10 CFR 50.90

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102-08299-BJR/TNW
July 29, 2021

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

Dear Sirs:

Subject: **Palo Verde Nuclear Generating Station Units 1, 2, and 3**
Docket Nos. STN 50-528, 50-529, and 50-530
Renewed Operating License Number NPF-41, NPF-51, and NPF-74
Application to Revise Technical Specifications - Administrative Changes

Pursuant to 10 CFR 50.90, Arizona Public Service Company (APS) is submitting a request for an amendment to the Technical Specifications (TS) for Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3.

APS requests administrative changes to the TS that remove no longer applicable information resulting from the completion of the degraded and loss of voltage relay modifications approved in License Amendment 201 [NRC Agencywide Documents Access and Management System (ADAMS) Accession No. ML17090A164], and to correct a typographical error on the footer of page 3.7.5-4.

The enclosure provides a description and assessment of the proposed changes. Attachment 1 to the enclosure provides the existing TS pages marked up to show the proposed changes. Attachment 2 to the enclosure provides revised (re-typed) TS pages. Attachment 3 to the enclosure provides marked up TS Bases pages to show the proposed changes. The changes to the TS Bases are provided for information only.

Approval of the proposed amendment is requested by July 23, 2022. Once approved, the amendment will be implemented within 90 days.

PVNGS has determined that there are no significant hazards considerations associated with the proposed change and that the TS change qualifies for a categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9).

In accordance with the PVNGS Quality Assurance Program, the Plant Review Board has reviewed and approved the license amendment request (LAR). By copy of this letter, the LAR is being forwarded to the Arizona Department of Health Services – Bureau of Radiation Control in accordance with 10 CFR 50.91(b)(1).

No new commitments are being made to the NRC by this letter.

Should you need further information regarding this letter, please contact Matthew S. Cox, Licensing Section Leader, at (623) 393-5753.

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

Executed on: July 29, 2021
(Date)

Sincerely,

Rash, Bruce (Z77439)

Digitally signed by Rash, Bruce (Z77439)
DN: cn=Rash, Bruce (Z77439)
Date: 2021.07.29 08:58:33 -07'00'

BJR/TNW/mg

Enclosure: Description and Assessment of Proposed License Amendment

cc:	S. A. Morris	NRC Region IV Regional Administrator
	S. P. Lingam	NRC NRR Project Manager for PVNGS
	L. N. Merker	NRC Senior Resident Inspector for PVNGS
	B. Goretzki	Arizona Department of Health Services – Bureau of Radiation Control

ENCLOSURE

Description and Assessment of Proposed License Amendment

Enclosure
Description and Assessment of Proposed License Amendment

Subject: License Amendment Request to Make Miscellaneous Administrative Changes

Table of Contents

ATTACHMENTS:

1. Proposed Technical Specification Changes (Mark-up)
2. Proposed Technical Specification Changes (Re-Typed)
3. Revised Technical Specification Bases Changes (Page Markups – For Information)

1.0 SUMMARY DESCRIPTION

Arizona Public Service Company (APS) is requesting a license amendment to the Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2 and 3 Technical Specifications (TS). The proposed amendment would modify the TS by making various administrative changes.

Specifically, this License Amendment Request (LAR) proposes administrative changes to the TS that remove no longer applicable information resulting from the completion of the degraded and loss of voltage relay modifications approved in License Amendment (LA) 201 [NRC Agencywide Documents Access and Management System (ADAMS) Accession No. ML17090A164], and to correct a typographical error on the footer of page 3.7.5-4.

2.0 DETAILED DESCRIPTION

2.1 Degraded and Loss of Voltage Relay Modification Changes

2.1.1 Description of the Proposed Change

Completion of the degraded and loss of voltage relay modifications for each of the Class 1E buses for PVNGS Units 1, 2, and 3, resulted in the need to remove the old design and operational information from the TS and TS Bases. This included the removal of the old surveillance requirement (SR) 3.3.7.3, renumbering existing SR 3.3.7.4 to 3.3.7.3, and removal of Limiting Condition for Operation (LCO) 3.8.1, Condition G. This change fulfills a stated action from LA 201, dated April 27, 2017.

2.1.2 Reason for the Proposed Change

The NRC safety evaluation for LA 201 stated, in part, in Section 3.2:

> "The current operating procedures at PVNGS rely on administrative controls to improve Class 1E bus voltages when degraded voltage conditions are observed. Specifically, TS 3.8.1, Condition G, allows 1 hour to restore offsite power to operable status in the event of degraded voltage conditions. The proposed change [LA 201] will provide reasonable assurance for adequate post-trip voltage support for accident mitigation equipment and rely on automatic actuation of the DVRs and LVRs to ensure proper equipment performance."

The LA 201 NRC safety evaluation continued, in Section 3.2.1.3:

> "Once this new scheme is implemented, the currently credited preventive administrative controls designated in TS 3.8.1, Condition G will no longer be required. This is currently a 1-hour required action completion time. As such, a subsequent license amendment will be processed to remove TS 3.8.1, Condition G,

> as well as SR 3.3.7.3, once plant modifications are complete."

The LA 201 NRC safety evaluation continued, in Section 3.4.3:

> "The NRC staff reviewed the proposed modification to LCO 3.8.1 Condition G. LCO 3.8.1, Condition G, applies when one or more required offsite circuits do not meet required capability. The licensee stated that the new design will rely upon the actuation of the degraded voltage protection scheme on a deterministic basis, without crediting the preventive administrative controls implemented per LCO 3.8.1, Condition G, and that Condition G would no longer be applicable once the modification is complete."
>
> "The staff reviewed the licensee's statement and the reason for Condition G stated in the Bases for LCO 3.8.1, Condition G, and concluded that LCO 3.8.1, Condition G would no longer be necessary once the modifications are completed. Therefore, the Note stating that Condition G is not applicable for Class 1E buses provided with a two stage delay for the degraded voltage relays and a fixed time delay for the loss of voltage relays is appropriate."

As a practical matter, since each of the Class 1E 4.16 kiloVolt (kV) buses have been modified, the existing Note applied to LCO 3.8.1, Condition G, means that Condition G no longer applies at PVNGS. This proposed TS change is, therefore, an administrative effort to remove obsolete information from the TS and TS Bases.

The LA 201 NRC safety evaluation continued, in Section 3.5, *Summary*:

> "Following the completion of the modifications, an administrative LAR will be submitted to remove TS 3.8.1, Condition G, and the old relay information from SR 3.3.7.3. The administrative controls, as documented in the TS Bases, will remain as a defense-in-depth preventive strategy, as compared to being the licensed success path for degraded voltage protection."

This administrative LAR fulfills the action to request NRC staff approval to remove the obsolete information from the PVNGS TS. APS retains the defense-in-depth administrative controls in plant procedures in lieu of remaining in the TS Bases. The proposed changes to the TS Bases are provided in Attachment 3 for information.

2.2 Correction of Typographical Error

2.2.1 Description of the Proposed Change

The footer of existing TS page 3.7.5-4 contains a typographical error in that the previous License Amendment (LA) that altered the page was not LA 206, but instead was LA 188. This typographical error is corrected by replacement of the 206 strike-out with the appropriate 188 strike-out in the footer of the page.

2.2.2 Reason for the Proposed Change

This change corrects an error in the revision history of the affected page.

3.0 TECHNICAL EVALUATION

3.1 Degraded and Loss of Voltage Relay Modification Changes

Pursuant to 10 CFR 50.36(c)(2), the TS contain limiting conditions for operation, which represent "the lowest functional capability or performance levels of equipment required for safe operation of the facility." The specific criterion applicable to LCO 3.8.1 is that the AC sources satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii), which is that they are "part of the primary success path" … "to mitigate a design basis accident."

Previous to the modifications of the degraded and loss of voltage relays, LCO 3.8.1, Condition G, applied when one or more required offsite circuits did not meet required capability. The new design relies upon the actuation of the degraded voltage protection scheme on a deterministic basis, without crediting the preventive administrative controls in effect per LCO 3.8.1, Condition G. LCO 3.8.1, Condition G, is no longer applicable now that the modifications are complete.

Also, the completion of the modifications to the degraded and loss of voltage relays render the previous surveillance requirements of the old design moot, such that the old design SR 3.3.7.3 is deleted and the previously numbered SR 3.3.7.4 is renumbered 3.3.7.3.

3.2 Correction of Typographical Error

This change corrects an error in the revision history of the affected page.

4.0 REGULATORY EVALUATION

4.1 Precedent

None, however, this administrative change is the logical result of LA 201 (ADAMS Accession No. ML17090A164).

4.2 No Significant Hazards Consideration

Arizona Public Service Company (APS) is requesting an amendment to Renewed Facility Operating Licenses NPF-41, NPF-51, and NPF-74 for Palo Verde Nuclear Generating Station (PVNGS), Units 1, 2 and 3, respectively. The proposed amendment would modify Technical Specifications (TS) by making various administrative changes.

Specifically, APS requests administrative changes to the Technical Specifications that remove no longer applicable information resulting from the completion of the degraded and loss of voltage relay modifications approved in License Amendment 201 (ADAMS Accession No. ML17090A164), and to correct a typographical error on the footer of page 3.7.5-4.

APS has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10 CFR 50.92, *Issuance of amendment*, as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed changes are administrative. The removal of no longer applicable descriptions aligns TS with current plant configurations, provides clarity to avoid operator misinterpretation and allows consistency across PVNGS documentation and procedures. Removal of no longer applicable descriptions will restore the Technical Specifications to full applicability with the current plant configuration.

   The administrative changes return TS descriptions to align with current plant configurations approved in previous License Amendments. Therefore, these changes do not involve a significant increase in the probability or consequence of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed changes are administrative. The removal of no longer applicable descriptions aligns TS with current plant configurations, provides clarity to avoid operator misinterpretation and allows consistency across PVNGS documentation and procedures. Removal of no longer applicable descriptions will restore the Technical Specifications to full applicability with the current plant configuration.

   The administrative changes return TS descriptions to align with current plant configurations approved in previous License Amendments. The proposed changes will not affect the operation of structures, systems, or components, and will not reduce programmatic controls such that plant safety would be affected. Therefore, these changes do not involve a significant increase in the probability or consequence of an accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed changes are administrative. The removal of no longer applicable descriptions aligns TS with current plant configurations, provides clarity to avoid operator misinterpretation and allows consistency across PVNGS documentation and procedures. Removal of no longer applicable descriptions will restore the Technical Specifications to full applicability with the current plant configuration.

   The administrative changes return TS descriptions to align with current plant configurations approved in previous License Amendments. The changes are administrative and will not diminish any organizational or administrative controls currently in place to address design basis accidents. The proposed changes will not affect the operation of structures, systems, or components, and will not reduce programmatic controls such that plant safety would be affected. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, APS concludes that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

4.3 Conclusion

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL EVALUATION

The proposed change would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, *Standards for Protection Against Radiation*, or would change an inspection or surveillance requirement. However, the proposed change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed change.

6.0 REFERENCE

6.1. NRC issued Amendment No. 201 to Renewed Facility Operating Licenses No. NPF-41, NPF-51 and NPF-74 for the Palo Verde Nuclear Generating Station, Units 1, 2, and 3, dated April 27, 2017 (ADAMS Accession No. ML17090A164)

ATTACHMENT 1:

Proposed Technical Specification Changes (Mark-Up)

Changed Page(s)

3.3.7-3
3.3.7-4

3.7.5-4

3.8.1-5
3.8.1-6

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
~~SR 3.3.7.3~~	~~-----NOTE-----~~ ~~Only applicable for Class 1E bus(es) provided with a single stage time delay for the degraded voltage relays and an inverse time delay for the loss of voltage relays.~~ ~~----------~~ ~~Perform CHANNEL CALIBRATION with setpoint Allowable Values as follows:~~ ~~a. Degraded Voltage Function ≥ 3697 V and ≤ 3786 V~~ ~~Time delay: ≥ 28.6 seconds and ≤ 35 seconds; and~~ ~~b. Loss of Voltage Function~~ ~~Time delay: ≥ 10.3 seconds and ≤ 12.6 seconds at 2929.5 V, and ≥ 2.0 seconds and ≤ 2.4 seconds at 0 V.~~	~~In accordance with the Surveillance Frequency Control Program~~

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.7~~.4~~ 3	~~-----NOTE-----~~ ~~Only applicable for Class 1E bus(es) provided with a two stage time delay for the degraded voltage relays and a fixed time delay for the loss of voltage relays.~~ ~~----------~~ Perform CHANNEL CALIBRATION with setpoint Allowable Values as follows: a. Degraded Voltage Function ≥ 3712 V and ≤ 3767 V with a two stage time delay Short stage time delay: ≥ 5.5 seconds and ≤ 8.5 seconds; and Long stage time delay: ≥ 31.0.seconds and ≤ 40.0 seconds; and b. Loss of Voltage Function ≥ 3240 V and ≤ 3300 V Time delay: ≥ 1.4 seconds and ≤ 2.3 seconds	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.5.1	Verify each AFW manual, power operated, and automatic valve in each water flow path and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.5.2	-----------------------------NOTE------------------------- Not required to be performed for the turbine driven AFW pump until 72 hours after reaching 532°F in the RCS. ---	
	Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.7.5.3	---------------------------NOTES------------------------- 1. Not required to be performed for the turbine driven AFW pump until 72 hours after reaching 532°F in the RCS. 2. Not applicable in MODE 4 when steam generator is relied upon for heat removal. ---	
	Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One automatic load sequencer inoperable.	F.1 Restore automatic load sequencer to OPERABLE status. AND	24 hours OR In accordance with the Risk Informed Completion Time Program
	F.2 Declare required feature(s) supported by the inoperable sequencer inoperable when its redundant required feature(s) is inoperable.	4 hours from discovery of Condition F concurrent with inoperability of redundant required feature(s)
~~G.~~ ~~------------NOTE------------ Condition G is not applicable for Class 1E bus(es) provided with a two stage time delay for the degraded voltage relays and a fixed time delay for the loss of voltage relays. -------------------------------~~ ~~One or more required offsite circuit(s) do not meet required capability.~~	~~G.1 Restore required capability of the offsite circuit(s).~~ ~~OR~~	~~1 hour~~
	~~---------------NOTE--------------- Enter LCO 3.8.1 Condition A or C for required offsite circuit(s) inoperable. ------------------------------------~~ ~~G.2 Transfer the ESF bus(es) from the offsite circuit(s) to the EDG(s).~~	~~1 hour~~

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~H.~~ G ------------NOTES------------ 1. Not applicable when the third or a subsequent required AC source intentionally made inoperable. 2. The following Section 5.5.20 constraints are applicable: parts b, c.2, c.3, d, e, f, g, and h. --------------------------------- Three or more required AC sources inoperable.	~~H~~.1 Restore required AC source(s) to OPERABLE status.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
~~I.~~ H Required Action and Associated Completion Time of Condition A, B, C, D, E, F, ~~G, or H~~ or G not met.	~~I~~.1 Be in MODE 3. <u>AND</u> ~~I~~.2 Be in MODE 5.	6 hours 36 hours

ATTACHMENT 2:

Proposed Technical Specification Changes (Re-Typed)

Changed Page(s)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.7.3	Perform CHANNEL CALIBRATION with setpoint Allowable Values as follows: a. Degraded Voltage Function ≥ 3712 V and ≤ 3767 V with a two stage time delay Short stage time delay: ≥ 5.5 seconds and ≤ 8.5 seconds; and Long stage time delay: ≥ 31.0.seconds and ≤ 40.0 seconds; and b. Loss of Voltage Function ≥ 3240 V and ≤ 3300 V Time delay: ≥ 1.4 seconds and ≤ 2.3 seconds	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify each AFW manual, power operated, and automatic valve in each water flow path and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.5.2	-----------------------------NOTE------------------------- Not required to be performed for the turbine driven AFW pump until 72 hours after reaching 532°F in the RCS. --- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.7.5.3	---------------------------NOTES------------------------- 1. Not required to be performed for the turbine driven AFW pump until 72 hours after reaching 532°F in the RCS. 2. Not applicable in MODE 4 when steam generator is relied upon for heat removal. --- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One automatic load sequencer inoperable.	F.1 Restore automatic load sequencer to OPERABLE status. AND	24 hours OR In accordance with the Risk Informed Completion Time Program
	F.2 Declare required feature(s) supported by the inoperable sequencer inoperable when its redundant required feature(s) is inoperable.	4 hours from discovery of Condition F concurrent with inoperability of redundant required feature(s)

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. ------------NOTES----------- 1. Not applicable when the third or a subsequent required AC source intentionally made inoperable. 2. The following Section 5.5.20 constraints are applicable: parts b, c.2, c.3, d, e, f, g, and h. --------------------------------- Three or more required AC sources inoperable.	G.1 Restore required AC source(s) to OPERABLE status.	1 hour OR In accordance with the Risk Informed Completion Time Program
H. Required Action and Associated Completion Time of Condition A, B, C, D, E, F, or G not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours

ATTACHMENT 3:

Revised Technical Specification Bases Changes
(Page Markups – For Information)

Changed Page

3.3.7-1
3.3.7-2
3.3.7-7
3.3.7-8

3.8.1-2
3.8.1-3
3.8.1-4
3.8.1-7
3.8.1.14
3.8.1-16
3.8.1.17
3.8.1-18
3.8.1-19
3.8.1-20
3.8.1-21

B 3.3 INSTRUMENTATION

B 3.3.7 Diesel Generator (DG) - Loss of Voltage Start (LOVS)

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or insufficiently stable to allow safe unit operation. Undervoltage protection will generate a LOVS in the event a Loss of Voltage (LOV) or Degraded Voltage (DV) condition occurs.

Four solid state degraded voltage and four solid state under voltage relays ~~[four solid-state relays and four induction disk relays]~~[1] are provided on each 4.16 kV Class 1E bus for the purpose of detecting a sustained degraded voltage or a loss of bus voltage condition, respectively. The protective function of the Degraded Voltage Relays is maintained by assuring that they always actuate when voltage is ≤3712 ~~[3697]~~[1] V. To prevent spurious actuations, time delays are provided; one for when a SIAS~~[2]~~ is present (i.e., short stage time delay) and a second when no SIAS is present (i.e., long stage time delay). The Degraded Voltage Relays will not actuate when voltage is >3767 ~~[3786]~~[1] V. The time delay for the Degraded Voltage Relays is a maximum of 40 ~~[35]~~[1] seconds when no SIAS~~[2]~~ is present to permit Reactor Coolant Pump starts, without creating the potential for inappropriate loss of offsite power, and is not affected by the voltage level at which they are actuated. The time delay when a SIAS~~[2]~~ is present (i.e., short stage time delay) is less than 8.5 seconds to coordinate with the design bases accident analysis.

The Loss of Voltage Relays actuate at a lower voltage. ~~Their time delay varies depending on the voltage level, the lower the voltage, the shorter the time delay for Class 1E bus(es) that have not replaced the inverse time delay relay with a fixed time delay relay~~. The function of the Loss of Voltage Relays is to trip in 2.3 ~~[2.4]~~[1] seconds or less for a loss of voltage condition ~~[and trip within 12.6 seconds if voltage drops to 2929.5 volts]~~[1].

~~Footnote 1: Information in brackets [ ] relate to Class 1E buses that have not implemented the Degraded Voltage Relay two stage timer modifications and replaced the inverse time delay Loss of Voltage Relay.~~

~~Footnote 2: Discussion of two stage timer (i.e., SIAS signal time delay) applies only to Class 1E buses with the two stage timer DVR and fixed time delay LVR modification installed.~~

(continued)

BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Balance of Plant Engineered Safety Features Activation System (BOP ESFAS) Loss of Power/Load Shed (LOP/LS) module receives inputs from the LOV and DV relays. The LOP/LS module has four channels, each of the channels has one LOV input and one DV input. If either a LOV or DV signal is received in that channel, the channel trips. If any 2 of the 4 channels trip, a signal is sent to the BOP ESFAS Diesel Generator Start Signal (DGSS) module starting the diesel. The LOVS initiated actions are described in "Onsite Power Systems" (Ref. 1).

The trip setpoints and Allowable Values are based on the analytical limits presented in Reference 5, 6 and 7. Reference 8 establishes allowable minimum dropout and maximum reset values for the Degraded Voltage Relays, taking into account calibration tolerances, instrumentation uncertainties, and instrument drift. Maintaining the minimum dropout voltage (≥3712 ~~[3697]~~[1] V and ≤3767 ~~[3786]~~[1] V) ensures protection during degraded voltage conditions.

The actual nominal trip setpoint is more conservative than that required by the plant specific setpoint calculations. If the measured setpoint does not exceed the Allowable Values, the relays are considered OPERABLE.

Setpoints in accordance with the Allowable Values will ensure that the consequences of accidents will be acceptable, providing the plant is operated from within the LCOs at the onset of the accident and the equipment functions as designed.

The undervoltage protection scheme has been designed to protect the plant from spurious trips caused by the offsite power source. This is made possible by the inverse voltage time characteristics of the relay used. A complete loss of offsite power will result in approximately a 2 second delay in LOVS actuation. The DG starts and is available to accept loads within a 10 second time interval on the Engineered Safety Features Actuation System (ESFAS) or LOVS. Emergency power is established within the maximum time delay assumed for each event analyzed in the accident analysis (Ref. 2).

Since there are four protective channels in a two-out-of-four trip logic for each division of the 4.16 kV power supply, no single sensor failure will cause or prevent protective system actuation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

The following SRs apply to each DG - LOVS Function.

SR 3.3.7.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter. A CHANNEL CHECK consists of verifying all relay status lights on the control board are lit. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff. If the channels are within the criteria, it is an indication that the channels are OPERABLE. For clarification, a CHANNEL CHECK is a qualitative assessment of an instrument's behavior. Where possible, a numerical comparison between like instrument channels should be included but is not required for an acceptable CHANNEL CHECK performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.2

A CHANNEL FUNCTIONAL TEST is performed to ensure that the entire channel will perform its intended function when needed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The as found and as left values must also be recorded and reviewed for consistency.

SR 3.3.7.3 ~~and 3.3.7.4~~

is

SR 3.3.7.3 ~~and SR 3.3.7.4~~ ~~are~~ the performance of a CHANNEL CALIBRATION. The CHANNEL CALIBRATION verifies the accuracy of each component within the instrument channel. This includes calibration of the Loss of Voltage and Degraded Voltage

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.7.3 ~~and 3.3.7.4~~ (continued)

relays and demonstrates that the equipment falls within the specified operating characteristics defined by the manufacturer. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive surveillances to ensure the instrument channel remains operational. CHANNEL CALIBRATIONS must be performed consistent with the plant specific setpoint analysis. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint analysis.

The as found and as left values must also be recorded and reviewed for consistency.

The setpoints, as well as the response to a Loss of Voltage and Degraded Voltage test, shall include a single point verification that the trip occurs within the required delay time, as shown in Reference 1. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

~~SR 3.3.7.3 is modified by Note. The Note indicates that the SR is only applicable to Class 1E buses that are provided with a single stage time delay Degraded Voltage Relays and an inverse time delay for the Loss of Voltage Relays. The Allowable Values of SR 3.3.7.3 reflect an allowable range about a nominal setpoint.~~

~~SR 3.3.7.4 is modified by a Note. The Note indicates the SR is only applicable to Class 1E bus(es) that are provided with a two stage time delay for the Degraded Voltage Relays and a fixed time delay for the Loss of Voltage Relays.~~ The Allowable Values protect analytical limits as described in References 5, 6 ~~and~~ 7. ~~The short stage (i.e., SIAS) time delay and the long stage (i.e., non SIAS) time delay is applicable only to Class 1E buses that have implemented the two stage time delay modification on the Degraded Voltage Relays.~~

(,)

(continued)

BASES

BACKGROUND (continued)

The onsite standby power source for each 4.16 kV ESF bus is dedicated DG. DG-A and DG-B are dedicated to ESF buses PBA-S03 and PBB-S04, respectively. A DG starts automatically (in emergency mode) on a safety injection actuation signal (SIAS) (i.e., low pressurizer pressure or high containment pressure signals), auxiliary feedwater actuation signals (AFAS-1 and AFAS-2) (e.g., low steam generator level), or on a loss of power (an ESF bus degraded voltage or undervoltage signal). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with a SIAS or AFAS signal. Following the loss of offsite power, the sequencer sheds nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application. The DGs will also start and operate in the standby mode (running unloaded) without tying to the ESF bus on a SIAS or AFAS.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 40 seconds after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 5500 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in the updated FSAR, Chapter 8 (Ref. 2).

~~Offsite power sources must have the capability to effect a safe shutdown and to mitigate the effects of an accident as specified in Regulatory Guide 1.93 (Ref. 6). As a result of~~

(continued)

BASES

BACKGROUND (continued)

~~certain anticipated operational occurrences (AOOs) and design basis accidents (DBAs), the voltage to ESF buses PBA-S03 and PBB-S04 would change as a result of one or more of the following three automatic operations: (1) tripping of the generating unit, (2) fast bus transfer of the non-Class 1E distribution system to the startup transformers, and (3) powering of the ESF loads by the automatic load sequencer. Analyses have been performed to determine the magnitude of voltage change due to each of these operations. Under conditions where these voltage changes would result in either inadequate voltages to the ESF equipment or tripping of the degraded voltage relays, the guidance from Regulatory Guide 1.93 (Ref. 6) is not met and the affected offsite circuit(s) do not meet their required capability.~~

~~Tripping of a Palo Verde unit can result in either a decrease or increase in the switchyard voltage due to the change in the flow of volt-amperes reactive (VARs) into or out of the electrical grid. If two or more of Palo Verde units are on line and available to regulate switchyard voltage, the voltage will not change significantly following tripping of one unit. If only one unit is on line, is not providing switchyard voltage support (generator gross MVAR output ≤ 0), and it trips, the post-trip switchyard voltage will be equal to or greater than the pre-trip switchyard voltage. If it had been providing switchyard voltage support (generator gross MVAR output > 0) the post-trip switchyard voltage could be lower than the pre-trip switchyard voltage. In this case, adequate voltage to the Class 1E buses is assured by blocking fast bus transfer and thus minimizing the loading and voltage drop on the startup transformer secondary circuit.~~

~~Voltage analyses also conclude that the maximum switchyard voltage should not exceed 535.5 kV. However, even if this limit is exceeded, the offsite circuits still have the capability to effect a safe shutdown, mitigate the effects of an accident, and continue to meet the operability requirements of Regulatory Guide 1.93 (Ref. 6). Sustained switchyard overvoltages during startup transformer light loading conditions can cause accelerated thermal aging of some plant electrical equipment. However, this would not cause catastrophic equipment failure or unavailability. A high voltage alarm at the APS Energy Control Center (ECC) alerts the transmission grid operators of the need for corrective actions, which could involve adjustment of the MVAR output of the Palo Verde generator(s), adjustment of the MVAR output of nearby cogeneration units, or switching of transmission system voltage control devices. Therefore, there is no LCO for high switchyard voltage.~~

(continued)

BASES

BACKGROUND (continued)

~~Grid frequency can also affect the operation of safety equipment. For example, sustained high frequency can result in an excessive differential pressure across motor operated valves, and sustained low frequency can result in substandard pump flow. There are no LCOs for offsite circuit frequency, because the grid frequency is continuously monitored and maintained within a tight tolerance by non-Palo Verde organizations. These organizations utilize various automatic and manual methods to control frequency, such as maintaining a spinning reserve, load shedding, and turbine governor controls. Analyses, as discussed in UFSAR Section 8.2.2 (Ref. 2), and operating experience have demonstrated that the tripping of a Palo Verde unit has a minimal effect on grid frequency.~~

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the updated FSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

~~Condition A applies only when the offsite circuit is unavailable to commence automatic load sequencing in the event of a design basis accident (DBA). In cases where the offsite circuit is available for sequencing, but a DBA could cause actuation of the Degraded Voltage Relays, Condition G applies for Class 1E bus(es) with single stage time delay DVRs and inverse time delay LVRs.~~

A note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with the one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the train (i.e., ESF bus) cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and include: charging pumps; radiation monitors Train A RU-29 and Train B RU-30 (TS 3.3.9), Train A RU-31 and Train B RU-145; pressurizer heaters (TS 3.4.9); ECCS (TS 3.5.3 and TS 3.5.4); containment spray (TS 3.6.6); containment isolation valves NCA-UV-402, NCB-UV-403, WCA-UV-62, and WCB-UV-61 (TS 3.6.3),

(continued)

BASES

ACTIONS C.1 and C.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

~~Condition C applies only when the offsite circuits are unavailable to commence automatic load sequencing in the event of a design basis accident (DBA). In cases where the offsite circuits are available for sequencing, but a DBA could cause actuation of the Degraded Voltage Relays, Condition G applies for Class 1E bus(es) with single stage time delay DVRs and inverse time delay LVRs.~~

(continued)

ACTIONS

E.1 (continued)

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Condition is modified by two Notes. Note 1 states that this condition is not applicable when the second DG train is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one DG train is inoperable for any reason and a second DG train is found to be inoperable, or if two DG trains are found to be inoperable at the same time. Note 2 provides constraints for this condition, the applicable constraints are located in TS section 5.5.20.

F.1 and F.2

The sequencer(s) is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the load group. The 24 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal. Required Action F.2 is intended to provide assurance that a single failure of a DG Sequencer will not result in a complete loss of safety function of critical redundant required features.

~~G.1 and G.2~~

~~A Note indicates that Condition G is not applicable for Class 1E bus(es) provided with a two stage time delay for the Degraded Voltage Relays (DVR) and a fixed time delay Loss of Voltage Relays (LVR). The DVRs are being modified to install a two stage time delay design: one short stage time delay for when a SIAS is present and a second long stage time delay when no SIAS is present. The LVRs are being modified to replace the existing mechanical inverse time delay relays with fixed time delay relays. Condition G is not applicable to Class 1E bus DVRs and LVRs that have been modified. The installation of the two stage time delays ensures automatic actuation of the DVRs within the assumptions of the accident analysis should the offsite source~~

(continued)

ACTIONS ~~G.1 and G.2 (continued)~~

~~post trip voltage be degraded. Conditions A and C remain applicable to Class 1E buses that have been modified. The more restrictive requirements of Condition G reflect the single stage time delay DVR design not being consistent with the time delay assumptions of the accident analysis.~~

~~To ensure offsite circuits will not be lost as a consequence of a DBE, certain conditions must be maintained. Failure to maintain these conditions may result in double sequencing should an accident requiring sequencer operation occur.~~

~~An offsite circuit meets its required capability by maintaining either of the following conditions:~~

~~1.~~ ~~Steady state switchyard voltage at or above the minimum level needed to support the offsite circuit's functions. The minimum allowable voltage is the value calculated as follows or 528.5 kV, whichever is less:~~

~~Base minimum voltage (provides for emergency loads on PBA-S03 or PBB-S04 and house loads on NAN-S01 or NAN-S02)~~		~~518 kV~~
~~If the offsite circuit is connected to 1-E-NAN-S05 or 1-E-NAN-S06~~	~~add~~	~~6.5 kV~~
~~If the house load group associated with the offsite circuit is connected to both NBN-S01 and NBN-S02 (tie breaker NBN-S01C closed)~~	~~add~~	~~4 kV~~
~~If the offsite circuit is connected to another unit's PBA-S03 or PBB-S04~~	~~add~~	~~1.5 kV~~

~~This option does not apply if the unit under review is the only Palo Verde unit synchronized to the 525 kV switchyard and its main generator gross MVAR output is > 0 or if the offsite circuit is connected to both PBA-S03 and PBB-S04 in the same unit.~~

~~The values used to calculate minimum allowable voltage are based on calculations 01, 02, 03-EC-MA-0221 that analyze many different bus alignment conditions. The values are conservative, with sufficient margin to account for analytical uncertainties and to provide assurance that the degraded voltage relays will not actuate as a result of an accident.~~

(continued)

ACTIONS ~~G.1 and G.2 (continued)~~

~~The highest minimum voltage of 528.5 kV is based on management of the loading of the startup transformer secondary windings to not exceed their rated 70 MVA capacity during a design basis event. When two units are sharing a secondary winding, the associated tie breaker NAN-S03B or NAN-S04B must always be open and fast bus transfer control switch NAN-HK-S03B or NAN-HK-S04B in "Manual" position in at least one of the units.~~

~~Meters A-E-MAN-EI-001 and A-E-MAN-EI-002 are used to monitor switchyard voltage. The allowable values take into account metering uncertainties. A voltage dip lasting 35 seconds or less is considered a transient, rather than steady state condition based on the credited 35 second time delay of the degraded voltage relay. The time delay feature on the meters' alarms may be set up to 35 seconds to avoid nuisance alarms.~~

~~2. Associated tie breaker NAN-S03B or NAN-S04B to house load buses NAN-S01 or NAN-S02 open and fast bus transfer control switch NAN-HK-S03B or NAN-HK-S04B in "Manual" position. When two units are sharing a startup transformer secondary winding, this condition must be met in both units.~~

~~If the required capability in Condition G is not met, the effects of an AOO or DBA could cause further depression of the voltage at the ESF bus and actuation of the degraded voltage relays. These actuations would result in disconnection of the bus from the offsite circuits. Regulatory Guide 1.93 (Ref. 6) defines this condition as "The Available Offsite Power Sources Are One Less Than the LCO" or "The Available Offsite AC Power Sources Are Two Less Than the LCO," depending on the number of affected circuits. However, degraded post-trip voltage could also cause ESF electrical equipment to be exposed to a degraded condition during the degraded voltage relay time-out period. There is a risk that equipment misoperation or damage could occur during this time. In this scenario, the ESF equipment may not perform as designed following an automatic disconnection of the offsite circuits and reconnection to the diesel generators (DGs), even though adequate power is available from the DG. For certain DBAs, an additional consideration is that the initial sequencing of the ESF equipment onto the offsite circuits, subsequent tripping of the degraded voltage relays, and interruption in equipment credited in the UFSAR Chapter 6 and 15 safety analyses could challenge the credited equipment response times. Therefore, it is appropriate to implement Required Actions that are more stringent than those specified in Condition A or C.~~

(continued)

ACTIONS

~~G.1 and G.2 (continued)~~

~~If the required capability in Condition G is not met, the following options are available to restore full or partial Operability. Options are listed in their order of preference.~~

~~1. Achieve Condition 1 as discussed above (switchyard voltage at or above the minimum allowable value). This is accomplished by either of the following:~~

   - ~~Increase switchyard voltage. If more than one Palo Verde unit is operating, switchyard voltage is increased by increasing MVAR output of any Palo Verde unit, or by any number of methods implemented by the Energy Control Center. If only one Palo Verde unit is operating, switchyard voltage is increased by any number of methods implemented by the Energy Control Center while maintaining the generator gross MVAR output of the Palo Verde unit to ≤ 0.~~

   - ~~Reduce minimum allowable voltage as calculated above. This is achieved by realignment of equipment power sources, if such an option is available.~~

~~2. Achieve Condition 2 as discussed above. This is accomplished by ensuring the affected tie breaker (NAN-S03B or NAN-S04B) is open and the fast bus transfer control switch (NAN-HK-S03B or NAN-HK-S04B) is in the "Manual" position. If two units are sharing a startup transformer secondary winding, this condition must be achieved in both units. Although Palo Verde has no formal restrictions on the amount of time that fast bus transfer can be out of service, this option should be used judiciously in order to maintain forced circulation capability.~~

~~3. Transfer the safety bus(es) to the diesel generator(s). This is less desirable than option 2, because it would perturb the plant. It would cause the plant to remain in an LCO 3.8.1 condition (A or C, depending on whether one or two buses are transferred).~~

~~Options 1 and 2 satisfy Required Action G.1, and Option 3 satisfies Required Action G.2. With more than one offsite circuit that does not meet the required capability, Condition G could be satisfied for each offsite circuit by the use of Required Action G.1 or G.2. The Completion Time for both Required Action G.1 and G.2 is one hour. The one hour time limit is appropriate and consistent with the need to remove the unit from this condition, because it supports an~~

(continued)

BASES

ACTIONS

~~G.1 and G.2 (continued)~~

~~initial condition for the degraded voltage prevention strategy. In a scenario involving automatic load sequencing and low voltage to the ESF buses with a single stage time delay DVR design, adequate voltage is not assured from any of the power sources for the following systems immediately after the accident signal has been generated (i.e., while the degraded voltage relay is timing out): radiation monitors Train A RU-29 or Train B RU-30 (TS 3.3.9), Train B RU-145; ECCS (TS 3.5.3); containment spray (TS 3.6.6); containment isolation valves (TS 3.6.3); auxiliary feedwater system (TS 3.7.5); essential cooling water system (TS 3.7.7); essential spray pond system (TS 3.7.8); essential chilled water system (TS 3.7.10); control room essential filtration system (TS 3.7.11); ESF pump room air exhaust cleanup system (TS 3.7.13); and fuel building ventilation.~~

~~Required Action G.2 is modified by a Note. The reason for the Note is to ensure that the offsite circuit is not inoperable for a time greater than the Completion Time allowed by LCO 3.8.1 Condition A or C. Therefore, if Conditions A or C are entered, the Completion Time clock for Conditions A and C would start at the Time Condition G was entered.~~

~~H~~.1

G

With three or more required AC sources inoperable, the Required Action is to restore the required AC source(s) to OPERABLE status within 1 hour to regain some level of redundancy in the AC electrical power supplies. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of required AC sources. Alternately, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Condition is modified by two Notes. Note 1 states that this condition is not applicable when the third or a subsequent required AC source is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if two required AC sources are inoperable for any reason and additional required AC sources are found to be inoperable, or if three or more required AC sources are found to be inoperable at the same time. Note 2 provides constraints for this condition, the applicable constraints are located in TS section 5.5.20.

(continued)

BASES

ACTION (continued)

~~I~~.1 and ~~I~~.2

H

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions).

The SR for demonstrating OPERABILITY of the DGs are based on the recommendations of Regulatory Guide 1.9 (Ref. 3), unless otherwise noted in the Updated FSAR Section 1.8.

The DG capabilities (starting and loading) are required to be met from a variety of initial conditions such as DG in standby condition with the engine hot (SR 3.8.1.15) and DG in standby condition with the engine at normal keep-warm conditions (SR 3.8.1.2, SR 3.8.1.7 and SR 3.8.1.19). Although it is expected that most DG starts will be performed from normal keep-warm conditions, DG starts should be performed with the jacket water cooling and lube oil temperatures within the lower to upper limits of DG OPERABILITY, except as noted above. Rapid cooling of the DG down to normal keep-warm conditions should be minimized.

The required steady state frequency range for the DG is 60 +0.7/-0.3 Hz to be consistent with the safety analysis to provide adequate safety injection flow. In accordance with the guidance provided in Regulatory Guide 1.9 (Ref. 3), where steady state conditions do not exist (i.e., transients), the frequency range should be restored to within ± 2% of the 60 Hz nominal frequency (58.8 Hz to 61.2 Hz) and the voltage range should be restored to within ± 10% of the 4160 volts nominal voltage (3740 volts to 4580 volts). The timed start is satisfied when the DG achieves at least 3740 volts and 58.8 Hz within 10 seconds. At these values, the DG output breaker permissives are satisfied. Then, with concurrent or

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