APS

Palo Verde Nuclear
Generating Station

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102-05637-CDM/SAB/GAM
January 25, 2007

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

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2 and 3
Docket Nos. STN 50-528, 50-529, and 50-530
Response to NRC Request for Additional Information Regarding Request for Amendment to Technical Specification Surveillance Requirements 3.8.1.9, 3.8.1.10, and 3.8.1.14

By letter no. 102-05546, dated August 16, 2006, Arizona Public Service Company (APS), submitted a request to change PVNGS Technical Specification (TS) Section 3.8.1, AC Sources – Operating. The proposed changes would revise the Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 Operating Licenses to modify the notes to TS Surveillance Requirements (SRs) 3.8.1.9, diesel generator (DG) single largest load rejection test, 3.8.1.10, DG full load rejection test, and 3.8.1.14, DG endurance and margin test to (1) allow these SRs to be performed, or partially performed, in reactor modes that currently are not allowed by the TSs, and (2) require that SRs 3.8.1.10 and 3.8.1.14 be performed at a power factor of ≤ 0.9 if performed with the emergency DGs synchronized to the grid unless grid conditions do not permit.

By letter dated October 18, 2006, the NRC requested additional information (RAI) related to APS' August 16, 2006 amendment request, due within 60 days of the date of the letter. Subsequently, Mr. Mel Fields, NRC Project Manager for PVNGS, verbally authorized an extension to the RAI response due date until January 26, 2007.

The Enclosure to this letter contains Arizona Public Service Company's response to NRC's RAI. Attachment 1 to the enclosure contains proposed changes to the TS Bases that reflect the proposed changes submitted in APS' August 16, 2006 submittal and additional changes to (1) add the compensatory measures to SRs 3.8.1.9 and 3.8.1.10

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as described in the response to NRC Question 8 and (2) add the requirement to perform SRs 3.8.1.10 and 3.8.1.14 at $\leq$ 0.9 power factor least once every 36 months for each DG as described in the response to 12(b). Regulatory commitments in this letter are identified in Attachment 2 to the Enclosure.

If you have any questions, please contact Thomas N. Weber at (623) 393-5764.

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

Executed on 25 JAN. 2007

Sincerely,

David Mauldin

CDM/SAB/GAM/gt

Enclosure: As stated

cc:	B. S. Mallett	NRC Region IV Regional Administrator
	M. B. Fields	NRC NRR Project Manager
	M.T. Markley	NRC NRR Project Manager
	G. G. Warnick	NRC Senior Resident Inspector for PVNGS
	A. V. Godwin	Arizona Radiation Regulatory Agency (ARRA)
	T. Morales	Arizona Radiation Regulatory Agency (ARRA)

ENCLOSURE

ARIZONA PUBLIC SERVICE COMPANY'S RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING REQUEST FOR AMENDMENT TO TECHNICAL SPECIFICATION SURVEILLANCE REQUIREMENTS 3.8.1.9, 3.8.1.10, AND 3.8.1.14

NRC Request 1

Confirm that proposed power factor of $\leq$ 0.9 is the calculated worst case power factor. The confirmation should include actual calculated power factor of each diesel generator (DG) for loss of offsite power (LOOP) and LOOP with loss-of-coolant accident loading.

APS Response 1

Calculated DG loadings are shown in the table below. These values include automatically sequenced loads as well as discretionary loads that may be manually energized. The SR 3.8.1.10 and 3.8.1.14 test requirements are also listed for comparison.

CALCULATED DG LOAD DEMAND					
Unit	**Train**	**Mode**	**KW**	**KVAR**	**PF**
1	A	LOOP/Forced Shutdown	5173	2676	0.89
		LOOP/LOCA	5149	2451	0.90
	B	LOOP/Forced Shutdown	4503	2362	0.89
		LOOP/LOCA	5322	2514	0.90
2	A	LOOP/Forced Shutdown	5221	2708	0.89
		LOOP/LOCA	5085	2436	0.90
	B	LOOP/Forced Shutdown	4511	2393	0.88
		LOOP/LOCA	5273	2522	0.90
3	A	LOOP/Forced Shutdown	5203	2735	0.89
		LOOP/LOCA	5082	2450	0.90
	B	LOOP/Forced Shutdown	4473	2406	0.88
		LOOP/LOCA	5211	2521	0.90

SR 3.8.1.10 TEST REQUIREMENT			
Duration	**KW**	**KVAR**	**PF**
N/A	4950 to 5500	2397 to 2664	0.90
SR 3.8.1.14 TEST REQUIREMENT			
Duration	**KW**	**KVAR**	**PF**
22 hours	4950 to 5500	2397 to 2664	0.90
2 hours	5775 to 6050	2797 to 2930	0.90

The stress of electrical loading on the DGs is a function of real and reactive power levels (KW and KVAR) rather than power factor. The tables above show these power levels as well as the associated power factors. As shown on the tables, testing at the SR 3.8.1.10 and 3.8.1.14 (first 22 hours) required KW loading and a power factor of $\leq$ 0.9 would be representative of the calculated inductive loading a DG would see under design basis accident conditions. The final 2-hour loading for SR 3.8.1.14 at the TS required KW and $\leq$ 0.9 power factor would test the DGs to a greater KVAR loading than any calculated accident load KVAR.

NRC Request 2

The Bases for SR 3.8.1.10 implies that the bus voltage can be varied by adjusting the DG field excitation when operating in parallel with the grid. Adjusting the field excitation should only momentarily affect the bus voltage. The grid voltage is primarily controlled by the transmission system operators and the automatic voltage regulators installed on the large generating units tied to the grid. However, the staff does believe that potentially high-bus voltage may prevent the DG from obtaining the power factor limit specified in the TS due excessive excitation, and under these conditions the proposed Note is warranted. Provide analysis or operating data to demonstrate that the voltage on the emergency bus can be varied by adjusting the field excitation of the DG when operating in parallel with the grid. Otherwise, the Bases for SR 3.8.1.10 should be revised to delete this condition.

APS Response 2

The wording of the proposed changes to SR 3.8.1.10 Bases that is being questioned is exactly the same wording as in NRC-approved TSTF-276, Revision 2, and is in Revision 3 of NUREG-1432, CE Improved Standard Technical Specifications. APS' intent was to be as consistent as possible with changes that have been approved by the NRC for the Improved Standard Technical Specifications and that would be applicable to Palo Verde.

At Palo Verde, adjustment of DG field excitation does not significantly affect the 525 kV switchyard bus voltage. However, it does significantly affect the 4.16 kV emergency bus voltage when paralleled with the grid. This is the bus referred to in the Bases for SR 3.8.1.10. This voltage effect is the result of the impedances of the conductors and transformers between the 4.16 kV emergency bus and the switchyard bus. Lowering of the EDG power factor from unity to 0.9 results in an 11% increase in apparent power output (volt-amps) due to the additional reactive power (volt-amperes reactive) that are being generated. Thus, both the EDG terminal voltage and its output current will rise, with their product (volts x amps) rising 11%. The proportion of this rise associated with each of these two variables can be determined using complex mathematics. It is heavily affected by the impedance of the electrical distribution equipment between the EDG terminals and the switchyard. For this example at Palo Verde, the voltage would rise by a factor of 1.02 and the current by a factor of 1.09 (1.02 x 1.09 = 1.11).

NRC Request 3

> **The Bases state that house loads must be transferred from the auxiliary transformers to the startup transformers in order to lower the voltage on the emergency bus. The voltage on the emergency bus must be lower in order to meet the power factor requirements of SR 3.8.1.10 and SR 3.8.1.14. This manipulation of the offsite power circuits to perform surveillance is unusual and could perturb the onsite alternating current electrical distribution systems. Normally this SR is performed during shutdown. Provide assurance that manipulation of the offsite power circuits would not significantly increase the probability of LOOP.**

APS Response 3

As stated on pages 17 and 19 of the August 16, 2006 letter, transferring house loads from the auxiliary transformer to the startup transformer is routinely performed at power (prior to plant shutdown), in accordance with procedure 40OP-9NA03. The circuit breakers supplying the house loads (NAN-S01 and NAN-S02) from the auxiliary and startup transformers are interlocked such that one supply breaker does not open until the alternate supply breaker is closed. This ensures that the bus remains energized during the transfer. This 'make-before-break' design ensures that the transferred loads remain in synchronism with the startup transformer voltage during the transfer, so the transfer does not result in a significant transient current surge. The house loads transferred from the auxiliary transformer to the startup transformer (approximately 40 MVA during power operation and less than 6 MVA while shutdown) are well within the 70 MVA capacity of the startup transformer.

NRC Request 4

Provide a detailed description of how the SR 3.8.1.9 is performed.

APS Response 4

PVNGS Procedures 73ST-9DG01, "Class 1E Diesel Generator Integrated Safeguards Test Train A," Revision 11, and 73ST-9DG02, "Class 1E Diesel Generator Integrated Safeguards Test Train B," Revision 13, provide the following instructions for performing SR 3.8.1.9:

- The DG is tested for auto start and load capabilities in the isochronous mode (isolated from offsite power) in this procedure section by simultaneously opening the 13.8 kV feeder breaker to the affected ESF bus and manually initiating a safety injection actuation signal (SIAS), and containment isolation actuation signal (CIAS). (Step 8.6.27, Train A: Step 8.6.26, Train B)

- With the DG as the sole source of power to the Class 4.16 kV bus, the following three pumps are all stopped simultaneously: high pressure safety injection (HPSI), low pressure safety injection (LPSI), and either containment spray (CS) for the DG Train A test or auxiliary feedwater for the DG Train B test. (Step 8.6.48, Train A; Step 8.6.46, Train B)

- The difference between the pre-load rejection and post-load rejection kW loads are verified to be greater than the largest single load described in TS Bases for SR 3.8.1.9 (Normal Water Chiller, 842 kW, for Train A, and Auxiliary Feedwater Pump, 936 kW, for Train B). (Step 8.6.50, Train A; Step 8.6.48, Train B)

- The post load rejection response for DG frequency and voltage are verified using chart recorders to meet the requirements of SR 3.8.1.9. (Step 8.6.52, Train A; Step 8.6.50, Train B)

NRC Request 5

On page 12 of the application, it is stated that "only one DG per unit is paralleled to offsite power at any one time and any offsite grid disturbances would only possibly affect one operable DG." Confirm that at PVNGS no more than one DG to be paralleled to the offsite power at the same time.

APS Response 5

(Note: The following response is from APS letter no. 102-05040, dated January 22, 2004, provided to the NRC in response to a similar question that was asked when the proposed change to perform SR 3.8.1.9, 10 and 14 at power was previously being reviewed, except that procedural references have been added.)

Currently, PVNGS does not forbid more than one units' DG being paralleled to the grid at a time. There is a restriction preventing any unit's two DGs from being paralleled to the grid at the same time. Additionally, there is a procedural precaution to not have two different units DGs, if paralleled to offsite, connected to the same startup transformer primary winding. (Section 5.2 of PVNGS Procedures 40ST-9DG01, "Diesel Generator A Test," and 40ST-9DG02, "Diesel Generator B Test.")

The normal scheduling and risk practice for DGs is that maintenance will not be scheduled for more than one diesel at a time. The most likely situation to challenge this practice would be while a particular unit's DG were being restored from scheduled maintenance and another unit's DG were to be declared inoperable for some unplanned cause. If the timing of both DGs operability runs were to coincide, there would be an evaluation performed to determine the acceptability of paralleling both of these DGs to the offsite grid at the same time. It has not been a normal practice at PVNGS to allow more than one DG to be paralleled to offsite power at the same time.

NRC Request 6

> **On page 12 of the application, it is stated that "at PVNGS when the DG full load reject SR is performed at shutdown, the voltage transients experienced by the loads on the associated bus are considered minimal (an approximate 10 percent step change (400 VAC) in the bus voltage at the 4.16 kV level, with voltage recovery within 1 second." Discuss the impact of this voltage transient on a degraded voltage relay. Also, since the voltage at the safety buses during power operation are relatively lower during shutdown, what will be the voltage transient due to a full load rejection test during power operation?**

APS Response 6

Degraded voltage relays have a time delay of 31.8 seconds (Technical Specification [TS] Surveillance Requirement [SR] 3.3.7.3 requires this time delay to be between 28.6 and 35 seconds), so they will not be affected by the short-duration voltage transients caused by testing. The magnitude and duration of the transient voltage dip would not be significantly affected by the bus loading or voltage. However, the reactive power level of the DG prior to the full load reject will affect the steady-state voltage change. At a generation level of 5500 kW at 0.90 power factor (the full load rejection requirement of TS SR 3.8.1.10 is between 4950 and 5500 KW), the DG will elevate the bus voltage about 125 V above its normal level. The full load reject will return the bus voltage to the same level that occurs any time the house loads are connected to the startup transformer without the DG paralleled to offsite power. This is 3900 V or higher, depending on switchyard voltage and loading conditions. It is well above the degraded voltage relay setting of 3744 V (TS SR 3.3.7.3 requires this setting to be between 3697 and 3786 V).

APS also reviewed the effect of a DG full load rejection test transient on non-safety related equipment such as reactor coolant pumps when the test is performed with the house loads transferred to the startup transformer during Mode 1. Because of the large inertia of the interconnected generators in the Western transmission system, including Palo Verde, the change in inertia due to tripping of an EDG is insignificant and would have no noticeable effect on frequency. Although a slight transient voltage effect might be reflected to the non-safety related distribution system, its duration would be much shorter than the time delays of any protective undervoltage relays that monitor the voltage. The steady-state voltage change would be well within the normal operating band of the electrical distribution system and typical of the range in which the unit operates immediately preceding and following outages.

<u>**NRC Request 7**</u>

> **On page 12 of the application, it is stated that "If a LOP [loss of offsite power] occurs during testing, the DG either trips on over current or continues to run, depending upon if the resulting load is in excess of the DG's load rating. If the load is excessive, the DG will trip on over current and the DG breaker will trip automatically on a DG shutdown signal." Discuss how the DG will be started and DG breaker closed once the over current relay trips the DG? Will it involve manual resetting of the relays? If so, discuss the time associated with the manual resetting of the relay.**

<u>**APS Response 7**</u>

(Note: The following response is from APS letter no. 102-05040, dated January 22, 2004, provided to the NRC in response to the same question that was asked when the proposed change to perform SR 3.8.1.9, 10 and 14 at power was previously being reviewed.)

This question refers to an overcurrent condition caused by a loss of offsite power (such as tripping of the startup transformer circuit breaker) while the DG is paralleled to the offsite circuit in preparation for a full load reject test.

The overcurrent condition would cause tripping of the DG output circuit breaker (but not the offsite power supply breaker to the Class 1E 4.16 kV ESF switchgear due to its higher setting). Then the following automatic actuations would occur:

- A DG shutdown signal would trip the DG
- The LOV relays would sense the loss of voltage and initiate a LOP signal
- The offsite power supply breaker would trip open.
- Load shedding of the Class 1E 4.16 kV ESF bus would occur.
- The DG would restart in the emergency mode (which automatically bypasses the overcurrent trip).
- The DG output breaker would re-close onto the Class 1E 4.16 ESF kV bus when rated voltage/frequency are reached.

- Required loads would automatically re-sequence onto the Class 1E 4.16 ESF kV bus.
- No manual resetting of any protective relays would be required.

If a DG circuit breaker overcurrent relay trip were to occur during this test (not related to an actual loss of offsite power) and it was desirable to start the DG up again in the "test mode" of operation, the following would have to occur:

- The cause of the trip would be investigated and resolved.
- Manually resetting of the trip relays, including independent verification.
- Reset of the emergency diesel generator and placing it in a "standby" condition.

The manual actions for this process would take about 30-45 minutes once the cause of the trip had been investigated and resolved.

NRC Request 8

> **Confirm that SR 3.8.1.9 and 3.8.1.10 will not be scheduled during periods where the potential for grid or bus disturbance increases (i.e., storm, grid emergencies, etc.).**

APS Response 8

Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following compensatory measures for SR 3.8.1.9 and 3.8.1.10 would be added to the TS Bases, as shown in the TS Bases markup pages in Attachment 1:

> *The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:*
>
> a. *Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.*
>
> b. *No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.*
>
> c. *All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.*

These are the same measures that were proposed in the August 16, 2006, letter for performing SR 3.8.1.14 in Mode 1 or 2.

NRC Request 9

> **Discuss administrative controls to preclude performing these SRs during other maintenance and test conditions that could have adverse effects on the offsite power system or plans for restricting additional maintenance or testing of safety related systems that depend on the remaining DG as a source. Additionally, discuss if the remaining DG were to become inoperable while the other DG is being tested, would the test be aborted?**

APS Response 9

(Note: The following response is from APS letter no. 102-05040, dated January 22, 2004, provided to the NRC in response to the same question that was asked when the proposed change to perform SR 3.8.1.9, 10 and 14 at power was previously being reviewed, except that the procedure reference has been updated to reflect the latest Palo Verde Maintenance Rule procedure.)

Paragraph (a)(4) of 10 CFR 50.65 (the Maintenance Rule) requires that "Before performing maintenance activities (including but not limited to surveillance, post maintenance testing, corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities". PVNGS procedure 70DP-0RA05, "Assessment and Management of Risk When Performing Maintenance in Modes 1 and 2," was developed to document how PVNGS will perform the assessments required for on-line maintenance and manage the risk resulting from these maintenance activities.

All scheduled work (i.e., corrective maintenance, plant modifications, surveillance testing, preventative maintenance, etc.) is evaluated as an integrated schedule of activities and risk associated with those activities is part of that evaluation. The following discussion is the process that PVNGS uses to control and schedule all plant activities associated with maintenance and testing, including those items associated with offsite and onsite power systems.

All planned work (i.e., corrective maintenance, plant modifications, surveillance testing, preventative maintenance, etc.) is evaluated prior to approval of the maintenance schedule as an integrated schedule of activities. The risk associated with those activities is part of that evaluation. This evaluation would identify any high risk plant configurations and preclude unnecessary entry into those configurations. Planned work is then performed according to the approved schedule.

Emergent conditions are evaluated as soon as possible after the emergent condition is known. This evaluation includes the risk impact of the emergent condition concurrent with the previously planned activities. The decision to proceed with any work, given an emergent condition is contingent on this integrated evaluation of the impact on risk.

Additionally, if the remaining DG were to become inoperable while the other DG is being tested, an evaluation of the actual conditions at that time would be conducted using the above process along with entering any appropriate TS LCO Condition(s) (i.e., 3.8.1, Condition E). This real time evaluation would dictate the specific actions that would be taken, up to and including possibly aborting any testing that may be in progress.

NRC Request 10

> **Discuss whether the Transmission System Operator is notified in advance that a DG is going to be taken out for surveillance testing on-line.**

APS Response 10

Section 8.5.1 of PVNGS Procedures 73ST-9DG01, "Class 1E Diesel Generator Integrated Safeguards Test Train A," Revision 11, and 73ST-9DG02, "Class 1E Diesel Generator Integrated Safeguards Test Train B," Revision 13, specifies the following prerequisite prior to performing the surveillance testing for SR 3.8.1.10 or 3.8.1.14 (note: SR 3.8.1.9 is not performed while paralleled to the grid):

> *ECC [Energy Control Center] has been notified to minimize switchyard changes that could affect the DG while paralleled to the offsite power grid.*

In addition, as stated in APS letter 102-05531, dated July 13, 2006, in response to Generic Letter 2006-02, contacts with the transmission system operator (ECC) to determine current and anticipated grid maintenance conditions is accomplished by Palo Verde having a listing of current and planned maintenance activities 1) in the Palo Verde switchyard and 2) on overhead lines that feed the Palo Verde switchyard. This planned switchyard maintenance is included in the risk assessment associated with evaluating grid-risk-sensitive maintenance activities.

The TSO normally provides at least 3 days notice on planned switchyard maintenance that could impact Palo Verde. The TSO also notifies Palo Verde of emergent work activities that could impact Palo Verde, as described in procedure 40DP-9OP34, "Switchyard Administrative Control."

The TSO (ECC) is responsible for issuing curtailment alerts to the APS owned and operated power plants. These alerts are based on the reasonable potential that the loss of a generating unit will create a system disturbance (e.g., customer outages, transmission line overloads, and voltage instability).

The TSO also notifies Palo Verde when equipment problems occur in the Palo Verde switchyard as directed by Palo Verde procedure 40DP-9OP34, "Switchyard Administrative Control."

NRC Request 11

Discuss what action will be taken if degraded grid conditions occur during the DG surveillance testing.

APS Response 11

No single course of action would be appropriate for every situation if degraded grid conditions were to occur during DG surveillance testing. If degraded grid conditions occur during the DG surveillance testing, action would be taken as required to remain in compliance with plant technical specifications. In addition, if a degraded or nonconforming situation exists, action would be taken in accordance with the 10 CFR Part 50 Appendix B corrective action program.

NRC Request 12(a)

The new Note added in SR 3.8.1.10 and 3.8.1.14 states that "If performed with the DG synchronized with offsite power, it shall be performed at a power factor of ≤ 0.9. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable." The staff understands that the Palo Verde units have difficulty maintaining this power factor during these SRs.

(a) Provide a discussion regarding the acceptable power factor during these SRs performed at high grid voltage conditions (what is meant by as close to the limit as practicable).

APS Response 12(a)

The wording of the proposed new note being added to SRs 3.8.1.10 and 3.8.1.14 regarding the power factor requirement is exactly the same wording as in NRC-approved TSTF-276, Revision 2, which has been incorporated into NUREG-1432.

As stated on pages 13 and 16 and in the TS Bases markup for SRs 3.8.1.10 and 3.8.1.14 in APS' August 16, 2006, letter, during shutdown conditions at Palo Verde the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.9 power factor when the DG is synchronized with the grid. In this situation, the typical kVAR loading without exceeding any voltage limits is the equivalent of a unity power factor.

Please note that the Palo Verde Technical Specifications currently do not require DG testing to be performed at a specified power factor. The NRC safety evaluation for Palo Verde Operating License Amendment Nos. 114, 107, and 86 for Units 1, 2, and 3, respectively, dated October 6, 1997, discussed the acceptability of not including a power factor requirement in the DG SRs during the conversion of TS 3.8.1 to reflect the content of the CE Improved Technical Specifications, NUREG-1432. In the amendment application for conversion to Improved Technical Specifications in letter no. 102-03794, dated October 4, 1996, APS provided the following description of the design and testing of the DGs that ensures that the DGs will perform at the accident loading power factor when needed, even though the DGs would not be tested at the accident loading power factor:

> *The [DG] excitation circuitry is composed primarily of solid state electronic devices and other electrical components that do not drift (i.e., the components either function or fail to function). The excitation circuitry may, in time, be required to deliver greater amounts of excitation energy to achieve generator rated load and power factor in order to compensate for degradation that may occur in the generator (i.e., windings). Every 18 months (refueling outage), Palo Verde maintenance activities monitor for generator winding degradation during generator open circuit testing. Open circuit testing measures the amount of excitation energy necessary to obtain a predetermined generator output voltage. Generator winding degradation is evident if additional excitation energy is required to achieve the predetermined output voltage as compared to baseline values. If generator winding degradation is detected, appropriate evaluations and corrective actions would be implemented. At least every 31 days (ITS SR 3.8.1.2), the excitation circuitry is verified to function during voltage verification. In addition, any time the DG is run, electrical parameters from the excitation circuitry and generator output are recorded and monitored per procedures. Therefore, it is APS' position that a specific surveillance requirement for testing at rated power factor during full load is not necessary because existing monitoring, maintenance activities, and surveillances already ensure adequate exciter function, monitor for degradation, and ensure excitation circuitry capability to perform as designed.*

Therefore, when SR 3.8.1.10 or 3.8.1.14 are performed while shutdown when the power factor limit cannot be met due to grid conditions, the current DG monitoring, maintenance activities, and surveillances ensure adequate exciter function, monitor for degradation, and ensure the DG circuitry capability to perform as designed.

NRC Request 12(b)

> **Provide an assurance that the Note will not be used routinely or used for convenience.**

APS Response 12(b)

The current Palo Verde Technical Specifications, which only allow SRs 3.8.1.10 and 3.8.1.14 to be performed while shutdown, do not require these SRs be performed at a specified power factor. This is because grid conditions at Palo Verde do not permit a

0.9 power factor limit to be met when SR 3.8.1.10 or SR 3.8.1.14 is performed while shutdown. This has been acceptable as discussed in the response to 12(a) above.

The proposed amendment would allow SRs 3.8.1.10 and 3.8.1.14 to be performed during power operations (in Mode 1 or 2), as well as while shutdown. As stated in the August 16, 2006, amendment request letter, the proposed Note allowing the new power factor limit to not be met would be used whenever SR 3.8.1.10 or SR 3.8.1.14 is performed while the plant is shutdown. When SR 3.8.1.10 or SR 3.8.1.14 is performed during power operations, it is expected that the power factor requirement would be able to be met and therefore the Note would not be used.

Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following requirement will be added to the TS Bases for SRs 3.8.1.10 and 3.8.1.14, as shown in TS Bases markup in Attachment 1:

> *This SR must be performed at a lagging power factor of ≤ 0.9 at least once every 36 months for each DG.*

<u>**NRC Request 12(c)**</u>

> **Describe the grid voltage that would not permit the power factor limit to be satisfied and how often these grid conditions are expected to occur in the future.**

<u>**APS Response 12(c)**</u>

At Palo Verde, the grid voltage is maintained in a narrow band between approximately 525 to 535.5 kV in order to prevent the potential for double sequencing of safety-related loads following a postulated design-basis accident while avoiding overvoltages. This is discussed in the NRC Safety Evaluation for Amendment No. 123 to the Palo Verde Facility Operating Licenses, dated December 29, 1999 (ADAMS accession no. ML003670588). To maintain margin within these limits and account for measuring uncertainties, the typical operating band is even tighter than 2%. When the grid voltage is at its upper limit and the startup transformer is lightly loaded, the 480 V system Class 1E emergency bus voltages are also near their upper limits (about 514 V). When the DG is synchronized with offsite power in this condition, the additional DG field excitation needed to get the power factor to ≤ 0.9 would result in an approximately 2% increase in voltage at the EDG terminals, as discussed in Response 2 above, and a corresponding 2% voltage increase on the emergency busses. This could raise the voltages on the 480 V system from about 514 to 524 V, which would be unacceptably high. Although lowering the switchyard voltage to its minimum level of 525 kV would lower the voltage of these buses back to about 514 V, it would not be practical to operate at that level for the duration of the test.

APS also considered the feasibility of implementing temporary modifications to change transformer tap settings in order to permit testing at a power factor of ≤ 0.9 while the system is lightly loaded (while the plant is shut down). It was concluded that this would not be feasible. None of the Palo Verde transformers have taps that can be adjusted while the transformer is energized. Deenergizing the transformers and their downstream safety equipment in order to change the taps, and then deenergizing them again after the test to restore them to their original position, would introduce an unacceptable level of risk into the DG test evolution. Deenergization of a 525 to 13.8 kV startup transformer would affect the offsite power supplies to two Palo Verde units. Deenergization of a 13.8 to 4.16 kV ESF transformer would affect an entire train of safety-related equipment. The 4.16 kV load center taps are bolted connections that involve deenergization, removal of a large panel, relocation of the connector to a different lug, and reassembly of the transformer enclosure. This would have to be performed on three separate transformers to perform the test on one DG.

As stated in APS' August 16, 2006, amendment request letter (Enclosure 2, Sections 4.2.2 and 4.3.2, and TS Bases markups for SRs 3.8.1.10 and 3.8.1.14), when the SRs are performed at power, as would be allowed by this proposed amendment, a DG power factor $\leq$ 0.9 should be able to be achieved when synchronized with offsite power. This would be accomplished by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. When the unit is at power, the magnitude of house loads is high enough (approximately 40 MVA) to adequately reduce the voltage on the associated Class 1E bus to allow the $\leq$ 0.9 diesel generator power factor to be achieved regardless of what level within the allowable band the switchyard voltage is at.

NRC Request 12(d)

Provide the nominal grid voltage.

APS Response 12(d)

The Palo Verde switchyard is operated within a range of 525 to 535.5 kV. The actual voltage within this range is a function of grid loading conditions and the settings of the voltage regulators at Palo Verde and other nearby generators. These settings are as requested by the transmission system operator. The operational status of the Palo Verde generators has no significant bearing on actual switchyard voltage levels.

Attachment 1
Changes to Technical Specification Bases Pages

Pages:
B 3.8.1-29 (For information; no changes)
B 3.8.1-30
B 3.8.1-30A (For information; no changes)
B 3.8.1-31*
B 3.8.1-31A*
B 3.8.1-31B
B 3.8.1-36 (For information; no changes)
B 3.8.1-37
B 3.8.1-37A*
B 3.8.1-37B

*** NOTE: Additions to TSTF-276, Revision 2, wording on these pages are underlined.**

SURVEILLANCE REQUIREMENTS

OPERABILITY

SR 3.8.1.8 (continued)

OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load, or equivalent load, without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. Train A Normal Water Chiller (at 842 kW) and Train B AFW pump (at 936 kW) are the bounding loads for the DG A and DG B to reject, respectively. These values were established in reference 14. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by IEEE-308 (Ref. 11), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are the voltage and frequency values the system must meet, within three seconds, following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by a Note. The reason for the Note is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems. This SR is performed in emergency mode (not paralleled to the grid) ensuring that the DG is tested under load conditions that are as close to design basis conditions as possible. **This restriction from normally performing the surveillance in Mode 1, 2, 3, or 4 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines that plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.**

(continued)

SR 3.8.1.9 (continued)

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG will not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the guidance of Regulatory Guide 1.9 (Ref. 3). Consistent with the guidance provided in the Regulatory Guide 1.9 full-load rejection test description, the 4950 - 5500 kW band will demonstrate the DG's capability to reject a load equal to 90 to 100 percent of its continuous rating. Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result power factors deviating much from unity are currently not possible when the DG runs parallel to the grid **while the plant is shutdown**. To the extent practicable, ~~VARs will be provided by the DG~~ during this SR.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.8 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. ~~The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.~~ This Note ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a lagging power factor of ≤ 0.9. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high,

(continued)

SR 3.8.1.10 (continued)

and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. This would occur when performing this SR while shutdown and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.9 power factor. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding DG excitation limits.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

This SR must be performed at a lagging power factor of ≤ 0.9 at least once every 36 months for each DG.

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SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG and its associated 4.16 KV output breaker noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, generator differential current, engine low lube oil pressure, and manual emergency stop trip), trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to 105 to 110% of the continuous rating of the DG (5775 - 6050 kW) and ≥ 22 hours at a load equivalent to 90 to 100% of the continuous duty rating of the DG (4950 - 5500 kW). The DG starts for this Surveillance can be performed either from normal keep-warm or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR (Note 3 and Note 4).

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the intent of Regulatory Guide 1.9 (Ref. 3). Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result, power factors deviating much from unity are currently not possible when the DG runs parallel to the grid **while the plant is shutdown**. To the extent practicable, VARs will be provided by the DG during this SR. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2 with the DG connected to an offsite circuit:

a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.

b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.

c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.

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SR 3.8.1.14 (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by four Notes. Note 1 states that momentary variations due to changing bus loads do not invalidate the test. ~~The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.~~ Note 2 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a lagging power factor of ≤ 0.9. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. This power factor should be able to be achieved when performing this SR at power and synchronized with offsite power by transferring house loads from the auxiliary transformer to the startup transformer in order to lower the Class 1E bus voltage. Under certain conditions, however, Note 2 allows the surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency busses that are too high. This would occur when performing this SR while shutdown, and the loads on the startup transformer are too light to lower the voltage sufficiently to achieve a 0.9 power factor. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG

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SR 3.8.1.14 (continued)

excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.9 without exceeding DG excitation limits. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR (Note 3 and Note 4).

This SR must be performed at a lagging power factor of ≤ 0.9 at least once every 36 months for each DG.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds, and subsequently achieves steady state required voltage and frequency ranges. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.10.

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Attachment 2
Regulatory Commitments

Regulatory Commitment	Due Date
RCTSAI _2957438 From response to NRC Question 8. Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following compensatory measures for SR 3.8.1.9 and 3.8.1.10 would be added to the TS Bases, as shown in the TS Bases markup pages in Attachment 1: *The following compensatory measures shall be implemented prior to the performance of this SR in MODE 1 or 2:* *a. Weather conditions will be assessed, and the SR will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.* *b. No discretionary maintenance activities will be scheduled in the APS switchyard or the unit's 13.8 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability to the unit performing this SR.* *c. All activity, including access, in the Salt River Project (SRP) switchyard shall be closely monitored and controlled. Discretionary maintenance within the switchyard that could challenge offsite power supply availability will be evaluated in accordance with 10 CFR 50.65(a)(4) and managed on a graded approach according to risk significance.*	Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006
RCTSAI _2957441 From Response to NRC Question 12(b): Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006, the following requirement will be added to the TS Bases for SRs 3.8.1.10 and 3.8.1.14, as shown in TS Bases markup in Attachment 1: *This SR must be performed at a lagging power factor of ≤ 0.9 at least once every 36 months for each DG.*	Upon implementation of the TS amendment requested in letter no. 102-05546, dated August 16, 2006