APS

Palo Verde Nuclear
Generating Station

David Mauldin
Vice President
Nuclear Engineering
and Support

TEL (623) 393-5553
FAX (623) 393-6077

10 CFR 50.90

Mail Station 7605
P.O. Box 52034
Phoenix, AZ 85072-2034

102-05040-CDM/TNW/JAP
January 22, 2004

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

References: 1) Letter 102-04946-CDM/TNW/JAP, dated May 28, 2003, "PVNGS Units 1, 2, and 3 Amendment to Technical Specification 3.8.1, AC Sources – Operating and 3.8.4, DC Sources – Operating," from C. D. Mauldin to USNRC

2) Letter dated September 25, 2003, "Request for Additional Information 3.8.1 and 3.8.4 for Callaway, Diablo Canyon, Palo Verde and Wolf Creek Plants (TAC Nos. MB9664, MB9477, MB9150, MB9151, MB9152, and MB8763, Respectively," from USNRC to G. R. Overbeck, APS

Subject: **Palo Verde Nuclear Generating Station (PVNGS)**
Units 1, 2 and 3
Docket Nos. STN 50-528/529/530
Response to NRC Request for Additional Information Regarding License Amendment Request to Technical Specification 3.8.1, AC Sources – Operating and 3.8.4, DC Sources – Operating (TAC Nos. MB9150, MB9151, and MB9152)

Dear Sirs:

In reference 1, Arizona Public Service Company (APS) proposed changes to Technical Specification (TS) 3.8.1, "AC Sources – Operating," and TS 3.8.4, "DC Sources – Operating," to allow surveillance testing of the emergency diesel generators (DGs) during MODES in which it is currently prohibited and to incorporate changes based on the Industry/Technical Specification Task Force (TSTF) Standard Technical Specification change TSTF-283, Revision 3.

APS submitted this license amendment request (LAR) (Reference 1) in conjunction with an industry consortium of six plants as a result of a mutual agreement known as Strategic Teaming and Resource Sharing (STARS). Three

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of the members of this group, Union Electric Company, Wolf Creek Nuclear Operating Corporation, and Pacific Gas and Electric Company provided concurrent LAR submittals. The concurrent submittals were intended to allow the NRC to review these submittals as a group.

Reference 2 provided a Request for Additional Information (RAI) from the NRC concerning this proposed change. The responses to the RAI are provided in the Enclosure to this letter.

The responses to the Request for Additional Information were discussed with the NRC on November 19, 2003. The proposed revision to the Notes in Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8 allows portions of the surveillances to be performed at power to reestablish OPERABILITY provided an assessment determines that the safety of the plant is maintained or enhanced. The inclusion of the changes to the Notes in SR 3.8.4.7 and SR 3.8.4.8 is consistent with NRC approval of TSTF-283. Additional discussions were held with the lead NRC Project Manager regarding the NRC concerns that the proposed changes to SR 3.8.4.7 and SR 3.8.4. could result in a partial discharge of the batteries. PVNGS is providing a response to all the Requests for Additional Information and is in agreement with the lead NRC Project Manager to process separately the proposed changes to SR 3.8.4.7 and SR 3.8.4.8 based on the potential additional time to resolve the concerns both generically and for PVNGS.

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

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

Sincerely,

David Mauldin

CDM/TNW/JAP

Enclosure

cc:	B. S. Mallett	Regional Administrator, NRC Region IV
	M. B. Fields	NRC NRR Project Manager
	J. N. Donohew	NRC NRR Project Manager
	N. L. Salgado	NRC Senior Resident Inspector for PVNGS

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, David Mauldin, represent that I am Vice President Nuclear Engineering and Support, Arizona Public Service Company (APS), that the foregoing document has been signed by me on behalf of APS with full authority to do so, and that to the best of my knowledge and belief, the statements made therein are true and correct.

David Mauldin

David Mauldin

Sworn To Before Me This 22nd Day Of January, 2004.

Susie Lynn Ergish

Notary Public

OFFICIAL SEAL
Susie Lynn Ergish
NOTARY PUBLIC - STATE of ARIZONA
MARICOPA COUNTY
MY COMM. EXPIRES July 14, 2007

Notary Commission Stamp

Enclosure

PVNGS' Responses to NRC Request for Additional Information to License Amendment Request to Technical Specification 3.8.1, AC Sources – Operating and 3.8.4, DC Sources – Operating

The following responses are for those requests for additional information (RAIs) identified as applicable to Palo Verde Nuclear Generating Station (PVNGS) in the NRC's RAI letter dated September 25, 2003. The numbering for the questions below are those as listed in the NRC RAI letter. NRC questions 1.a through 1.g are those questions applicable to all four STARS plants and the response to these questions only contains the PVNGS response. NRC questions 4.a through 4.f are questions specific to PVNGS only.

Callaway, Diablo Canyon Units 1/2, Palo Verde Units 1/2/3, And Wolf Creek applicable questions:

NRC Question:

1.a Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8 contain a Note that has been modified to add "However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced." Provide the intent of this note in detail (what exactly will be done at power, the duration of these surveillances and its impact on the limiting condition of operation, details regarding assessment, etc.)

PVNGS Response:

SR 3.8.4.7 and 3.8.4.8 are the DC battery service and the DC battery discharge tests and are performed using surveillance test procedures 32ST-9PK03 and 32ST-9PK04. Both tests would normally not be performed in Modes 1, 2, 3 and 4, because of the required configuration of the tests and the possibility of electrical perturbations. However, the revised note in the license amendment, using the approved TSTF-283, would allow the flexibility to perform a portion of the test to reestablish operability of a battery after corrective maintenance.

The intent of this requested revision is not to run either of these tests in the restricted modes (Modes 1-4) on a normal basis. It is to allow the flexibility to perform portions of these tests to reestablish operability of a battery as recovery to corrective maintenance as long as an evaluation of the risk has been completed and the risk found acceptable.

LCO 3.8.4, Condition A for the batteries, only allows an allowed outage time (AOT) of 2 hours. If the battery is not restored by then, Condition B of LCO 3.8.4 is entered which requires a shutdown to Mode 3 over the next six hours. This very short AOT is the result of the safety significance of having an inoperable battery train. These surveillances require about two hours to perform.

When entering an AOT, it is always PVNGS' intent to return the system to operable status within the allowed AOT (typical scheduled maintenance is no more than ½ of the allowable AOT). However, in the case of the batteries the subject tests require several hours to complete and determine operability. As a result, even if the corrective maintenance were to be completed within the AOT it may require additional time to complete the testing to return the batteries to an operable status. This is where the flexibility provided by this license amendment request (LAR) is directed and would be considered. In using this flexibility it would include an evaluation of the current conditions, configurations, and risks involved with delaying actual shutdown to allow completion of these tests. Delay of the shutdown for completion of operability testing is considered to be an unusual practice and is not intended to be a normal evolution. The use of this flexibility would be evaluated on a case-by-case basis.

The responses to the Request for Additional Information were discussed with the NRC on November 19, 2003. Additional discussions were held with the lead NRC Project Manager regarding the NRC concerns that the proposed changes to SR 3.8.4.7 and SR 3.8.4.8 could result in a partial discharge of the batteries. PVNGS is in agreement with the lead NRC Project Manager to process separately the proposed changes to SR 3.8.4.7 and SR 3.8.4.8.

<u>NRC Question:</u>

1.b Does the work control programs, risk management programs, and/or procedures cover a comprehensive walk-down just prior to entering the period of reduced equipment availability during EDG testing? Provide details about the walk-down or justify why such walk-down is not required.

PVNGS Response:

Walkdowns of equipment that is to be removed from service are routinely performed in order to prepare for the planned work activities. There are no specific requirements for walking down equipment that is not going to be removed from service prior to entering the period of reduced equipment availability such as during emergency diesel generator (EDG) maintenance/testing. It is required that the functional and operable status of all equipment be known and understood at all times. This is accomplished through routine (i.e., hourly, shiftly, daily, monthly, etc.) monitoring, operators who physically walkdown the plant equipment at routine intervals, testing by plant personnel and monitoring equipment. Additionally when an EDG is removed from service, within one hour as required by TS LCO 3.8.1, Required Actions B.1 and B.2 are performed. These required actions verify the correct breaker alignment and indicated power availability for each required offsite circuit along with declaring the required feature(s), supported by the inoperable emergency diesel generator, inoperable when its redundant required feature(s) is inoperable.

It should be noted that during testing of an EDG that although the diesel may be considered inoperable (i.e., following the restoration of the diesel after maintenance) the EDG is fully functional during this testing period. If the EDG is being tested for a scheduled SR only, the EDG is not considered inoperable in nearly all of its related SR testing.

Additional Information

Further discussions were held between NRC and PVNGS personnel during a November 19, 2003 phone call. It was requested that Palo Verde provide additional information as to how access and work to the switchyard is controlled to minimize the potential of a loss of offsite power. The following is PVNGS' response to this question.

There are two switchyards associated with the Palo Verde Nuclear Generating Station. They are termed the Startup Transformer Yard and the 525KV Switchyard (also called the Salt River Project (SRP) or SRP yard).

The Startup Transformer Yard provides the offsite power source to each of the three PVNGS units. It is owned and managed exclusively by Arizona Public Service Company (APS). Access to the Startup Transformer Yard is controlled by PVNGS.

PVNGS personnel perform all work in the Startup Transformer Yard. All work is scheduled and controlled through Unit 1 Operations control room. All Startup Transformer Yard work is on the PVNGS 12-Week schedule. During Startup Transformer Yard operations, a nuclear Auxiliary Operator is stationed in the switchyard with a radio.

Plant procedures do not currently prohibit the scheduling of Startup Transformer outages at the same time as Emergency Diesel Generator outages.

The Salt River Project (SRP) yard (525kV Switchyard) provides output power and grid interface for the PVNGS. SRP is the managing partner of the 525kV switchyard. SRP performs all maintenance in the 525kV Switchyard. SRP is also responsible for operation of all equipment with the exception of the Motor Operated Disconnects (MODs) associated with each unit's output. Operational control of MODs remains with APS/PVNGS to be able to isolate plants and startup transformers. Plant procedures control the switching of MODs in the SRP Switchyard by

APS/PVNGS personnel. Access to the 525kV Switchyard is controlled by SRP.

Mid-loop Operations - During Mid-loop operations, SRP personnel or vehicles are only allowed in a designated area along the south fence of the SRP switchyard. All other access including emergency access must be cleared through Unit 1 control room. Gates are posted during any unusual event or Mid-loop operations.

Planning and Scheduling
All Planned SRP yard breaker work is scheduled through APS/PVNGS and is identified through the Palo Verde 12 week scheduling process. The SRP Breaker Overhaul Plan is also integrated into the Palo Verde Long-Range Maintenance Plan. Seasonal weather conditions are also taken into consideration for scheduling of maintenance in the SRP yard.

Switchyard Scheduling and Coordination
A dedicated Switchyard Component Outage Coordinator works in the PVNGS Work Management Department. This person is responsible for developing the integrated SRP schedule and integrating the SRP breaker overhaul plans with the PVNGS Long-Range Maintenance Plan and 12-week schedules. All planned maintenance, testing and modifications are scheduled through the Switchyard Coordinator. All equipment outage schedules go through plant review and approval since they must be evaluated for risk per the Maintenance Rule, 10CFR 50.65 paragraph (a)(4). The Switchyard Coordinator provides APS presence in the switchyard daily, provides status of work in the switchyard and technically reviews the impact on Palo Verde operations.

NRC Question:

1.c Indicate where the loss-of-offsite power signal comes from when the EDG is powering, or is paralleled to, the safety bus.

PVNGS Response:

The loss-of-offsite power signal comes from the same place whether the EDG is powering, or is paralleled to, the Class 1E 4.16 kV Engineered Safety Features (ESF) safety bus(es).

The loss of offsite power/load shed (LOP/LS) actuation signals use undervoltage relays as a method of detection. The LOP/LS module uses the combined inputs from eight separate undervoltage relays per safety train. The undervoltage relays monitor the Class 1E 4.16 kV buses, PBA-S03 and PBB-S04, for undervoltage conditions.

Four solid-state relays and four induction disk relays are provided on each Class 1E 4.16 kV safety 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 ≤3697 volts. To prevent spurious actuations, the Degraded Voltage relays will not actuate when voltage is >3786 volts. The time delay for the Degraded Voltage relays is a maximum of 35 seconds and a minimum of 28.6 seconds (considering tolerance). 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. The primary function of the Loss of Voltage relays is to trip in 2.4 seconds or less for a complete loss of voltage condition. The Balance of Plant Engineered Safety Features Activation System (BOP ESFAS) Loss of Offsite 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 LOP signal occurs to start and operate the EDG in the emergency mode of operation and automatically loads onto its associated Class 1E Engineered Safety Function (ESF) bus.

The EDGs provide a source of emergency power when offsite power is either unavailable or voltage is insufficient to allow safe unit operation. Undervoltage protection will generate a loss of offsite power start in the event a Loss of Voltage (LOV) or if a Degraded Voltage (DV) condition occurs.

The plant technical specifications (SR 3.3.7.3) govern the setpoint of the LOV and DV relays.

<u>NRC Question:</u>

1.d Discuss administrative controls to preclude performing these surveillances 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 required safety systems that depend on the remaining EDG as a source. Additionally, discuss if the remaining EDG were to become inoperable while the other EDG is being tested, would the test be aborted.

PVNGS Response:

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 30DP-9MT03 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 EDG were to become inoperable while the other EDG 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.

Also, all scheduled testing for the emergency diesel generators is typically scheduled and performed at the low risk times of the day (i.e., 4:00 am to 9:00 am).

Refer to the response to question 4.f below for additional administrative restrictions associated with EDG testing.

NRC Question:

1.e Discuss if there be procedures in place to alert operators when to perform either portions or full SRs/Testing. Will the operators receive training on the procedures related to the proposed Technical Specification changes prior to implementation?

PVNGS Response:

There are two main reasons for performing any testing. Those are:

1. Surveillance or routine testing – These ensure that equipment is capable of performing to expected or required performance levels.
2. Post Maintenance Testing (PMT) – These tests ensure that prior to equipment being returned to service, that appropriate testing occur to ensure that maintenance was completed satisfactorily and equipment can and does perform to required specifications.

Surveillance or routine testing

Technical Specifications (TS) dictate specific tests and frequencies for the performance of these tests to occur for helping to ensuring that safety related equipment is performing or will perform to satisfactory levels when called upon. The integration and scheduling of these required tests is accomplished as described in the answer to previous question 1.d above.

Post Maintenance Testing (PMT)

Procedure 30DP-9WP04, Post-Maintenance Testing Development describes the following; The person who specifies the Post-Maintenance Test (PMT) is the "Retest Designator". This should usually be the developer of the maintenance instruction. The PMT designator shall be familiar with the work to be performed prior to specifying the retest.

The Post-Maintenance Test designator should consider:
- The nuclear safety significance of the equipment being tested.
- The possible consequences of an inadequate PMT.
- The actions necessary for a failed PMT.
- For certain equipment functions the PMT will be the only opportunity to ensure proper emergency response.
- The plant impact of the PMT.
- The history and nature of failures on the equipment being tested, and how this should be incorporated into the PMT.
- The actions necessary to preclude duplicate testing.

Therefore, depending on the specifics, it may not be possible to list the particular retest that may be required to be performed for the restoration of a piece of equipment (including the emergency diesel generator) before it is known what maintenance is needed or has been accomplished. However, routine tasks and maintenance items that are currently known to have specific retests prescribed. When a "portion of" or a "full" surveillance test has been designated to be performed that test is integrated into the Work Schedule as described in response to question 1.d above.

Along with the process described above, the Operations Department performs a final review to ensure that all applicable retest(s) is performed prior to restoring any safety related equipment to operable status.

Additionally, the normal implementation process for any approved Technical Specification is to change the affected plant procedures and provide appropriate training to all those affected by the change. Whether this training is provided prior to or after implementation depends on the complexity and magnitude of the change. This particular TS change will not be trained on prior to its implementation due to its relative non-complex nature. Training on this TS change will occur after it is implemented.

NRC Question:

1.f Discuss the compensatory measures that will be implementing during performance of SRs 3.8.1.10, 3.8.1.13, and 3.8.1.14.

PVNGS Response:

The risk and coordination for the performance of the above SR tests will be evaluated and performed by procedure 30DP-9MT03, Assessment and Management of Risk When Performing Maintenance in Modes 1 – 4, along with the 12-Week Integrated Schedule Matrix. This process is discussed in the answer to question 1.d above. No additional compensatory measures will be applied for these specific surveillances.

NRC Question:

1.g For SR 3.8.1.13, discuss (1) how the SR is performed, and (2) how the safety injection (SI) signal is generated without disturbing power operation.

PVNGS Response:

SR 3.8.1.13 ensures that the EDG automatic trips are bypassed on an actual or simulated Loss of Voltage /ESF actuation signals, except for 4 emergency trips. The ESF actuation signals discussed here for the emergency start of the EDG are the Safety Injection Actuation Signal (SIAS) and Auxiliary Feedwater Actuation Signal (AFAS). This is accomplished using procedures 73ST-9DG01 (Class 1E Diesel Generator and Integrated Safeguards Test – Train A) and 73ST-9DG02 (Class 1E Diesel Generator and Integrated Safeguards Test – Train B).

Automatic Trips that are not bypassed (emergency trips)

These tests are performed at the local control panels for the emergency diesel generators. This is accomplished by two different means.

- For three of the emergency trips (Engine overspeed, Generator Differential, and Manual Emergency Stop) the test is performed as follows: The EDG is placed in a "standby" lineup, ready to automatically start. There are two pushbuttons located at the EDG local control panel that simulate a Loss of Offsite Power and ESF signal. These pushbuttons, when actuated, provide a simulated LOP and ESF emergency start signal to the EDG exactly as if an actual Loss of Offsite Power or ESF signal was present. The particular trip to be tested is actuated (by means of a jumper or manual actuation), giving the EDG an emergency trip signal. Both the LOP and ESF test pushbuttons are simultaneously depressed. The EDG is then checked to ensure that it did not start. The EDG is then reset and placed back into its "standy" lineup. The next emergency trip is tested in the same manner. This is performed for all three of these emergency trips. Thus, verifying that these emergency trips are not bypassed upon a LOP and ESF actuation.

- The other emergency trip (Engine Low Lube Oil Pressure) test is performed as follows: The EDG is running in the emergency mode of operation due to an ESF signal. Field wires are lifted to simulate a loss of lube oil pressure. The EDG is then checked to ensure that it has tripped. Then the simulated LOP pushbutton is depressed. The EDG is the checked to ensure that is has not restarted. Thus verifying the EDG engine low lube oil pressure trip is not bypassed when the EDG is in the emergency mode of operation with a LOP and ESF signal present.

Automatic Trips that are bypassed (non-critical trips)

The EDG is started in an emergency start mode of operation, with a concurrent simulated Loss of Offsite Power and ESF signal present. There are then two separate tests conducted.

- An electrical jumper is installed to simulate a non-critical trip signal for the EDG output breaker. The EDG output breaker is then verified to have not tripped open with this trip signal in.
- A solenoid valve is then de-energized that vents air from the control air circuitry to the non-critical trips, thereby simulating these non-critical trips actuating. Then the EDG is checked to ensure that is has not tripped.

This verifies that these non-critical trips are bypassed during a concurrent Loss of Offsite Power and ESF signal.

Therefore, with the use of the simulated LOP and ESF (SIAS/AFAS) signal test pushbuttons there is no disturbance of the electrical system during this test.

Palo Verde Units 1/2/3 Questions Only

NRC Question:

4.a SR 3.8.4.6 contains a Note that has been modified to add, "However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced." Discuss the intent of this note in details (e.g., what exactly will be done at power, the duration of these surveillances and its impact on the limiting condition of operation, details regarding assessment, etc.)

PVNGS Response:

32ST-9ZZ34, "Battery Charger Surveillance Test," is the surveillance procedure that satisfies SR 3.8.4.6. This procedure verifies that each battery charger supplies > 400 amps for Class 1E Batteries A and B and > 300 amps for Class 1E Batteries C and D at > 125 V for > 8 hours. To perform this test the battery charger is removed from the bus and de-energized. A load cell is then connected to the output of the battery charger (usually connected at the associated motor control center). The battery charger is then energized. The load cell then places the appropriate amount of load on the battery charger for at least 8 hours.

For the performance of SR 3.8.4.6 on any Class 1E Battery Charger, the Class 1E Backup Battery Charger would normally be available to be placed on the DC bus to maintain its appropriate lineup as an Operable DC source. Placing the backup battery charger on a Class 1E bus takes a very short period of time (less than 5 minutes) and will cause only a slight drop in voltage on the DC bus until the other charger is placed into service. In the remote possibility that a backup charger is not available to maintain the DC bus in an operable lineup, LCO 3.8.4, Condition C, would be entered for the performance of this surveillance test. TS Required Actions C.1 and C.2 would ensure battery cell parameters are monitored to acceptable levels (as contained in TS Table 3.8.6-1), up to 24 hours. After this 24 period, if the required charger has not been restored to an operable status or battery parameters fall outside of prescribed limitations, the applicable DC electrical power subsystem/battery would be declared inoperable.

This surveillance would take approximately 12 hours to perform. Along with the appropriate risk evaluation (as described in the answer to question 1.d above), there would be sufficient time to perform this surveillance within the allowable constraints of LCO 3.8.4, Condition C. Again, this would be a very unusual situation that would require the use of LCO 3.8.4, Condition C, for performing this test on line due to the normal Class 1E backup battery charger(s) not being available.

The allowance to use Condition C of LCO 3.8.4 would also depend on having at least a functional battery charger on the Class 1E DC Bus/Battery. Condition C requires that the battery cell parameters meet Table 3.8.6-1 (contained in LCO 3.8.6) 'Category A' limits for designated pilot cells. It is expected for all of the Class 1E Batteries that these pilot cell parameters (specifically float voltage) would not be able to be maintained with no battery charger connected to the bus/battery. It is expected that with a functional battery charger, even thought it may be inoperable, these pilot cell parameters would be able to be maintained and the allowance of Condition C to be used.

This surveillance would not normally be performed in Modes 1, 2, 3, or 4. Modifying this Note would allow for the testing of a battery charger in these previously restricted Modes. The intent of this requested revision is not to run this test in the restricted modes on a normal basis. The intent is to allow the flexibility to perform portions of this test at power, if the Class 1E backup battery charger were not available, to reestablish operability as recovery to corrective action (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) as long as an evaluation of the risk has been completed and the risk found acceptable.

NRC Question:

4.b For SR 3.8.1.10, in Section 4.1 of the application, it is stated that "at PVNGS when the EDG full load reject SR is performed at shutdown, the voltage transients experienced by the loads on the associated bus are considered minimal [at approximate 10 percent step change (400Vac)] in the bus voltage at the 4.16 kV level, with voltage recovery within 1 second." Discuss the impact of this voltage transient on degraded voltage relay. Also, since the voltages at the safety buses during power operation are relatively lower than during shutdown, what will be the voltage transient due to full load rejection test during power operation?

PVNGS Response:

Degraded voltage relays have a time delay of 31.8 seconds (TS SR 3.3.7.3 requires this time delay to be between 28.6-35 seconds), so they will not be affected by the short-duration voltage transients caused by testing. Additionally, safety bus voltages are not lower during power operation than they are during shutdown. At PVNGS, the voltage on the Class 1E 4.16 kV ESF buses is higher than it is at shutdown, typically around 4300 VAC. During power operation these buses are very lightly loaded. During shutdown, the additional non-Class 1E loads connected to the startup transformers result in heavier loading and lower voltage. Therefore, performing a full load rejection test at full power operations should have no impact on the degraded voltage relays. This type of test has been performed many times during shutdown with no negative consequences to the degraded or loss of voltage relays.

NRC Question:

4.c For SR 3.8.1.10, in Section 4.1 of the application, it is stated that "If a LOP occurs during testing, the diesel generator either trips on overcurrent or continues to run, depending upon if the resulting load is in excess of the diesel generator's load rating. If the load is excessive, the diesel generator will trip on overcurrent and the diesel generator breaker will trip automatically on a DG shutdown signal." Discuss how will the diesel generator be started and diesel generator breaker be closed once overcurrent relay tripped the DG? Will it involve manual resetting of the relays? If so, discuss the time associated with the manual resetting of the relay.

PVNGS Response:

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 EDG is paralleled to the offsite circuit in preparation for a full load reject test.

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

- An EDG shutdown signal would trip the EDG
- 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 EDG would restart in the emergency mode (which automatically bypasses the overcurrent trip)
- The EDG 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 an EDG 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 EDG 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.

<u>NRC Question:</u>

4.d Questions b and c above are also applicable to SR 3.8.1.14.

PVNGS Response:

The response to questions 4.b and 4.c above are also applicable answers for the performance of SR 3.8.1.14.

NRC Question:

4.e Discuss the compensatory measures that will be implemented during performance of SR 3.8.1.20.

PVNGS Response:

As described in the answer to question 1.f above, there are no additional specific compensatory measures that will be applied for the performance of this surveillance. Normal risk management and evaluation processes will determine if and when this surveillance will take place at power.

NRC Question:

4.f 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 affect one operable DG." Discuss the possibility of testing an EDG of each unit being simultaneously paralleled to offsite power, such that an offsite disturbance could affect all three units. Discuss the testing practice for SRs 3.8.1.10, 3.8.1.13, 3.8.1.14, and 3.8.1.20 in terms of such a situation.

PVNGS Response:

Currently, PVNGS does not forbid more than one unit's EDG being paralleled to the grid at a time. There is a restriction preventing any unit's two EDGs from being paralleled to the grid at the same time. Additionally, there is a procedural precaution to not have two different units EDGs, if paralleled to offsite, connected to the same startup transformer primary winding.

The normal scheduling and risk practice for EDGs is that maintenance will not be schedule for more than one diesel at a time. The most likely situation to challenge this practice would be while a particular unit's EDG were being restored from scheduled maintenance and another unit's EDG were to be declared inoperable for some unplanned cause. If the timing of both EDGs operability runs were to coincide, there would be an evaluation performed to determine the acceptability of paralleling both of these EDGs to the offsite grid at the same time. It has not been a normal practice at PVNGS to allow more than one EDG to be paralleled to offsite power at the same time. Additionally, PVNGS would not allow for the performance of SR 3.8.1.20 in one unit, while SR 3.8.1.10, 3.8.1.13, or 3.8.1.14 testing is occurring in another unit.