Technical Specification 5.5.14

APS

A subsidiary of Pinnacle West Capital Corporation

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102-05631-SAB/TNW/CJS
January 23, 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 50-528/529/530
Technical Specifications Bases Revision 41 Update

Pursuant to PVNGS Technical Specification (TS) 5.5.14, "Technical Specifications Bases Control Program," Arizona Public Service Company (APS) is submitting changes to the TS Bases incorporated into Revision 41, implemented on December 14, 2006. The Revision 41 insertion instructions and replacement pages are provided in the Enclosure.

No commitments are being made to the NRC by this letter. Should you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

TN Weber... for

SA Bauer

SAB/TNW/CJS/gt

A001

Enclosure: PVNGS Technical Specification Bases Revision 41 Insertion Instructions and Replacement Pages

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

ENCLOSURE

PVNGS
Technical Specification Bases
Revision 41

Insertion Instructions and Replacement Pages

PVNGS Technical Specifications Bases
Revision 41
Insertion Instructions

Remove Page:	Insert New Page:
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B 3.8.3.9/blank	B 3.8.3-9/B 3.8.3-10

Michael, Glenn A(Z01119)

Digitally signed by Michael, Glenn A (Z01119)
DN: CN = Michael, Glenn A(Z01119)
Reason: This is an accurate copy of the original document.
Date: 2006.12.13 16:00:41 -07'00'

PVNGS

Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Technical Specification Bases

Revision 41
December 14, 2006

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B 3.4 REACTOR COOLANT SYSTEMS (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level and the required heaters and their backup heater controls. Pressurizer safety valves and pressurizer vents are addressed by LCO 3.4.10 "Pressurizer Safety Valves-MODES 1, 2, and 3," LCO 3.4.11 "Pressurizer Safety Valves-MODE 4," and LCO 3.4.12 "Pressurizer Vents", respectively.

The maximum steady state water level limit has been established to ensure that a liquid to vapor interface exists to permit RCS pressure control, using the sprays and heaters during normal operation and proper pressure response for anticipated design basis transients. The maximum and minimum steady state water level limit serves two purposes:

a. Pressure control during normal operation maintains subcooled reactor coolant in the loops and thus in the preferred state for heat transport; and

b. By restricting the level to a maximum, expected transient reactor coolant volume increases (pressurizer insurge) will not cause excessive level changes that could result in degraded ability for pressure control.

The maximum steady state water level limit permits pressure control equipment to function as designed. The limit preserves the steam space during normal operation, thus, both sprays and heaters can operate to maintain the design operating pressure. The level limit also prevents filling the pressurizer (water solid) for anticipated design basis transients, thus ensuring that pressure relief devices

(continued)

BASES

BACKGROUND (continued)

(pressurizer safety valves) can control pressure by steam relief rather than water relief. If the level limits were exceeded prior to a transient that creates a large pressurizer insurge volume leading to water relief, the maximum RCS pressure might exceed the Safety Limit of 2750 psia.

The minimum steady state water level in the pressurizer assures pressurizer heaters, which are required to achieve and maintain pressure control, remain covered with water to prevent failure, which could occur if the heaters were energized uncovered.

The requirement to have two groups of pressurizer heaters ensures that RCS pressure can be maintained. The pressurizer heaters maintain RCS pressure to keep the reactor coolant subcooled. Inability to control RCS pressure during natural circulation flow could result in loss of single phase flow and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. No safety analyses are performed in lower MODES. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensable gases normally present.

An implicit initial condition assumption of the Safety Analyses is that the RCS is operating at normal pressure. The individual UFSAR Accident Analysis Sections must be reviewed to determine the assumed pressurizer heater operation during the transient. Steam generator tube rupture, for example, credits pressurizer class backup heaters to maintain adequate subcooling margin.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Class 1E pressurizer backup heaters are needed to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 1). The intent is to keep the reactor coolant in a subcooled condition with natural circulation at hot, high pressure conditions for an undefined, but extended, time period after a loss of offsite power. While loss of offsite power is a coincident occurrence assumed in the accident analyses, maintaining hot, high pressure conditions over an extended time period is not evaluated in the accident analyses. The pressurizer satisfies Criterion 2 and Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirement for the pressurizer to be OPERABLE with water level ≥ 27% indicated level (425 cubic feet) and ≤ 56% indicated level (948 cubic feet) ensures that a steam bubble exists. Limiting the maximum operating water level preserves the steam space for pressure control. The LCO has been established to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 125 kW. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide subcooling margin to saturation can be obtained in the loops.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, Applicability has been designated for MODES 1 and 2. The Applicability is also provided for MODE 3. It is assumed pressurizer level is under steady state conditions. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational

(continued)

BASES

APPLICABILITY (continued)

perturbation, such as reactor coolant pump startup. The LCO does not apply to MODE 5 (Loops Filled) because LCO 3.4.13, "Low Temperature Overpressure Protection (LTOP) System," applies. The LCO does not apply to MODES 5 and 6 with partial loop operation. Also, a Note has been added to indicate the limit on pressurizer level may be exceeded during short term operational transients such as a THERMAL POWER ramp increase of > 5% RTP per minute or a THERMAL POWER step increase of > 10% RTP.

In MODES 1, 2, and 3, the initial conditions of these MODES gives the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODES 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Shutdown Cooling System is in service and therefore the LCO is not applicable.

ACTIONS

A.1 and A.2

With pressurizer water level not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the plant out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses.

Six hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Further pressure and temperature reduction to MODE 4 brings the plant to a MODE where the LCO is not applicable. The 12 hour time to reach the nonapplicable MODE is reasonable based on operating experience for that evolution.

(continued)

ACTIONS (continued)

C.1

If two required Shutdown Cooling System suction line relief valves are inoperable, or if a Required Action and the associated Completion Time of Condition A or B are not met, the RCS must be depressurized and a vent established within 8 hours. The vent must be sized at least 16 square inches to ensure the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action protects the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel. For personnel safety considerations, the RCS cold leg temperature must be reduced to less than 200°F prior to venting.

The Completion Time of 8 hours to depressurize and vent the RCS is based on the time required to place the plant in this condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and 3.4.13.2

SR 3.4.13.1 and SR 3.4.13.2 require verifying that the RCS vent is open ≥ 16 square inches or that the Shutdown Cooling System suction line relief valves be aligned to provide overpressure protection for the RCS is proven OPERABLE by verifying its open pathway condition either:

Shutdown Cooling System suction/line relief valves

a. Once every 12 hours for a valve that is unlocked, not sealed, or otherwise not secured open in the vent pathway, or

b. Once every 31 days for a valve that is locked, sealed, or otherwise secured open in the vent pathway.

RCS Vent

a. Once every 12 hours for a vent pathway that is unlocked, not sealed, or otherwise not secured open

b. Once every 31 days for a vent pathway that is locked, sealed, or otherwise secured open.

For an RCS vent to meet the specified flow capacity, it requires removing all pressurizer safety valves, or similarly establishing a vent by opening the pressurizer manway (Ref. 11). The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and 3.4.13.2 (continued)

The passive vent arrangement must only be open (vent pathway exists) to be OPERABLE. These Surveillances need only be performed if the vent or the Shutdown Cooling System suction line relief valves are being used to satisfy the requirements of this LCO. The Frequencies consider operating experience with mispositioning of unlocked and locked pathway vent valves, and passive pathway obstructions.

SR 3.4.13.3

SRs are specified in the Inservice Testing Program. Shutdown Cooling System suction line relief valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 10), which provides the activities and the Frequency necessary to satisfy the SRs. The Shutdown Cooling System suction line relief valve set point is 467 psig.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. UFSAR, Section 15.
4. 10 CFR 50.46.
5. 10 CFR 50, Appendix K.
6. Generic Letter 90-06.
7. UFSAR, Section 5.2.
8. Pressure Transient Analyses
   a. V-PSAC-009 (3876 MWt w/Original Steam Generators)
   b. MN725-00118 (Unit 2, 4070 MWt w/Replacement Steam Generators)
   c. MN725-00562 (Units 31, 4070 MWt w/Replacement Steam Generators)

(continued)

REFERENCES (continued)

9. Mass Input Pressure Transient in Water Solid RCS

   a. V-PSAC-010 (3876 MWt w/Original Steam Generators)

   b. MN725-00117 (Unit 2, 4070 MWt w/Replacement Steam Generators)

   c. MN725-01495 (Units 31,4070 MWt w/Replacement Steam Generators)

10. ASME, Boiler and Pressure Vessel Code, Section XI.

11. 13-COO-93-016, Sensitivity Study on Pressurizer Vent Paths vs. Days Post Shutdown.

12. PVNGS Calculation 13-N001-6.02-652-2.

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BASES

ACTIONS (continued)

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 10 days. This could lead to a total of 13 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 10 days (for a total of 23 days) allowed prior to complete restoration of the LCO. The 13 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 13 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits 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 being not met. However, if an offsite circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action.

(continued)

BASES

ACTIONS

B.2 (continued)

Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 10 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

When utilizing an extended DG Completion Time (a Completion Time greater than 72 hours and less than or equal to 10 days), the compensatory measures listed below shall be implemented. For planned maintenance utilizing an extended Completion Time, the compensatory measures shall be implemented prior to entering Condition B. For an unplanned entry into an extended Completion Time, the compensatory measures shall be implemented without delay.

1. The redundant DG (along with all of its required systems, subsystems, trains, components, and devices) will be verified OPERABLE (as required by TS) and no discretionary maintenance activities will be scheduled on the redundant (OPERABLE) DG.
2. No discretionary maintenance activities will be scheduled on the gas turbine generators (GTGs).
3. No discretionary maintenance activities will be scheduled on the startup transformers.
4. 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 utilizing the extended DG Completion Time.
5. 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.
6. The GTGs will not be used for non-safety functions (i.e., power peaking to the grid).

(continued)

BASES

ACTIONS

B.4 (continued)

7. Weather conditions will be assessed prior to removing a DG from service during planned maintenance activities. Additionally, DG outages will not be scheduled when severe weather conditions and/or unstable grid conditions are predicted or present.
8. All maintenance activities associated with the unit that is utilizing the extended DG Completion Time will be assessed and managed per 10 CFR 50.65 (Maintenance Rule).
9. The functionality of the GTGs will be verified by ensuring that the monthly start test has been successfully completed within the previous four weeks before entering the extended DG Completion Time.
10. The OPERABILITY of the steam driven auxiliary feedwater pump will be verified before entering the extended DG Completion Time.
11. The system dispatcher will be contacted once per day and informed of the DG status, along with the power needs of the facility.
12. Should a severe weather warning be issued for the local area that could affect the switchyard or the offsite power supply during the extended DG Completion Time, an operator will be available locally at the GTG should local operation of the GTG be required as a result of on-site weather related damage.
13. No discretionary maintenance will be allowed on the main and unit auxiliary transformers associated with the unit.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours (3 days). This could lead to a total of 13 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 16 days) allowed prior to complete restoration of the LCO. The 13 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet

(continued)

BASES

ACTIONS

B.4 (continued)

the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 10 day and 13 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

If at any time during the existence of Condition C (two offsite circuits inoperable) and a required feature becomes inoperable, this Completion Time begins to be tracked.

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.

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.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to a train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

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. 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.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

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

BASES

ACTIONS

G.1 and G.2 (continued)

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.

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.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

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 the level of degradation exceeds that described in Regulatory Guide 1.93 (Ref. 6) for two offsite circuits inoperable. The regulatory guide assumes that an adequate onsite power source is still available to both safety trains, but in a scenario involving automatic load sequencing and low voltage to the ESF buses, 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.

(continued)

BASES

ACTIONS (continued)

H.1 and H.2

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.

I.1

Condition I corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. At these values, the DG output breaker permissives are satisfied, and on detection of bus undervoltage or loss of power, the DG breakers would close, reenergizing its respective ESF bus.

Steady state voltage and frequency limits have not been adjusted for instrument accuracy. Error values for specific instruments are established by plant staff to derive the indicated values for the steady state voltage and frequency limits.

Specific MODE restraints have been footnoted where applicable to each 18 month SR. The reason for "This Surveillance shall not be performed in MODE 1 or 2" is that during operation with the reactor critical, performance of this SR could cause perturbations to the EDS that could challenge continued steady state operation and, as a result, unit safety systems; or that performing the SR would remove a required DG from service. The reason for "This Surveillance shall not be performed in MODE 1, 2, 3, or 4" is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems.

<u>SR 3.8.1.1</u>

This SR assures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and indicated availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby condition. Standby conditions for a DG mean that the engine lube oil and coolant temperatures are maintained consistent with manufacturer recommendations. Additionally, during standby conditions the diesel engine lube oil is circulated continuously and the engine coolant is circulated on and off via thermostatic control.

In order to reduce stress and wear on diesel engines, the DG manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. This is the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

SR 3.8.1.2 Note 4 and SR 3.8.1.7 Note 2 state that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions with the engine at normal keep-warm conditions and achieves required voltage and frequency within 10 seconds, and subsequently achieves steady state required voltage and frequency ranges. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

A minimum voltage and frequency is specified rather than an upper and a lower limit because a diesel engine acceleration at full fuel (such as during a fast start) is likely to "overshoot" the upper limit initially and then go through several oscillations prior to a voltage and frequency within the stated upper and lower bounds. The time to reach "steady state" could exceed 10 seconds, and be cause to fail the SR. However, on an actual emergency start, the EDG would reach minimum voltage and frequency in ≤ 10 seconds at which time it would be loaded. Application of the load will dampen the oscillations. Therefore, only specifying the minimum voltage and frequency (at which the EDG can accept load) demonstrates the necessary capability of the EDG to satisfy safety requirements without including a potential for failing the Surveillance.

While reaching minimum voltage and frequency (at which the DG can accept load) in ≤ 10 seconds is an immediate test of OPERABILITY, the ability of the governor and voltage regulator to achieve steady state operation, and the time to do so are important indicators of continued OPERABILITY. Therefore, the time to achieve steady state voltage and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

frequency will be monitored as a function of continued OPERABILITY.

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads of 90 to 100 percent (4950 - 5500 kW) of the continuous rating of the DG. Consistent with the guidance provided in the Regulatory Guide 1.9 (Ref. 3) load-run test description, the 4950 - 5500 kW band will demonstrate 90 to 100 percent of the continuous rating of the DG. The load band (4950 - 5500 kW) is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing may be performed within the guidance of the generator capability curve.

A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

The normal 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Note 3

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

Since the design of the fuel transfer system is such that pumps will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing, a 31 day Frequency is appropriate.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the auto-connected emergency loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the 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.

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 perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the surveillance in MODE 1 or 2 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

(continued)

BASES

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.

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BASES

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.

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.

(continued)

BASES

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. 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The DG auto-start time of 10 seconds is derived from requirements of the accident analysis. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or shutdown cooling (SDC) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified to the extent possible ensuring power is available to the component.

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

This SR is modified by four Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of 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,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

and other unanticipated 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 the failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system within they are tied together or operated independently for the partial 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 portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that momentary voltage and frequency transients induced by load changes do not invalidate this test. Note 4 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis accident signal (LOCA) signal, and subsequently achieves steady state required voltage and frequency ranges, and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and auto-connected emergency loads (auto-connected through the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

automatic load sequencer) are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the offsite circuit loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or SDC systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the offsite circuit system to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified to the extent possible ensuring power is available to the component.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

(continued)

BASES

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).

(continued)

BASES

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. 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 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. 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).

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

This SR is modified by three Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Per the guidance in Regulatory Guide 1.9, this SR would demonstrate the hot restart functional capability at full-load temperature conditions, after the DG has operated for 2 hours (or until operating temperatures have stabilized) at full load. Momentary transients due to changing bus loads do not invalidate the test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at rated speed and voltage, in standby operation (running unloaded), the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 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 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 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready-to-load operation if a LOCA actuation signal (e.g., simulated SIAS) is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage, in standby operation (running unloaded) with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 12), paragraph 6.2.6(2) and Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.13.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, 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 performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 1 second load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. FSAR, Chapter 8 (Ref. 2) provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, takes into consideration unit conditions required to perform the Surveillance, 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 performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 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 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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified. The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, and 4 is further amplified to allow portions of 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 plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the surveillance are performed in MODE 1, 2, 3,

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

or 4. Risk insights or deterministic methods may be used for this assessment. Note 3 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyze values for the steady-state diesel generator voltage limits are ≥ 4000 and ≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref.12), and ≥ 59.9 and ≤ 60.5 hertz (Ref.13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.3.2.4 and Regulatory Guide 1.137 (Ref. 9).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. Note 2 states that the steady state voltage and frequency limits are analyzed values and have not been adjusted for instrument accuracy. The analyzed values for the steady-state diesel generator voltage limits are ≥ 4000 and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

≤ 4377.2 volts and the analyzed values for the steady-state diesel generator frequency limits are ≥ 59.7 and ≤ 60.7 hertz. The indicated steady state diesel generator voltage and frequency limits, using the panel mounted diesel generator instrumentation and adjusted for instrument error, are ≥ 4080 and ≤ 4300 volts (Ref. 12), and ≥ 59.9 and ≤ 60.5 hertz (Ref. 13), respectively. If digital Maintenance and Testing Equipment (M&TE) is used instead of the panel mounted diesel generator instrumentation, the instrument error may be reduced, increasing the range for the indicated steady state voltage and frequency limits.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17
2. Updated FSAR, Chapter 8
3. Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," July 1993.
4. Updated FSAR, Chapter 6
5. Updated FSAR, Chapter 15
6. Regulatory Guide 1.93, "Availability of Electric Power Sources," Revision 0, December 1974.
7. GL 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18
9. Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators," Revision 1, October 1979.
10. ANSI C84.1-1982
11. IEEE Standard 308-1974, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

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BASES

REFERENCE (continued)	12.	Calculation 13-EC-PE-123, "Diesel Generator voltage meter loop E-PEN-EI-G01/G02 uncertainty calculation."
	13.	Calculation 13-EC-PE-124, "Diesel Generator frequency meter loop E-PEN-SI-G01/G02 uncertainty calculation."
	14.	Calculation 13-MC-DG-401

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BASES

ACTIONS (continued)

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

E.1

Each DG is OPERABLE with one air receiver capable of delivering an operating pressure of ≥ 230 psig indicated. Although there are two independent and redundant starting air receivers per DG, only one starting air receiver is required for DG OPERABILITY. Each receiver is sized to accomplish 5 DG starts from its normal operating pressure of 250 psig, and each will start the DG in ≤ 10 seconds with a minimum pressure of 185 psig. If the required starting air receiver is < 230 psig and ≥ 185 psig, the starting air system is degraded and a period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This 48-hour period is acceptable based on the minimum starting air capacity (≥ 185 psig), the fact that the DG start must be accomplished on the first attempt (there are no sequential starts in emergency mode), and the low probability of an event during this brief period. Calculation 13-JC-DG-203 (Ref. 9) supports the proposed values for receiver pressures.

F.1

With a Required Action and associated Completion Time not met, or one or more DGs with diesel fuel oil, lube oil, or starting air subsystem inoperable for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

(continued)

BASES

ACTIONS

F.1 (continued)

A Note modifies condition F. Periodic starting of the Emergency Diesel Generator(s) requires isolation on one of the two normally aligned air start receivers. During the subsequent Diesel Generator start, the air pressure in the one remaining air receiver may momentarily drop below the minimum required pressure of 185 psig. This would normally require declaring the now running Diesel Generator inoperable, due to low pressure in the air start system. This is not required, as the Diesel Generator would now be running following the successful start. Should the start not be successful, the DG would be declared inoperable per the requirements of LCO 3.8.1. As such, this Condition is modified by a Note stating that should the required starting air receiver pressure momentarily drop to <185 psig while starting the Diesel Generator on one air receiver only, then entry into Condition F is not required. It is expected that this condition would be fairly short duration (< 3 minutes), as the air start compressors should quickly restore the air receiver pressure after the diesel start.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The 2.5 inches visible in the sightglass requirement is based on the DG manufacturer consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to

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SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

transfer the lube oil from its storage location to the DG, when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

The 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the unit staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the fuel oil in accordance with ASTM-D4057 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89, or an API gravity at 60°F of ≥ 27° and ≤ 39°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point ≥ 125°F; and

c. Verify in accordance with the tests specified in ASTM D1796 (Ref. 6) that the sample water and sediment is ≤ 0.05 percent volume.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975 (Ref. 6), except that the analysis for cetane number may be performed in accordance with ASTM D976 (Ref. 6) or ASTM D4737 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each tank must be considered and tested separately.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds or cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the DG can be considered OPERABLE.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil storage tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this Surveillance.

(continued)

BASES

REFERENCES

1. FSAR, Section 9.5.4.2.

2. Regulatory Guide 1.137.

3. ANSI N195-1976, Appendix B.

4. FSAR, Chapter 6.

5. FSAR, Chapter 15.

6. ASTM Standards: D4057-81; D975-91; D976-91; D4737-90; D1796-83; D2276-89, Method A.

7. ASTM Standards, D975, Table 1.

8. ASME, Boiler and Pressure Vessel Code, Section XI.

9. "Emergency Diesel Generator and Diesel Fuel Oil Systems Instrumentation Uncertainty Calculation", 13-JC-DG-203, Parts 23 and 51