability is slightly more than an order of magnitude larger than the nominal SDC alignment HEP of 3.10E-03. Considering that the action is performed locally and that it does include a small potential for hardware failures, 5.00E-02 is considered to be reasonable. A lower value could be assumed, but the results would not be greatly impacted. Additionally, further reductions are not suggested given that dependence between the nominal SDC alignment action and the alternate action is not addressed in the SAMA logic.

The fire protection system logic is already included in the PRA model for the fire model and it was used to represent the availability of fire protection system flow for this SAMA. For supplying flow to the SDC heat exchangers, it is assumed that both the North and South headers are required for success. For actual implementation, the pumps and some piping would likely have to be increased in size even if both headers are used, but the failure probabilities for the components would be about the same, so any required component changes are assumed not to impact the system reliability. The following table summarizes the changes that were made:

SAMA 11 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GDHR-HX1A: Fault in Systems Supplying Cooling Water to Train A SDCHX	Changed gate type from "OR" to "AND". Deleted following transfer gates: • GDHR-HX1B • 1ESS-CLG----1OP • 1ESS-SPA-----1OP Added new OR gates: • GDHRHX1A-S11 • SAMA-11-ALTCLGA
GDHRHX1A-S11: Original Cooling Water logic to HX A	New "OR" gate with the following inputs: • GDHR-HX1B (existing gate) • 1ESS-CLG----1OP (existing gate) • 1ESS-SPA-----1OP (existing gate)
SAMA-11-ALTCLGA: Alt SDC A HX Cooling	New "OR" gate with the following inputs: • SAMA11-ALTCLGHR (new be) • GFWTR-NHDR (existing gate) • GFWTR-SHDR (existing gate)

SAMA 11 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GDHR-HX2A: Fault in Systems Supplying Cooling Water to Train B SDCHX	Changed gate type from "OR" to "AND". Deleted following transfer gates: • GDHR-HX2B • 1ESS-CLGB---1OP • 1ESS-SPB-----1OP Added new OR gates: • GDHR-HX2A-S11 • SAMA11-ALTCLGB
GDHR-HX2A-S11: Original Cooling Water logic to HX B	New "OR" gate with the following inputs: • GDHR-HX2B (existing gate) • 1ESS-CLGB---1OP (existing gate) • 1ESS-SPB-----1OP (existing gate)
SAMA11-ALTCLGB: Alt SDC HX B Cooling	New "OR" gate with the following inputs: • SAMA11-ALTCLGHR (new be) • GFWTR-NHDR (existing gate) • GFWTR-SHDR (existing gate)
SAMA11-ALTCLGHR: Lumped Event for Operator Alignment Failure and FP System Hardware	New basic event. Assigned failure probability of 5.00E-02.

D.6.5.1 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 11 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	4.97E-06	13.07	$14,562	2.72E-06
Percent Change	-2.0%	-4.0%	-2.5%	0.0%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 11 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.73E-07	5.08E-07	1.86E-06	5.02E-07	1.19E-06	5.27E-07	1.01E-07	1.51E-08	9.24E-09	0.00E+00	2.530E-07	**5.14E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.45	0.06	3.68	6.06	0.25	0.14	0.16	0.00	2.27	**13.07**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$9	$1	$119	$9802	$9	$447	$228	$0	$3947	**$14,562**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $753,114.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 11 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$753,114	0.464	$349,445

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 11 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.72E-06	$417,008

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 11 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)
$753,114	$349,445	$417,008	3	$4,558,701

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 11 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,558,701	$109,299

D.6.5.2 COST OF IMPLEMENTATION

Two similar industry estimates are available for this type of enhancement, but the actual cost will be highly subject to piping locations in the plant. As a result, the range of costs has been reviewed and the lower end cost has been chosen as a bounding case for PVNGS:

- TVA: $500,000 per Hx (TVA 2003)
- Calvert Cliffs $565,000, appears to equate to "per Hx" (BGE 1998)

For PVNGS, it is assumed that the cost is $500,000 per SDC HX, which equates to $3,000,000 for the site.

D.6.5.3 NET VALUE

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

SAMA 11 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$109,299	$3,000,000	-$2,890,701

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

D.6.6 SAMA NUMBER 13: MITIGATE LOSS OF TCW EVENTS: PROVIDE PERMANENT, HARD-PIPED CONNECTIONS BETWEEN THE FIRE PROTECTION SYSTEM AND CRITICAL LOADS

Turbine building cooling water (TCW) provides cooling water to several loads, but those that are most important to plant safety include the Instrument Air system and the Condensate pump upper bearing oil coolers. If permanent, hard-piped connections were installed between the Fire Protection system and those loads, a means of recovering MFW and/or Condensate would be available for loss of TCW events. Long term success is assumed to require the addition of an alternate suction path between the Fire Protection system and the spray pond.

In the PRA model, The TCW system's logic is limited to two house events linked to the initiating event for Loss of TCW and the initiating event itself. For the purposes of this analysis, it was assumed that the alternate TCW cooling alignment proposed in this SAMA was capable of both mitigating the loss of the system as well as preventing the conditions that would cause a plant trip. The assumption that this SAMA could prevent the initiating event is likely optimistic for multiple reasons, but performing a local action to restore oil bearing cooling for the condensate pumps would be especially difficult due to time constraints. However, the increase in this SAMA's benefit due to this assumption is conservative and it has been included in the analysis. Specifically, it was assumed that the operators are 90% effective in preventing a trip on Loss of TCW. Given failure to prevent the Loss of TCW initiating event, a conditional failure probability of 1.00E-02 was assigned to the action to prevent loss of the oil bearing coolers or the instrument air (IA) compressors during the accident response. In order to credit the SAMA's ability to prevent loss of the IA compressors and the Condensate pumps, the house events used to fail those components on Loss of TCW were "AND"ed with a lumped event representing the human and hardware failures for the alternate cooling alignment. The value of 1E-02, which has a minimal impact on the results of this quantification, was assigned based on judgment and the fact that the ASEP upper bound diagnosis error ranges from 1.00E-02 to 3.00E-03 for diagnosis times from 30 to 60 minutes. The following table summarizes the changes that were made:

SAMA 13 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GIACOMP-HDR: Insufficient Air Flow From Receiver IAN-X01B to Discharge Hdr	Deleted following house event: • IE-PCW-TCW-IAS Added new OR gate: • SAMA13-ALTTCW (new "OR" gate)
SAMA13-ALTTCW: Initiator Impacts	New "OR" gate including the following inputs: • SAMA13-ALTCL-1 (New "AND" gate) • SAMA13-ALTCL-2 (New "AND" gate) • SAMA13-ALTCL-3 (New "AND" gate)

SAMA 13 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
SAMA13-ALTCL-1: For Loss of TCW	New “AND” gate with the following inputs: • SAMA13-ALTTCW (new basic event) • IE-PCW-TCW-IAS (existing house event) • IETCW (existing basic event)
SAMA13-ALTTCW: Lumped Event for Op Action and Hdwr Failures for alt TCW Cooling Late (IE Prevention Fails)	New basic event with failure probability of 1.00E-02.
SAMA13-ALTCL-2: For Loss of IAS	New “AND” gate with the following inputs: • IE-PCW-TCW-IAS (existing house event) • IEIAS (existing basic event)
SAMA13-ALTCL-3: For Loss of PCW	New “AND” gate with the following inputs: • IE-PCW-TCW-IAS (existing house event) • IEPCW (existing basic event)
GALF-PUMP-IE: IEs Resulting in Loss of All Three Condensate Pumps	Deleted following house event: • IE-TCW Added new OR gate: • SAMA13-CND-CL (new “AND” gate)
SAMA13-CND-CL: No Alt Cooling with initiating eventTCW Initiating Event	New “AND” gate with the following inputs: • IE-TCW (existing house event) • SAMA13-ALTTCW (new basic event)
GGAN2BACKUP: IEs Leading to Automatic Backup of Instrument Air by N2	Deleted following house event: • IE-PCW-TCW-IAS Added new AND gates: • SAMA13-TCW-CL (new “AND” gate) • SAMA13-IASFL (new “AND” gate) • SAMA13-PCWFL (new “AND” gate)
SAMA13-TCW-CL: For Loss of TCW	New “AND” gate with the following inputs: • SAMA13-ALTTCW (new basic event) • IE-PCW-TCW-IAS (existing house event) • IETCW (existing basic event)
SAMA13-IASFL: No Credit for IAS Initiating Event	New “AND” gate with the following inputs: • IE-PCW-TCW-IAS (existing house event) • IEIAS (existing basic event)
SAMA13-PCWFL: No Credit for PCW Initiating Event	New “AND” gate with the following inputs: • IE-PCW-TCW-IAS (existing house event) • IEPCW (existing basic event)
IETCW: Initiating Event - loss of Turbine cooling Water	Changed frequency from 8.92E-03 to 8.92E-04.

D.6.6.1 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 13 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	4.97E-06	13.53	$14,810	2.72E-06
Percent Change	-2.0%	-0.7%	-0.8%	0.0%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 13 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.660E-07	4.770E-07	1.780E-06	5.010E-07	1.280E-06	5.440E-07	1.210E-07	1.510E-08	9.24E-09	0.000E+00	2.480E-07	**5.14E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.43	0.06	3.96	6.26	0.30	0.14	0.16	0.00	2.22	**13.53**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$8	$1	$128	$10,118	$11	$447	$228	$0	$3869	**$14,810**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $770,681.

The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 13 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk

SAMA 13 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$770,681	0.464	$357,596

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 13 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.72E-06	$417,008

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 13 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)
$770,681	$357,596	$417,008	3	$4,635,855

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 13 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,635,855	$32,145

D.6.6.2 COST OF IMPLEMENTATION

The cost estimate for SAMA 11 is used as the basis for this cost estimate. It is assumed that the cost of each connection between Fire Protection and a critical load is the same as the connection between Fire Protection and an SDC Hx ($500,000). In this case, there are two critical loads per unit (condensate upper bearing oil coolers and IA (1 train of each required)), which yields $1 million per unit, or $3 million for the site.

D.6.6.3 NET VALUE

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

SAMA 13 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$32,145	$3,000,000	-$2,967,855

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

D.6.7 SAMA NUMBER 15: 100% CAPACITY BATTERY CHARGERS

The current battery chargers are capable of supplying the DC loads without the batteries in the later stages of an accident scenario; however, it has been determined that the loads in the first hours after a plant trip can exceed the output of the chargers such that the batteries are required to supplement them. Enhancing the battery chargers so that they can supply all DC loads without tripping when the battery is not available in the circuit would increase the DC system's capabilities and provide greater defense in depth.

The PVNGS model does not include the battery chargers in the logic that is used for short term DC applications, which properly credits the batteries as being capable of supplying DC loads without a charging source in that time frame. This approach also breaks the circular logic that typically exists between the EDGs and the station batteries. In order to represent this SAMA in the PRA, the logic was manipulated to include the DC chargers as viable power sources for all loads except those that are used to support alignment or recovery of an AC power source to mitigate a loss of the normal ESF bus supplies. This exclusion is required given that the chargers would not have power after a loss of the ESF buses. The following table summarizes the changes that were made:

SAMA 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
1PKAM41-125--1PW: Loss of Power at DC Control Center PKA-M41	Deleted following transfer gate: • GPKA41-5 Added new AND gate: • @1PKAM41-125--1PW-1

SAMA 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
@1PKAM41-125--1PW-1: Chargers and Batteries Unavailable (A)	New "AND" gate including the following inputs: • GPKA41-5 (existing gate for battery "A" power) • GPKA41-4 (existing gate for charger "A" power)
1PKBM42-125--1PW: Loss of Power at DC Control Center PKB-M42	Deleted following transfer gate: • GPKB42-5 Added new AND gate: • @1PKBM42-125--1PW-1
@1PKBM42-125--1PW-1: Chargers and Batteries Unavailable (B)	New "AND" gate including the following inputs: • GPKB42-5 (existing gate for battery "B" power) • GPKB42-4 (existing gate for charger "B" power)
1PKCM43-125--1PW: Loss of Power at DC Control Center PKC-M43	Deleted following transfer gate: • GPKC43-1 Added new AND gate: • @1PKCM43-125--1PW-1
@1PKCM43-125--1PW-1: Chargers and Batteries Unavailable (C)	New "AND" gate including the following inputs: • GPKC43-1 (existing gate for battery "C" power) • GPKC43-4 (existing gate for charger "C" power)
1PKDM44-125--1PW: Loss of Power at DC Control Center PKD-M44	Deleted following transfer gate: • GPKD44-5 Added new AND gate: • @1PKDM44-125--1PW-1
@1PKDM44-125--1PW-1: Chargers and Batteries Unavailable (D)	New "AND" gate including the following inputs: • GPKD44-5 (existing gate for battery "D" power) • GPKD44-4 (existing gate for charger "D" power)

D.6.7.1 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 15 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	4.89E-06	12.36	$13,150	2.64E-06
Percent Change	-3.6%	-9.2%	-11.9%	-2.9%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 15 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.70E-07	4.83E-07	1.82E-06	5.00E-07	1.23E-06	4.61E-07	1.20E-07	1.510E-08	9.11E-09	0.00E+00	2.41E-07	**5.05E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.44	0.06	3.80	5.30	0.30	0.14	0.16	0.00	2.16	**12.36**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$8	$1	$123	$8575	$11	$447	$225	$0	$3760	**$13,150**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $708,263.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 15 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$708,263	0.464	$328,634

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 15 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.64E-06	$404,743

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 15 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)
$708,263	$328,634	$404,743	3	$4,324,920

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 15 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,324,920	$343,080

D.6.7.2 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $547,566 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be three times greater at $1,642,698.

D.6.7.3 NET VALUE

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

SAMA 15 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$343,080	$1,642,698	-$1,299,618

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

D.6.8 SAMA NUMBER 17: MODIFY THE PROCEDURES TO PRECLUDE RCP OPERATIONS THAT WOULD CLEAR THE WATER SEALS IN THE COLD LEG AFTER CORE DAMAGE

The probability of a temperature-induced SGTR event increases when the water seal in the reactor coolant loop is not present. In these cases, an open pathway exists that will allow circulation of the hot core gases through the SGs. Procedurally preventing operation of the RCPs in conditions that would clear the loop water seal would improve the probability that the RCS would remain intact.

The probability that a temperature-induced SGTR (TI SGTR) will occur at PVNGS after core damage is based on event tree quantification. This event tree considers, among other things, whether or not the RCP loop seal would be cleared during the time after core damage. The Level 2 model uses the result of the event tree quantification as the basis for a Level 2 basic event that represents the probability that a TI SGTR will occur after core damage. This SAMA can be represented by modifying the probability that the RCP loop seal will be cleared during the time after core damage and updating the corresponding Level 2 basic event with the results. For this analysis, it is assumed that providing explicit instructions in the procedures that direct the operators to avoid running the RCPs will reduce the probability that the RCP loop seal will be cleared by a factor of 10. The following table summarizes the changes that were made:

SAMA 17 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
L2-LSCB-CLEARED: L2 Loop Seal & Core Barrel Cleared	Probability changed from 1.40E-01 to 1.40E-02 for TI SGTR event tree.
L2-LSCB-NOTCLEARED: : L2 Loop Seal & Core Barrel Not Cleared	Probability changed from 8.60E-01 to 9.86E-01 for TI SGTR event tree.
L2-TI-SGTR: L2 Temperature Induced SGTR	Probability changed from 5.29E-02 to 4.12E-02 based on TI SGTR event tree quantification.

D.6.8.1 AVERTED COST-RISK

The model changes identified above yielded a reduction in the 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 17 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	5.07E-06	13.37	$14,492	2.72E-06
Percent Change	0.0%	-1.8%	-2.9%	0.0%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 17 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.72E-07	4.92E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.25E-07	**5.21E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.02	**13.37**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**

SAMA 17 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
$OECR_{SAMA}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3510	**$14,492**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $763,908.

The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 17 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$763,908	0.464	$354,453

The fire cost-risk contribution is calculated differently for this case than for other cases. Because the internal events quantification was based on modification of Level 2 model components, an alternate approach is required to measure the fire impact given that a comparable Level 2 model does not exist for internal fires. This was required because TI SGTR scenarios can occur in fire scenarios and the fire initiators would be impacted by this SAMA. For this analysis, it was assumed that the total fire cost-risk would be reduced by the same factor as the internal events SGTR release category frequency. The following table summarizes these results for a single unit:

SAMA 17 Fire Cost-Risk Contribution

	Internal Events SGTR Frequency (per yr)	Fire Cost-Risk
Base Results	2.53E-07	$417,008
SAMA Results	2.25E-07	$370,857

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

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.

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 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 calculations. The cost-risk calculation for this SAMA is straightforward and is equal to the total cost-risk from fire compartments FZ 5A and 5Z 5B for all three units, or $177,645 (($54,211 + $5004) * 3 = $177,645).

D.6.9.1 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $1,553,894 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $4,661,682.

D.6.9.2 NET VALUE

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

SAMA 19 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$177,645	$4,661,682	-$4,484,037

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

D.6.10 SAMA NUMBER 20: INSTALL FIRE BARRIERS BETWEEN FIRE ZONE TB1 AND TB5

Fires in fire zone TB5 (Turbine Building 140 ft West)) do not pose a large risk to the plant from equipment losses within that zone, but if the fire propagates to fire zone TB1 (Turbine Building 100 ft West), the consequences are more severe. Installing a fire barrier between these two zones would prevent propagation of a fire from TB5 to TB1 and the consequential loss of AFN-P01, Alternative Feedwater, and load centers L01 and L25. In addition, the barrier must protect fire zone TB1 from the effects of suppression system actuation in fire zone TB5 as the water can damage TB1 equipment.

It is assumed that if the portion of the PVNGS CDF and release consequences related to fire compartment FZ TB5 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 compartment FZ TB5
- 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 its relative contribution 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 TB5	6.6%	$27,523

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the small cost-risk contribution from this fire compartment, it was conservatively assumed that this SAMA eliminates all risk associated with the compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to the total cost-risk from fire compartment FZ TB5 for all 3 units, or $82,569 ($27,523 * 3 = $82,569).

D.6.10.1 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $1,208,564 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,625,692.

D.6.10.2 NET VALUE

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

SAMA 20 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$82,569	$3,625,692.	-$3,543,123

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

D.6.11 SAMA NUMBER 21: INSTALL FIRE RESISTANT CABLE WRAP ON SELECTED CABLES IN FIRE COMPARTMENT TB4B

Transient fires in FZ TB4B (Station DC Equipment Room - 110 ft Turbine Building) can fail cables related to NAN-S03 and NAN-S04 (loss of switchyard) or NBNX03 (loss of Train A ESF service transformer). Installing fire resistant cable wrap on these circuits in the sections of the cable trays that are close enough to the floor to be impacted by transient fires could prevent the loss of critical equipment in fire events.
It is assumed that if the portion of the PVNGS CDF and release consequences related to fire compartment FZ TB4B 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 compartment FZ TB4B
- 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 its relative contribution 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 TB4B	1.2%	$5004

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the small cost-risk contribution from this fire compartment, it was conservatively assumed that this SAMA eliminates all risk associated with the compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to the total cost-risk from fire compartment FZ TB4B for all 3 units, or $15,012 ($5004 * 3 = $15,012).

D.6.11.1 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $1,121,838 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,365,514.

D.6.11.2 NET VALUE

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

SAMA 21 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$15,012	$3,365,514	-$3,350,502

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

D.6.12 SAMA NUMBER 22: ENHANCE THE MCC M71 FIRE BARRIERS

Transient fires in FZ 42A (Electrical Penetration Room - Train A, Channel C - Auxiliary Building - 100 ft) can result in the loss of MCC M71, which results in the failure of AFN-P01. Improving the MCC's barriers to better withstand fires could prevent the loss of the equipment in certain fire scenarios.

It is assumed that if the portion of the PVNGS CDF and release consequences related to fire compartment FZ 42A 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 compartment FZ 42A
- Calculate the% 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 42A	1.1%	$4587

The risk reduction possible for this area is a fraction of the total based on the potential capabilities of the changes proposed in this SAMA. Due to the small cost-risk contribution from this fire compartment, it was conservatively assumed that this SAMA eliminates all risk associated with the compartment to simplify the calculations. The cost-risk calculation for this SAMA is straightforward and is equal to the total cost-risk from fire compartment FZ 42A for all 3 units, or $13,761 ($4587 * 3 = $13,761).

D.6.12.1 COST OF IMPLEMENTATION

PVNGS estimated an implementation cost of $1,090,700 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,272,100.

D.6.12.2 NET VALUE

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

SAMA 22 Net Value

Total Averted Cost-Risk	Cost of Implementation	Net Value
$13,761	$3,272,100	-$3,258,339

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

D.6.13 SAMA NUMBER 23: ENHANCE PROCEDURES TO DIRECT STEAMGENERATOR FLOODING FOR RELEASE SCRUBBING

The existing PVNGS guidance governs SG levels for heat removal considerations, which may consequently result in release scrubbing; however, the guidance is not tailored to meet this need. Expanding the existing guidance to direct SG flooding prior to core damage would potentially improve the probability that water would be available above the break point in the SG and provide a mechanical means of scrubbing the fission products during a release.

The impact of implementing this SAMA was estimated by reviewing the Level 1 and Level 2 event trees to identify which sequences could benefit from directions to flood the SGs before core damage and removing their contributions from the SGTR bin (no model quantification required). The sequences that were chosen were those in which makeup to the SGs was available to carry out the flooding action. The PI SGTR and TI SGTR sequences were not credited because SG makeup is not available in those cases.

This method is conservative in that it assumes that the flooding action is 100% reliable and because it does not redistribute the frequency of the “scrubbed” events into a representative release category (likely a small early release). This approach was chosen given that the source term for the small early release was not immediately available and because the results are not sensitive to reliability of the flooding action over the range of reasonable failure probabilities for the action. The following table summarizes the changes that were made:

SAMA 23 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
SGTR Release Category Frequency	Eliminated the contributions from the following SGTR sequences: • Sequence 4: 2.66E-10. In this sequence, Rx trip is successful, HPSI is successful, SG heat removal is successful, depressurization is successful, SG isolation fails, SDC fails, and RWT makeup fails. • Sequence 7: 7.67E-09. In this sequence, Rx trip is successful, HPSI is successful, SG heat removal is successful, depressurization fails, SG isolation fails, SDC fails, and RWT makeup fails. • Sequence 10: 2.20E-08. In this sequence, Rx trip is successful, HPSI fails, SG heat removal is successful, depressurization is successful, and SG isolation fails. • Sequence 11: 2.07E-08. In this sequence, Rx trip is successful, HPSI fails, SG heat removal is successful, and depressurization fails.

D.6.13.1 AVERTED COST-RISK

The model changes identified above yielded a reduction in the 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 23 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	5.07E-06	13.19	$14,180	2.72E-06
Percent Change	0.0%	-3.2%	-5.0%	0.0%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 23 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq.	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**

(per yr)$_{BASE}$												
Freq. (per yr)$_{SAMA}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.05E-07	**5.19E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	1.84	**13.19**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3198	**$14,180**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $753,802.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 23 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$753,802	0.464	$349,764

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. Note that special consideration for the benefit of this SAMA in fire scenarios is not required as it was for SAMA 17; if flooding an SG were an option, a pressure induced or temperature induced SGTR event would not occur. Normal SGTR events, where water for flooding an SG may be available, are not included in the fire model (no dual initiators).

The following table summarizes the fire results for a single unit:

SAMA 23 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.72E-06	$417,008

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

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.

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 the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PRA results on the Phase I SAMA analysis has been examined. The MACR is the primary Phase I criteria affected by PRA uncertainty. Thus, this portion of this sensitivity is focused on recalculating the MACR using the 95th percentile PRA results and re-performing the Phase I screening process.

As discussed above, the 95th PRA results are approximately a factor of 2.7 greater than point estimate CDF. The uncertainty analyses that are available for the Level 1 models are not available for Level 2 and Level 3 PRA models. In order to simulate the use of the 95th percentile results for the Level 2 and Level 3 models, the same scaling factor calculated for the Level 1 results was assumed to apply to the Level 2 and Level 3 models. Because the MACR calculations scale linearly with the CDF, dose-risk, and off-site economic cost-risk, the 95th percentile MACR can be calculated by multiplying the base case MACR by 2.7. This results in a 95th percentile MACR of $12,603,600. The initial SAMA list has been re-examined using the revised MACR to identify SAMAs that would be retained for the Phase 2 analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $4.67 million are now retained if the costs of implementation are less than $12.60 million. Of the SAMAs screened in the baseline Phase 1 analysis, SAMAs 2, 5, 7, 12, and 14 would be retained based on the use of the 95th percentile MACR. As shown below, the lowest of the implementation costs is equal to over 52% of the 95th percentile MACR:

SAMA	Cost of Implementation	Percent of 95th Percentile MACR
2: Replace one Low Pressure Condensate Pumps with a High Pressure Motor Driven Pump (or Add a Booster Pump) and Add Hotwell Makeup Controls to the MCR from a Non-CST Source	$6,600,000	52.4%
5: Install an Automatic Transfer Switch for the Non-Safety AFW Pump (AFN-P01) Power Supply	$6,801,762	54.0%
7: Add Auto Start Capability to AFN-P01 on Low SG Level and an Automatic Power Transfer Switch to Address Loss of MFW Cases with Div 1 Power Failures and Operator Start Errors	$9,801,762	77.8%
12: Install an Automatic Transfer Switch for the AFW Pump AFB-P01 Power Supply	$6,801,762	54.0%
14: Provide a Permanent, Hard-piped Suction Line from the RMWT to AFN-P01	$6,647,190	52.7%

Based on a review of the scenarios that would not be impacted by the SAMAs, it was possible to determine that SAMAs 2 and 7 would not eliminate enough plant risk to be cost beneficial. For example, for SAMA 7 to be cost beneficial, it would have to eliminate over 77% of the MACR; however, the SAMA would not impact 42.8% of the CDF so it could not reduce the CDF by more than 57.2%. Given that the Level 2 contributions show a similar potential reduction of 59.3% (based on the importance rankings developed in Section D.5.1.2), there is no way for SAMA 7 to yield enough of a risk reduction to be cost effective. The case is similar for SAMA 2.

SAMA	Limitations	Potential Risk Reduction Estimate
2: Replace one Low Pressure Condensate Pump with a High Pressure Motor Driven Pump (or Add a Booster Pump) and Add Hotwell Makeup Controls to the MCR from a Non-CST Source	Not available for LOOP, which comprises 30.2% of CDF and 64.5% of the "composite" Level 2 frequency. Would not mitigate Loss of all Condensate Pumps: 7.5% of CDF and 8.2% of the "composite" Level 2 frequency. Would not mitigate ATWS with unfavorable moderator coefficient: 7.3% of CDF. Would not mitigate MLOCA: 2.5% of CDF. Other smaller contributors	<52.5% of CDF <27% of composite Level 2 frequency
5: Install an Automatic Transfer Switch for the Non-Safety AFW Pump (AFN-P01) Power Supply	Detailed analysis described below	--
7: Add Auto-Start Capability to AFN-P01 on Low SG Level and an Automatic Power Transfer Switch to Address Loss of MFW Cases with Div 1 Power Failures and Operator Start Errors	Not available for SBO, which comprises 23.3% of CDF and 30.5% of the "composite" Level 2 frequency. Would not mitigate ATWS with unfavorable moderator coefficient: 7.3% of CDF. Would not mitigate CCF of electric AFW pumps to start: 6.1% of CDF and 7.2% of the "composite" Level 2 frequency. Would not mitigate MLOCA: 2.5% of CDF Would not mitigate CCF of electric AFW pumps to run: 2.5% of CDF and 3.0% of the "composite" Level 2 frequency. Other smaller contributors	<57.2% of CDF <59.3% of composite Level 2 frequency
12: Install an Automatic Transfer Switch for the AFW Pump AFB-P01 Power Supply	Detailed analysis described below	--

SAMA	Limitations	Potential Risk Reduction Estimate
14: Provide a Permanent, Hard-piped Suction Line from the RMWT to AFN-P01	Detailed analysis described below	--

For SAMAs 5, 12, and 14, detailed quantifications were considered to better demonstrate that the proposed plant changes would not be cost effective. The following subsections provide the results in the same format used for the Phase II quantifications provided in Section D.6. Note that the impact of using the 95th percentile results for these cases is estimated by multiplying the base case averted cost risk by a factor of 2.7, which is consistent with the process established for estimating the 95th percentile MACR above.

D.7.2 SAMA NUMBER 5: INSTALL AN AUTOMATIC TRANSFER SWITCH FOR THE NON-SAFETY AFW PUMP (AFN-P01) POWER SUPPLY

Loss of division 1 power currently results in the loss of both AFA-P01 and AFN-P01. Providing an automatic power transfer capability would eliminate the need for operator intervention to supply AFN-P01 with power and preclude the need to depressurize the SGs for Alternate FW makeup. A subsequent manual transfer of DC control power would also be required, but there would be abundant time to perform this action.
This SAMA could have been represented by editing all of the power sources for all portions of the non-class AFW fault tree (for pump AFN-P01); however, this would be a time consuming effort and would require great care to prevent crediting other systems with the alternate power alignments intended for the non-class AFW system. As an alternative, a simplified approach was taken in which the non-class AFW logic was “AND”ed with the opposite division’s power logic. In order to prevent crediting the opposite power division for recovering non-power related AFW failures, the power logic was “OR”ed with the major non-power related failures for the non-class AFW system. The failures were identified through a review of the top 99.99% of the AFW system cutsets. The following table summarizes the changes that were made:

SAMA 5 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GAF1: AFW System Fails to Provide Flow to Steam Generator 1	Deleted following transfer gate: • GAF1R Added new “OR” gate: • @AF1-1

SAMA 5 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
@AF1-1: AFW Failure with Alt Power Supply	New “AND” gate including the following events: • GAF1R (existing gate) • SAMA5-ALT-PWR-1 (New FT Top)
SAMA5-ALT-PWR-1: Failure of Alt Power Supply or Major Non-Power AFW Failure	New FT Top “OR” gate with the following inputs: • GPBB-1-1GTG (existing gate for power to ESF Bus B) • 1AFNP01----MPAFR (existing AFN FTR logic) • 1CTAHV001--MV-FO (existing BE for AFN suction valve failure) • 1CTAHV004--MV-FO (existing BE for AFN pump supply valve failure) • 1AFNP01----MPAFS (existing AFN FTs logic) • 1AFNSYS----AFNCM (existing BE for AFN maintenance) • 1AFN---MFW----HR (existing BE for op alignment failure for AFN (MFW avail) • 1AFN-NOMFW----HR (existing BE for op alignment failure for AFN (MFW not avail) • 1AFNV013---NVNRM (existing BE for AFN pump discharge vlv maintenance) • 1AFNV013---NV-RO (existing BE for AFN pump discharge vlv fail closed) • 1AFNV012---CVAFO (existing logic for AFN pump discharge vlv fail to open) • 1CTET01----TKAEL (existing BE for CST failure)
GAF2: AFW System Fails to Provide Flow to Steam Generator 2	Deleted following transfer gate: • GAF2R Added new “AND” gate: • @AF2-1
@AF2-1: AFW Failure with Alt Power Supply	New “AND” gate including the following events: • GAF2R (existing gate) • SAMA5-ALT-PWR-1 (New FT Top)

D.7.2.1 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 5 PRA Model Results

	IE CDF (per yr)	Dose-Risk	OECR	Fire CDF
Base Results	5.07E-06	13.62	$14,929	2.72E-06
SAMA Results	4.13E-06	11.39	$11,750	1.04E-06
Percent Change	-18.5%	-16.4%	-21.3%	-61.8%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 5 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.18E-07	3.79E-07	1.26E-06	5.01E-07	1.23E-06	4.19E-07	1.21E-07	1.510E-08	6.91E-09	0.00E+00	2.05E-07	**4.26E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.31	0.06	3.80	4.82	0.30	0.14	0.12	0.00	1.84	**11.39**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$6	$1	$123	$7793	$11	$447	$171	$0	$3198	**$11,750**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $636,573.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 5 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk

SAMA 5 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$636,573	0.464	$295,370

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 5 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	1.04E-06	$159,444

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 5 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)
$636,573	$295,370	$159,444	3	$3,274,161

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 5 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$3,274,161	$1,393,839

In order to convert this to the 95th percentile averted cost-risk, it is multiplied by the 95th percentile factor of 2.7 to yield $3,763,365.

D.7.2.2 Cost of Implementation

PVNGS estimated an implementation cost of $2,267,254 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $6,801,762.

D.7.2.3 Net Value

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

SAMA 5 Net Value (95th %)

Total Averted Cost-Risk	Cost of Implementation	Net Value
$3,763,365	$6,801,762	-$3,038,397

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

D.7.3 SAMA NUMBER 12: INSTALL AN AUTOMATIC TRANSFER SWITCH FOR THE AFW PUMP AFB-P01 POWER SUPPLY

Loss of division 2 power currently results in the loss of AFB-P01. Providing an automatic power transfer capability would allow rapid recovery of AFB-P01 and preclude the need to depressurize the SGs for Alternate FW makeup. A subsequent manual transfer of DC control power would also be required, but there would be abundant time to perform this action.

This SAMA could have been represented by editing all of the power sources for all portions of the “B” division class AFW fault tree (for pump AFB-P01); however, this would be a time consuming effort and would require great care to prevent crediting other systems with the alternate power alignments intended for the “B” AFW system. As an alternative, a simplified approach was taken in which the “B” AFW logic was “AND”ed with the opposite division’s power logic. In order to prevent crediting the opposite power division for recovering non-power related AFW failures, the power logic was “OR”ed with the major non-power related failures for the “B” AFW system. The failures were identified through a review of the top 99.99% of the AFW system cutsets. The following table summarizes the changes that were made:

SAMA 12 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GAF1AB: No Flow to SG 1 AFW Check Valve V079 From Either Train A or B AFW	Deleted following transfer gate: • GAF1B1 Added new “AND” gate: • @AF1AB-1

SAMA 12 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
@AF1AB-1: AFW B with Additional, Alt Power Supply Fails to Provide Flow	New "AND" gate including the following events: • GAF1B1 (existing gate) • SAMA12-ALTPWR-1 (New FT TOP)
SAMA12-ALTPWR-1: Power Failures from Train A and Major Non-Power AFW Faults	New FT Top "OR" gate with the following inputs: • GPBA-1-1GTG (existing gate for power to ESF Bus A) • 1AFBP01----MPAFR (existing AFB FTR logic) • 1SABAF-K222RXAFT (relay failure for start logic) • 1SAB-LOADSQSQ-CM (load sequencer maintenance) • 1AFBP01----MPAFS (existing AFB FTs logic) • 1AFBV025---NVNRM (existing BE for AFB pump discharge vlv restoration failure) • 1AFBV025---NV-RO (existing BE for AFB pump discharge vlv fail closed) • 1AFBV022---CVAFO (existing logic for AFB pump discharge vlv fail to open)
GAF2AB: No Flow to SG 2 AFW Check Valve V080 From Either Train A or B AFW	Deleted following transfer gate: • GAF2B1 Added new "AND" gate: • @AF2AB-1
@AF2AB-1: No Flow From AFW Train B with Alternate Power Source Included	New "AND" gate including the following events: • GAF2B1 (existing gate) • SAMA12-ALTPWR-1 (New FT Top)

D.7.3.1 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 12 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	4.32E-06	12.09	$12,882	2.09E-06
Percent Change	-14.8%	-11.2%	-13.7%	-23.2%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 12 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.34E-07	3.47E-07	1.42E-06	5.01E-07	1.22E-06	4.75E-07	1.210E-07	1.510E-08	8.68E-09	0.00E+00	2.08E-07	**4.45E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{SAMA}$	0.00	0.00	0.35	0.06	3.77	5.46	0.30	0.14	0.15	0.00	1.86	**12.09**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{SAMA}$	$0	$0	$7	$1	$122	$8835	$11	$447	$214	$0	$3245	**$12,882**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $680,019.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 12 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$680,019	0.464	$315,529

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 12 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.09E-06	$320,422

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 12 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)
\$680,019	\$315,529	\$320,422	3	\$3,947,910

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 12 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
\$4,668,000	\$3,947,910	\$720,090

In order to convert this to the 95th percentile averted cost-risk, it is multiplied by the 95th percentile factor of 2.7 to yield \$1,944,243.

D.7.3.2 Cost of Implementation

This cost is assumed to be the same as that for SAMA 5 (\$6,801,762).

D.7.3.3 Net Value

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

SAMA 12 Net Value (95th %)

Total Averted Cost-Risk	Cost of Implementation	Net Value
\$1,944,243	\$6,801,762	-\$4,857,519

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

D.7.4 SAMA NUMBER 14: PROVIDE A PERMANENT, HARD-PIPED SUCTION LINE FROM THE RMWT TO AFN-P01

In the event that SG makeup capability has been lost and the failure of AFN-P01 is due to a failure of the suction line valves, having an alternate suction source for the pump would restore secondary side heat removal. Providing a permanent, hard-piped connection from the reactor makeup water tank (RMWT) will improve the reliability of the alignment action.

This SAMA was represented in the PRA model by crediting an alternate suction path to the RMWT for failures of the normal suction path (excluding pump suction valve failures). It was assumed that the alternate suction path could be failed by either an operator alignment failure or by the catastrophic failure of the RMWT. The operator alignment failure probability was assigned based on the following assumption:

- About one hour is available to core damage on loss of SG makeup
- Alignment time is about 15 minutes, which leaves about a 45 minute diagnosis time
- Two local valve manipulations are required.

If the median response curve is chosen in the nominal ASEP diagnosis curve, a 45-minute diagnosis time would correspond to a failure probability of 2.6E-04. Assuming the valves used for the alternate cooling alignment are clearly marked and identifiable, the local valve manipulations are assumed to have a manipulation failure probability of 1.00E-03 each. The total failure probability for the alignment action is 2.30E-03. The RMWT failure probability was assumed to be the same as that for the existing CST event. The following table summarizes the changes that were made:

SAMA 14 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
GAF5: No Flow to AFW Pump N Suction From CST	Deleted following inputs: • GAFHV4 (existing gate) • GAFHV1 (existing gate) • 1CTET01----TKAEL (existing basic event) Added new “AND” gates: • GAFHV4A • GAFHV1A • CST-RUPT-ALT
GAFHV4A: Credit for Alt Suction Recovering HV4 Faults	New “AND” gate including the following inputs: • GAFHV4 (existing gate) • @AF5-1 (new “OR” gate)
GAFHV1A: Credit for Alt Suction Recovering HV1 Faults	New “AND” gate including the following inputs: • GAFHVa (existing gate) • @AF5-2 (new “OR” gate)
CST-RUPT-ALT: Credit for Alt Suction Recovering CST Ruptures	New “AND” gate including the following inputs: • 1CTET01----TKAEL (existing basic event) • @AF5-3 (new “OR” gate)

SAMA 14 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
@AF5-1: Failure of RMWT or Alignment	New “OR” gate including the following inputs: • 1RWMT------TKAEL (new basic event) • ALT-AFN-H2O (new basic event)
@AF5-2: Failure of RMWT or Alignment	New “OR” gate including the following inputs: • 1RWMT------TKAEL (new basic event) • ALT-AFN-H2O (new basic event)
@AF5-3: Failure of RMWT or Alignment	New “OR” gate including the following inputs: • 1RWMT------TKAEL (new basic event) • ALT-AFN-H2O (new basic event)
1RWMT------TKAEL: RWMT Catastrophic Failure	New basic event. Assigned failure probability of 1.2E-08.
ALT-AFN-H2O: Operator Fails to Align AFW to RMWT	New basic event. Assigned failure probability of 2.3E-03.

D.7.4.1 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 14 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	4.91E-06	13.37	$14,554	2.68E-06
Percent Change	-3.2%	-1.8%	-2.5%	-1.5%

A further breakdown of this information is provided below according to release category for the internal events quantification:

SAMA 14 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Freq. (per yr)$_{SAMA}$	1.62E-07	4.83E-07	1.73E-06	5.010E-07	1.280E-06	5.37E-07	1.210E-07	1.510E-08	9.21E-09	0.00E+00	2.40E-07	**5.08E-06**

SAMA 14 Internal Events Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Dose-$Risk_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-$Risk_{SAMA}$	0.00	0.00	0.42	0.06	3.96	6.18	0.30	0.14	0.16	0.00	2.15	**13.37**
$OECR_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
$OECR_{SAMA}$	$0	$0	$8	$1	$128	$9988	$11	$447	$227	$0	$3744	**$14,554**

Using the methodology from Section D.4, these results were used to calculate the single unit internal events cost-risk contribution, which is $760,324.
The non-fire external events contribution to cost-risk can be calculated using the 0.464 multiplier on the single unit internal events cost-risk estimate:

SAMA 14 Non-Fire External Events Cost-Risk Contribution

SAMA Case Single Unit Internal Events Cost-Risk	Non-Fire External Events Multiplier	Total Non-Fire Cost-Risk
$760,324	0.464	$352,790

The assumption that the Fire CDF reduction is directly proportional to the reduction in the fire cost-risk contribution can be used to calculate the cost-risk contribution from fire events for this SAMA. The following table summarizes these results for a single unit:

SAMA 14 Fire Cost-Risk Contribution

	CDF (per yr)	Fire Cost-Risk
Base Results	2.72E-06	$417,008
SAMA Results	2.68E-06	$410,876

The site cost-risk for the SAMA is the sum of the cost-risks for the internal events, fire, and non-fire external events contributors times a multiplier of three to account for the three units:

SAMA 14 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)
$760,324	$352,790	$410,876	3	$4,571,970

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 14 Averted Cost-Risk

Base Case Total Cost-Risk (MACR)	Total SAMA Cost-Risk	Averted Cost-Risk
$4,668,000	$4,571,970	$96,030

In order to convert this to the 95th percentile averted cost-risk, it is multiplied by the 95th percentile factor of 2.7 to yield $259,281.

D.7.4.2 Cost of Implementation

PVNGS estimated an implementation cost of $2,215,730 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $6,647,190.

D.7.4.3 Net Value

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

SAMA 14 Net Value (95th %)

Total Averted Cost-Risk	Cost of Implementation	Net Value
$259,281	$6,647,190	-$6,387,909

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

D.7.5 PHASE I IMPACT SUMMARY

While SAMAs 2, 5, 7, 12, and 14 would be retained for Phase II quantification if the 95th percentile PRA results were used in place of the point estimate results, none of these SAMAs would be cost beneficial.

D.7.6 PHASE II IMPACT

As mentioned above, the 95th percentile PRA results are not available for the Level 2 and Level 3 models. In order to estimate the impact of using the 95th percentile PRA results in the Phase 2 SAMA analysis, the same process used to calculate the revised MACR was applied to each of the Phase 2 SAMAs (the averted cost-risk for each SAMA was increased by a factor of 2.7 over the base case).

The following table provides a summary of the impact of using the 95th percentile PRA results in the detailed cost-benefit calculations that have been performed.

Results Summary for the 95th Percentile PRA Results

SAMA ID	Cost of Implement-ation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effective-ness?
SAMA 4	$5,498,862	$1,015,032	-$4,483,830	$2,740,586	-$2,758,276	No
SAMA 6	$363,374	$352,815	-$10,559	$952,601	$589,227	Yes
SAMA 8	$3,125,000	$835,689	-$2,289,311	$2,256,360	-$868,640	No
SAMA 10	$3,000,000	$278,154	-$2,721,846	$751,016	-$2,248,984	No
SAMA 11	$3,000,000	$109,299	-$2,890,701	$295,107	-$2,704,893	No
SAMA 13	$3,000,000	$32,145	-$2,967,855	$86,792	-$2,913,209	No
SAMA 15	$1,642,698	$343,080	-$1,299,618	$926,316	-$716,382	No
SAMA 17	$410,473	$200,346	-$210,127	$540,934	$130,461	Yes
SAMA 19	$4,661,682	$177,645	-$4,484,037	$479,642	-$4,182,041	No
SAMA 20	$3,625,692	$82,569	-$3,543,123	$222,936	-$3,402,756	No
SAMA 21	$3,365,514	$15,012	-$3,350,502	$40,532	-$3,324,982	No
SAMA 22	$3,272,100	$13,761	-$3,258,339	$37,155	-$3,234,945	No
SAMA 23	$415,620	$106,278	-$309,342	$286,951	-$128,669	No

Of the SAMAs classified as “not cost beneficial” in the baseline Phase 2 analysis, two SAMAs (SAMAs 6 and 17) were found to be cost beneficial when the 95th percentile PRA results were applied. The use of the 95th percentile PRA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA; however, these additional SAMAs could be considered for implementation to address the uncertainties inherent in the SAMA analysis.

D.7.7 MACCS2 INPUT VARIATIONS

The MACCS2 model was developed using the best information available for the PVNGS site; however, reasonable changes to modeling assumptions can lead to variations in the Level 3 results. In order to determine how certain assumptions could impact the SAMA results, a sensitivity analysis was performed on a group of parameters that has previously been shown to impact the Level 3 results. These parameters include:

Meteorological data
Evacuation Speed
Release Height
Release Heat
Wake Effects
Surface Roughness
Rainfall variations

Among the parameters analyzed, release height, release heat, evacuation speed and meteorological data year have been analyzed in previous SAMAs. In addition to these sensitivities, the effect of building wake on the risk was also determined because the proximity of site buildings introduces uncertainty as to local air flow around these buildings. The base case surface roughness length of 10 cm, which represents terrain roughness for suburban areas, was varied to 1 cm to represent some of the more desert-like conditions surrounding the plant.

Also, severe meteorological conditions in the last spatial segment of the model domain (40-50 miles) were chosen to assure conservatively high impacts and risks. Most especially, perpetual rainfall was imposed on this segment so that a conservatively large quantity of the nuclides released in each scenario were deposited (via wet deposition) within the model domain.

The following table gives the sensitivity of the risk to the choice of these parameters. The table also discusses the reason for considering that parameter and the result.

Case	Input Description	Pop. Dose Risk % of Base	Cost Risk % of Base	Output Comments
Annual Met Data Set (2004)	Use of 2004 Met Data	86%	84%	(2003 chosen as baseline. Maximum dose and cost risk.)
Annual Met Data Set (2005)	Use of 2005 Met Data	84%	83%	(2003 chosen as baseline. Maximum dose and cost risk.)
Evacuation Speed	Baseline updated 2005 study with 2040 population, assumed EPZ roads at saturation in former.	100%	100%	Faster 2005 evacuation speed results in <0.3% decrease in pop-dose. 0-10 mile dose is minor contributor to 50-mile dose.

Case	Input Description	Pop. Dose Risk % of Base	Cost Risk % of Base	Output Comments
Release Height (top of containment)	Baseline assumed ground level release except for tube rupture (aux bldg roof). Ground level releases changed to top of containment building.	107%	108%	Increase in release height decreases close-in deposition. Large downwind population affected by relatively undepleted plume.
Release Heat (1 MW per segment)	Baseline assumed no heat. Up to 4 segments released per scenario.	102%	101%	Effect of buoyant plume rise is analogous to increase in release height.
Release Heat (10 MW per segment)	Baseline assumed no heat. Large value to consider severe effects.	107%	108%	Increase in buoyancy increases downwind pop-dose. See release height notes above.
Wake Effects (50% of Baseline), SIGYINIT, SIGZINIT	Baseline determined from release building dimensions. Uncertainty due to proximity of buildings.	97%	96%	Change in concentration/deposition near release affects larger downwind population.
Wake Effects (200% of Baseline), SIGYINIT, SIGZINIT	Baseline determined from release building dimensions. Uncertainty due to proximity of buildings.	104%	106%	Change in concentration/deposition near release affects larger downwind population.
Surface Roughness Length, z_0	Baseline assumed value indicative of suburban areas. Value simulating desert considered.	93%	90%	Smaller desert roughness lengths result in lesser downwind effects.
Meteorology specification in last spatial segment, LIMSPA	Rainfall imposed at all times from 40 to 50 miles from release to force conservative population exposure.	60%	51%	Entire decrease is due to removing perpetual rainfall (wet deposition) and specifying measured meteorology in ring from 40 to 50 miles from site.

D.7.7.1 IMPACT ON SAMA ANALYSIS

Several different Level 3 input parameters have been examined as part of the PVNGS MACCS2 sensitivity analysis. The primary reason for performing these sensitivity runs was to identify any reasonable changes that could be made to the Level 3 input parameters that would impact the conclusions of the SAMA analysis. While the table in

Section D.7.7 summarizes the changes to the dose-risk and OECR estimates for each sensitivity case, it was necessary to determine if any of these changes would result in the retention of the SAMAs that were screened using the baseline results.

Of all the MACCS2 sensitivity cases, the largest increase in either dose-risk or OECR was 7% and 8%, respectively (for both cases "Release Height (top of containment)" and"Release Heat (10 MW per segment)"). The PVNGS MACR was recalculated using these results to determine the impact of using the worst case for each parameter simultaneously. The resulting MACR was $4,872,843, which is less than $12,603,600 calculated in Section D.7.1 for the 95th percentile PRA results. The 95th percentile PRA results sensitivity is considered to bound this case and no SAMAs would be retained based on this sensitivity that were not already identified in Section D.7.1.

D.7.8 CORRECTION OF REACTOR BUILDING WAKE HEIGHT

During the internal review of the SAMA analysis, a minor error was identified in the Level 3 analysis. It was determined that the Reactor Building wake height was based on the total height of the building 210 feet rather than the height above grade 190 feet (APS 2008b), which resulted in a small, overestimation of the accident consequences. Rather than perform the extensive rework that would be required to update the analysis to eliminate this bias, the impact of the error has been documented here.

When the corrected wake height is used in place of the original height of the total 50-mile dose-risk decreases by 0.3% and the economic cost-risk decreases by 0.8%:

Impact of Wake Height Correction on Level 3 Model Results

	Dose-Risk	OECR
Base Results	13.62	$14,929
Revised Wake Height Results	13.58	$14,814
Percent Change	-0.3%	-0.8%

A further breakdown of this information is provided below according to release category for the internal events quantification:

Impact of Wake Height Correction: Results By Release Category

Release Category	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	Sum of Annual Risk
Freq.	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**

(per yr)$_{BASE}$												
Freq. (per yr)$_{wake}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
Dose-Risk$_{wake}$	0.00	0.00	0.45	0.06	3.92	6.28	0.30	0.14	0.16	0.00	2.27	**13.58**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**
OECR$_{wake}$	$0	$0	$8	$1	$127	$10,046	$11	$445	$229	$0	$3,947	**$14,814**

Using the methodology provided in Section D.4, a revised MACR can be calculated. The internal events results are summarized in the following table:

Maximum Averted Internal Events Cost-Risk for Revised Wake Height

Off-site exposure cost	=	$408,476
Off-site economic cost	=	$222,797
On-site exposure cost	=	$3,138
On-site cleanup cost	=	$98,814
Replacement Power cost	=	$41,190
Total cost	=	$774,415

Rounding the total cost-risk to the next highest thousand results in a single unit internal events contribution of $775,000. In order to account for external events contributions, this number is doubled to $1,550,000. The site MACR is obtained by multiplying the single unit value by 3 to obtain $4,650,000, which is 0.4 percent less than the base case MACR of $4,668,000.

This small reduction in the MACR has no impact on the Phase I screening analysis.

The small reduction in the both the overall MACR and the individual release category results imply that the impact on the Phase II calculations is also small and that the averted cost-risks for the SAMAs will go down (apart from any rounding issues). The potential impact of incorporating the wake height correction is that a borderline cost effective SAMA would be redefined as “not cost effective”. Given that SAMAs 6 and 17 are both cost effective by a substantial margin when the 95th percentile PRA results are used, use of the incorrect reactor building wake height in the MACCS2 model has no impact on the conclusions of the SAMA analysis.

D.7.9 USE OF A 7 PERCENT REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 3 percent, which could be viewed as conservative, has been changed to 7 percent and the maximum averted cost-risk was re-calculated using the methodology outlined in Section D.4. The Phase 1 screening against the MACR was re-examined using the revised MACR to identify any SAMA candidates that could be screened from further analysis based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase 2 analysis was re-performed using the 7 percent RDR.

Implementation of the 7 percent RDR reduced the MACR by 26.2 percent compared with the case where a 3 percent RDR was used. This corresponds to a decrease in the MACR from $4,668,000 to $3,444,000. The Phase 1 SAMA list was reviewed to determine if such a decrease in the MACR would impact the disposition of any SAMAs. It was determined that only SAMA 20 could have been screened in the Phase 1 if an RDR of 7 percent were used in place of the 3 percent value.
The Phase 2 SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 7 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness did not change for any Phase 2 SAMA when the 7 percent RDR was used in lieu of 3 percent.

Phase 2 Results Summary for 7 Percent RDR Sensitivity

SAMA ID	Cost of Implement-ation	Averted Cost-Risk (3 percent RDR)	Net Value (3 percent RDR)	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Change in Cost Effective-ness?
SAMA 4	$5,498,862	$1,015,032	-$4,483,830	$742,224	-$4,756,638	No
SAMA 6	$363,374	$352,815	-$10,559	$260,076	-$103,298	No
SAMA 8	$3,125,000	$835,689	-$2,289,311	$605,898	-$2,519,102	No
SAMA 10	$3,000,000	$278,154	-$2,721,846	$207,483	-$2,792,517	No
SAMA 11	$3,000,000	$109,299	-$2,890,701	$79,707	-$2,920,293	No
SAMA13	$3,000,000	$32,145	-$2,967,855	$24,489	-$2,975,511	No
SAMA 15	$1,642,698	$343,080	-$1,299,618	$249,012	-$1,393,686	No
SAMA 17	$410,473	$200,346	-$210,127	$146,439	-$264,034	No
SAMA 19	$4,661,682	$177,645	-$4,484,037	$131,064	-$4,530,618	No
SAMA 20	$3,625,692	$82,569	-$3,543,123	$60,918	-$3,564,774	No
SAMA 21	$3,365,514	$15,012	-$3,350,502	$11,076	-$3,354,438	No
SAMA 22	$3,272,100	$13,761	-$3,258,339	$10,152	-$3,261,948	No
SAMA 23	$415,620	$106,278	-$309,342	$76,056	-$339,564	No

D.8 CONCLUSIONS

The benefits of revising the operational strategies in place at PVNGS and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PRA in conjunction with cost-benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on off-site dose and economic impacts. The results of this study indicate that of the identified potential improvements that can be made at PVNGS, two are cost beneficial based on the methodology applied in this analysis and the cost estimates that have been developed for the SAMA analysis.

The baseline Phase II analysis indicates that none of the SAMAs have a positive net value. However, when the 95th percentile PRA results are considered, the following two SAMAs are cost beneficial:

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 6 requires the development of completely new procedures to provide explicit guidance to address cases where spurious electrical protection faults preclude use of the emergency buses. In reality, the plant staff members are trained to recover from these events, but the credit that can be taken in the PRA for such action is extremely limited. The implication is that the benefit shown for this SAMA may be somewhat overstated, but at the same time, there is likely a real benefit related to formalizing the recovery process for these types of events. This SAMA should be considered for implementation.

SAMA 17 is another procedure-related SAMA. In this case, it is directed at providing explicit guidance to aid operators in preventing TI SGTR after core damage. Specifically, the procedures would be enhanced to direct the operators not to operate the RCPs after core damage so that the water seal is not removed from the cold leg. Without the water seal, high temperature gases from the core could flow into the steam generators and degrade their integrity. This change would not impact the PVNGS CDF, but it does have a meaningful impact of the plant’s post core damage response. It is suggested that this SAMA be considered for potential implementation.

SAMA 23 provided cost-risk analysis for procedure enhancements to direct steam generator flooding for release scrubbing. Although SAMA 23 concluded with a negative net value, follow-up discussions with Operations personnel and PVNGS Management resulted in a decision to consider this SAMA for potential implementation

In summary, three relatively low cost SAMAs (SAMAs 6, 17 and 23) have been identified as cost beneficial and are suggested for potential implementation at PVNGS. While these results are believed to accurately reflect potential areas for improvement at the plant, 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. APS will consider the three SAMAs (6,17 and 23) identified in the analysis using the appropriate PVNGS design process.

D.9 FIGURES

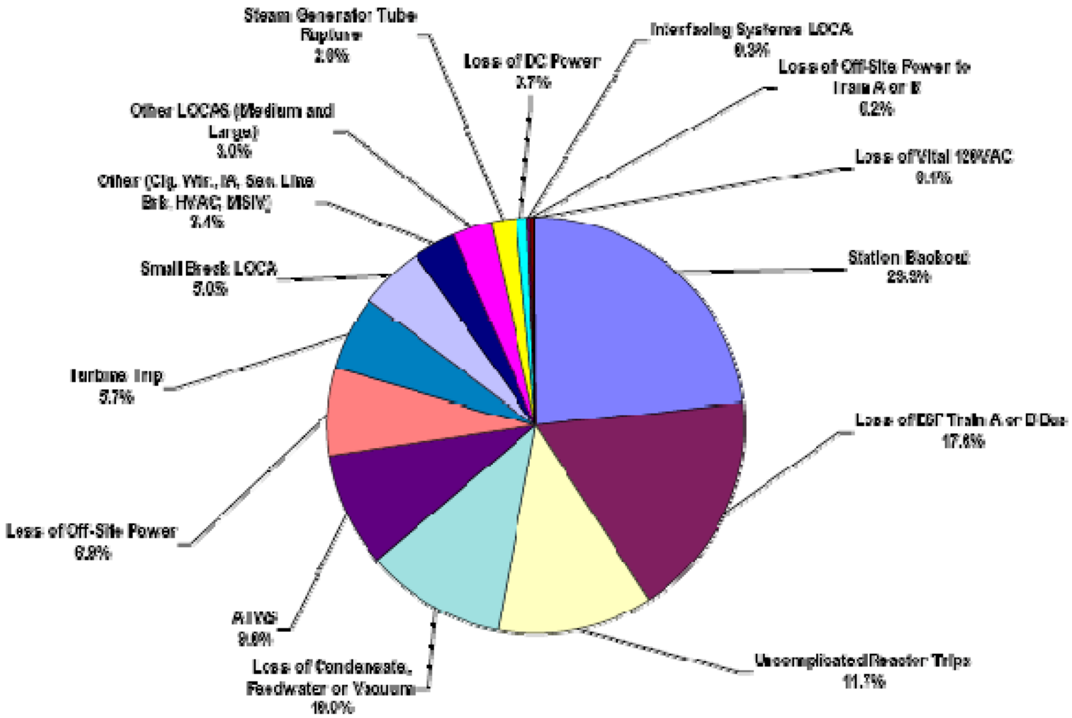


Figure D.2-1
Internal Events CDF Distribution by Initiator

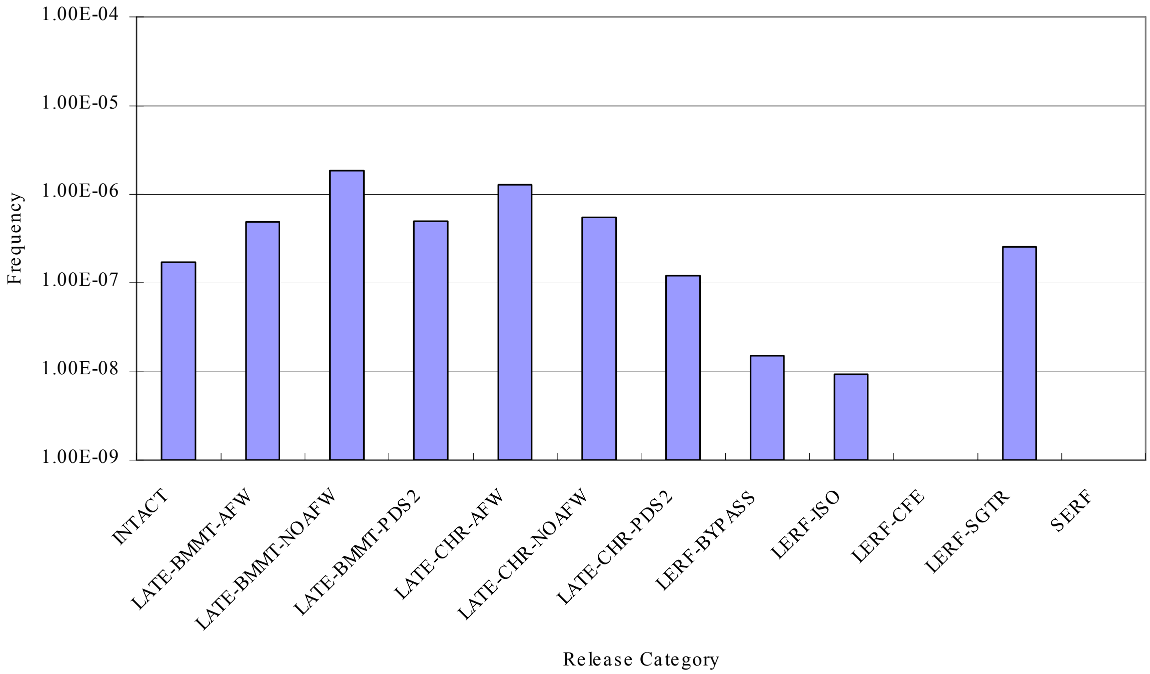


Figure D.2-2
Refined Release Category Frequency Summary

D.10 TABLES

TABLE D.2-1
Top 40 internal event-importances by Fussell-Vesely

NO	Name	FV
1	1AFAP01----TPAFR	3.210E-001
2	IELOOP	3.018E-001
3	SBO-SEQUENCE	2.332E-001
4	1SPURMFWTRIP-2OP	1.897E-001
5	LOOP-RECOVR3-2PW	1.848E-001
6	1AFA-RECOVERABLE	1.711E-001
7	1ALFW-NOMFW---HR	1.536E-001
8	IEPBA	1.420E-001
9	1PE-CC1DGAFR-ALL	1.205E-001
10	IEMISC	1.171E-001
11	1ALFW---MFW---HR	9.481E-002
12	1AFBP01----MPAFR	9.415E-002
13	1RPS-RODDROP-2OP	9.042E-002
14	1AFBV025---NVNRM	8.644E-002
15	1PEAG01----DGAFR	8.091E-002
16	1PBAS03LBKXCXAXX	8.068E-002
17	1AFN-NOMFW----HR	7.892E-002
18	1PEBG02----DGAFR	7.843E-002
19	AGT-FAILSTRT-2HR	7.776E-002
20	IECPST	7.534E-002
21	IEATWS4	7.356E-002
22	1MTC-UNFAV---2OP	7.351E-002
23	1AFNP01----MPAFR	7.118E-002
24	LOOP---------2PW	7.075E-002
25	1AF-CC1MPAFS-ALL	6.114E-002
26	IETT	5.732E-002
27	ANANS07-138EXBPW	5.576E-002
28	1AFBP01----MPAFS	5.044E-002
29	1ALFW-NOMFWND-HR	5.012E-002

TABLE D.2-1
Top 40 internal event-importances by Fussell-Vesely

NO	Name	FV
30	IESLOCA	4.976E-002
31	1AFN-NOMFW-ND-HR	3.600E-002
32	IEPBB	3.414E-002
33	1PBAS03-416BSEPW	2.961E-002
34	1AFA-NOMFW----HL	2.756E-002
35	1AFNP01----MPAFS	2.737E-002
36	IEMLOCA	2.531E-002
37	1AF-CC1MPAFR-ALL	2.505E-002
38	1AFNSYS----AFNCM	2.495E-002
39	1AF-CC2MV-FO-ALL	2.470E-002
40	1AF-CC1MV-FO-ALL	2.470E-002

TABLE D.2-2
REFINED RELEASE CATEGORY SEQUENCE FREQUENCY TOTALS

Release Category	DESCRIPTION	CONTRIBUTING LEVEL 2 SEQUENCES	FREQUENCY	PERCENT
INTACT	Containment remains intact	PDS3:0005	1.72E-07	3.3%
LATE-BMMT-AFW	Late containment failure due to base-mat melt-through with AFW available	PDS3:0002	4.92E-07	9.4%
LATE-BMMT-NOAFW	Late containment failure due to BMMT with AFW not available	PDS3:0009 PDS3:0014	1.85E-06	35.3%
LATE-BMMT-PDS2	LOCA or RCS depressurized case with late containment failure due to BMMT	PDS2:0019	5.00E-07	9.5%
LATE-CHR-AFW	Late overpressure containment failure due to containment heat removal (CHR) unavailable, but with AFW available	PDS3:0003 PDS6:0003	1.28E-06	24.4%
LATE-CHR-NOAFW	Late overpressure containment failure due to CHR failure, and with AFW unavailable	PDS3:0006 PDS3:0010 PDS3:0015 PDS6:0007 PDS6:0011 PDS6:0016	5.46E-07	10.4%
LATE-CHR-PDS2	Late overpressure containment failure due to containment heat removal (CHR) unavailable, but with AFW available	PDS2:0020	1.21E-07	2.3%
LERF-BYPASS	LERF containment bypass scenarios that result from ISLOCA initiators	PDS1A:0025	1.51E-08	0.3%
LERF-ISO	LERF scenarios due to undetected pre-existing or subsequent containment isolation failure	PDS2:0023 PDS3:0023 PDS6:0024	9.33E-09	0.2%

TABLE D.2-2
REFINED RELEASE CATEGORY SEQUENCE FREQUENCY TOTALS

Release Category	DESCRIPTION	CONTRIBUTING LEVEL 2 SEQUENCES	FREQUENCY	PERCENT
LERF-CFE	LERF sequences with early containment failure due to severe accident phenomena at or near the time of vessel failure	N/A	0.00	0.0%
LERF-SGTR	LERF bypass scenarios that result from early SGTR scenarios	PDS1B:0025 PDS3:0012 PDS3:0017 PDS6:0013 PDS6:0018	2.53E-07	4.8%
SERF	Early releases that have the source term reduced from LERF due to some phenomenological means	N/A	0.00	0.0%
Total:	Sum of all the contributing release categories.		5.24E-06	100.0%

TABLE D.3-1
ESTIMATED PVNGS CORE INVENTORY

NUCLIDE	CORE INVENTORY (CURIES)	NUCLIDE	CORE INVENTORY (CURIES)
Kr-83m	1.66E+07	I-132	1.52E+08
Kr-85	1.38E+06	I-133	2.24E+08
Kr-85m	5.19E+07	I-134	2.62E+08
Kr-87	8.58E+07	I-135	2.03E+08
Kr-88	1.28E+08	Xe-131m	1.04E+06
Br-84	3.05E+07	Xe-133	2.24E+08
Rb-88	1.08E+08	Xe-133m	5.51E+06
Rb-89	1.40E+08	Xe-135	2.14E+08
Sr-89	1.32E+08	Xe-135m	7.26E+07
Sr-90	1.10E+07	Xe-138	1.98E+08
Sr-91	1.74E+08	Sb-131	8.98E+07
Y-90	1.15E+07	Te-131	9.54E+07
Y-91	1.68E+08	Te-133	1.31E+08
Y-91m	1.02E+08	Te-133m	9.14E+07
Y-95	2.01E+08	Te-134	2.12E+08
Zr-95	2.14E+08	Cs-134	2.22E+07
Nb-95	2.36E+08	Cs-135	5.47E+01
Mo-99	1.99E+08	Cs-136	5.59E+06
Tc-99m	1.74E+08	Cs-137	1.47E+07
Ru-103	1.63E+08	Cs-138	2.16E+08
Ru-106	5.75E+07	Ba-137m	1.40E+07
Sb-129	3.40E+07	Ba-140	1.98E+08
Te-129	3.34E+07	La-140	2.11E+08
Te-129m	4.95E+06	La-143	1.86E+08
Te-131m	1.53E+07	Ce-143	1.85E+08
Te-132	1.52E+08	Ce-144	1.66E+08
I-129	4.19E+06	Pr-143	1.76E+08
I-131	1.00E+08	Pr-144	1.67E+08

TABLE D.3-2
ACCIDENT RELEASE CATEGORY FREQUENCIES AND SOURCE TERMS

RELEASE CATEGORY	**INTACT**	**LATE-BMMT-AFW**	**LATE-BMMT-NOAFW**	**LATE-BMMT-PDS2**	**LATE-CHR-AFW**	**LATE-CHR-NOAFW**
FREQUENCY	**1.72E-07**	**4.92E-07**	**1.85E-06**	**5.01E-07**	**1.28E-06**	**5.46E-06**
Release Fraction by Release and Source Term Category						
Xe/Kr	9.41E-04	1.00E+00	1.00E+00	1.00E+00	1.00E+00	1.00E+00
I	1.60E-07	4.00E-06	1.10E-03	3.30E-04	1.20E-02	2.30E-01
Cs	1.23E-07	1.98E-06	2.56E-04	1.19E-04	3.92E-03	5.22E-02
Te	3.00E-10	1.70E-05	6.50E-09	9.00E-07	3.40E-04	1.00E-03
Sr	1.40E-08	3.00E-07	9.00E-08	2.00E-07	4.70E-06	1.40E-05
Ru	3.10E-08	6.00E-07	1.00E-07	2.30E-07	1.00E-06	1.40E-05
La	1.40E-08	1.60E-07	5.00E-09	1.00E-08	5.40E-07	1.30E-06
Ce	1.40E-08	2.20E-07	9.00E-08	1.50E-07	4.30E-06	2.30E-05
Ba	2.10E-08	6.00E-07	2.60E-07	3.00E-07	9.00E-06	2.50E-05
Sb	2.00E-07	1.10E-05	7.20E-05	5.00E-05	6.10E-02	1.70E-02
Release time (hr from scram) of majority of noble gas / Cs release	2-48[a] / 2-4	34.9-72 / 4-12	21.6-40 / 21.6-72	16.9-40 / 16.9-20	44.8-46.8 / 44.8-72	23.1-25.1 / 23.1-72

Sequence	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR
Frequency	1.21E-07	1.51E-08	9.33E-09	0.00E+00	2.53E-07
Release Fraction by Release and Source Term Category					
Xe/Kr	1.00E+00	1.00E+00	1.00E+00	1.00E+00	8.80E-01
I	8.80E-03	9.70E-01	3.30E-01	6.90E-02	1.60E-01
Cs	2.93E-03	9.70E-01	2.01E-01	4.14E-02	9.58E-02
Te	1.70E-03	3.10E-03	1.20E-03	7.30E-04	2.30E-04
Sr	5.30E-04	7.60E-02	1.70E-02	6.80E-03	7.60E-04
Ru	1.70E-04	6.30E-02	1.30E-01	8.30E-03	3.60E-02
La	2.80E-05	2.90E-03	1.20E-02	3.00E-03	1.70E-04
Ce	6.70E-05	3.90E-02	1.50E-02	7.00E-03	4.40E-04
Ba	4.90E-04	7.50E-02	4.00E-02	6.91E-03	1.60E-02
Sb	4.60E-03	5.00E-01	3.40E-01	1.70E-01	2.10E-01
Release time (hr from scram) of majority of noble gas / Cs release	37.7-40 / 37.7-72	0.2-1.2 / 0.2-1.2	1.1-7 / 1.1-7	2.8-5 / 2.8-7	2.1-3.1 / 2.1-4

TABLE D.3-3
MACCS RELEASE CATEGORIES VS. PVNGS RELEASE CATEGORIES

MACCS SOURCE TERM CATEGORIES	PVNGS SOURCE TERM CATEGORIES
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	2 & 6 – CsI and CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2
Ba	7 – BaO
Sb (supplemental category)	10 – Sb

TABLE D.3-4
GENERAL EMERGENCY DECLARATION TIMES (HOURS FROM REACTOR TRIP)

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW
G.E. Time	2.1	1.1	1.7	0.5	7.9	2.1
RELEASE CATEGORY	**LATE-CHR-PDS2**	**LERF-BYPASS**	**LERF-ISO**	**LERF-CFE**	**LERF-SGTR**	
G.E. Time	5.0	0.2	1.1	1.7	2.1	

TABLE D.3-5
RESULTS OF PVNGS LEVEL 3 PRA ANALYSIS (ANNUAL RISK)

RELEASE CATEGORY	INTACT	LATE-BMMT-AFW	LATE-BMMT-NOAFW	LATE-BMMT-PDS2	LATE-CHR-AFW	LATE-CHR-NOAFW	LATE-CHR-PDS2	LERF-BYPASS	LERF-ISO	LERF-CFE	LERF-SGTR	SUM OF ANNUAL RISK
Freq. (per yr)$_{BASE}$	1.720E-07	4.920E-07	1.850E-06	5.010E-07	1.280E-06	5.460E-07	1.210E-07	1.510E-08	9.330E-09	0.000E+00	2.530E-07	**5.24E-06**
Dose-Risk$_{BASE}$	0.00	0.00	0.45	0.06	3.96	6.28	0.30	0.14	0.16	0.00	2.27	**13.62**
OECR$_{BASE}$	$0	$0	$9	$1	$128	$10,156	$11	$447	$230	$0	$3947	**$14,929**

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFAP01----TPAFR	7.61E-02	1.473	#EOOS# AFW Pump A Fails to Run 24 Hours	The contributors to the importance of this event are diverse and while no particular scenario dominates, there are multiple potential enhancements that could mitigate the circumstances. One change that could impact most accident scenarios would be enhancing the primary system such that it could support feed and bleed cooling (SAMA 1), which is a general observation about the plant. Others include: replace one low pressure condensate pump with a high pressure motor driven pump and add hotwell makeup controls to the MCR from a non-CST source (SAMA 2), install an independent AFW system with a dedicated power supply (SAMA 3).
IELOOP	2.13E-02	1.432	INITIATING EVENT - Loss of Off-Site Power at Switchyard	Almost 80% of the LOOP contributors are SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
SBO-SEQUENCE	1.00E+00	1.304	FLAG: Station Blackout (SBO) Sequence	These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump in the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1SPURMFWTRIP-2OP	1.20E-01	1.234	Main FW Pumps Spurious Trip Following Reactor Trip	Approximately 75% of the contributors including this event are evolutions in which MFW is not available and the operators fail to depressurize the SGs and align AltFW for makeup. These cases could be mitigated by replacing one of the LP condensate pumps with a high pressure motor driven pump in conjunction with the addition of hotwell makeup controls located in the MCR (SAMA 2). About 60% of the contributors including this event are evolutions in which the "A" emergency bus fails. This could be mitigated by providing an automatic power transfer switch to the AFN-P01 pump so that it could rapidly transition to "B" division power in these cases (SAMA 5). Developing procedures to address spurious electrical protection faults could enhance power recovery (SAMA 6).
LOOP-RECOVR3-2PW	2.00E-01	1.227	Off-Site Power (via Switchyard) Non-Recovery Within 3 Hours	Over 97% of the cutsets including LOOP-RECOVR3-2PW are SBO evolutions and use of a portable 480V AC generator to provide power to the division 1 battery chargers and the charging pumps would provide a means of maintaining long term primary and secondary side makeup (from the MCR) (SAMA 4).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFA-RECOVERABLE	1.00E+00	1.206	FLAG: Cutset is Recoverable by RE-AFA-LCL*	About 65% of the cutsets including the this flag include failure of division 1 power (mostly ESF bus failure) such that the non-essential aux feed pump (AFN-P01) is unavailable due to lack of power. If an auto transfer switch were installed such that loss of the normal power supply would result in auto transfer of power to the remaining division, AFN-P01 could be used to provide makeup to the SGs (SAMA 5). Alternatively, about the same contribution could be addressed by replacing one of the low pressure condensate pumps with a high pressure pump and the MCR could be updated to include controls to allow remote alignment of Hotwell makeup (SAMA 2). Given loss of MFW is a condition of many of the contributors that include the "1AFA-RECOVERABLE" event, the effectiveness of this SAMA would depend on the cause of the MFW failure in the some events may also render Condensate unavailable. A potentially more cost effective solution would be to develop procedures to address the portion of the bus failures caused by spurious electrical protection faults (SAMA 6).
1ALFW-NOMFW---HR	1.70E-01	1.181	CR Ops Fails to Depress SG & Supply ALTFW (MFW Not Avail)	Over 72% of the cutsets including this action include failure of division 1 power (mostly ESF bus failure). In these cases, SG makeup is available, but the operator action to align it fails. As a result, providing additional SG makeup sources alone would not be highly beneficial due to operator dependence issues. If an auto start signal were provided for AFN-P01 in conjunction with an automatic power transfer switch, a fully automated backup SG makeup source would be available to mitigate these contributors (SAMA 7).
IEPBA	3.65E+02	1.166	INITIATING EVENT - Loss of Train A ESF Bus	Most of the contribution from the event is linked to the failure of the AFA-P01 and AFN-P01 AFW pumps due to power dependence and the subsequent failure of AFB-P01. Installing an automatic transfer switch that could provide alternate power to AFN-P01 without operator intervention would eliminate most of these contributors (SAMA 5). A potentially more cost effective solution would be to develop procedures to address the portion of the bus failures caused by spurious electrical protection faults (SAMA 6).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PE-CC1DGAFR-ALL	2.01E-03	1.137	Diesel Generator (DG) Group Fail to Run - PEAG01, PEBG02	Over 70% of the EDG A/B common cause failure (CCF) contributors are SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4). About 35% of the contributors include the failure to direct the start of the GTGs; these failures could be addressed providing the GTGs with the capability to auto start and load on ESF bus undervoltage. Inclusion of a time delay on the start signal could be used to ensure that GTGs are not started until it is clear that auto start of the EDGs has failed (SAMA 8).
IEMISC	7.93E-01	1.133	INITIATING EVENT - Miscellaneous Transients (Uncomplicated Reactor Trip)	The contributors including this event are comprised of a variety of AFW hardware failures, AFW alignment errors, and AFW support system failures. Failure of the AFA-P01 to run for 24 hours is included in 63% of the cutset contribution, but the pump's importance is driven by a diverse set of AFB-P01, AFN-P01, and ALTFW failures. Installing an independent AFW system is an option that would address these cases (SAMA 3). A smaller portion of the contribution (33%) is related to the failure to depressurize the SGs and align ALTFW. These contributions could be reduced by maintaining MFW as the primary source for SG makeup through establishment of SDC by replacing one of the low pressure condensate pumps with a high pressure pump and providing hotwell makeup (controlled from the MCR) (SAMA 2).
1ALFW---MFW---HR	2.50E-02	1.105	CR Ops Fails to Depress SG & Supply ALTFW (MFW Avail)	Over 80% of the contributors including this event also include a running failure for AFA-P01. The reliability of steam driven pump AFA-P01 appears to be an obvious area of attention that could be addressed by replacing it with a more reliable motor driven pump. However, AFA-P01 provides diversity to the AFW system and is the only pump that could operate for any time in an SBO. For this reason alone, AFA-P01 should not be replaced by a motor driven pump. A potential solution would be to replace one of the Condensate pumps with a high pressure pump and provide the MCR with controls that would allow the operators to align a long term suction source to the hotwell (SAMA 2). A small portion of the contribution (35%) could be addressed by installing an automatic power transfer switch on the AFN-P01 pump to improve the operators ability to align the pump to the alternate power source (SAMA 5).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFBP01----MPAFR	3.10E-03	1.104	AFW Pump B Fails to Run 24 Hours	About 50% of the contributors include a failure of the operators to start AFN-P01 or a power failure eliminates the normal power supply to the pump. If AFN-P01 were provided with an automatic power transfer switch and an automatic start signal on low SG level, these contributors would be greatly reduced (SAMA 7). Alternatively, for the scenarios in which the Condensate System remains available, one of the low pressure condensate pumps could be replaced with a high pressure pump and the MCR could be updated to include controls to allow remote alignment of Hotwell makeup (SAMA 2). This would allow the plant to retain a normally running system through the transition to SDC.
1RPS-RODDROP-2OP	2.10E-06	1.099	#EOOS# Failure to Drop Sufficient CEAs to Prevent RCS Over-pressure	Over 80% of the contribution for this event is related to event 1MTC-UNFAV---2OP, which represents the presence of an MTC that corresponds to an anticipated transient without scram (ATWS) heat balance above the pressure limits of the RCS. A potential solution would be to install a backup CEA drive system to force the CEAs into the core when normal insertion fails (SAMA 9).
1AFBV025---NVNRM	1.96E-03	1.095	AFW Pump B Discharge Isolation Valve Not Restored After Mntc	About 45% of the contributors including this event also include a failure to depressurize the SGs and align Alternate FW. These events could be mitigated by replacing a low pressure condensate pump with a high pressure pump and retaining MFW as the primary SG makeup source after a plant trip (SAMA 2). Cases where this SAMA would not be effective include LOOPs, main steam isolation cases, and potentially some of those where MFW is unavailable. Approximately 45% of the contribution is linked to the failure of the AFA-P01 and AFN-P01 AFW pumps due to power dependence and the subsequent failure of AFB-P01. Installing an automatic transfer switch that could provide alternate power to AFN-P01 without operator intervention would eliminate most of these contributors (SAMA 5).
1PEAG01----DGAFR	3.41E-02	1.088	#EOOS# DGA Fails to Run	Over 83% of the EDG A failure contributors are SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1PBAS03LBKXCXAXX	6.50E-06	1.088	Spur Elect Prot on Train A ESF Bus Locks Out All Power Sources	The cutsets including this event are characterized by power failures that eliminate both AFA-P01 and AFN-P01. Providing an automatic transfer switch on the AFN-P01 power supply would improve the reliability of the power transfer after loss of division 1 power and greatly reduce the contributions from these events (SAMA 5). Another potential option is to proceduralize steps to recover from spurious trips such that power could be restored in relatively short order (SAMA 6).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFN-NOMFW----HR	3.20E-03	1.086	CR Operator Fails to Align AFN (MFW Lost)	The cases involving failure to manually start AFN-P01 could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).
1PEBG02----DGAFR	3.41E-02	1.085	#EOOS# DGB Fails to Run	Over 86% of the EDG B failure contributors are SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
AGT-FAILSTRT-2HR	1.60E-01	1.084	CR Operators Fail to Direct WRF Operator To Start GTGs	These failures could be addressed providing the GTGs with the capability to auto start and load on ESF bus undervoltage. Inclusion of a time delay on the start signal could be used to ensure that GTGs are not started until it is clear that auto start of the EDGs has failed (SAMA 8). Alternatively, these evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
IECPST	3.50E-02	1.081	INTIATING EVENT - Loss of All Condensate Pumps	Loss of all condensate pumps eliminates MFW (and Alt FW) as a source of SG makeup and different combinations of AFW pump failures remove the remaining source of SG makeup. Installation of an independent AFW system would provide a diverse means of supplying makeup to the SGs (SAMA 3). A dedicated power source could be helpful in other scenarios, but loss of power is not important for IECPST. In order to address those other important scenarios, such as divisional power failures, an independent power supply is included in the SAMA design.
IEATWS4	8.11E-01	1.079	INTIATING EVENT - No Turbine Trip with MFW - ATWS Category 4	Over 90% of the contributions including this initiating event are related to event 1MTC-UNFAV---2OP, which corresponds to an ATWS heat balance above the pressure limits of the RCS. A potential solution would be to install a backup CEA drive system to force the CEAs into the core when normal insertion fails (SAMA 9).
1MTC-UNFAV---2OP	2.00E-01	1.079	MTC Unfavorable Regardless of AFW or Turbine Trip	This represents the presence of an MTC that corresponds to an ATWS heat balance above the pressure limits of the RCS. A potential solution would be to install a backup CEA drive system to force the CEAs into the core when normal insertion fails (SAMA 9).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFNP01----MPAFR	3.10E-03	1.077	AFW Pump N Fails to Run for 24 Hours	Failure of AFN-P01 implies that MFW, AFA-P01, and AFB-P01 have also failed to provide SG makeup. The contributors to these failures are diverse and apart from establishing an independent AFW system (SAMA 3), a single plant change to address all of these failures has not been identified. Under 50% of the contributors could potentially be addressed by replacing one of the low pressure condensate pumps with a high pressure pump so that MFW could be maintained as the SG makeup source after a plant trip (SAMA 2).
LOOP---------2PW	2.32E-03	1.076	Loss of Off-Site Power to Switchyard Post Trip	Many of the evolutions with this even result in SBOs that can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump in the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4). Alternatively, providing an auto start function for the GTGs on low bus voltage would address over 55% of the risk for these cases (SAMA 8).
1AF-CC1MPAFS-ALL	2.94E-05	1.065	AF Electric Pumps Fail to Start - AFBP01, AFNP01	Almost 90% of the contributors including 1AF-CC1MPAFS-ALL also include failure of AFA-P01 to run (1AFAP01----TPAFR). These cases could be addressed by replacing one low pressure condensate pump with a high pressure motor driven pump and adding hotwell makeup controls to the MCR from a non-CST source (SAMA 2) (not effective for the cases with Condensate failures), or by installing an independent AFW system with a dedicated power supply (SAMA 3).
IETT	3.90E-01	1.061	INITIATING EVENT - Turbine Trip (Load Rejection)	About 45% of the contributors that include this event could be mitigated if a low pressure condensate pump were replace with a high pressure pump so that MFW could be maintained as the primary source of SG makeup after a trip (provided that the long term suction source is not the CST) (SAMA 2). The remainder of the contributions are comprised mostly of various failure combinations of AFW hardware that could be addressed by an independent AFW system (SAMA 3).
ANANS07-138EXBPW	1.16E-02	1.059	Buried Power Cables From GTGs to Unit Fail	Over 86% of the contributions including ANANS07-138EXBPW are SBO evolutions and use of a portable 480V AC generator to provide power to the division 1 battery chargers and the charging pumps would provide a means of maintaining long term primary and secondary side makeup (from the MCR) (SAMA 4).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFBP01----MPAFS	1.15E-03	1.053	AFW Pump B Fails to Start	If an automatic transfer switch were installed such that loss of the normal power supply would result in automatic transfer of power to the remaining division, AFN-P01 could be used to provide makeup to the SGs (SAMA 5). A potentially more cost effective solution would be to develop procedures to address the portion of the bus failures caused by spurious electrical protection faults (SAMA 6). Alternatively, one low pressure condensate pump could be replace with a high pressure pump and the MCR could be updated to include Hotwell makeup controls so that Main FW could be retained as the primary source for SG makeup after a plant trip (SAMA 2).
1ALFW-NOMFWND-HR	3.50E-01	1.053	CR Operator Fails to Align AFN (MFW Lost) - No Diagnosis	The evolutions that include these events include the failure of MFW, by definition, and various other failures that eliminate AFW, including CCF, independent pump failures, and power failures. Providing more reliable secondary side heat removal would require an additional SG makeup source that depends less on operator intervention. This could be accomplished by automating secondary side depressurization for ALT FW injection, but a more credible choice may be to replace one of the low pressure condensate pumps with a higher pressure pump such that FW could be maintained in operation after a plant trip. Providing MCR controls for Hotwell makeup would improve the reliability of maintaining FW in operation in the long term (SAMA 2).
IESLOCA	3.60E-04	1.052	INITIATING EVENT - Small Loss of Coolant Accident	The contributors for the SLOCA initiator are diverse with the largest single contributor being the failure of the operator to depressurize the PCS at 28 percent. The remaining contributors include combinations of sensor miscalibrations and hardware failures, including sump suction valve failures, spray pond pump actuation relay failures, miscalibration of the RWT level sensors, and miscalibration of the pressurizer sensors. As a group, failures of Essential Cooling Water to the SDC heat exchangers contribute to about 20% of the SLOCA scenarios. These cases could be addressed by using Fire Protection Water or a direct connection to the Essential Spray Pond as an alternate means of cooling the SDC heat exchangers (SAMA 11).
1AFN-NOMFW-ND-HR	2.20E-01	1.037	CR Operator Fails to Align AFN (MFW Lost) - No Diagnosis	The cases involving failure to manually start AFN-P01 could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
IEPBB	3.65E+02	1.035	INITIATING EVENT - Loss of Train B ESF Bus	Just as an automatic power transfer switch could be used to improve the reliability of AFN-P01, an automatic power transfer switch could be used for the AFB-P01 power source (SAMA 12). Alternatively, about 35% of the contributors including this event could be mitigate by creating a backup auto start signal on a lower SG level and use it to start AFN-P01. Additional benefit could be obtained by using the backup signal for AFW pumps AFA-P01 and AFB-P01 (SAMA 10).
1PBAS03-416BSEPW	2.40E-06	1.031	#EOOS# Train A ESF Bus Fault	Most of the contribution from the event is linked to the failure of the AFA-P01 and AFN-P01 AFW pumps due to power dependence and the subsequent failure of AFB-P01. Installing an automatic transfer switch that could provide alternate power to AFN-P01 without operator intervention would eliminate most of these contributors (SAMA 5). A potentially more cost effective solution would be to develop procedures to address the portion of the bus failures caused by spurious electrical protection faults (SAMA 6).
1AFA-NOMFW----HL	4.20E-02	1.028	AO Fails to Locally Align AFAP01 After Recoverable Start Failure - MFW Unavailable	About 57% of the contributors including 1AFA-NOMFW----HL also include the failure of the operators to direct the start of the GTGs. These cases could be addressed through installation of a GTG auto start signal on low emergency bus voltage (SAMA 8).
1AFNP01----MPAFS	1.15E-03	1.028	AFW Pump N Fails to Start	Failure of AFN-P01 implies that MFW, AFA-P01, and AFB-P01 have also failed to provide SG makeup. The contributors to these failures are diverse and apart from establishing an independent AFW system (SAMA 3), a single plant change to address all of these failures has not been identified. Under 50% of the contributors could potentially be addressed by replacing one of the low pressure condensate pumps with a high pressure pump so that MFW could be maintained as the SG makeup source after a plant trip (SAMA 2).
IEMLOCA	2.70E-05	1.026	INITIATING EVENT - Medium Loss of Coolant Accident	Over 42% of the MLOCA contribution comes from a single cutset, which represents the failure to initiate hot leg injection within 3 hours of accident initiation. However, this cutset corresponds to an RRW of only 1.01, which corresponds to a potential averted cost-risk of only about $46,000. This implies that the only potentially cost effective changes to address this action are procedure changes. No procedure changes have been identified that would reduce this HEP in a meaningful way. The remainder of the contributor's together represent an RRW of only 1.014 and consist mostly of valve and pump failures. While this contribution is low, providing a feed and bleed capability would mitigate may of the relevant failures by allowing the operators to depressurize the RCS and use only the LPSI system for injection (SAMA 1).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AF-CC1MPAFR-ALL	1.21E-05	1.026	AF Electric Pumps Fail to Run - AFBP01, AFNP01	Over 40% of the contributors including CCF of the electric AFW pumps could be mitigated by replacing one low pressure condensate pump with a high pressure pump so that MFW/Condensate could be maintained for SG makeup after a plant trip (SAMA 2). The remaining contributors are diverse and no single change would have an impact on a large number of them beyond an independent AFW system (SAMA 3).
1AFNSYS----AFNCM	1.05E-03	1.026	Train N Auxiliary Feedwater Unavailable Due to Maintenance	Failure of AFN-P01 implies that MFW, AFA-P01, and AFB-P01 have also failed to provide SG makeup. The contributors to these failures are diverse and apart from establishing an independent AFW system (SAMA 3), a single plant change to address all of these failures has not been identified. Under 50% of the contributors could potentially be addressed by replacing one of the low pressure condensate pumps with a high pressure pump so that MFW could be maintained as the SG makeup source after a plant trip (SAMA 2).
1AF-CC2MV-FO-ALL	5.17E-05	1.025	AF Injection Gate Valves Fail to Open - AFAUV37, AFBUV34, AFBUV35, AFCUV36	About 40% of the contributors that include this event also include the operator failure to initiate AFN-P01. These contributors could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).
1AF-CC1MV-FO-ALL	5.17E-05	1.025	AF Injection Globe Valves Fail to Open - AFAHV32, AFBHV30, AFBHV31, AFCHV33	About 40% of the contributors that include this event also include the operator failure to initiate AFN-P01. These contributors could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).
IECONDVAC	4.40E-02	1.023	INTIATING EVENT - Loss of Condenser Vacuum	About 40% of the contributors that include this event also include the operator failure to initiate AFN-P01. These contributors could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10). About 30% of the contributors include operator failure to initiate Alt FW. These cases could be mitigated by replacing one of the LP condensate pumps with a high pressure motor driven pump in conjunction with the addition of hotwell makeup controls located in the MCR (SAMA 2).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PEAG01----DG-CM	6.74E-03	1.021	DGA Unavailable Due to Maintenance	Over 65% of the contributors including this failure are SBO sequences, which can be addressed by providing a 480V AC generator that could support a battery charger for long term TD AFW support and primary side makeup using at least two charging pumps (SAMA 4). Many of the non-SBO cases would also be addressed by SAMA 4 as power could be supplied to the division 1 battery chargers to support long term AFW operation.
IETCW	8.92E-03	1.021	INITIATING EVENT - Loss of Turbine Cooling Water	A potential solution to addressing loss of TCW events would be to provide a means of aligning alternate cooling water to the critical loads supplied by TCW. These loads include the Instrument Air system and the upper bearing oil coolers for the Condensate pumps. If a permanent, hard-piped connection were provided between Fire Protection and these loads, the contribution from loss of TCW events would be reduced (SAMA 13).
RE-CT-HV14-MV	2.10E-01	1.021	Operator fails to locally recover AFN suction valves	The failure probability for this recovery action is high, which is reasonable given that the causes of the valve failure that necessitated the action are not known and may be difficult to resolve. The need to open a failed valve to establish a suction source for AFN-P01 could be greatly reduced if a permanent, alternate, hardpiped water source were made available to AFN-P01. Just as the RMWT serves as a backup to the CST for the essential AFW pumps (not credited in the PRA), this water source could also be used as a reliable inventory supply for AFN-P01 (SAMA 14).
IESGTR	6.25E-03	1.021	INITIATING EVENT - Steam Generator Tube Rupture	AFW failure, through a multitude of combinations, is the primary contributor to core damage in SGTR evolutions for PVNGS. In many of these cases, MFW would still be available if it could be used continuously from trip to SDC initiation. These cases could be mitigated by replacing one of the LP condensate pumps with a high pressure motor driven pump in conjunction with the addition of hotwell makeup controls (non-CST source) located in the MCR (SAMA 2).
1AFASYS----AFACM	2.75E-03	1.020	Train A Auxiliary Feedwater Unavailable Due to Maintenance	The contributors that include this event are diverse and no single change has been identified to mitigate these contributors beyond an independent AFW system (SAMA 3). Developing procedures to address spurious electrical protection faults is a potential low cost SAMA (SAMA 6), but it would only address about 8% of the contributors that include AFA-P01 maintenance events. Installing a connection to an emergency power supply could be suggested for an MFW train to address LOOP scenarios, but these contributors account for under 40% of the contributors that include AFA-P01 maintenance and major hardware changes would not be cost effective. The maintenance plan for AFW is considered to be addressed and governed through the Maintenance Rule and no changes are suggested to the AFW system's maintenance schedule.

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PBBS04KBLXCXAXX	6.50E-06	1.020	Spur Elect Prot on Train B ESF Bus Locks Out All Power Sources	Developing procedures to address spurious electrical protection faults could enhance power recovery (SAMA 6).
1PEBG02----DG-CM	6.74E-03	1.020	DGB Unavailable Due to Maintenance	Over 90% of the EDG B maintenance contributors are SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1SAA--LDSHED-2SA	1.47E-06	1.019	#EOOS# Load Sequencer or LOP/LS Module Causes Spur Load Shed	Over 90% of the cutsets including this flag include failure of division 1 power (ESF bus failure) such that the non-essential aux feed pump (AFN-P01) is unavailable due to lack of power. If an auto transfer switch were installed such that loss of the normal power supply would result in auto transfer of power to the remaining division, AFN-P01 could be used to provide makeup to the SGs (SAMA 5).
HE-GTGSTRT---2HR	2.50E-02	1.018	Adjustment Factor - Additional 1 Hour to Start GTGs Given AFA Initially Runs	These failures could be addressed providing the GTGs with the capability to auto start and load on ESF bus undervoltage. Inclusion of a time delay on the start signal could be used to ensure that GTGs are not started until it is clear that auto start of the EDGs has failed (SAMA 8).
LOOP-RECOVR1-2PW	5.20E-01	1.018	Off-Site Power (via Switchyard) Non-Recovery Within 1 Hour	The evolutions that include LOOP-RECOVR1-2PW are mainly SBO sequences that can be addressed by providing a 480V AC generator for AFW instrumentation and charging pump support (SAMA 4). Alternatively, nearly 70% of the contributors include the operator error to start the GTGs. These scenarios can be mitigated by automating the start of the GTGs (SAMA 8).
1PKBF12----BXAFS	2.91E-04	1.018	Channel B Battery Fails on Demand	About 45% of these contributors include a form of the operator action to depressurize the SGs and initiate Alternate FW, which could be addressed by replacing a condensate pump with a high pressure pump (SAMA 2). However, a more cost effective way to treat battery failures may be to ensure the battery chargers can provide 100% of the DC system demands so that the station batteries are not required for DC system success (SAMA 15).
1PK-CC1BXAFS-12	2.88E-06	1.017	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	A potentially cost effective way to treat battery failures is to ensure the battery chargers can provide 100% of the DC system demands so that the station batteries are not required for DC system success (SAMA 15).
1NANS03AB-XCYKFT	3.53E-03	1.017	GTG Supply Bkr to ESF Serv X-fmr NBN-X03 Fail to Close (Cntrl Ckt Fault)	The scenarios involving 1NANS03AB-XCYKFT are essentially all SBO evolutions that can be addressed by providing a 480V AC generator for AFW instrumentation and charging pump support (SAMA 4).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFAP01----TPAFS	6.79E-03	1.017	AFW Pump A Fails to Start	About 60% of the contributors that include this event also include the operator failure to initiate AFN-P01. These contributors could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).
1SAA2-K204-RX-SE	1.20E-06	1.015	#EOOS# LOP Group 2 L/S Spurious Actuation Signal Due to K204 Spur Energize	The 1SAA2-K204-RX-SE event is closely linked to the loss of "Train A ESF Bus" initiating event. Installing an automatic transfer switch that could provide alternate power to AFN-P01 without operator intervention would eliminate most of these contributors (SAMA 5)
ANANS07A---XMDPW	3.07E-03	1.015	GTG Auxiliary Power Stepdown Transformer Fails	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
ANANS07A---FUHOC	3.01E-03	1.015	GTG Auxiliary Power Bkr High Voltage Fuse Premature Open	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
ANHNU5607--CB-FT	3.00E-03	1.014	Transfer Switch NHN-U5607 Fails to Transfer to emerg source (credits manual action)	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
ANANS07D---CBOFT	3.00E-03	1.014	GTG Bus Supply Breaker to Unit 1 Fails to Close (Local Fault)	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1NANS03AB--CBOFT	3.00E-03	1.014	#EOOS# GTG Supply Bkr to ESF Serv X-fmr NBN-X03 Fail to Close (Local Fault)	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1SABAF-K222RXAFT	3.27E-04	1.014	#EOOS# AF Pump B Fails to Start Due to K222 Failure	If an automatic transfer switch were installed such that loss of the normal power supply would result in automatic transfer of power to the remaining division, AFN-P01 could be used to provide makeup to the SGs (SAMA 5). A potentially more cost effective solution would be to develop procedures to address the portion of the bus failures caused by spurious electrical protection faults (SAMA 6). Alternatively, one low pressure condensate pump could be replace with a high pressure pump and the MCR could be updated to include Hotwell makeup controls so that Main FW could be retained as the primary source for SG makeup after a plant trip (SAMA 2).
1AFAV016---NVNRM	1.96E-03	1.014	AFW Pump A Discharge Isolation Valve Not Restored After Mntc	There are multiple, diverse, contributors that cause failure of SG makeup related to AFW Pump A discharge isolation valve failure events. Some portion (about 10 percent) could be eliminated by providing an automatic transfer switch for the AFB-P01 power supply (SAMA 12). An independent AFW system is also means of addressing these cases (SAMA 3). Given that the valve 1PAFAV016 is locked open and that the position of the valve is independently verified and documented after maintenance, no procedure changes have been identified that would reduce the misalignment probability in any measurable way.
1AFBV025---NV-RO	3.01E-04	1.013	#EOOS# AFW Pump B Discharge Isolation Valve Fails Closed	If an automatic transfer switch were installed such that loss of the normal power supply would result in automatic transfer of power to the remaining division, AFN-P01 could be used to provide makeup to the SGs (SAMA 5). This would address about 50% of the 1AFBV025---NV-RO contributions. Alternatively, one low pressure condensate pump could be replace with a high pressure pump and the MCR could be updated to include Hotwell makeup controls so that Main FW could be retained as the primary source for SG makeup after a plant trip (SAMA 2).
1AFN-CPWR-----HL	3.50E-02	1.013	AO Fails to Align Backup Control Power to AF Pump N (MFW Lost)	These failures could be mitigated by providing an automatic power transfer switch to the AFN-P01 pump so that it could rapidly transition to "B" division power in these cases (SAMA 5).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1RCS-DEPRES--2HR	2.70E-01	1.013	CR Operators Fail to Initiate RCS Depressurization	Adding pressurizer PORVs, block valves, and enhancing the reactor drain tank (SAMA 1) would provide both a means of rapidly depressurizing the RCS and heat removal. This would improve the reliability of the depressurization action by simplifying the steps required to initiate depressurization and by reducing the time required for depressurization.
1HLI-3HR-OP--2HR	2.00E-03	1.013	CR Operators Fail to Initiate Hot Leg HPSI Injection w/i 3 Hours	While the reliabilities of some operator actions suffer from lack of procedures or poor procedure quality, this action is reasonably reliable, is proceduralized, contains guidance that can help the operators recover some potential errors, and is performed by operators in the simulator. No procedure changes have been identified that would improve the reliability of this action in any meaningful way. In addition, the basis for the requirement to switch to hot leg injection/recirculation is questionable based on the latest information (Fink 2006) and no SAMAs are suggested to address this issue.
1PK-CC1BXAFS-123	2.10E-06	1.013	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	A potentially cost effective way to treat battery failures is to ensure the battery chargers can provide 100% of the DC system demands so that the station batteries are not required for DC system success (SAMA 15).
1PK-CC1BXAFS-124	2.10E-06	1.013	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	A potentially cost effective way to treat battery failures is to ensure the battery chargers can provide 100% of the DC system demands so that the station batteries are not required for DC system success (SAMA 15).
IEFWP	2.74E-02	1.012	INITIATING EVENT - Loss of Both Feedwater Pumps	About 50% of the contributors including this event could be mitigated by creating a backup auto start signal on a lower SG level and using it to start AFN-P01 (SAMA 10).
1PEAG01----DGAFS	3.72E-03	1.012	DGA Fails to Start	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1PK-CC1BXAFS-ALL	1.57E-06	1.011	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	A potentially cost effective way to treat battery failures is to ensure the battery chargers can provide 100% of the DC system demands so that the station batteries are not required for DC system success (SAMA 15).

TABLE D.5-1
LEVEL 1 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PEBG02----DGAFS	3.72E-03	1.011	DGB Fails to Start	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1CTAHV001--MV-FO	1.53E-03	1.010	#EOOS# CST to AFW Pump N Supply Valve HV1 Fails to Open	The cutsets including this event require the operators to perform a recovery action that is assigned a high failure probability, which is reasonable given that the causes of the valve failure that necessitated the action are not known and may be difficult to resolve. The need to open a failed valve to establish a suction source for AFN-P01 could be greatly reduced if a permanent, alternate, hardpiped water source were made available to AFN-P01. Just as the RMWT serves as a backup to the CST for the essential AFW pumps (not credited in the PRA), this water source could also be used as a reliable inventory supply for AFN-P01 (SAMA 14).
1CTAHV004--MV-FO	1.53E-03	1.010	#EOOS# CST to AFW Pump N Supply Valve HV4 Fails to Open	The cutsets including this event require the operators to perform a recovery action that is assigned a high failure probability, which is reasonable given that the causes of the valve failure that necessitated the action are not known and may be difficult to resolve. The need to open a failed valve to establish a suction source for AFN-P01 could be greatly reduced if a permanent, alternate, hardpiped water source were made available to AFN-P01. Just as the RMWT serves as a backup to the CST for the essential AFW pumps (not credited in the PRA), this water source could also be used as a reliable inventory supply for AFN-P01 (SAMA 14).
1SAB-LOADSQSQ-CM	2.02E-04	1.010	Seqr B (Incl LOP/LS, DGSS Modules) Unavailable Due to Mntc	The primary importance of this event is that it leads to failure of the B EDG to start. In this case, the primary initiator to which it is linked is the loss of the "A" ESF Bus (about 50%). These events result in the failure of both AFA-P01 and AFN-P01. Installing an automatic power transfer switch on the AFN-P01 would allow for a rapid transfer of power to the opposite division without operator interface, which would greatly reduce these contributors (SAMA 5).

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
L2-NOCMNTFAILEARLY	1.00E+00	1.454E+01	L2 no Containment failure early	This event marks sequences that do not include early containment failures. Based on the WCAP Level 2 model guidance, early failures do not occur, so this event is set to 1.0. Containment bypass sequences, such as SGTR, do not include an event node for early containment failure, which is why this event is not in every cutset. No particular insight is gained from the presence of this event and no SAMAs are suggested.
L2-NOT-PI-SGTR	9.92E-01	2.733E+00	L2 no Pressure induced SGTR	This event represents the probability that a pressure induced SGTR does not occur even with the vessel at high pressure. Limited insights are available based on the presence of this event in the cutsets beyond the fact that high pressure core melts are contributors to high consequence core melt scenarios. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR would address many of the high pressure melt cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).
L2-NORCSDEPRESSEARLY	9.25E-01	2.404E+00	L2 no RCS depressurization early due to Stuck PSV	This event represents the probability that the PSVs do not stick open and depressurize the reactor, which results in conditions that could lead to pressure induced SGTRs. Limited insights are available based on the presence of this event in the cutsets beyond the fact that high pressure core melts are contributors to high consequence core melt scenarios. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR would address many of the high pressure melt cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
L2-RCSDEPRESSLATE	9.03E-01	2.178E+00	L2 Hot Leg/Surge Line fails or Late Stuck Open PSV	This event represents the probability that the RCS will be depressurized after core damage due to either a stuck open PSV or due to overheating of the hot leg/surge line. The presence of this event in the cutsets provides limited insights beyond the fact that high pressure melt cases are contributors to high consequence scenarios. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump would address many of the high pressure melt cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).
L2-NOT-TI-SGTR	9.47E-01	2.139E+00	L2 not Temperature induced SGTR	This event represents the probability that a temperature induced SGTR does not occur even with the vessel at high pressure. Limited insights are available based on the presence of this event in the cutsets beyond the fact that high pressure core melts are contributors to high consequence core melt scenarios. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR would address many of the high pressure melt cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).
L2-BMMT	1.00E+00	1.904E+00	L2 Basemat melt-through	Prevention of core damage for scenarios leading to basemat melt-through can be addressed by improving the reliability of secondary side heat removal. An effective enhancement is to replace a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1). The probability of basemat failure could be reduced by installing a reactor cavity flooding system that would ensure that the water is present on the containment floor at the time of vessel failure and that a continuous cooling supply would be available (SAMA 16).

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFAP01----TPAFR	7.61E-02	1.558E+00	#EOOS# AFW Pump A Fails to Run 24 Hours	Event addressed in the Level 1 importance list.
IELOOP	2.13E-02	1.549E+00	INITIATING EVENT - Loss of Off-Site Power at Switchyard	Event addressed in the Level 1 importance list.
SBO-SEQUENCE	1.00E+00	1.440E+00	FLAG: Station Blackout Sequence	Event addressed in the Level 1 importance list.
L2-NOT-CD-STOP	1.00E+00	1.437E+00	Core Damage Not Arrested in Vessel Prior to Vessel Breach	This event is used in SBO cases and represents the probability that power cannot be recovered and injection aligned in time to prevent core damage/vessel failure. The available PVNGS procedural guidance directs vessel flooding in these cases, but no credit is take for this in the model as it does not place the plant in a stable state. Preventing core damage in an SBO sequence is considered to be the most appropriate method of reducing the L2-NOT-CD-STOP contributors. SAMA 4 proposes the use of a 480V AC generator to power the charging pumps for primary side makeup and the division 1 battery chargers to support long term AFW operation.
1SPURMFWTRIP-2OP	1.20E-01	1.309E+00	Main FW Pumps Spurious Trip Following Reactor Trip	Event addressed in the Level 1 importance list.
LOOP-RECOVR3-2PW	2.00E-01	1.307E+00	Off-Site Power (via Switchyard) Non-Recovery Within 3 Hours	Event addressed in the Level 1 importance list.
1AFA-RECOVERABLE	1.00E+00	1.245E+00	FLAG: Cutset is Recoverable by RE-AFA-LCL*	Event addressed in the Level 1 importance list.
1ALFW-NOMFW---HR	1.70E-01	1.230E+00	CR Ops Fails to Depress SG & Supply ALTFW (MFW Not Avail)	Event addressed in the Level 1 importance list.
IEPBA	3.65E+02	1.215E+00	INITIATING EVENT - Loss of Train A ESF Bus	Event addressed in the Level 1 importance list.
1PE-CC1DGAFR-ALL	2.01E-03	1.187E+00	Diesel Generator Group Fail to Run - PEAG01, PEBG02	Event addressed in the Level 1 importance list.
IEMISC	7.93E-01	1.170E+00	INITIATING EVENT - Miscellaneous Transients (Uncomplicated Reactor Trip)	Event addressed in the Level 1 importance list.
1ALFW---MFW---HR	2.50E-02	1.127E+00	CR Ops Fails to Depress SG & Supply ALTFW (MFW Avail)	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PEAG01----DGAFR	3.41E-02	1.112E+00	#EOOS# DGA Fails to Run	Event addressed in the Level 1 importance list.
1PBAS03LBKXCXAXX	6.50E-06	1.111E+00	Spur Elect Prot on Train A ESF Bus Locks Out All Power Sources	Event addressed in the Level 1 importance list.
1PEBG02----DGAFR	3.41E-02	1.111E+00	#EOOS# DGB Fails to Run	Event addressed in the Level 1 importance list.
1AFBP01----MPAFR	3.10E-03	1.109E+00	AFW Pump B Fails to Run 24 Hours	Event addressed in the Level 1 importance list.
1AFBV025---NVNRM	1.96E-03	1.103E+00	AFW Pump B Discharge Isolation Valve Not Restored After Mntc	Event addressed in the Level 1 importance list.
LOOP---------2PW	2.32E-03	1.101E+00	Loss of Off-Site Power to Switchyard Post Trip	Event addressed in the Level 1 importance list.
AGT-FAILSTRT-2HR	1.60E-01	1.096E+00	CR Operators Fail to Direct WRF Operator To Start GTGs	Event addressed in the Level 1 importance list.
IECPST	3.50E-02	1.090E+00	INTIATING EVENT - Loss of All Condensate Pumps	Event addressed in the Level 1 importance list.
1AFNP01----MPAFR	3.10E-03	1.090E+00	AFW Pump N Fails to Run for 24 Hours	Event addressed in the Level 1 importance list.
1AF-CC1MPAFS-ALL	2.94E-05	1.078E+00	AF Electric Pumps Fail to Start - AFBP01, AFNP01	Event addressed in the Level 1 importance list.
IETT	3.90E-01	1.077E+00	INITIATING EVENT - Turbine Trip (Load Rejection)	Event addressed in the Level 1 importance list.
ANANS07-138EXBPW	1.16E-02	1.075E+00	Buried Power Cables From GTGs to Unit Fail	Event addressed in the Level 1 importance list.
1ALFW-NOMFWND-HR	3.50E-01	1.064E+00	CR Operator Fails to Align AFN (MFW Lost) - No Diagnosis	Event addressed in the Level 1 importance list.
1AFN-NOMFW----HR	3.20E-03	1.062E+00	CR Operator Fails to Align AFN (MFW Lost)	Event addressed in the Level 1 importance list.
1AFBP01----MPAFS	1.15E-03	1.058E+00	AFW Pump B Fails to Start	Event addressed in the Level 1 importance list.
L2-RCSDEPRESSEARLY	7.50E-02	1.053E+00	L2 RCS depressurization early due to Early Stuck Open PSV	Cases with stuck open PSVs could be addressed by enhancing the RCS so that Feed and Bleed heat removal is possible (SAMA 1).
IEPBB	3.65E+02	1.045E+00	INITIATING EVENT - Loss of Train B ESF Bus	Event addressed in the Level 1 importance list.
1PBAS03-416BSEPW	2.40E-06	1.038E+00	#EOOS# Train A ESF Bus Fault	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AFNP01----MPAFS	1.15E-03	1.033E+00	AFW Pump N Fails to Start	Event addressed in the Level 1 importance list.
L2-LERF	1.00E+00	1.032E+00	L2 Large and early release	The presence of this flag does not provide any particular insight other than LERF events are contributors to high consequence scenarios. No SAMAs suggested.
L2-TI-SGTR	5.29E-02	1.032E+00	L2 Temperature induced SGTR	This event represents the probability that a temperature induced tube rupture will occur after core damage. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump would address many of the core damage scenarios leading to TI-SGTR scenarios (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1). Finally, procedures could be modified to preclude any RCP operations that would clear the water seals in the cold leg (SAMA 17).
IESLOCA	3.60E-04	1.032E+00	INITIATING EVENT - Small Loss of Coolant Accident	Event addressed in the Level 1 importance list.
1AF-CC1MPAFR-ALL	1.21E-05	1.031E+00	AF Electric Pumps Fail to Run - AFBP01, AFNP01	Event addressed in the Level 1 importance list.
1AFNSYS----AFNCM	1.05E-03	1.030E+00	Train N Auxiliary Feedwater Unavailable Due to Maintenance	Event addressed in the Level 1 importance list.
IESGTR	6.25E-03	1.028E+00	INITIATING EVENT - Steam Generator Tube Rupture	Event addressed in the Level 1 importance list.
1AFN-NOMFW-ND-HR	2.20E-01	1.027E+00	CR Operator Fails to Align AFN (MFW Lost) - No Diagnosis	Event addressed in the Level 1 importance list.
1AFA-NOMFW----HL	4.20E-02	1.026E+00	AO Fails to Locally Align AFAP01 After Recoverable Start Failure - MFW Unavailable	Event addressed in the Level 1 importance list.
1PBBS04KBLXCXAXX	6.50E-06	1.025E+00	Spur Elect Prot on Train B ESF Bus Locks Out All Power Sources	Event addressed in the Level 1 importance list.
RE-CT-HV14-MV	2.10E-01	1.024E+00	Operator fails to locally recover AFN suction valves	Event addressed in the Level 1 importance list.
1PEAG01----DG-CM	6.74E-03	1.024E+00	DGA Unavailable Due to Maintenance	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1AF-CC1MV-FO-ALL	5.17E-05	1.024E+00	AF Injection Globe Valves Fail to Open - AFAHV32, AFBHV30, AFBHV31, AFCHV33	Event addressed in the Level 1 importance list.
1AF-CC2MV-FO-ALL	5.17E-05	1.024E+00	AF Injection Gate Valves Fail to Open - AFAUV37, AFBUV34, AFBUV35, AFCUV36	Event addressed in the Level 1 importance list.
1PEBG02----DG-CM	6.74E-03	1.024E+00	DGB Unavailable Due to Maintenance	Event addressed in the Level 1 importance list.
HE-GTGSTRT---2HR	2.50E-02	1.023E+00	Adjustment Factor - Additional 1 Hour to Start GTGs Given AFA Initially Runs	Event addressed in the Level 1 importance list.
1SAA--LDSHED-2SA	1.47E-06	1.023E+00	#EOOS# Load Sequencer or LOP/LS Module Causes Spur Load Shed	Event addressed in the Level 1 importance list.
1PK-CC1BXAFS-12	2.88E-06	1.023E+00	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	Event addressed in the Level 1 importance list.
IETCW	8.92E-03	1.022E+00	INITIATING EVENT - Loss of Turbine Cooling Water	Event addressed in the Level 1 importance list.
LOOP-RECOVR1-2PW	5.20E-01	1.022E+00	Off-Site Power (via Switchyard) Non-Recovery Within 1 Hour	Event addressed in the Level 1 importance list.
1AFASYS----AFACM	2.75E-03	1.022E+00	Train A Auxiliary Feedwater Unavailable Due to Maintenance	Event addressed in the Level 1 importance list.
1NANS03AB-XCYKFT	3.53E-03	1.022E+00	GTG Supply Bkr to ESF Serv X-fmr NBN-X03 Fail to Close (Cntrl Ckt Fault)	Event addressed in the Level 1 importance list.
1PKBF12----BXAFS	2.91E-04	1.022E+00	Channel B Battery Fails on Demand	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
L2-NOT-TI-SGTR-SBO	9.60E-01	1.019E+00	L2 not Temperature induced SGTR (SBO)	This event represents the probability that a temperature induced SGTR does not occur even with the vessel at high pressure in SBO sequences. Based on the definition of the flag, all contributors are SBO cases, which could be addressed with the addition of a portable 480V AC generator to support SG level instrumentation and charging pump operation (SAMA 4). Another large contributor is the failure to align the GTGs, which could be addressed by automating GTG start (SAMA 8). Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR would address many of the high pressure melt cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).
ANANS07A---XMDPW	3.07E-03	1.019E+00	GTG Auxiliary Power Stepdown Transformer Fails	Event addressed in the Level 1 importance list.
1SAA2-K204-RX-SE	1.20E-06	1.019E+00	#EOOS# LOP Group 2 L/S Spurious Actuation Signal Due to K204 Spur Energize	Event addressed in the Level 1 importance list.
ANANS07A---FUHOC	3.01E-03	1.018E+00	GTG Auxiliary Power Bkr High Voltage Fuse Premature Open	Event addressed in the Level 1 importance list.
ANANS07D---CBOFT	3.00E-03	1.018E+00	GTG Bus Supply Breaker to Unit 1 Fails to Close (Local Fault)	Event addressed in the Level 1 importance list.
ANHNU5607--CB-FT	3.00E-03	1.018E+00	Transfer Switch NHN-U5607 Fails to Transfer to emerg source (credits manual action)	Event addressed in the Level 1 importance list.
1NANS03AB--CBOFT	3.00E-03	1.018E+00	#EOOS# GTG Supply Bkr to ESF Serv X-fmr NBN-X03 Fail to Close (Local Fault)	Event addressed in the Level 1 importance list.
IECONDVAC	4.40E-02	1.017E+00	INTIATING EVENT - Loss of Condenser Vacuum	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1PK-CC1BXAFS-123	2.10E-06	1.017E+00	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	Event addressed in the Level 1 importance list.
1PK-CC1BXAFS-124	2.10E-06	1.017E+00	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	Event addressed in the Level 1 importance list.
1SABAF-K222RXAFT	3.27E-04	1.016E+00	#EOOS# AF Pump B Fails to Start Due to K222 Failure	Event addressed in the Level 1 importance list.
1AFAV016---NVNRM	1.96E-03	1.015E+00	AFW Pump A Discharge Isolation Valve Not Restored After Mntc	Event addressed in the Level 1 importance list.
1AFN-CPWR-----HL	3.50E-02	1.015E+00	AO Fails to Align Backup Control Power to AF Pump N (MFW Lost)	Event addressed in the Level 1 importance list.
1PK-CC1BXAFS-ALL	1.57E-06	1.015E+00	125VDC Class 1E batteries fail on demand - PKAF11, PKBF12, PKCF13, PKDF14	Event addressed in the Level 1 importance list.
1AFBV025---NV-RO	3.01E-04	1.014E+00	#EOOS# AFW Pump B Discharge Isolation Valve Fails Closed	Event addressed in the Level 1 importance list.
1AFAP01----TPAFS	6.79E-03	1.013E+00	AFW Pump A Fails to Start	Event addressed in the Level 1 importance list.
1PEAG01----DGAFS	3.72E-03	1.013E+00	DGA Fails to Start	Event addressed in the Level 1 importance list.
1PEBG02----DGAFS	3.72E-03	1.013E+00	DGB Fails to Start	Event addressed in the Level 1 importance list.
1SAB-LOADSQSQ-CM	2.02E-04	1.012E+00	Seqr B (Incl LOP/LS, DGSS Modules) Unavailable Due to Mntc	Event addressed in the Level 1 importance list.
1CTAHV004--MV-FO	1.53E-03	1.012E+00	#EOOS# CST to AFW Pump N Supply Valve HV4 Fails to Open	Event addressed in the Level 1 importance list.
1CTAHV001--MV-FO	1.53E-03	1.012E+00	#EOOS# CST to AFW Pump N Supply Valve HV1 Fails to Open	Event addressed in the Level 1 importance list.

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
AGT-CC1GTAFS-ALL	1.95E-03	1.012E+00	Gas Turbine Generator Group Fail to Start - GTN-G01, GTN-G02	The cutsets including this event are essentially all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
1AFAP01-2H-TPAFR	6.58E-03	1.011E+00	AFW Pump A Fails to Run 2 Hours	The cutsets including this event are all SBO sequences. These evolutions can be addressed by using a 480V AC generator to provide power to the class 1E battery chargers so that DC power is maintained to support long term operation of the TD AFW pump from the MCR. Primary side makeup is also required due to SBO induced seal LOCAs. Given that the 480V AC generator is sized appropriately, it could be used to power the charging pumps to provide makeup flow (SAMA 4).
L2-NORCSDEPRESSLATE	9.70E-02	1.011E+00	L2 Hot Leg/Surge Line not failed and no stuck open PSV	This event represents the probability that the PSVs do not stick open and depressurize the reactor (after initial success of secondary side heat removal), which results in conditions that could lead to press/temp induced SGTRs. Limited insights are available based on the presence of this event in the cutsets beyond the fact that high pressure core melts are contributors to high consequence CD scenarios. Enhancing MFW capabilities by replacing a low pressure condensate pump with a high pressure pump in conjunction with the addition of a long term suction source (non-CST) that can be aligned from the MCR would address many of the HP CD cases (SAMA 2). Alternatively, the RCS could be enhanced to include PORVs so that Feed and Bleed cooling could be used if secondary side cooling has failed (SAMA 1).

TABLE D.5-2
LEVEL 2 IMPORTANCE REVIEW

EVENT NAME	PROBABILITY	RED W	DESCRIPTION	POTENTIAL SAMAS
1SPBSYS----SPSCM	2.02E-03	1.010E+00	Train B Spray Pond Unavailable Due to Maintenance	About 50% of the contributors are SBO cases, which can be addressed by SAMA 4, but a large portion of the remainder are related to the failure to provide cooling flow for heat removal. These could potentially be addressed by providing alternate cooling flow to the SDC heat exchangers using the Fire Protection System (SAMA 11).
1PSRV-WTRREL-2FC	5.80E-02	1.010E+00	#EOOS# Pressurizer Safety Valve Fails to Reseat After Water Relief	Loss of all SG makeup leads to the situation in which water is forced out of the pressurizer SVs. In this case, about 40% is related to the failure of the station batteries, which could be addressed by ensuring the battery chargers are capable of providing 100% of the DC load (SAMA 15). Other highly expensive alternatives, such as installation of an independent AFW system (SAMA 3), would be effective SAMAs, but they would not likely be as cost effective as providing DC power without the batteries.
1AFN---MFW----HR	1.00E-03	1.010E+00	CR Operator Fails to Align AFN (MFW Available)	The cases involving failure to manually start AFN-P01 could be mitigated by providing a signal that would auto start AFN-P01. The signal could be established so that it would be generated at a point where it is clear that AFA-P01 and AFB-P01 have failed to start. As this signal would be diverse from the existing AFW start signal, it could also be used as a backup start for AFA-P01 and AFB-P01 to address control circuit failures (SAMA 10).
1SPASYS----SPSCM	2.02E-03	1.010E+00	Train A Spray Pond Unavailable Due to Maintenance	The event 1SPASYS----SPSCM is contributes to two major types of failures; one is the failure to support cooling for EDG operation and the other is the failure to support containment heat removal. LOOP with EDG cooling failures comprise about 70% of the total while containment heat removal failures make up most of the rest of the contributions. The lowest cost alternative for addressing the SBO cases is likely the installation of a portable 480V AC generator (SAMA 4). Cooling to the SDC heat exchangers could be provided by a connection to the Fire Protection system to address cases where the Spray Pond is not available to remove heat (SAMA 11).

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
1	Modify the Primary RCS to Allow Feed and Bleed Cooling	Adding power operated relief valve (PORVs), block valves, and an enhanced reactor drain tank to support feed and bleed cooling would provide the capability of removing decay heat even if secondary side heat removal fails.	General Level 1 and 2 PRA Insight	PVNGS estimated an implementation cost of $10,957,158 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $32,871,474.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
2	Replace one Low Pressure Condensate Pumps with a High Pressure Motor Driven Pump (or Add a Booster Pump) and Add Hotwell Makeup Controls to the MCR from a Non-CST Source	MFW can be used as the primary SG makeup source after a plant trip, but loss of MFW cases or those with AFW failures after SG makeup has been transitioned to AFW can still be problematic. Replacing a low press. Condensate pump with a high press. pump will allow the operators to restore SG makeup with the Condensate system without the requirement to reduce secondary side pressure to below 500 psig. If flow requirements are an issue for a high pressure pump, a booster pump could be installed instead. Enhancing the MCR to include the capability to align a long term hotwell makeup source is required (non-CST). This ensures an inventory source can easily be aligned that will allow operation through the transition to SDC.	PVNGS Level 1 Importance List	Addition of a Motor-driven Feedwater Pump has been estimated to be $5,000,000 (TVA 2003), but this cost is for a BWR. The Farley SAMA analysis (SNC 2003) includes a cost of $2,200,000 for the installation of a motor driven feedwater pump to address cases where MSIV closure fails the turbine driven feedwater pump. It is assumed that the cost provided is for pump replacement rather than the addition of a pump. While the PVNGS SAMA also requires the addition of an MOV with MCR controls, the Farley implementation cost is used for a lower bound estimate for this SAMA for each unit and is assumed to address either the addition of a booster pump or the replacement of an existing pump with a high pressure pump. The cost for 3 units would be $6.6 million.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
3	Install an Independent AFW System with a Dedicated Power Supply	Loss of AFW due to hardware and support failures in conjunction with MFW/Condensate unavailability leaves the plant without secondary side cooling. Installation of an independent AFW system could mitigate those scenarios where no secondary side makeup is available. An independent power supply, whether supplied by separate EDG or by an generator on an engine driven pump, should be available to provide power to the system valves and control functions. Alternatively, if the power to the system could be aligned to either division, most of the benefit of the SAMA would be achieved as the cases it has been developed to addresses are not SBO events.	PVNGS Level 1 Importance List	Calvert Cliffs estimated the cost of installing an additional HPSI pump with a dedicated diesel to be between \$5 million and \$10 million (BGE 1998). This type of enhancement is similar is scope to the changes required for this SAMA and the lower bound estimate of \$5 million is used for the single unit cost for this SAMA as the changes are not required to be incorporated into the primary system and use of the existing emergency power divisions is possible. The 3 unit cost would be \$15,000,000.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
4	SBO Mitigation (GTGs not available)	SBO scenarios lead to core damage once the station batteries deplete at three hours. In the event that AC power is not recovered, a 480V AC generator could be used to power the division 1 station batteries to support continued used of the turbine driven AFW pump from the MCR. Given that the 480V AC generator is sized appropriately, it could also be used to power at least two charging pumps such that a primary side makeup source is available to mitigate the RCP seal LOCAs.	PVNGS Level 1 Importance List	PVNGS estimated an implementation cost of \$1,832,954 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at \$5,498,862.	The cost of implementation is greater than the MACR, but this SAMA has been retained for Phase II analysis given that this is a high profile issue.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
5	Install an Automatic Transfer Switch for the Non-Safety AFW Pump (AFN-P01) Power Supply	Loss of division 1 power currently results in the loss of both AFA-P01 and AFN-P01. Providing an automatic power transfer capability would eliminate the need for operator intervention to supply AFN-P01 with power and preclude the need to depressurize the SGs for Alternate FW makeup. A subsequent manual transfer of DC control power would also be required, but it there would be abundant time to perform this action.	PVNGS Level 1 Importance List	PVNGS estimated an implementation cost of $2,267,254 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $6,801,762.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
6	Develop Procedures to Guide Recovery Actions for Spurious Electrical Protection Faults	Loss of bus initiators are potentially recoverable in accident scenarios, but procedures are not currently available to provide guidance for those evolutions. The recovery process may be enhanced if guidance is developed for the site.	PVNGS Level 1 Importance List	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.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
7	Add Auto Start Capability to AFN-P01 on Low SG Level and an Automatic Power Transfer Switch to Address Loss of MFW Cases with Div 1 Power Failures and Operator Start Errors	Loss of MFW cases include diverse circumstances that also challenge AFW capabilities. Many AFW failures are related to loss of division 1 power or the failure to manually initiate AFN-P01. This SAMA would address a majority of the cases by providing a means automatically aligning either power division to AFN-P01 and auto-starting the pump on a diverse low level signal.	PVNGS Level 1 Importance List	This cost is a combination of SAMAs 5 and 10. The total is, therefore, $9,801,762.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
8	Add Auto Start/Load Capability to the GTGs	Automating the start and load of the GTGs would improve the reliability of the emergency ESF bus power alignment.	PVNGS Level 1 Importance List	TMI-1 estimated the cost of modifying the SBO EDG so that it could auto start and load to be $3,125,000 (Exelon 2008). It is assumed that the cost of this type of modification for a GTG is about the same. For PVNGS only one GTG is required for SBO loads and it is assumed that all 3 units can be addressed through the enhancement of one GTG. The cost for implementing this SAMA for 3 units is $3,125,000.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
9	Install a Backup Control Element Assembly Drive Mechanism	For cases where sufficient CEAs do not drop into the core to shut the reactor down, a backup drive system could be installed to force the CEAs into the core. This would be of particular use when the MTC is unfavorable and the operability of the CEAs is the only potential means of preventing core damage.	PVNGS Level 1 Importance List	PVNGS estimated an implementation cost of $4,738,339 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $14,215,017.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
10	Provide a Backup AFW Start Signal on a Lower SG Level and Use it for All Three AFW Pumps	This enhancement would provide a diverse, backup to the auto-start logic currently used for AFA-P01 and AFB-P01 and provide a primary start signal for AFN-P01. This enhancement improves the reliability of a function that is critical to the mitigation of almost all accident scenarios.	PVNGS Level 1 Importance List	The Farley SAMA analysis (SNC 2003) provides a cost of implementation of $1,000,000 to provide backup start signals for the standby CCW trains on loss of the running train. A CCW system is different than a feedwater system, but the installation of sensors to provide a start signal to a pump is common to both SAMAs and the changes are considered to be similar. The Farley estimate of $1,000,000 per unit is used for this SAMA. For 3 units, the cost of implementation is $3,000,000.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
11	Alternate Cooling Flow to SDC Heat Exchangers	For scenarios that require recirculation mode, if EW flow is lost to the SDC heat exchangers, there is no other means of removing heat from the core/containment. Providing an alternate means of cooling the SDC HXs could address EW system failures. The existing Fire Protection system may not be able to provide the required cooling flows, but if significant enhancements were made (including an alternate suction alignment of the Spray Pond), it could be connected to the SDC HXs with a hard piped connection and provide backup cooling. This would also address some Emergency Spray Pond failures.	PVNGS Level 1 Importance List	Two similar industry estimates are available for this type of enhancement, but the actual cost will be highly subject to piping locations in the plant. As a result, the range of costs has been reviewed and the lower end cost has been chosen as a bounding case for PVNGS: - TVA: $500,000 per Hx (TVA 2003) - Calvert Cliffs $565,000, appears to equate to "per Hx" (BGE 1998) For PVNGS, it is assumed that the cost is $500,000 per SDC HX, which equates to $3,000,000 for the site.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.
12	Install an Automatic Transfer Switch for the AFW Pump AFB-P01 Power Supply	Loss of division 2 power currently results in the loss of AFB-P01. Providing an automatic power transfer capability would allow rapid recovery of AFB-P01 and preclude the need to depressurize the SGs for Alternate FW makeup. A subsequent manual transfer of DC control power would also be required, but it there would be abundant time to perform this action.	PVNGS Level 1 Importance List	Assumed to be the same cost as SAMA 5 ($6,801,762).	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
13	Mitigate Loss of TCW Events: Provide Permanent, Hard Piped Connections Between the Fire Protection System and Critical Loads	TCW provides cooling water to several loads, but those that are most important to plant safety include the Instrument Air system and the Condensate pump upper bearing oil coolers. If permanent, hard piped connections were installed between the Fire Protection system and those loads, a means of recovering MFW and/or Condensate would be available for loss of TCW events. Long term success is assumed to require the addition of an alternate suction path between the Fire Protection system and the Spray Pond.	PVNGS Level 1 Importance List	The cost estimate for SAMA 11 is used as the basis for this cost estimate. It is assumed that the cost of each connection between Fire Protection and a critical load is the same as the connection between Fire Protection and an SDC Hx ($500k). In this case, there are two critical loads per unit (condensate upper bearing oil coolers and IA (1 train of each required)), which yields $1 million/unit, or $3 million for the site.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.
14	Provide a Permanent, Hardpiped Suction Line from the RMWT to AFN-P01	In the event that SG makeup capability has been lost and the failure of AFN-P01 is due a failure of the suction line valves, having an alternate suction source for the pump would restore secondary side heat removal. Providing a permanent, hardpiped connection will improve the reliability of the alignment action.	PVNGS Level 1 Importance List	PVNGS estimated an implementation cost of $2,215,730 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $6,647,190.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
15	100 Percent Capacity Battery Chargers	Enhancing the battery chargers so that they can supply all DC loads without tripping, when the battery is not available in the circuit would prevent DC system failures when the battery has failed or is unavailable.	PVNGS Level 1 Importance List	PVNGS estimated an implementation cost of $547,566 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $1,642,698.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
16	Install a Reactor Cavity Flooding System	Providing a system that could deliver water to reactor pedestal area under the reactor vessel before vessel breach would help cool molten core debris and prevent basemat failure.	PVNGS Level 2 Importance List	PVNGS estimated an implementation cost of $6,014,882 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $18,044,646.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
17	Modify the Procedures to Preclude RCP Operations that Would Clear the Water Seals in the Cold Leg After Core Damage	The probability of a temperature induced SGTR event is increased when the water seal in the reactor coolant loop is not present. In these cases, an open pathway exists that will allow circulation of the hot core gases through the SGs. Procedurally preventing operation of the RCPs in conditions that would clear the loop water seal would improve the probability that the RCS would remain intact.	PVNGS Level 2 Importance List	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 2 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.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
18	Fire Proof All Cables and Equipment Required for AFN-P01 Operation in Important Fire Areas	Fire induced failure of AFN-P01 is common to many of the largest contributors to the fire CDF. Wrapping all power and control cables in the four important fire areas for AFN-P01 would reduce the probability that AFN-P01 would be lost in a fire event, which would help maintain the availability of a secondary side cooling system. In order for this SAMA to be effective, it would also be necessary to identify and protect all cables and equipment required to support operation of AFN-P01.	PVNGS Fire Model Review	PVNGS estimated an implementation cost of $5,648,794 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $16,946,382.	As the cost of implementation is greater than the MACR, this SAMA has been screened from further analysis.
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 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.	PVNGS Fire Model Review	PVNGS estimated an implementation cost of $1,553,894 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $4,661,682.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
20	Install Fire Barriers Between Fire Zone TB01 and TB05	Fires in fire zone TB05 (Turbine Building 140 ft West)) do no pose a large risk to the plant from equipment losses within that zone, but if the fire propagates to fire zone TB01 (Turbine Building 100 ft West), the consequences are more severe. Installing a fire barrier between these two zones would prevent propagation of a fire from TB05 to TB01 and the consequential loss of AFN-P01, Alt Feedwater, and load centers L01 and L25. In addition, the barrier must protect fire zone TB01 from the effects of suppression system actuation in fire zone TB05 as the water can damage TB01 equipment.	PVNGS Fire Model Review	PVNGS estimated an implementation cost of $1,208,564 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,625,692.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.
21	Install Fire Resistant Cable Wrap on Selected Cables in Fire Compartment TB4B	Transient fires in FZ TB4B (Station DC Equipment Room - 110 ft Turb Bldg) can fail cables related to NAN-S03 and NAN-S04 (loss of switchyard) or NBNX03 (loss of Train A ESF service transformer). Installing fire resistant cable wrap on these circuits in the sections of the cable trays that are close enough to the floor to be impacted by transient fires could prevent the loss of critical equipment in fire events.	PVNGS Fire Model Review	PVNGS estimated an implementation cost of $1,121,838 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,365,514.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis..

TABLE D.5-3
PHASE 1 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	COST ESTIMATE	PHASE I DISPOSITION
22	Enhance the MCC M71 Fire Barriers	Transient fires in FZ 42A (Electrical Penetration Room - Train A, Channel C - Aux Bldg - 100 ft) can result in the loss of MCC M71, which results in the failure of AFN-P01. Improving the MCC's barriers to better withstand fires could prevent the loss of the equipment in certain fire scenarios.	PVNGS Fire Model Review	PVNGS estimated an implementation cost of $1,090,700 for a single unit (APS 2008a). The site-wide implementation cost is assumed to be 3 times greater at $3,272,100.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.
23	Enhance Procedures to Direct Steam Generator Flooding for Release Scrubbing	The existing PVNGS guidance governs SG level for heat removal considerations, which may consequently result in release scrubbing; however, the guidance is not tailored to meet this need. Expanding the existing guidance to direct SG flooding prior to core damage would potentially improve the probability that water would be available above the break point in the SG and provide a mechanical means of scrubbing the fission products during a release.	Industry SAMA List Review (ANO 2)	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.	As the cost of implementation is less than the MACR, this SAMA has been retained for Phase II analysis.

TABLE D.5-4
PHASE 2 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
4	SBO Mitigation (GTGs not available)	SBO scenarios lead to core damage once the station batteries deplete at three hours. In the event that AC power is not recovered, a 480V AC generator could be used to power the division 1 station batteries to support continued used of the turbine driven AFW pump from the MCR. Given that the 480V AC generator is sized appropriately, it could also be used to power at least two charging pumps such that a primary side makeup source is available to mitigate the RCP seal LOCAs.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
6	Develop Procedures to Guide Recovery Actions for Spurious Electrical Protection Faults	Loss of bus initiators are potentially recoverable in accident scenarios, but procedures are not currently available to provide guidance for those evolutions. The recovery process may be enhanced if guidance is developed for the site.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
8	Add Auto Start/Load Capability to the GTGs	Automating the start and load of the GTGs would improve the reliability of the emergency ESF bus power alignment.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
10	Provide a Backup AFW Start Signal on a Lower SG Level and Use it for All Three AFW Pumps	This enhancement would provide a diverse, backup to the auto-start logic currently used for AFA-P01 and AFB-P01 and provide a primary start signal for AFN-P01. This enhancement improves the reliability of a function that is critical to the mitigation of almost all accident scenarios.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.

TABLE D.5-4
PHASE 2 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
11	Alternate Cooling Flow to SDC Heat Exchangers	For scenarios that require recirculation mode, if EW flow is lost to the SDC heat exchangers, there is no other means of removing heat from the core/containment. Providing an alternate means of cooling the SDC HXs could address EW system failures. The existing Fire Protection system may not be able to provide the required cooling flows, but if significant enhancements were made (including an alternate suction alignment of the Spray Pond), it could be connected to the SDC HXs with a hard piped connection and provide backup cooling. This would also address some Emergency Spray Pond failures.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
13	Mitigate Loss of TCW Events: Provide Permanent, Hard Piped Connections Between the Fire Protection System and Critical Loads	TCW provides cooling water to several loads, but those that are most important to plant safety include the Instrument Air system and the Condensate pump upper bearing oil coolers. If permanent, hard piped connections were installed between the Fire Protection system and those loads, a means of recovering MFW and/or Condensate would be available for loss of TCW events. Long term success is assumed to require the addition of an alternate suction path between the Fire Protection system and the Spray Pond.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
15	100% Capacity Battery Chargers	Enhancing the battery chargers so that they can supply all DC loads without tripping, when the battery is not available in the circuit would prevent DC system failures when the battery has failed or is unavailable.	PVNGS Level 1 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.

TABLE D.5-4
PHASE 2 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
17	Modify the Procedures to Preclude RCP Operations that Would Clear the Water Seals in the Cold Leg After Core Damage	The probability of a temperature induced SGTR event is increased when the water seal in the reactor coolant loop is not present. In these cases, an open pathway exists that will allow circulation of the hot core gases through the SGs. Procedurally preventing operation of the RCPs in conditions that would clear the loop water seal would improve the probability that the RCS would remain intact.	PVNGS Level 2 Importance List	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
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 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.	PVNGS Fire Model Review	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
20	Install Fire Barriers Between Fire Zone TB01 and TB05	Fires in fire zone TB05 (Turbine Building 140 ft West)) do no pose a large risk to the plant from equipment losses within that zone, but if the fire propagates to fire zone TB01 (Turbine Building 100 ft West), the consequences are more severe. Installing a fire barrier between these two zones would prevent propagation of a fire from TB05 to TB01 and the consequential loss of AFN-P01, Alt Feedwater, and load centers L01 and L25. In addition, the barrier must protect fire zone TB01 from the effects of suppression system actuation in fire zone TB05 as the water can damage TB01 equipment.	PVNGS Fire Model Review	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.

TABLE D.5-4
PHASE 2 SAMA LIST

SAMA NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	BASELINE PHASE II DISPOSITION
21	Install Fire Resistant Cable Wrap on Selected Cables in Fire Compartment TB4B	Transient fires in FZ TB4B (Station DC Equipment Room - 110 ft Turb Bldg) can fail cables related to NAN-S03 and NAN-S04 (loss of switchyard) or NBNX03 (loss of Train A ESF service transformer). Installing fire resistant cable wrap on these circuits in the sections of the cable trays that are close enough to the floor to be impacted by transient fires could prevent the loss of critical equipment in fire events.	PVNGS Fire Model Review	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
22	Enhance the MCC M71 Fire Barriers	Transient fires in FZ 42A (Electrical Penetration Room - Train A, Channel C - Aux Bldg - 100 ft) can result in the loss of MCC M71, which results in the failure of AFN-P01. Improving the MCC's barriers to better withstand fires could prevent the loss of the equipment in certain fire scenarios.	PVNGS Fire Model Review	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.
23	Enhance Procedures to Direct Steam Generator Flooding for Release Scrubbing	The existing PVNGS guidance governs SG level for heat removal considerations, which may consequently result in release scrubbing; however, the guidance is not tailored to meet this need. Expanding the existing guidance to direct SG flooding prior to core damage would potentially improve the probability that water would be available above the break point in the SG and provide a mechanical means of scrubbing the fission products during a release.	Industry SAMA List Review (ANO 2)	The cost of implementation is greater than averted cost risk and this SAMA's net value is negative.

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