Tennessee Valley Authority, Post Office Box 2000, Spring City, Tennessee 37381-2000

William R. Lagergren, Jr.
Site Vice President, Watts Bar Nuclear Plant

WBN-TS-01-04

10 CFR 50.4
10 CFR 50.90

AUG 0 7 2001

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

In the Matter of the	)	Docket No. 50-390
Tennessee Valley Authority	)	

WATTS BAR NUCLEAR PLANT (WBN) - TECHNICAL SPECIFICATION CHANGE TS-01-04, DIESEL GENERATOR (DG) RISK INFORMED ALLOWED OUTAGE TIME (AOT) EXTENSION

The purpose of this letter is to request that Appendix A of Facility Operating License NPF-90, Watts Bar Unit 1 Technical Specifications, be amended in accordance with 10 CFR 50.90 to add a new condition and associated actions to Limiting Condition for Operation (LCO) 3.8.1, "AC Sources Operating," to allow one DG to be out of service for 14 days. Changes to the Technical Specification Bases for the affected actions are also included.

The enclosed amendment request is based on a risk evaluation which was developed in accordance with the guidelines established in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis" and RG 1.177, "An Approach for Plant-Specific Risk Informed Decision Making: Technical Specifications." Based on the evaluation, the proposed amendment increases the AOT from the current 72-hour period to 14 days for restoration of one inoperable DG.

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A complete description of the proposed amendment and the bases revision are included in the enclosures listed below:

Enclosure 1 - Description of the proposed amendment.
Enclosure 2 - No significant hazards determination (this amendment has been determined to not involve a significant hazard consideration).
Enclosure 3 - Annotated Technical Specification and Bases pages.
Enclosure 4 - Revised Technical Specification and Bases pages.
Enclosure 5 - Commitment List

The proposed amendment has been reviewed and approved by the Watts Bar Plant Operations Review Committee and Nuclear Safety Review Board.

In accordance with 10 CFR 50.91(b)(1), a copy of this proposed license amendment is being forwarded to the state designee for the State of Tennessee.

This amendment has the potential to impact the scope of the upcoming spring refueling outage. Therefore, TVA requests NRC action on this amendment by early February 2002.

If you have any questions about this request, please contact P. L. Pace at (423) 365-1824.

Sincerely,

W. R. Lagergren

Subscribed and sworn to before me
on this 7 day of August, 2001

Judie C. Lancaster
Notary Public

My Commission Expires 2-23-2005

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cc (Enclosures):

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IV. SAFETY ANALYSIS

A. WBN Emergency DGs - General Description:

The standby DGs serve as the plant emergency standby alternating current (ac) power source. They are designed, installed and tested to requirements necessary to assure their availability. The DGs are also designed to operate in parallel with the normal power source for test and exercise purposes.

For WBN Unit 1, the DGs consist of four self-contained, water-cooled, automatic starting, diesel engine driven, stationary electric generators. Two DGs in the same train are required to mitigate a Design Basis Event (DBE). Redundancy for single failure is provided by maintaining four DGs in ready condition for automatic start.

The WBN DGs were furnished by Engine Systems Inc. and consist of two 16-cylinder engines manufactured by General Motors-Electro-Motive Division (type 16-645-E4) directly connected to a common 6.9-kV Electric Products (now known as NEI Peebles) generator with exciter. Each DG is capable of starting and accelerating to rated speed within 10 seconds to provide power to the needed engineered safety features (ESF) and shutdown loads. The units have a "continuous" and "short time" rating at 4400 kW-5500 kVA and 4840 kW-6050 kVA respectively.

The DGs are designed to operate under each of the following onsite events or any simultaneous combination thereof:

1. Loss Of Offsite Power (LOOP).
2. Degraded voltage on the 6.9 kV shutdown boards.
3. Safety Injection (SI) signal.

The DGs are also designed for a life of 40 years with normal maintenance. DG voltage and frequency limits and the starting and loading reliability factors meet RG 1.9 and IEEE Standard 387-1984, "Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Stations." Additional information regarding the design of the WBN electrical system is contained in Chapter 8, "Electric Power," of the Updated Final Safety Analysis Report.

B. Engineering Evaluation (RG 1.177 C.2):

B1. Compliance with Current Regulations (RG 1.177 C.2.1):

The proposed Technical Specification amendment was developed consistent with the following requirements:

- 10 CFR 50.36, "Technical Specifications,"

- 10 CFR 50.63, "Loss of all Alternating Current Power," and

- 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

The actions taken to maintain compliance with these regulations included a review of appropriate sections of the Technical Specifications along with a review of key licensing basis documents including the Updated Final Safety Analysis Report (UFSAR). The events considered in this review included loss of offsite power (LOOP), station blackout (SBO), degraded voltage on the 6.9 kV shutdown boards, and the initiation of a Safety Injection (SI) signal.

Regarding a SBO, 10 CFR 50.63, the basis for the established 4 hour SBO coping duration was reviewed and was considered during the development of this proposed amendment. Similar reviews were performed for Maintenance Rule, 10 CFR 50.65, compliance. Further, a review of industry sponsored revisions to the Technical Specifications was performed to ensure that this proposed amendment is consistent with any Technical Specification Task Force (TSTF) travelers which have been approved by NRC. Based on the TSTF review, no approved travelers were identified which affected the LCO actions being revised by the proposed amendment.

B2. Defense in Depth (RG 1.177 C.2.2.1):

The following is presented to demonstrate how WBN implements the appropriate restrictions that preclude simultaneous equipment outages that would erode the principles of redundancy and diversity.

<u>Work Planning:</u>

The following procedures control WBN's work control risk evaluation processes[1]:

- Standard Programs and Processes (SPP) 7.1, "Work Control Process"

- Technical Instruction (TI) 124, "Equipment to Plant Risk Matrix"

SPP-7.1 specifies the general responsibilities and standard programmatic controls for the work control process during plant operation. This procedure

[1] The resolution of NRC Unresolved Item (URI) 390/96-14-02 documented NRC's review of WBN's justification for performing 18-month surveillances online. The results of the review performed for URI 390/96-14-02 were documented in NRC's letter dated July 10, 1997, Inspection Report 390/97-04. WBN's process for control of safety system risk was also reviewed as part of this inspection. This portion of the review outlined the risk assessment process that was controlled by Site Standard Practice (SSP) 7.1, "Work Control," and indicated that WBN's risk calculational methods and techniques would be reviewed as part of a planned Maintenance Rule Baseline inspection. The Maintenance Rule inspection was conducted between May 18th and 22nd, 1998 and was documented in NRC's letter dated July 6, 1998, Inspection Report 390/98-05.

applies to all work activities that affect or have the potential to affect a plant component, system, or unit configuration. Work performed during a planned or forced outage is controlled by SPP-7.2, Outage Management."

WBN's long-term maintenance plan is a product of the preventive and surveillance process and specifies the frequency for implementation of maintenance and surveillance activities necessary for the reliability of critical components in each system. An established 12-week rolling schedule includes the preliminary defense-in-depth assessment, which documents the allowable combinations of system and functional equipment groups (FEGs) that may be simultaneously worked online or during shutdown conditions. FEGs are sets of equipment that have been evaluated for acceptable out-of-service combinations. They are used to schedule planned maintenance and establish equipment clearances.

Predetermined FEG work windows are established for online maintenance and outage periods. The work windows are based on recommended maintenance frequencies and sequenced to minimize the risk of online maintenance. Work windows are defined by week and repeat at 12-week intervals. The work windows ensure required surveillances are performed within their required frequency and that division/train/loop/channel interferences are minimized. The WBN Scheduling organization maintains a long range schedule based on required surveillance testing of online activities and plant conditions.

The surveillance testing schedule provides the "backbone" for the long-term maintenance plan. Other periodic activities (preventive maintenance items) are scheduled with related surveillance tests to maximize component availability. FEGs are used to ensure work on related components is evaluated for inclusion in the work window. Related corrective maintenance (CM) activities are also evaluated for inclusion in the work window provided by surveillance and preventive maintenance performance. The inclusion of identified work in the FEG work window with the surveillance tests and preventive maintenance items maximizes component availability and operability.

The TI-124 risk assessment methodology is used for online maintenance activities. For online maintenance a risk assessment is performed prior to work window implementation and emergent work is evaluated against the assessed scope.

The TI-124 risk assessment guidelines utilize the results of the WBN Probabilistic Safety Analysis (PSA). Other safety considerations, such as Technical Specifications, are also used to determine which system, component, and FEG combinations may be worked online. In addition, an assessment of scheduled activities is performed before implementation of a work window. The assessment includes reviews for the following:

- The schedule is evaluated against the risk bases outlined in the WBN PSA.
- Maximizing safety (reduce risk) when performing online work.
- Avoidance of recurrent entry into a specific limiting condition for operation (LCO) for multiple activities. Activities that require entering the same LCO are combined to limit the number of times an LCO must be established, thus maximizing the equipment's availability.
- If the risk associated with a particular activity cannot be determined, Nuclear Engineering is requested to perform a risk assessment.

During power operation, the DGs help to ensure that sufficient power is available to the safety-related equipment, which is needed for safe shutdown of the plant and for mitigation and control during accident conditions. During shutdown and refueling conditions, the DGs help to ensure that the facility is able to maintain shutdown or refueling conditions for extended periods of time.

Experience has shown that, even with careful planning, maintenance duration sometimes approaches the current 72-hour Completion Time. In order to accommodate unanticipated problems, WBN has developed the practice of scheduling work for only 50 to 60 percent of the Completion Time. It is estimated that the proposed 14-day Completion Time would reduce DG unavailability by approximately 50 percent for the upcoming 12 and 6-year maintenance. Maintenance activities that are currently being performed within the 72-hour Completion Time provision are not expected to change. However, future considerations may indicate improvements in DG availability by combining activities into fewer outages of the DGs, which would result in additional risk reductions.

Offsite Transmission Network:

WBN is connected to a strong offsite transmission network by two 161kV lines and five 500kV lines. The 500-kV switchyard has two bus sections, one with two 500-kV lines and the other with three 500-kV lines. Unit 1 is electrically connected to each bus section. Preferred power is supplied from the existing Watts Bar Hydro 161kV switchyard over the two radial 161kV overhead lines approximately 1.5 miles long. These transmission lines provide power to the nuclear plant's CSSTs A and D and CSSTs B and C and are routed to the east and north of the nuclear plant transformer yard respectively. These lines are routed to minimize the likelihood of their simultaneous failure.

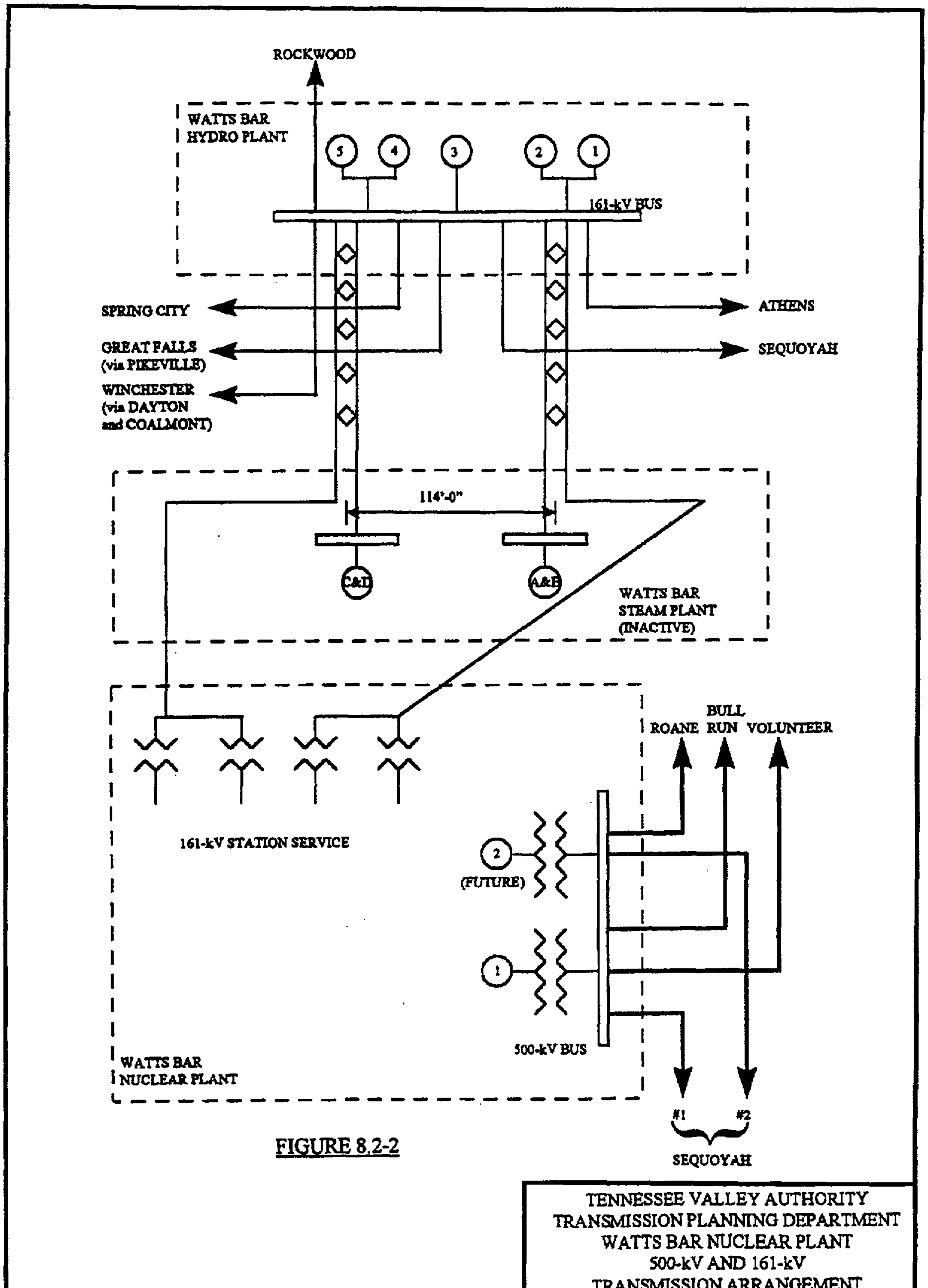
The Watts Bar Hydro 161kV switchyard bus arrangement is designed so that the loss of any one of the four main bus sections will not cause loss of power to either of the two preferred power source lines to the nuclear plant. The Watts Bar Hydro Plant switchyard is interconnected with the TVA power system through six 161kV transmission lines and the five Watts Bar Hydro generators. The portion of the TVA power system that interfaces with WBN is outlined in the following discussion and is depicted in Figure 1 (UFSAR Figure 8.2-2).

The Watts Bar-Sequoyah and the Watts Bar-Athens 161kV lines both terminate on the Hydro plant switchyard bus 1, Section 1. These two lines are on separate rights-of-way except for sharing a common 0.87-mile, double-circuit tower river crossing. The Athens line terminates in the Athens 161kV substation along with one 161kV line from Fort Loudon Hydro Plant, one 161kV line from Loudon 161kV substation via the Sweetwater substation, and one line from Charleston 161kV substation which is tied to Sequoyah Nuclear Plant (SQN). The Sequoyah line terminates in the 161kV switchyard at SQN. The Sequoyah 161kV switchyard is connected to the 500kV system through an intertie transformer bank, to one of the generating units at SQN, to Chickamauga Hydro Plant, and to other substations which are integral parts of the transmission system with either direct or indirect connections to other TVA steam or hydro electric generating plants.

The Watts Bar-Great Falls 161kV transmission line terminates on bus 2, section 2 in the Watts Bar Hydro Plant switchyard. At Great Falls Hydro Plant this line is terminated in the 161kV switchyard along with a second circuit from Watts Bar Hydro which is routed by way of Spring City 161kV substation and with 161kV transmission lines that interconnects with the power system network through the Murfreesboro 161kV substation, McMinnville 161kV substation, West Cookeville 161kV substation, and the Center Hill Hydro Plant. The Great Falls and the Winchester 161kV transmission lines cross approximately 2.87 miles from the Watts Bar Hydro switchyard.

The Watts Bar-Spring City 161kV transmission line terminates on bus 1, Section 3 in the Watts Bar Hydro Plant switchyard. At Spring City this line is terminated on the 161kV bus along with a 161kV line that extends to Great Falls Hydro Plant. The Spring City and Winchester lines that extend from Watts Bar Hydro Plant cross 2.74 miles from the switchyard.

Figure 1 - TVA Power System Interfaces with WBN



The Watts Bar-Rockwood and the Watts Bar-Winchester 161kV transmission lines are terminated on bus 2, section 4, in the Watts Bar Hydro Plant switchyard. The Rockwood line terminates on the Rockwood 161kV bus along with a 161kV line from the Crossville 161kV substation and a 3-terminal line tied to the 161kV switchyard of the Roane County 500kV substation and the Kingston Steam Plant. The Crossville 161kV substation and Kingston Steam Plant are further connected to the TVA 161kV transmission system network. The Watts Bar-Rockwood line is on a separate right-of-way except for being on double-circuit towers with the Watts Bar-Winchester line for 0.9 mile and does not cross other lines that terminate at Watts Bar Hydro switchyard. The Watts Bar-Winchester 161kV transmission line terminates at Winchester 161kV substation. The Winchester, Spring City, and Great Falls 161kV transmission lines have crossings near the Watts Bar Hydro Plant switchyard.

Two incoming 161kV transmission lines extend approximately 1.5 miles from Watts Bar Hydro Plant switchyard to the Watts Bar Nuclear Plant site to furnish preferred power to the nuclear plant. The transmission line for CSSTs A and D terminates on bus 1, Section 1 and bus 2, Section 2. This line does not cross other 161kV lines. The transmission line for CSSTs B and C terminates on bus 2, section 4 and bus 1, section 3 in the hydro plant switchyard. This line crosses over the Spring City and the Great Falls 161kV transmission lines near the hydro plant switchyard.

The transmission line structures for 161kV lines are designed to meet or exceed load requirements specified in the National Bureau of Standards Handbook No. 81 (National Electric Safety Code Part 2). Designing to these requirements ensures the adequacy of lines for wind and heavy icing conditions in excess of those that would be expected to occur in this area. The phase conductor and shield wire design tensions are selected to avoid vibration problems. Long experience with area transmission lines verifies that TVA design practices have been successful in avoiding vibration problems. No galloping conductor conditions have been observed in the eastern portion of the TVA transmission system.

Ground wires are provided for lightning protection on the 161kV voltage class transmission lines. The use of circuit breakers with high speed reclosing relays results in the majority of interruptions due to lighting being momentary.

In a letter to NRC dated August 31, 1992, TVA provided the expected frequency of grid-related LOOP events does not exceed once per 20 years for WBN. That statement is readily supported by site-specific records, as well as published industry reports, such as the annual report issued by the Electric Power Research Institute (EPRI) on LOOP events at U.S. Nuclear Plants.

TVA's records dating back to 1977, approximately the time that the two 161 kV incoming lines were installed, show that WBN has never had a LOOP. Note that an individual line has been out-of-service for limited periods due to such reasons as maintenance, but never both lines concurrently. These records are kept by TVA's Customer Group, which has jurisdiction over TVA's transmission and distribution system.

EPRI report, Nuclear Safety Analysis Center (NSAC) 182, "Losses of Off-Site Power at U.S. Nuclear Power Plants - through 1991," summarizes the Nuclear Industry's experience with partial and total LOOP events at licensed nuclear facilities through the year 1991. Although WBN's experience is not included in this document, the reliability of the TVA grid at the Sequoyah Nuclear Plant (SQN) and Browns Ferry Nuclear Plant (BFN) is included. TVA's experience at these other nuclear facilities does serve to provide a good indicator of the expected grid reliability at WBN. As documented in NSAC-182, a complete LOOP has not been experienced at either of these facilities for the time periods covered in the EPRI report. The EPRI report reflects data back to October 1980 for SQN and June 1973 for BFN.

EPRI Technical Report 158, "Losses of Off-Site Power at U.S. Nuclear Power Plants - through 1999, dated July 2000, documents the operational period for WBN. This report indicates that there have been three minor events (two at SQN and one at BFN) which affected those plant's offsite power supply. However, these events do not change TVA's conclusion that the expected frequency of grid-related LOOP events for WBN will not exceed once per 20 years.

B3. Safety Margins (RG 1.177 C.2.2.2):

The proposed AOT does not change the conditions, operating configurations, or minimum amount of operating equipment assumed in the safety analysis for accident mitigation. No changes are proposed in the manner in which the DGs provide plant protection or which create new modes of plant operation. Only the "Technical Specification Required Action Completion Times" have changed. Therefore, the change does not adversely affect any assumptions or inputs to the UFSAR.

B4. Evaluation of Risk Impact (RG 1.177 C.2.3):

B4.1 Tier 1 - Probabilistic Risk Assessment (PRA) Capability and Insights:

B4.1a Overview of PRA Background and Quality:

As stated previously, the risk impact of having a DG out of service for a fourteen day period was determined in accordance with the guidelines established in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant Specific Changes to the Licensing Basis" and RG 1.177, "An Approach for Plant-Specific Risk informed Decision Making: Technical Specifications."

The WBN Individual Plant Evaluation (IPE) was submitted on September 1, 1992. The IPE was also independently reviewed by Dr. Ian Wall. WBN submitted Revision 1 to the IPE on May 2, 1994 and an NRC safety evaluation was received on October 5, 1994. Since that time the PSA has undergone one additional revision. Revision 2 to the WBN PSA is the basis for this submittal and it was prepared for TVA by ERIN Engineering, Inc. The use of ERIN Engineering by TVA for Revision 2 also served as an independent check of the original model created by Pickard, Lowe, and Garrick, Inc. (PLG, Inc.). Revision 2 of the PSA was used by the NRC staff during their review of the implementation of the requirements of the Maintenance Rule.

The PSA model is evaluated periodically for update. The general guidance for this activity is contained in administrative procedures. WBN is in the process of completing such an update and the Revision 3 model has just undergone a Westinghouse Owners Group (WOG) Peer review. The draft peer review report for Revision 3 has not yet been issued. TVA anticipates that the independent review and resolution of pertinent WOG peer review comments will be completed later this year. Once Revision 3 of the PSA is finalized and pertinent comments dispositioned, TVA plans to compare the evaluation findings developed as a basis for this amendment to a similar evaluation based on Revision 3. The results of this review will be provided by December 14, 2001, to NRC as a supplement to this amendment request.

Regarding this, it should be noted that the electric power portion of the model, including the electrical power event trees, electric power systems analysis and electric power recovery model, were revised to create the PSA version used for this amendment request. After this update, the electric power portion of the model was the same between Revision 2 and Revision 3. Considering this, TVA does not anticipate any significant changes to the evaluation performed for this amendment when the evaluation is confirmed using Revision 3.

TVA has performed a self-assessment of the current Revision 2. Items identified in the self- assessment as affecting the electric power systems and recovery have been included in the model which forms the basis for this submittal. This update was performed for TVA by EQE/PLG.

The changes made to the model as a result of the self-assessment included:

- A change in the definition of LOOP to show that it includes the loss of both the 161kv and 500kv grids.

- A modification to the model to include loss of just one switchyard.

- A change to the electric power recovery model to; 1) credit recovering just the unit one diesel generators, and 2) consider the effect of a diesel generator out of service for maintenance.

- The electric power event trees were combined to allow basic event importance measures to be calculated.

- An intermediate top event was created to model the 480V transformer room ventilation.

The WBN baseline core damage frequency(CDF) with expected average annual equipment unavailabilities is 4.44 E-5/reactor-year[2]. The baseline Large Early Release Frequency (LERF) is 1.25 E-6/reactor-year. This CDF is a slight increase over the value of 4.43E-5/reactor-year documented in Revision 2 to the WBN Probabilistic Safety Assessment (PSA) model. The slight increase in CDF is the result of an update to the electric power portion of the PSA model which was performed in support of this submittal. Other key changes to the model, in addition to those identified during TVA's self assessment, are described below:

- Plant specific equipment performance data was incorporated for the DGs, the fuel oil system, ventilation equipment and the turbine-driven auxiliary feedwater pump. This update reflects plant equipment performance through the end of Cycle 2. The affect of this update on the model was a decrease in CDF for the DGs, fuel oil system and turbine-driven auxiliary feedwater pump and an increase in CDF for the fans and chillers. In particular the zero failures for the turbine-driven auxiliary feedwater pump lowered the CDF contribution from station blackout sequences.

- Common cause was added for several components such as dampers which resulted in an increase to the CDF.

- The Westinghouse seal loss of coolant accident (LOCA) model was replaced by the Brookhaven National Laboratory (BNL) seal LOCA model resulting in an increase to the CDF.

- Credit was taken for the operators' using the pressurizer power operated relief valves (PORVs) to depressurize the reactor coolant system during a station blackout. Earlier model revisions gave no credit to this action. This change to the model has the effect of reducing the reactor

[2] The is 4.44 E-5/reactor-year CDF is based on Revision 2 of the PSA and the specific analysis of the WBN electrical power systems performed in support of this amendment request.

coolant system (RCS) pressure for many sequences in which reactor coolant pump (RCP) seal LOCAs occur, and therefore lowers the leak rates. The lower leak rates provide more time for recovery and therefore, also reduce the overall frequency of core damage from station blackout sequences.

The quantifications for the base case and sensitivity runs described in this submittal were run with an individual sequence cut off set at 1×10^{-10} /year. All core damage sequences with a frequency above 1×10^{-9} /year were saved to the database and used in top event and split fraction importance calculations.

In summary, the preceding discussion outlines several measures which were taken to ensure the adequacy/quality of the model used as a basis for this amendment. With consideration of the actions taken, TVA believes the results of this evaluation are acceptable to support this amendment request.

B4-1b Case 1 - Three Day Completion Time (Baseline CDF Determination)

The baseline CDF was determined using the current Completion Time limit of 3-days. The maintenance frequency for the DGs was separated into corrective and preventive parts. It was assumed that the 6-year and 12-year preventive maintenance would not be performed on-line with the current 3-day Completion Time. It was assumed that the 18 month and three year maintenance would be performed online and these were included in the preventive maintenance (PM) alignments. Common cause was applied to the DGs using the Multiple Greek Letter method. Additional failure parameters used in the model are provided below:

Loss of offsite power (LOOP) initiating event frequency:	2.59 E-2
Failure of diesel to Start:	1.18 E-2
Failure of diesel to Run - first hour:	3.39 E-3
Failure of diesel to Run - after first hour:	8.39 E-4
Turbine-driven auxiliary feedwater (AFW) pump fails to Start:	3.31 E-2
Turbine-driven AFW pump fails to run:	1.03 E-3
Restart failed turbine-driven AFW pump after signal failure:	8.25 E-3
Locally operate turbine-driven AFW pump:	8.29 E-2
Transfer steam supply of turbine-driven AFW pump to other steam generator (SG).	1.78 E-2
Failure to restart turbine-driven AFW pump after LOOP:	0.4

As stated previously the baseline CDF with expected average annual equipment unavailabilities was quantified to be 4.44 x 10^{-5}/reactor-year and the Large Early Release Frequency (LERF) was 1.25 x 10^{-6}/reactor-year. Throughout the discussion that follows this case is referred to as Case 1, 3-day Completion Time. Similar references are made in the discussion for each of the eight cases.

B4-1c Case 2 - Fourteen Day Completion Time

Two changes were made to the model for Case 2. One change was that it was assumed that the six-year and twelve-year overhauls would be performed on-line so a 96 hour duration and a 144 hour duration were added as PM alignments. Ninety six hours is an average time estimated to complete the performance of the 6-year overhaul and 144 hours is the average time estimated to complete the 12-year overhaul. No changes were made to the duration of other PMs[3].

The second change was the implementation of the RG 1.77 requirement to scale the corrective maintenance frequency to allow for an assumed greater time to complete corrective maintenance due to the relaxed Completion Time. The corrective maintenance unavailability was scaled by the ratio of the proposed and current Completion Time or 14/3. It should be noted that although the Completion Time may be relaxed

[3] The use of 96/144 expected hours versus 336 hours in the proposed AOT for this risk case is consistent with RG 1.177.

WBN does not intend to relax the DG performance criteria established in response to station blackout (10 CFR 50.63) and the maintenance rule (10 CFR 50.65). WBN anticipates expeditious performance of maintenance to continue as site policy. Also, the reduction of the Completion Time for common cause determinations will result in expedited determination of the root cause of failures.

The changes described above were used to quantify the revised CDF and LERF using RISKMAN®. The electric power recovery model and LERF were also requantified. The result for the 14-day Completion Time case was a CDF of 4.48×10^{-5}/reactor-year and a LERF of 1.28×10^{-6}/reactor-year. The results for the 14-day completion time case, the cases for calculating the ICCDP, the incremental conditional large early release probability (ICLERP), and sensitivity analyses are summarized in Table 2.

The delta CDF for the 14-day Completion Time is then:

$$4.48 \times 10^{-5}\text{/reactor-year} - 4.44 \times 10^{-5}\text{/reactor-year} = 4 \times 10^{-7}\text{/reactor-year.}$$

4×10^{-7}/reactor-year is less than the 1×10^{-6}/reactor-year and may be considered very small according to the criteria listed in RG 1.174.

The delta LERF for the 14-day Completion Time is then:

$$1.28 \times 10^{-6}\text{/reactor-year} - 1.25 \times 10^{-6}\text{/reactor-year} = 3 \times 10^{-8}\text{/reactor-year.}$$

3×10^{-8} /reactor-year is less than the 1×10^{-7}/reactor-year and may be considered very small according to the criteria listed in RG 1.174.

To calculate the ICCDP and ICLERP additional cases were run where it was assumed that DG 1A was always in preventive maintenance (Case 3) and then in corrective maintenance (Case 4). All other DGs were assumed not to be in maintenance. The electric power recovery model was also changed to reflect that maintenance was being performed on DG 1A and it was not recoverable if a LOOP should occur.

B4-1d Case 3 - Planned Maintenance

The maintenance duration used was that of the longest expected event or the 12-year DG overhaul. Also, because the maintenance is planned and no component failure is involved no changes were made to the conditional failure probabilities of the redundant equipment. The ICCDP was calculated to be 6.60×10^{-7}.

6.60×10^{-7} is slightly greater than the 5×10^{-7} criteria listed in RG 1.177. Using the time for the 12-year overhaul is conservative and WBN expects most PMs to be completed in a much shorter time frame. If the average annual PM time for preventive maintenance is assumed instead of the time for the 12-year overhaul, the ICCDP is calculated to be 7.00×10^{-8} which is much less than the 5×10^{-7} criteria listed in RG 1.177.

It should be noted that WBN expects for the period that a DG is out of service for maintenance that the CDF will be lower than that calculated in this conservative evaluation. This evaluation assumes that all other components are at their average annual maintenance frequency. As described earlier, at WBN equipment is removed from service using a 12-week schedule and according to the guidelines established by TI-124, Equipment to Plant Risk Matrix. The guidelines in TI-124 limit the equipment that can be electively removed from service concurrent with one DG. Equipment that is not to be removed from service concurrent with a DG currently includes:

- The reactor protection system.
- The essential raw cooling water (ERCW) headers and pumps.
- The refueling water storage tank (RWST).
- The containment sump and equipment effecting high pressure recirculation.
- An offsite power line or switchyard equipment.

- The 6.9KV shutdown boards.
- The 480V shutdown boards.
- The 120 VAC power.
- Component cooling water header 1A or 1B.
- The steam generator power operated relief valves (PORVs).
- The pressurizer safety relief valves.

The ICLERP for the preventive maintenance case described in Case 3, using the worst case PM expected event duration value the ICLERP is 3.47×10^{-8}. For the average annual PM event duration case the ICLERP was calculated as 3.68×10^{-9}. Both of these values are below the 5×10^{-8} criteria listed in RG 1.177.

B4-1e Case 4 - Corrective Maintenance (CM)

For the corrective maintenance case, where a component is known to have failed, the RGs recognize that the conditional failure probabilities of redundant equipment may be higher due to common cause possibilities. At Watts Bar, the redundant equipment is not required to be tested for 24 hours. Therefore, it can not be determined if a common cause is present until then.

For such corrective maintenance conditions, the redundant equipment failure modes were adjusted to reflect the fact that one DG failure has already occurred, and that the redundant, identical equipment has not been tested.

The ICCDP calculated for the corrective maintenance case (Case 4) is 6.71×10^{-7}. The ICLERP calculated for the corrective maintenance case is 5.55×10^{-8}. These values are both slightly greater than the 5×10^{-7} ICCDP and 5×10^{-8} ICLERP criteria listed in RG 1.177. As stated earlier this increase in CDF and LERF was expected due to the effects of common cause. This slight exceedance of the criteria is compensated for by the proposed change to reduce the time for determining if a CCF is present from 24 to 12 hours, as discussed later.

RGs 1.174 and 1.177 also require that sensitivity analyses be performed for key modeling assumptions. The key modeling assumption identified for this evaluation is that of the RCP seal LOCA model to be used during electric power recovery calculations. The base case assumes that the Best Estimate Seal LOCA model defined by BNL applies. As a sensitivity case, the Rhode's model for RCP seal leakage was used. The same calculations outlined above for the base cases were also performed, but with the Rhode's model assumed as an alternate assumption.

B4-1f Case 5 - Time-Averaged Maintenance, Three Day Completion Time, Rhode's RCP Seal LOCA Model

Note: Cases 5 through 8 were performed to determine the risk impact of assuming the Rhode's RCP seal LOCA model applies.

The Case 5 model was developed for time-averaged maintenance using the current Completion Time of 3 days and the Rhode's RCP seal LOCA model. The Case 5 model is identical to the model quantified for the base case with the exception that the Rhode's RCP seal LOCA model was used rather than the BNL model. The CDF for this case was 4.47×10^{-5} /reactor-year which is a slight increase over the base case of 4.44×10^{-5}/reactor-year. The LERF for this case was 1.25×10^{-6}/reactor-year which is not a change compared to the base case model.

B4-1g Case 6 - Time-Averaged Maintenance, Fourteen Day Completion Time, Rhode's RCP Seal LOCA Model

The Case 6 model is identical to the model quantified for Case 2 with the exception that the Rhode's RCP seal LOCA model was used rather than the BNL model. The CDF for this case was 4.51 x 10^{-5}/reactor-year which is a slight increase over the Case 2 CDF of 4.48 x 10^{-5}/reactor-year. The LERF for this case was 1.28 x 10^{-6}/reactor-year which is not a change over the Case 2 model.

The delta CDF for the 14-day Completion Time using the Rhode's RCP seal LOCA model is then:

> 4.51E x 10^{-5}/reactor-year - 4.48 x 10^{-5}/reactor-year =
> 3 x 10^{-7}/reactor-year.

3 x 10^{-7}/reactor-year is less than the 1 x 10^{-6}/reactor-year and may be considered very small according to the criteria listed in RG 1.174.

The delta LERF for the 14-day Completion Time with the Rhode's RCP seal LOCA model is then:

> 1.28 x 10^{-6}/reactor-year - 1.25 x 10^{-6}/reactor-year =
> 3 x 10^{-8} reactor-year.

3 x 10^{-8}/reactor-year is less than the 1 x 10^{-7}/reactor-year and may be considered very small according to the criteria listed in RG 1.174.

B4-1h Case 7 - DG 1A Planned Maintenance, Rhode's RCP Seal LOCA Model

Case 7 addresses planned maintenance for the 1A DG using the Rhode's RCP seal LOCA model. The maintenance duration used was that of the longest expected event or the 12-year DG overhaul. Also, because the maintenance is planned and no component failure is involved, no changes were made to the conditional failure probabilities of the redundant equipment. Case 7 is equivalent to Case 3 with the only difference being the Rhode's RCP seal LOCA model. The ICCDP was calculated to be $7.05x10^{-7.}$

$7.05x10^{-7}$ is greater than the 5 x 10^{-7} criteria listed in RG 1.177. Using the time for the 12-year overhaul is conservative and as stated previously WBN expects most PMs to be completed in a much shorter time frame. If the average annual PM event duration for preventive maintenance is assumed instead of the time to complete a 12-year overhaul the ICCDP is calculated to be 7.47×10^{-8} which is much less than the 5×10^{-7} criteria listed in RG 1.177.

The ICLERP for the preventive maintenance case described in Case 3, using the worst case PM value the ICLERP is 3.51×10^{-8}. For the average annual PM event duration the ICLERP was calculated as 3.72×10^{-9}. Both of these values are below the 5×10^{-8} criteria listed in RG 1.177.

B4-1i Case 8 - Corrective Maintenance, Rhode's RCP Seal LOCA Model

Case 8 is similar to Case 4 and is the corrective maintenance case. Where a component is known to have failed, the RGs recognize that the conditional failure probabilities of redundant equipment may be higher due to common cause possibilities. Again, the difference between the two cases is the use of the BNL RCP seal LOCA model in Case 4 and the Rhode's RCP seal LOCA model in Case 8.

The ICCDP calculated for Case 8 is 7.16×10^{-7}. The ICLERP calculated for the corrective maintenance case is 5.59×10^{-8}. These values are both slightly greater than the 5×10^{-7} ICCDP and 5×10^{-8} ICLERP criteria listed in RG 1.177 and a slight increase over the BNL seal LOCA model case. This slight exceedance of the criteria is compensated for by the proposed change to reduce the time for determining if a CCF is present from 24 to 12 hours, as discussed later.

B4-1j Summary of Results for Cases 1 through 8

The results are summarized below in Table 2. Table 2 presents the delta core damage frequency, the delta large early release frequency, the ICCDP or the ICLERP for the eight RISKMAN® quantification cases. These frequencies are then compared to determine the impacts of the proposed completion time. The change in time-averaged CDF and LERF (i.e., Cases 1 and 2) are well below the acceptance criteria for changes in CDF and LERF. They are also below 10% of the criteria and therefore the changes can be considered small.

If the average planned maintenance event duration is assumed, all of the ICLERP and ICCDP valves are below the acceptance criteria. However, if the maximum expected planned duration is assumed, then the ICCDP for preventive maintenance and for corrective maintenance both slightly exceed the more restrictive criteria for these quantities; i.e., 5×10^{-7}. The ICLERP for preventive maintenance meets the criteria but slightly exceeds the criteria for corrective maintenance.

Cases 4 and 8 show increased unavailabilities compared to the other cases. These cases consider the 1A-A DG being out of service for corrective maintenance. Unlike the preventive maintenance assumed in cases 3 and 7, the corrective maintenance condition increases the conditional probabilities for common cause failures between the one DG known to have failed, and the remaining DGs. This evaluation conservatively assumes that testing of the redundant DGs does not occur for the entire time that corrective maintenance is ongoing. However, existing plant technical specifications show that such testing is unlikely to take place early in the 24 hour period. Therefore, the assumption that no testing takes place is conservative. It may not be overly conservative, however, because the expected duration of corrective maintenance is only about 17 hours per event. This 17 hours duration corresponds to the average, or expected, corrective maintenance event duration. Some corrective maintenance events will have longer and some will have a shorter duration. The corrective maintenance ICCDP and ICLERP criteria would both be met if the assumed event duration was 12.7 hours or less. This is the basis for requesting the change from 24 hours to 12 hours for the completion time for Technical Specification 3.8.1 Actions B.3.1, B.3.2, C.3.1 and C.3.2.

Results for the sensitivity case, assuming the Rhode's RCP seal LOCA model applies, are also shown in Table 2 While the impacts are all slightly increased from the base case, they are not significantly so. The time-averaged impacts are all small and well below the criteria. The ICCDP and ICLERP values are slightly greater than the criteria for corrective maintenance and the ICCDP value is greater than the criteria for preventive maintenance. The ICLERP value meets the criteria for preventive maintenance. With the Rhode's RCP seal LOCA model if the assumed corrective maintenance event duration is 11.9 hours or less, then the criteria for ICCDP would be met.

Table 2
CDF/LERF Results Computed

Case Identifier	Maintenance Model	RCP Seal Leakage Model	Acceptance Criteria	RISKMAN® Generated Results
Base Results				
DELTA CDF	Time-averaged (Case 2 - Case 1)	BNL	$1x10^{-5}$	$4 x10^{-7}$
DELTA LERF	Time-averaged (Case 2 - Case 1)	BNL	$1x10^{-6}$	$3 x10^{-8}$
ICCDP	DG 1A in Maintenance for PM - (Case 3)	BNL	$5x10^{-7}$	$7.00x10^{-8}$ ($6.60x10^{-7}$)
ICLERP	DG 1A in Maintenance for PM- (Case 3)	BNL	$5x10^{-8}$	$3.68x10^{-9}$ ($3.47x10^{-8}$)
ICCDP	DG 1A in Maintenance for CM (Case 4)	BNL	$5x10^{-7}$	$6.71x10^{-7}$
ICLERP	DG 1A in Maintenance for CM (Case 4)	BNL	$5x10^{-8}$	$5.55x10^{-8}$
Sensitivity Results				
DELTA CDF	Time-averaged (Case 6 - Case 5)	RHODE'S	$1x10^{-5}$	$3 x10^{-7}$
DELTA LERF	Time-averaged (Case 6 - Case 5)	RHODE'S	$1x10^{-6}$	$3x10^{-8}$
ICCDP	DG 1A in Maintenance for PM - (Case 7)	RHODE'S	$5x10^{-7}$	$7.47x10^{-8}$ ($7.05x10^{-7}$)
ICLERP	DG 1A in Maintenance for PM- (Case 7)	RHODE'S	$5x10^{-8}$	$3.72x10^{-9}$ ($3.51x10^{-8}$)
ICCDP	DG 1A in Maintenance for CM (Case 8)	RHODE'S	$5x10^{-7}$	$7.16x10^{-7}$
ICCDP	DG 1A in Maintenance for CM (Case 8)	RHODE'S	$5x10^{-8}$	$5.59x10^{-8}$

Note: If the maximum planned maintenance duration hours (rather than average planned maintenance event duration) is assumed, the values in parentheses apply

In addition to examining the CDF and LERF from internal events, external events should also be reviewed. Seismic and fire events can cause a LOOP, though the probability is extremely low. Potential vulnerabilities of WBN to both seismic and fire issues were evaluated in the WBN Individual Plant Examination of External Events (IPEEE). These issues were discussed previously in WBN submittals to NRC for Technical Specification (TS) Change WBN-TS-00-014 - DG Action Completion Time Extension, which requested a one time change in the DG completion time to 10 days.

B4-1k Seismic Considerations

The seismic calculations have been revised to discuss a 14-day completion time and the updated model. The WBN design basis safe shutdown earthquake (SSE) is 0.18g. The mean annual frequency of exceedance for a SSE at WBN is 2.25E-4. The probability of a SSE occurring during the 14-day (0.038 years) period the DG is out of service maybe taken from the equation:

$$P = 1 - e^{-\lambda\tau}$$

Therefore, P (SSE in 10 days) = $1 - e^{(-2.25E-4)(0.038)} = 8.55 \times 10^{-6}$ which is a small probability.

The evaluation of seismic events performed as part of the IPEEE used the Electrical Power Research Institution (EPRI) Seismic Margins Assessment methodology and the review level earthquake was 0.3g. Both trains of WBN DGs were included in the list of components analyzed for safe shutdown of the unit following an earthquake. The DG Building was also analyzed. This evaluation provided adequate evidence of the ability of WBN to resist a seismic event up to the review level earthquake (RLE) and initiate a safe shutdown of the unit. The IPEEE program did not identify any adverse spatial interactions or any components with seismic capacity below the RLE level.

In the WBN design bases, the switchyard is assumed to fail during a design basis earthquake. The conditional core damage frequency (CCDF) of an earthquake was assumed to be equal to that of a guaranteed LOOP. For this assessment, the WBN PSA model was modified with the LOOP frequency set equal to 1.0, DG 1A-A failed, the possibility of recovering offsite power during the first hour failed and the possibility of recovering diesel generator 1A-A during the next 24 hours failed. The possibility of recovering diesel generator 1A and any other diesel that failed during the 24 hour mission time was also failed. This is conservative because recovery of a failed diesel or a diesel in maintenance is possible. The results of the quantification show the CCDF to be 1.61×10^{-1}.

The CDF due to a design basis or greater earthquake during the 14-day period the DG is out of service may be calculated as:

$$(8.55 \times 10^{-6})(1.61 \times 10^{-1}) = 1.38 \times 10^{-6}$$

If an earthquake were to be considered one of the initiating events, and DG 1A-A was failed, and there was no recovery of offsite power or any diesel that fails, the CDF would increase approximately 3% percent.

In conclusion, the probability of a SSE occurring during the 14-day DG outage is low and the opposite train of DGs would be available to provide safe shutdown of the unit so no additional considerations due to seismic events are required.

B4-11 Fire Considerations

Based on information provided in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," WBN concluded that the site was reasonably clear of combustible materials and therefore, external fires were not considered in the WBN IPEEE. The effects from an internal fire were examined in the IPEEE using the Fire Induced Vulnerabilities Evaluation (FIVE) methodology. However, no fire-induced vulnerabilities were identified during the evaluation.

Each DG set is housed in its own room. Physical separation requirements are provided for each room as well as fire suppression from a CO_2 system described in the WBN Fire Protection Report, Parts II and III. In the IPEEE report, DG Rooms 1A, 2A, 1B, and 2B are Fire Areas 49, 50, 51, and 52 respectively; and these rooms screened out at Phase II.3. The fire related CDF for the DG Rooms ranged from 1.52×10^{-7} to 1.64×10^{-7}. This fire related frequency may increase during DG maintenance due to the potential for introducing additional transient combustibles. These transient combustibles if present, are controlled and any necessary fire protection and impairment permits are posted according to plant procedures. In addition, equipment in the opposite train is protected so that safe shutdown of the unit can occur.

The potential for a fire in other areas of the plant to occur was discussed in detail with DG 1B-B out of service in the submittals made to NRC regarding Amendment 30 to WBN's operating license. The objective of this review was to identify plant areas where a diesel generator was the only credited power train available following the fire. This was necessary to determine vulnerabilities to a combination station blackout and fire. Amendment 30 was issued by NRC on December 8, 2000, and allowed the Completion Time for Action B.4 of LCO 3.8.1 to be extended to 10 days for the replacement of the 1B-B generator. The information provided for Amendment 30 for DG 1B-B, which also includes DG 2B-B, is repeated in the following discussion. The core damage frequency results of the IPEEE reflect WBN Revision 2 of the PSA and not the PSA updated for the Amendment 30 submittals.

A review of the WBN Fire Protection Report identified three fire areas, where if a fire started in that area DGs 1B-B and 2B-B are the only protected train of power available to achieve safe shutdown. These areas are:

Table 3

	Fire Area	Compartment	Location
1.	Fire Area 14 - AV-036	737.0-A1A	Auxiliary Building, Column Lines Q-U1/A1-A6
		737.0-A1AN	Auxiliary Building, Column Lines Q-U1/A6-A8
		737.0-A2	Hot Instrument Shop
		737.0-A4	Air Lock
		757.0-A13	Refueling Room
2.	Fire Area 17 - AV-042	757.0-A2	6.9kV and 480-V Shutdown Board Room
		757.0-A9	Personnel and Equipment Access
	Fire Area 17 - AV-042D	757.0-A2	6.9kV and 480-V Shutdown Board Room
		757.0-A9	Personnel and Equipment Access
	Fire Area 17 - AV-042E	757.0-A2	6.9kV and 480-V Shutdown Board Room
		757.0-A9	Personnel and Equipment Access
	Fire Area 17 - AV-042F	757.0-A2	6.9kV and 480-V Shutdown Board Room
		757.0-A9	Personnel and Equipment Access
	Fire Area 17 - AV-042G	757.0-A2	6.9kV and 480-V Shutdown Board Room
		757.0-A9	Personnel and Equipment Access
3.	Fire Area 24 - AV-049	757.0-A28	Auxiliary Control Instrument Room 2B

WBN used the Fire Induced Vulnerability Evaluation (FIVE) methodology in its Individual Plant Examination of External Events (IPEEE) analysis. In Fire Area 14, area AV-036, compartments 737.0-A2 and 737.0-A4 screened out during Phase 1 using the FIVE methodology. Compartment 737.0-A2 is the Hot Instrument Shop. The Hot Instrument Shop does not contain any equipment required for safe shutdown or plant trip initiators and is separated from adjacent rooms in the Auxiliary Building by 2-hour rated reinforced concrete barriers with the door and penetrations also fire rated. The room is provided with a detection system and the combustible loading is low, $< 16{,}000$ BTU/ft^2. Compartment 737.0-A4 is the Air Lock between the Air Intake Room and Elevation 737.0-A1. This room is separated from the Air Intake Room by 2-hour fire rated reinforced concrete and from Compartment 737.0-A1 by non-fire rated reinforced concrete. The doors and penetrations are fire rated. The combustible loading in Room 737.0-A4, is insignificant. Compartments 737.0-A2 and 737.0-A4 will not be discussed further. The other compartments in Fire Area 14 contain the equipment which would affect safe shutdown of the unit.

Fire Compartment 737.0-A1A and 737.0-A1AN (20 foot buffer zone around compartment A1A) were evaluated together in the IPEEE. These compartments were screened in Phase II.3 using the FIVE methodology.

A fire in Compartment 737.0-A1A could affect systems and components powered from the A-train 6.9-kV and 480V shutdown boards, including DG 1A and normal power fed from common station service transformer (CSST) A. If the Train B DG is taken out of service for maintenance, a safe shutdown path is still provided through CSST B to shutdown boards 1B and 2A. The IPE evaluation did note that there were cables for 6.9k-V shutdown bus 2A in the area; however, the cables were away from any significant fire sources in the area.

Also, it was noted during the review that the alternate offsite feeds for these buses are routed at Elevation 772.0, such that each bus has at least one offsite power supply available, even during an engulfing fire on Elevation 737.0. The boards transfer to the alternate offsite feeds automatically on a containment spray system (CSS) transformer fault.

The evaluation of this fire compartment in the IPEEE was performed using three case scenarios ranging from a minor fire in the compartment to a severe fire assumed to result in extensive damage. The IPEEE assumes DG 1B-B is available. The results of this evaluation from the IPEEE are presented below.

Table 4
IPEEE Evaluation of Fire Area 737.0-A1A
(Corridor West)

Case	Description	Case Frequency (F1)	Conditional Core Damage Probability (P2) CCDP	Core Damage Frequency F2 = (F1 x P2) FCCDP
Case 1	Minor fire, suppressed	2.65E-03	2.16E-06	5.72E-09
Case 2	Significant fire with manual suppression	2.82E-05	1.29E-04	3.64E-09
Case 3	Severe fire, assumed to result in extensive damage, similar to screening evaluation	3.14E-06	7.49E-02	2.35E-07
Total		2.68E-03		2.44E-07

As can be seen in the above table, approximately 95% of the fire conditional core damage probability (FCCDP) comes from Case 3. This case was requantified with DG 1B-B failed in addition to what was already failed for this case. The CCDP for Case 3 increased to 7.58E-2 and F2 would equal 2.38E-7. Because offsite power is still available, the increase in fire CDF from this scenario still allows this case to remain below the IPEEE screening criteria.

Fire Compartment 757.0-A13 was evaluated in the IPEEE and screened in Phase II.3 using the FIVE methodology. The value for F2 was calculated as:

F2 = 2.00E-03 x 1.22E-05 = 2.44E-08

This case was requantified with DG 1B-B failed in addition to what was already failed for this case. The CCDP for this case increased to 1.36E-5 and F2 would equal 2.72E-8. Because offsite power is available and "bleed and feed" are still available the increase in fire CDF still allows this case to remain below the IPEEE screening criteria. "Bleed and feed" cooling consists of opening the pressurizer PORVs to bleed inventory from the RCS and Feeding inventory via the charging pumps to effect a once through cooling of the RCS.

Fire Area 17 - AV-042 is a fire volume that contains cables and/or equipment associated with the fifth Vital Battery. The fifth Vital Battery is an installed spare battery that can be used if one of the existing batteries is out of service for maintenance or testing. This fire area was originally analyzed as a spare battery and then four additional analyses (042D-G) were performed with the fifth Vital Battery in place of each of the four normally credited batteries. The results of the initial screening were similar so further evaluation as in Phase II.3, was performed as just one fire area.

The evaluation of this fire compartment in the IPEEE was performed using three case scenarios ranging from a minor fire in the compartment to a severe fire assumed to result in extensive damage. The results of this evaluation from the IPEEE are presented below.

Table 5
IPEEE Evaluation of Area 757.0-A2
(6.9kV and 480V Shutdown Board Room A)

Case	Description	Case Frequency (F1)	Conditional Core Damage Probability (P2) CCDP	Core Damage Frequency F2 = (F1 x P2) FCCDP
Case 1	Minor fire, suppressed	1.43E-03	5.98E-05	8.55E-08
Case 2	Significant fire with manual suppression	9.72E-06	7.34E-03	7.13E-08
Case 3	Severe fire, assumed to result in extensive damage, similar to screening evaluation	1.08E-06	0.338	3.65E-07
Total		1.44E-03		5.22E-07

In this case there is the potential for a fire-related loss of offsite power. When DG 1B-B is also failed, the CCDP for Case 3 approaches 1.0. While a safe-shutdown path would not be available for this area should a fire occur with DG 1B-B out of service, it should be noted that the actual probability for a severe fire is very low. The FCCDP for Case 3 would then approach 1.08 E-06. This is also an area that is well traveled and contains the personnel and equipment access into the Auxiliary Building. A fire in this area has a high probability of being noticed.

A review of the WBN Fire Protection Report identified four fire areas, where if a fire started in that area, DGs 1A-A and 2A-A are the only protected trains of power available to achieve safe shutdown. These areas are:

Table 6

	Fire Area	Compartment	Location
1.	Fire Area 14 - AV-037 and AV-037C	737.0-A1AN	Auxiliary Building, Column Lines Q-U/A6-A8
		737.0-A1BN	Auxiliary Building, Column Lines Q-U1/A8-A10
		737.0-A1C	Auxiliary Building, Column Lines U-RxCL/A5-A11
		737.0-A7	Unit 1 Letdown Heat Exchanger
		737.0-A8	Unit 2 Letdown Heat Exchanger
2.	Fire Area 20 - AV-045	757.0-A1	Auxiliary Control Room
3.	Fire Area 20 - AV-045	757.0-A1	Auxiliary Control Room
	Fire Area 31 - AV-057	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	- Fire Area 31 - AV-057D	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	- Fire Area 31 - AV-057E	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	- Fire Area 31 - AV-057F	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	- Fire Area 31 - AV-057F	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	- Fire Area 31 - AV-057G	757.0-A24	6.9kV and 480-V Shutdown Board Room B
		757.0-A17	Personnel and Equipment Access
	Fire Area 45 - AV-072	772.0-A15A1	480-V Board Room 1-B, Column Lines A13-A12
		772.0-A15A2	480-V Board Room 1-B, Column Lines A12-A11
4.	Fire Area 45 - AV-072	772.0-A15A1	480-V Board Room 1-B, Column Lines A13-A12
		772.0-A15A2	480-V Board Room 1-B, Column Lines A12-A11

Fire Area 20, area AV-045, screened out during Phase II.2 because the core damage probability due to a fire was less than 1E-6. This area is the auxiliary control room and a fire in this area could potentially affect systems and components necessary to maintain the steam generator inventory control, long term decay heat removal, containment Heating, Ventilation, and Air Conditioning (HVAC), fire pumps, reactor coolant inventory control, reactor pressure control and secondary side isolation functions. The conditional core damage frequency calculated for this top event was 1.22E-3. Examination of the equipment available shows that even with DG 1A failed in addition to the equipment already lost in the fire, a safe shutdown path is available using the turbine-driven auxiliary feedwater pump (125V DC power is not affected), secondary side cooling to SGs 1 and 2 and two ERCW pumps supplied by DG-2A. The conditional core damage probability would increase with DG 1A unavailable but the probability would not approach 1.0. It should also be noted that an automatic sprinkler system and fire pumps are available to the area.

Fire Area 45 - AV-072 is a fire volume for the 480-V Board Room 2-B. This area screened out during Phase II.3. An automatic sprinkler system and fire pumps are available to the area in the event of a fire. Both B-train DGs and offsite power are assumed unavailable in the event of a fire. A fire in this area could potentially affect systems and components necessary to maintain long term decay heat removal, the steam generator inventory control, containment HVAC, fire pumps, reactor coolant inventory control, and reactor pressure control. Unlike fire area 20 described above, the turbine-driven AFW pump is also unavailable due to a fire.

The evaluation of this fire compartment in the IPEEE was performed using three case scenarios ranging from a minor fire in the compartment to a severe fire assumed to result in extensive damage. The IPEEE assumes DG 1A-A and 2A-A are available. The results of this evaluation from the IPEEE are presented below.

Table 7 IPEEE Evaluation of Room 772.0-A15 (480V Board Room 2B)				
Case	Description	Case Frequency (F1)	Conditional Core Damage Probability (P2) CCDP	Core Damage Frequency F2 = (F1 x P2) FCCDP
Case 1	Minor fire, suppressed	1.87E-03	5.98E-05	1.12E-07
Case 2	Significant fire with manual suppression	1.27E-05	7.34E-03	9.31E-08
Case 3	Severe fire, assumed to result in extensive damage, similar to screening evaluation	1.41E-06	0.146	2.06E-07
Total		1.88E-03		4.11E-07

Like previous scenarios with DG 1B-B out of service, if DG 1A-A is removed from service the safe shutdown path credited is unavailable and the CCDP for Case 3 approaches 1.0. While a safe-shutdown path would not be available for this area should a fire occur with DG 1A-A out of service, it should be noted that the actual probability for a severe fire is very low. It is probable that a fire in the area might be noticed before it becomes severe because the auxiliary unit operators (AUOs) enter this area twice a shift. Also other activities like the tagging of equipment out of service for maintenance could result in additional entry to the area.

In Fire Area 14, Fire Compartment 737.0-A1AN, 737.0-A1BN, are 20 foot buffer zones created to analyze fire areas 36 (737-A1A) and 38 (737-A1B) on elevation 737. These areas were evaluated together with those rooms in the IPEEE. Fire area 36 was discussed above with the Train B DGs. In Fire area 38, the DGs are not the only safe shutdown path credited, offsite power is also credited and so this room is not analyzed as a part of this submittal. Rooms A4, A7 and A8 screened out in Phase 1 of the IPEEE evaluation.

Room 737.0-A4 is the Air Lock between the Air Intake Room and room 737-A1. This compartment is separated from the Air Lock room by 2-hour fire rated reinforced concrete and from 737.0-A1 by non-fire rated reinforced concrete twelve-inches thick. The doors and penetrations to this area are fire rated, and the combustible loading is insignificant. This area contains no safe shutdown or plant trip initiator equipment and was screened from further evaluation.

Room 737.0-A7 is the Unit 1 letdown Heat Exchanger Room. This compartment is separated from adjacent rooms by 2-hour fire rated reinforced concrete, with fire-rated doors and penetrations. The combustible loading is low (<7,500 BTU/ft^2) of which greater than 96% is located with two bags of radwaste located at the step off pad. This area contains no safe shutdown or plant trip initiator equipment and was screened from further evaluation.

Room 737.0-A4 is the Unit 1 letdown Heat Exchanger Room. This compartment is separated from adjacent rooms by 2-hour fire rated reinforced concrete, with fire-rated doors and penetrations. The combustible loading is very low (<200 BTU/ft^2). This area contains no safe shutdown or plant trip initiator equipment and was screened from further evaluation.

Fire Area 31 - AV-057 is a fire volume that contains two rooms, elevation 757 A17 and elevation 757 A24. Separate fire frequencies were developed for each of these rooms. These rooms contain cables and/or equipment associated with the fifth vital battery. The fifth vital battery is an installed spare battery that can be used if one of the existing batteries is out of service for maintenance or testing. This fire area was originally analyzed with the fifth vital battery as a spare battery and then four additional analyses (057D-G) were performed with the fifth vital battery in place of each of the four normally credited batteries. The results of the initial screening show that case 57G is the limiting case so further evaluation of the conditional core damage probability was performed as just one fire area using case 57G. A fire in area 57G assumes that the Train B DGs and the turbine-driven AFW pump are unavailable. Dominant failure sequences also involve the loss of the Train A DGs.

The evaluation of this fire compartment in the IPEEE was performed using three case scenarios ranging from a minor fire in the compartment to a severe fire assumed to result in extensive damage. The results of this evaluation from the IPEEE are presented below for room A17.

Table 8 IPEEE Evaluation of Area 757.0-A17 (Personnel and Equipment Access)				
Case	Description	Case Frequency (F1)	Conditional Core Damage Probability (P2) CCDP	Core Damage Frequency F2 = (F1 x P2) FCCDP
Case 1	Minor fire, suppressed	3.09E-04	5.98E-05	1.85E-08
Case 2	Significant fire with manual suppression	2.10E-06	7.34E-03	1.54E-08
Case 3	Severe fire, assumed to result in extensive damage, similar to screening evaluation	2.33E-07	0.143	3.34E-08
Total		3.11E-04		6.72E-08

In this case there is the potential for a fire-related loss of offsite power. When DG 1A-A is also failed, the CCDP for Case 3 approaches 1.0. While a safe-shutdown path would not be available for this area should a fire occur with DG 1A-A out of service, it should be noted that the actual probability for a severe fire is very low. The FCCDP for Case 3 above would then approach 2.33 E-07. This is also an area that is well traveled and contains the personnel and equipment access into the Auxiliary Building. A fire in this area has a high probability of being noticed.

The following are the results for room A24:

Table 9 IPEEE Evaluation of Area 757.0-A24 (6.9kV and 480-V Shutdown Board Room B)				
Case	Description	Case Frequency (F1)	Conditional Core Damage Probability (P2) CCDP	Core Damage Frequency F2 = (F1 x P2) FCCDP
Case 1	Minor fire, suppressed	1.74E-03	5.98E-05	1.04E-07
Case 2	Significant fire with manual suppression	1.18E-05	7.34E-03	8.67E-08
Case 3	Severe fire, assumed to result in extensive damage, similar to screening evaluation	1.31E-06	0.143	1.88E-07
Total		1.75E-03		3.78E-07

In room A24 there is the potential for a fire-related loss of offsite power. When DG 1A-A is also failed, the CCDP for Case 3 approaches 1.0. While a safe-shutdown path would not be available for this area should a fire occur with DG 1A-A out of service, it should be noted that the actual probability for a severe fire is very low. The FCCDP for Case 3 would then approach 1.31 E-06. This is also an area that is well traveled and is near the personnel and equipment access into the Auxiliary Building. A fire in this area has a high probability of being noticed.

Overall, the evaluation of the specific fire areas above demonstrate the risk increase due to severe fire with a combination of loss of offsite power is small. There are three areas where the probability of a severe fire while a diesel generator is out of service for maintenance could cause the conditional core damage frequency to slightly exceed the IPEEE screening criteria. These areas are Elevation 757, areas A2 and A24, 6.9-kV and 480V shutdown board rooms A and B respectively and Elevation 772 area A-15, 480V Board

Room 2B. The actual probability of a severe fire in these areas is low and fire in these areas would probably be detected before they would become severe. The 6.9 kV and 480 V shutdown board rooms A and B are located close to the main control room and personnel traverse these areas frequently. Personnel are also required to enter the 480 V Board Room at least twice a shift.

B4.2 Tier 2 - Avoidance of Risk-Significant Plant Configurations:

The discussion provided previously in Section B.2, "Defense in Depth (RG 1.177 C.2.2.1)," of this amendment request, described in detail the WBN work control processes that aid in the avoidance of risk-significant plant configurations. The work control processes discussed in Section B.2 include the following and Section B.2 should be referred to for details on the processes:

- Standard Programs and Processes (SPP) 7.1, "Work Control Process"
- Standard Programs and Processes (SPP) 7.2, "Outage Management"
- Technical Instruction (TI) 124, "Equipment to Plant Risk Matrix"

SPP-7.1 specifies the general responsibilities and standard programmatic controls for the work control process during plant operation. This procedure applies to all work activities that affect or have the potential to affect a plant component, system, or unit configuration. SPP-7.2 specifies the general responsibilities for the work control process during planned or forced outages.

The discussion in Section B.2 also addresses functional equipment groups (FEGs) and defines the relationship between FEGs and maintenance work windows. DGs 1A, 2A, 1B, and 2B are in FEGs 082A1, 082A2, 082B1, and 082B2 respectively. The DGs are scheduled for possible maintenance and/or surveillance testing during work weeks 1, 5, and 9 for DG 1A; 2, 6, and 10 for DG 2A; 3, 7, and 11 for DG 1B; and weeks 4, 8, and 12 for DG 2B.

The equipment controlled by the guidelines in TI-124 that can be electively removed from service concurrent with one DG, were previously identified in Section B4-1d, "Case 3 - Planned Maintenance," of this amendment request. The review of the model results from this evaluation for additional equipment which should not be removed from service concurrently with a DG is described below. This review identified additional compensatory measures that will be implemented to reduce risk during periods of extended diesel generator unavailability. Updates to TI-124 will be evaluated for implementation as a result of the independent review and approval of the Revision 3 model and/or NRC's approval of this amendment request.

The ten top events with the greatest risk achievement worth (RAW) or Fussel-Vesely Importance (FVI) rankings are provided in the following tables. The review covered top events with a RAW greater than 2 though only the top ten are shown. All of these tables assume that the base case BNL RCP seal LOCA model applies (i.e., cases 1 through 4). The rankings were also investigated assuming that the Rhode's RCP seal LOCA model applies (i.e., cases 5 through 8). The top event rankings were found to change very little between these two assumptions, and so the rankings, assuming that the Rhode's model applies, are not presented here. In a effort to clarify the events and how they are identified in the tables, Table 14 is provided in the attachment to this enclosure and provides a description of each top event.

The first table below (Table 10) presents the RAW importance rankings to CDF for the 10 top events with the highest RAW assuming the BNL model applies. There is no difference in the time-averaged rankings when the 14-day Completion Time is assumed versus the base case 3-day

Completion Time. When DG 1A-A is in maintenance, corrective or planned, the rankings change but only marginally. Top event OG, loss of offsite power, has a relatively higher RAW in response to other initiators. This was expected. The results of the BNL RCP seal LOCA model show that top event VT1A, which is the top event for 480V transformer room (elevation 772) ventilation, and VNV2R, which is recovery of the Unit 2 480V Board Room ventilation have risen in importance. This is the result of common cause factors added to these top event models.

Appropriate restrictions on plant operation (i.e., not taking the elevation 772 transformer room ventilation, or the Unit 2 480V board room ventilation out of service concurrently with the DGs) are being developed and will be defined and controlled in the TS Bases. A complete listing of the restrictions that will be placed in the TS Bases is provided in Section IV B.5 of this amendment request.

Table 10
Top Event Importance By RAW to CDF Assuming
BNL RCP Seal LOCA Model

RAW Ranking	Base Case 3-Day AOT	Proposed 14-Day AOT	DG 1A-A in Planned Maintenance	DG 1A-A in Corrective Maintenance
1	VT1A (480V Transformer Room Ventilation)	VT1A	VT1A	VT1A
2	RT (Reactor Trip Breakers)*	RT	RT	OG (Loss of 161-kV Grid)
3	AE(ERCW Train A pumps)	AE	AE	RT
4	AB(6.9kV Shutdown Bd. 2A)	AB	AB	AE
5	RW (RWST)	RW	RW	AB
6	AA(6.9kV Shutdown Bd. 1A)	AA	OG	RW
7	A1(480V Shutdown Bd. 1A1)	A1	AA	AA
8	DB (125V DC Bus II)	DB	A1	A1
9	B1(480V Shutdown Bd. 1A1)	B1	DB	DB
10	CE (ERCW Train A header)	CE	B1	B1
*--The Reactor Trip Breakers (RTBs) are usually not removed from service during power operations. However, as an added precaution, the RTBs will be added to the list of systems in TI-124 not to be removed from service concurrently with a DG. (Refer to Section IV B.5.)				

The second table (Table 11) presents the Fussel-Vesely importance rankings for the ten top events with greatest importance to CDF assuming the BNL model applies. Again, the rankings don't change between the 3-day AOT and the proposed 14-day AOT. When DG 1A-A is in maintenance, corrective or preventive, the relative importance of station blackout events is apparent. This leads to the higher rankings for the remaining DGs (i.e., top events GB, GC, and GD) and for the steam-driven AFW pump (i.e., top events TPR and TP). Considering this, appropriate restrictions on plant operation (i.e., not taking the turbine-driven auxiliary feedwater pump, the AFW level control valves supplying the steam generators or an opposite train residual heat removal (RHR) pump out of service concurrently with a Unit 1 DG) are being developed and will be defined and controlled in the TS Bases. A complete listing of the restrictions that will be placed in the TS Bases is provided in Section IV B.5 of this letter. Further, the ventilation to the 6.9-kV shutdown board rooms is being added to the list of equipment not to be removed from service while a DG is out of service. Currently the ventilation components are not on the list of components controlled by TI-124. A complete list of the components that will be added to TI-124 is also provided in Section IV B.5 of this letter.

Table 11
Top Event Importance By FVI to CDF Assuming BNL RCP Seal LOCA Model

RAW Ranking	Base Case 3-Day AOT	Proposed 14-Day AOT	DG 1A-A in Planned Maintenance	DG 1A-A in Corrective Maintenance
1	MU (Makeup to the RWST)	MU	OGR1 (Recovery of the Offsite Grid within 1 hr)	OGR1
2	OGR1	OGR1	REC (Recovery of the Offsite Grid)	REC
3	REC	REC	GB (DG 1B)	GB
4	GA (DG 1B)	GA	GD (DG 2B)	GD
5	RB (RHR pump 1B)	RB	MU	GC (DG 2A)
6	RA(RHR pump 1A)	RA	OG	AF (AFW Level Control Valves Supplying SGs)
7	DB	DB	BE	OG
8	GB	GB	GC	TPR (Recovery of Turbine-driven AFW pump)
9	CE	CE	DB	TP (Turbine-driven AFW pump)
10	RRH (High Pressure RHR recirc)	RRH	RB	TB (RCS Thermal Barrier Cooling)

The following table (Table 12) presents the top event RAW importance rankings to LERF assuming the BNL model applies. There is no difference in the time-averaged rankings when the 14-day AOT is assumed versus the base case 3-day AOT. When DG 1A-A is in maintenance, either corrective or planned, the rankings change more so than those for CDF. Top events OS, DC, AF, DCAC, and VNV2R all then have relatively higher RAW values for LERF than in the base case.

Table 12
Top Event Importance By RAW to LERF Assuming
BNL RCP Seal LOCA Model

RAW Ranking	Base Case 3-Day AOT	Proposed 14-Day AOT	DG 1A-A in Planned Maintenance	DG 1A-A in Corrective Maintenance
1	VT1A	VT1A	VT1A	VT1A
2	AE	AE	AE	OG
3	RT	RT	OG	AE
4	OS (Operator action to start AFW given ESFAS fails)	OS	RT	RT
5	AB	AB	OS	DC (125V DC Bus III)
6	OG	OG	AB	AF
7	DC	DC	DC	DCAC (120V AC Vital Bus III)
8	CE	CE	CE	VNV2R (Recovery of Unit 2 480V Bd. Room Vent)
9	A1	A1	A1	LER (LERF Binning Top)
10	DE	DE	DCAC	CT (CST)

The next table (Table 13) presents the top event Fussel-Vesely importance rankings to LERF assuming the BNL model applies. Again, the rankings don't change between the 3-day AOT and the proposed 14-day AOT. When DG 1A-A is in maintenance, either corrective or preventive, the relative importance of station blackout events is again apparent. This again leads to the higher rankings for the remaining DGs (i.e., top events GB, GC, and GD) and for the steam-driven AFW pump (i.e., top events TPR and TP).

Table 13
Top Event Importance By FVI to LERF Assuming BNL RCP Seal LOCA Model

RAW Ranking	Base Case 3-Day AOT	Propose 14-Day AOT	DG 1A-A in Planned Maintenance	DG 1A-A in Corrective Maintenance
1	LER	LER	LER	OGR1
2	OGR1	OGR1	OGR1	LER
3	OS	OS	REC	REC
4	REC	REC	GD	GD
5	ZA (Train A ESFAS)	ZA	AF	AF
6	ZB (Train B ESFAS)	ZB	GB	GB
7	GD	GD	TPR	GC
8	GA	GA	TP	TPR
9	AF	AF	OG	TP
10	GB	GB	GC	OG

B5. Conclusion of Risk Assessment:

Based on the preceding discussion the following can be concluded:

1. As described in Section IV B2, "Defense in Depth," of this document, WBN has processes in place to avoid risk significant plant configurations.

2. Controls are in place in TI-124 to ensure that critical equipment will not be removed from service concurrent with a DG.

3. With consideration of Section C.2.3.6 of RG 1.177, "Use of Compensatory Measures In TS Change Evaluations," the evaluation preformed in support of the requested amendment identified additional operational restrictions which must be invoked when extended scheduled maintenance on a DG is being performed. Therefore, the following additional requirements will be incorporated into the TS Bases for LCO 3.8.1, "AC Sources - Operating:"

a. Verification of the stability of the offsite power system in the vicinity of WBN. This action establishes that the power system is within "single contingency limits" and is capable of remaining stable upon the loss of any single component supporting the system.

b. Establishing the expected weather conditions for the outage period.

c. Postponement of the planned DG outage, if a grid stability problem exists or if inclement weather such as severe thunderstorms or heavy snowfall is projected.

d. Not taking the elevation 772 transformer room ventilation, the 6.9-kV shutdown board room ventilation or the Unit 2 480V Shutdown Board Room Ventilation out of service concurrently with the DG or will implement appropriate compensatory measures.

e. Not removing the Reactor Trip Breakers from service concurrently during power operation while a DG is out of service.

f. Not taking the turbine-driven auxiliary feedwater pump out of service concurrently with a Unit 1 DG

g. Not taking the AFW level control valves to the steam generators out of service concurrently with a Unit 1 DG.

h. Not taking the opposite train RHR pump out of service concurrently with a Unit 1 DG.

B5.1 Tier 3 - Risk Informed Configuration Management:

Paragraph (a)(4) of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," became effective in November 2000. The requirements of (a)(4) and the Configuration Risk Management Program (CRMP) as defined in RG 1.177 appear to overlap in certain areas. This was acknowledged by NRC in the "Statement of Considerations," for 10 CFR 50.65 (Federal Register: July 19, 1999, Volume 64, Number 137). In this statement, NRC indicated that after the revision to 10 CFR 50.65 is effective, NRC will expeditiously support licensee requests to remove the CRMP requirements from plant TS. Considering this, the CRMP is not addressed in this Amendment request.

Attachment
Table 14
Descriptions of Top Risk Events
(Page 1 of 2)

Top Event Identifier	Event Description
A1	Power at Unit 1 480V Shutdown Board 1A1-A. Also included are buses and breakers necessary to supply power to the associated Reactor Motor Operated Valve (MOV) board, diesel auxiliary board, reactor vent board, and control and auxiliary board.
A2	Power at Unit 1 480V Shutdown Board 1A2-A. Also included are buses and breakers necessary to supply power to the associated sub boards.
AA	Power at Unit 1 6.9-kV Board 1A-A. Includes the board and associated beakers.
AB	Power at Unit 1 6.9-kV Board 2A-A. Includes the board and associated beakers.
AC	Component Cooling System (CCS) Train A serves as intermediate heat sink. Includes pump 1A-A, 1B-B, heat exchanger 1A, and piping and valves.
AE	Flow from ERCW Train A pumps to the Train A headers. This includes the four Train A ERCW pumps that supply the headers.
AF	Auxiliary Feedwater discharge flow paths to the four steam generators. The components for flow to number 4 include the motor driven pump (MDP) 1A discharge path valves 3-829, LCV-3-171, 3-833, and 3-837; the turbine driven pump (TDP) discharge path valves 3-870, LCV-3-175, 3-874, and 3-878; and the common check valves 3-644 and 3-645. The flow path to the other steam generators are analogous.
BE	Flow from ERCW Train B pumps to the Train A headers. This includes the four Train B ERCW pumps that supply the headers.
CE	ERCW Header 1A-A
CT	Condensate Storage Tank
DB	125V DC Battery Board II
DC	125V DC Battery Board III.
DCAC	120V AC Power Subsystem 1-III. This models the availability of power at the 120V AC vital distribution panel channel 1-III. Equipment includes, the inverter, the bus, and associated breakers and fuses.
DE	ERCW header 1B-B
GA	Diesel Generator 1A-A. Includes the diesel generator and its auxiliaries, the generator sequencer, dedicated DC control power, electrical board room and diesel room ventilation, air start system, cooling water from ERCW, and associated piping and valves.
GB	Diesel Generator 1B-B. Includes the diesel generator and its auxiliaries, the generator sequencer, dedicated DC control power, electrical board room and diesel room ventilation, air start system, cooling water from ERCW, and associated piping and valves.
GC	Diesel Generator 2A-A. Includes the diesel generator and its auxiliaries, the generator sequencer, dedicated DC control power, electrical board room and diesel room ventilation, air start system, cooling water from ERCW, and associated piping and valves.
GD	Diesel Generator 2B-B. Includes the diesel generator and its auxiliaries, the generator sequencer, dedicated DC control power, electrical board room and diesel room ventilation, air start system, cooling water from ERCW, and associated piping and valves.

Attachment
Table 14
Descriptions of Top Risk Events
(Page 2 of 2)

Top Event Identifier	Event Description
MU	Makeup to the RWST. Modeled for steam generator tube ruptures (SGTRs) and small LOCAs. Models the addition of borated water for continued high pressure injection before the RWST empties. The makeup source is the primary water tank with boron via the boric acid tank.
OG	The offsite grid is available . Models the availability of AC power from the 161-kV switchyard following a plant trip and includes the switchyard.
OGR1	Offsite power is recovered within 1 hour.
OS	Manual Actions to backup ESFAS
RA	Residual Heat Removal (RHR) pump 1A-A. Includes the pump, suction valves and discharge valves, miniflow line valve, heat exchanger outlet throttle and check, the heat exchanger, pump room cooling, pump seal cooling, ERCW piping to the room cooler, CCS cooling to the seals.
RB	RHR pump 1B-B. Includes the pump, suction valves and discharge valves, mini-flow line valve, heat exchanger outlet throttle and check, the heat exchanger, pump room cooling, pump seal cooling, ERCW piping to the room cooler, CCS cooling to the seals.
REC	Recovery of offsite power. Statistical.
RRH	Containment Sump Recirculation - High Pressure
RT	Reactor Trip
RW	Refueling Water Storage Tank. Models the structural integrity of the RWST.
TB	Thermal Barrier Cooling. Includes the flow path to the thermal barrier booster pumps from the CCS heat exchanger A, the booster pumps, the associated piping and valves that form the flow path to the thermal barrier of each pump, and flow from the pumps through FCV-70-87, FCV-70-90, and 70-690.
TP	Turbine-Driven AFW (TDAFW) pump. The components modeled include CST suction valves 3-809 and 3-810; ERCW suction valves 3-136A, 3-136B, 3-179A, and 179B; steam generator number 3 admission valves FCV-1-15 and 3-891; steam generator number 4 admission valves FCV-1-16 and 3-892; downstream steamline valves FCV-1-17 and FCV-1-18; and the turbine pump and the discharge valve 3-864.
TPR	Restart TDAFW pump.
VNV2R	Recovery of Unit 2 480V Board Room Ventilation. Manual actions and unspecified equipment.
VT1A	480V Shutdown Transformer Room 1A Ventilation
ZA	ESFAS Train A
ZB	ESFAS Train B

Enclosure 2
No Significant Hazards Considerations (NSHC) Determination

This NSHC addresses a request for an amendment to the operating license for TVA's Watts Bar Nuclear Plant (WBN). The amendment request was dated August 7, 2001, and it added a new condition and associated actions to limiting condition for operation (LCO) 3.8.1 "AC Sources - Operating," of the WBN's Technical Specifications (TS)," for one diesel generator (DG) being inoperable. The completion time for Action B.4 currently requires that an inoperable DG or train of DGs be restored within 72 hours. The proposed amendment defines the following revisions:

1. The existing Conditions B through H are revised to be Conditions C through I.

2. A new Condition B is added for one DG being inoperable. The Completion Time for the new Action B.4 is set at 14 days for restoration of a single DG.

3. The "<u>AND</u>" portion of the Completion Time for the new Action B.4 is revised from "6 days from discovery of failure to meet LCO" to 17 days.

4. The Completion Time for determination of a common cause failure (new Action B.3.1 and revised Action C.3.1) is reduced from 24 hours to 12 hours.

5. The Completion Time for performance of Surveillance Requirement (SR) 3.8.1.2 for the operable DGs (new Action B.3.2 and revised Action C.3.2) is also reduced from 24 hours to 12 hours.

As indicated above, this amendment changes the numbering sequence of the conditions for LCO 3.8.1 to add a new Condition B. Since the new Condition B addresses the case of one DG being inoperable in either train, the previous Condition B is revised to address the case of two DGs being inoperable in one train. No changes are made in the AOT for the condition where two DGs are inoperable in one train. In addition to the changes previously described, the proposed amendment removes a one-time TS change which was implemented as Amendment 30 (NRC's letter to TVA dated December 8, 2000).

The risk impact of having a DG out of service for a fourteen day period was determined in accordance with the guidelines established in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis" and RG 1.177, "An Approach for Plant-Specific Risk Informed Decision Making: Technical Specifications."

A. <u>The proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.</u>

The emergency DGs are designed as backup AC power sources in the event of loss of offsite power. The proposed AOT does not change the conditions, operating configurations, or minimum amount of operating equipment assumed in the safety analysis for accident mitigation. No changes are proposed in the manner in which the DGs provide plant protection or which create new modes of plant operation. In addition, a Probabilistic Safety Analysis (PSA) evaluation concluded that the risk contribution of the AOT extension is non-risk significant. Therefore, the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

B. **The proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.**

The proposed change does not introduce any new modes of plant operation or make physical changes to plant systems. Therefore, extension of the allowable AOT for DGs does not create the possibility of a new or different accident.

C. **The proposed amendment does not involved a significant reduction in a margin of safety.**

The DGs are designed as backup AC power sources in the event of loss of offsite power. The proposed AOT does not change the conditions, operating configurations, or minimum amount of operating equipment assumed in the safety analysis for accident mitigation. No changes are proposed in the manner in which the DGs provide plant protection or which create new modes of plant operation. In addition, a PSA evaluation concluded that the risk contribution of the AOT extension is non-risk significant. Therefore, the proposed amendment does not involve a significant reduction in a margin of safety.

ENVIRONMENTAL IMPACT EVALUATION

The proposed change does not involve an unreviewed environmental question because operation of WBN, in accordance with these changes, does not cause a change in the type of or significant increase in the amounts of any effluent that may be released offsite, or a significant increase in the individual or cumulative occupational radiation exposure. The proposed change meets the eligibility for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed change is not required.

Enclosure 3

Annotated Technical Specification and Bases Pages

ACTIONS

CONDITION		REQUIRED ACTION		COMPLETION TIME
A.	(continued)	A.3	Restore offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
~~B.~~ C.	**Two** ~~One or more~~ required DG~~(s)~~ in Train A inoperable. OR **Two** ~~One or more~~ required DG~~(s)~~ in Train B inoperable.	~~B.1~~ C.1	Perform SR 3.8.1.1 for the offsite circuits.	1 hour AND Once per 8 hours thereafter
		AND		
		~~B.2~~ C.2	Declare required feature(s) supported by the inoperable DG~~(s)~~ inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition ~~B~~ **C** concurrent with inoperability of redundant required feature(s)
		AND		
		~~B.3.1~~ C.3.1	Determine OPERABLE DG~~(s)~~ ~~is~~ **are** not inoperable due to common cause failure.	~~24 hours~~ **12 hours**
			OR	
		~~B.3.2~~ C.3.2	Perform SR 3.8.1.2 for OPERABLE DG~~(s)~~.	~~24 hours~~ **12 hours**
		AND		
				(continued)

Insert A

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~B.~~ C. (continued)	~~B.4~~ C.4 Restore **at least one** required DG~~(s)~~ to OPERABLE status.	72 hours~~*~~ AND 6 days~~*~~ from discovery of failure to meet LCO
~~C.~~ D. Two offsite circuits inoperable.	~~C.1~~ D.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition D~~C~~ concurrent with inoperability of redundant required features
	AND	
	~~C.2~~ D.2 Restore one offsite circuit to OPERABLE status.	24 hours

(continued)

* 10 days is allowed for the 1B-B diesel generator to replace the electrical generator. This allowance is only applicable until the beginning of the Cycle 4 Refueling Outage.

Delete note

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~D.~~ E. One offsite circuit inoperable. <u>AND</u> One or more required DG(s) in Train A inoperable. <u>OR</u> One or more required DG(s) in Train B inoperable.	------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems Operating," when Condition **E**~~D~~ is entered with no AC power source to any train. -----------------------------	
	~~D.1~~ E.1 Restore offsite circuit to OPERABLE status.	12 hours
	<u>OR</u>	
	~~D.2~~ E.2 Restore required DG(s) to OPERABLE status.	12 hours
~~E.~~ F. One or more required DG(s) in Train A inoperable. <u>AND</u> One or more required DG(s) in Train B inoperable.	E.1 F.1 Restore required DGs in Train A to OPERABLE status.	2 hours
	<u>OR</u>	
	~~E.2~~ F.2 Restore required DGs in Train B to OPERABLE status	2 hours
~~F.~~ G. Required Action and Associated Completion Time of Condition A, B, C, D, ~~or~~ E, **or F,** not met.	~~F.1~~ G.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	~~F.2~~ G.2 Be in MODE 5.	36 hours

(continued)

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. ~~G.~~ Two offsite circuits inoperable. AND One or more required DG(s) in Train A inoperable. OR One or more required DG(s) in Train B inoperable.	H.1 ~~G.1~~ Enter LCO 3.0.3.	Immediately
I. ~~H.~~ One offsite circuit inoperable. AND One or more required DG(s) in Train A inoperable. AND One or more required DG(s) in Train B inoperable.	I.1 ~~H.1~~ Enter LCO 3.0.3.	Immediately

Insert A

B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for the offsite circuits. <u>AND</u> B.2 Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable. <u>AND</u> B.3.1 Determine OPERABLE DGs are not inoperable due to common cause failure. <u>OR</u> B.3.2 Perform SR 3.8.1.2 for OPERABLE DGs. <u>AND</u> B.4 Restore required DG to OPERABLE status.	1 hour <u>AND</u> Once per 8 hours thereafter 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) 12 hours 12 hours 14 days <u>AND</u> 17 days from discovery of failure to meet LCO

BASES

ACTIONS

A.3 (continued)

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.

B.1 **and C.1**

To ensure a highly reliable power source remains with one or more DGs inoperable in Train A OR with one or more DGs inoperable in Train B, 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 a 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 **and C.2**

Required Actions B.2 **and C.2 are** ~~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 critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as the turbine driven auxiliary feedwater pump, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has inoperable DG(s).

The Completion Time for Required Actions B.2 **and C.2 are** ~~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

(continued)

BASES

ACTIONS

B.2 **and C.2** (continued)

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one or more DGs inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one or more required DGs in Train A or one or more DGs in Train B inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DGs, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs 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, **C.3.1 and C.3.2**

Required Action**s** B.3.1 **and C.3.1** provide an allowance to avoid unnecessary testing of OPERABLE DG(s). 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 other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition **F**~~E~~ of LCO 3.8.1 would be entered if the other inoperable DGs are not on the same train, otherwise, if the other inoperable DGs are on the same train, the unit **is** ~~remains~~ in Condition **C**~~B~~. Once the failure is

(continued)

ACTIONS

B.3.1, ~~and~~ B.3.2, **C.3.1 and C.3.2** (continued)

repaired, the common cause failure no longer exists, and Required Actions B.3.1 **and B.3.2** ~~is~~ **are** satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), 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, **C.3.1 or C.3.2,** the corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the **12**~~4~~ hour constraint imposed while in Condition B **or C**.

Delete

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

B.4

According to Regulatory Guide 1.93, (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The **14 day** ~~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 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 restored OPERABLE, the LCO may already have been not met for up to **14 days** ~~72 hours~~ . This could lead to a total of **17 days** ~~144 hour~~, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs restored OPERABLE, and an additional 72 hours (for a total of **20** ~~9~~ days) allowed prior to

(continued)

ACTIONS

B.4 (continued)

complete restoration of the LCO. The **17**~~6~~ day Completion Time provides a limit on 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 **14 day and 17 day** ~~72 hour and 6 day~~ Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met. **Insert B**

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.

Insert C & D

D~~C~~.1 and **D**~~C~~.2

Required Action **D**~~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. This includes motor driven auxiliary feedwater pumps. Single train features, such as the turbine driven auxiliary pump, are not included in the list.

The Completion Time for Required Action **D**~~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:

(continued)

ACTIONS

<u>D~~C~~.1 and D~~C~~.2</u> (continued)

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition **D**~~C~~ (two offsite circuits inoperable) 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 **D**~~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 (e.g., combinations that involve an offsite circuit and one DG inoperable, or one or more DGs in each train 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 plant 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

(continued)

BASES

ACTIONS

D~~C~~.1 and D~~C~~.2 (continued)

AC electrical power system capable of meeting its design criteria.

According to Reference 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.

E~~D~~.1 and E~~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 **E**~~D~~ are modified by a Note to indicate that when Condition **E**~~D~~ is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition **E**~~D~~ to provide requirements for the loss of one offsite circuit and one or more DGs in a train, 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 **E**~~D~~ for a period that should not exceed 12 hours.

In Condition **E**~~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 **D**~~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)

F~~E~~.1

With one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B 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 very 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, however, 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 Reference 6, with one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B inoperable, operation may continue for a period that should not exceed 2 hours.

G~~F~~.1 and G~~F~~.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H~~G~~.1 and I~~H~~.1

Condition H~~G~~ and Condition I~~H~~ corresponds to a level of degradation in which all redundancy in the AC electrical power supplies cannot be guaranteed. At this severely degraded level, any further losses in the AC electrical

(continued)

BASES

ACTIONS

~~H~~G.1 and ~~I~~H.1 (continued)

power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The plant 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 SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 9), as addressed in the FSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. 6800 volts is the minimum steady state output voltage and the 10 second transient value. 6800 volts is 98.6% of the nominal bus voltage of 6900 V corrected for instrument error and is the upper limit of the minimum voltage required for the DG supply breaker to close on the 6.9 kV shutdown board. The specified maximum steady state output voltage of 7260 V is 110% of the nameplate rating of the 6600 V motors. The specified 3 second transient value of 6555 V is 95% of the nominal bus voltage of 6900 V. The specified maximum transient value of 8880 V is the maximum equipment withstand value provided by the DG manufacturer. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Insert E

Delete

Prior to performance of this SR in Modes 1 or 2, actions are taken to establish that adequate conditions exist for performance of the SR. The actions include the performance of the following:

1) Verification of the stability of the offsite power system in the vicinity of WBN. This action establishes that the power system is within "single contingency limits" and is capable of remaining stable upon the loss of any single component supporting the system.

2) Establishing of the expected weather conditions for the 24-hour testing period.

3) Postponement of the test, if a grid stability problem exists or if inclement weather such as severe thunderstorms or heavy snowfall is projected for the upcoming 24 hour period.

If during the performance of the test, a stability problem with the offsite power system arises or inclement weather (i.e., tornado watch or warning, heavy snowfall, etc.) is experienced, the testing is to be suspended.

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. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the

(continued)

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion (GDC) 17, "Electrical Power Systems."

2. Watts Bar FSAR, Section 8.2, "Offsite Power System," and Tables 8.3-1 to 8.3-3, "Safety-Related Standby Power Sources and Distribution Boards," "Shutdown Board Loads Automatically Tripped Following a Loss of Nuclear Unit and Preferred Power," and "Diesel Generator Load Sequentially Applied Following a Loss of Nuclear Unit and Preferred Power."

3. Regulatory Guide 1.9, Rev. 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. Watts Bar FSAR Section 6, "Engineered Safety Features."

5. Watts Bar FSAR, Section 15.4, "Condition IV-Limiting Faults."

6. Regulatory Guide 1.93, Rev. 0, "Availability of Electric Power Sources," December 1974.

7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

8. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 18, "Inspection and Testing of Electric Power Systems."

9. Regulatory Guide 1.137, Rev. 1, "Fuel Oil Systems for Standby Diesel Generators," October 1979.

10. Watts Bar Drawing 1-47W605-242, "Electrical Tech Spec Compliance Tables."

11. TVA's letter to NRC dated August 7, 2001, Technical Specification Change TS-01-04, Diesel Generator (DG) Risk Informed Allowed Outage Time (AOT) Extension

Bases Inserts

Insert B:

In addition, the contingency actions listed in Bases Table 3.8.1-2 must be invoked whenever the outage period will extend beyond 72 hours.

Insert C:

According to TVA's probabilistic safety analysis described in Reference 11, 12 hours is reasonable to confirm the OPERABLE DGs are not affected by the same problem as the inoperable DG.

Insert D:

C.4

According to Regulatory Guide 1.93, (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours.

In Condition C, the remaining OPERABLE DGs and offsite circuits 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. Restoration of at least one DG within 72 hours results in reverting back under Condition B and continuing to track the "time zero" completion time for one DG inoperable.

The second Completion Time for Required Action C.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 C is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on 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 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action C.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 C was entered.

Insert E:

Prior to performance of this SR in Modes 1 or 2, actions are taken to establish that adequate conditions exist for performance of the SR. The required actions are defined in Bases Table 3.8.1-2.

Insert F:

Insert the following table as page B 3.8-36a:

Bases Table 3.8.1-2
TS Action or Surveillance Requirement (SR) Contingency Actions

	Contingency Actions to be Implemented	**Applicable TS Action or SR**	**Applicable Modes**
1.	The stability of the offsite power system in the vicinity of WBN shall be verified. This action establishes that the power system is within "single contingency limits" and is capable of remaining stable upon the loss of any single component supporting the system.	Action B.4	1, 2, 3, 4
2.	The expected weather conditions for the outage/maintenance/testing period shall be established.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
3.	If during the outage/maintenance/testing period, a stability problem with the offsite power system arises or inclement weather (i.e., tornado watch or warning, heavy snowfall, etc.) is experienced, the activity is to be suspended or postponed, if possible.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
4.	During the outage/maintenance/testing period the following equipment should not be removed from service concurrent with the DGs; 1) the transformer room ventilation, 2) the 6.9-kV board room ventilation, 3) the Unit 2 480V shutdown board room ventilation. If the equipment must be removed from service during a DG outage, the compensatory measures contained in System Description N3-30AB-4001, "Auxiliary Building Heating, Ventilation, Air Conditioning," shall be implemented.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
5.	During the outage/maintenance/testing period the Reactor Trip Breakers are not to be removed from service concurrent with a DG.	Action B.4	1, 2, 3, 4
6.	During the outage/maintenance/testing period the turbine-driven auxiliary feedwater pump shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4
7.	During the outage/maintenance/testing period the AFW discharge supply valves to the steam generators shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4
8.	During the outage/maintenance/testing period the opposite train RHR pump shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4

Enclosure 4

Revised Technical Specification and Bases Pages

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore offsite circuit to OPERABLE status.	72 hours <u>AND</u> 6 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for the offsite circuits. <u>AND</u>	1 hour <u>AND</u> Once per 8 hours thereafter
	B.2 Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable. <u>AND</u>	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	B.3.1 Determine OPERABLE DGs are not inoperable due to common cause failure. <u>OR</u>	12 hours
	B.3.2 Perform SR 3.8.1.2 for OPERABLE DGs. <u>AND</u>	12 hours
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.4 Restore required DG to OPERABLE status.	14 days <u>AND</u> 17 days from discovery of failure to meet LCO
C. Two required DGs in Train A inoperable. <u>OR</u> Two required DGs in Train B inoperable.	C.1 Perform SR 3.8.1.1 for the offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	C.2 Declare required feature(s) supported by the inoperable DGs inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	C.3.1 Determine OPERABLE DGs are not inoperable due to common cause failure. <u>OR</u>	12 hours
	C.3.2 Perform SR 3.8.1.2 for OPERABLE DGs.	12 hours
	<u>AND</u>	(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.4 Restore at least one required DG to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
D. Two offsite circuits inoperable.	D.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition D concurrent with inoperability of redundant required features
	AND	
	D.2 Restore one offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One offsite circuit inoperable. AND One or more required DG(s) in Train A inoperable. OR One or more required DG(s) in Train B inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems Operating," when Condition E is entered with no AC power source to any train. ---------------------------- E.1 Restore offsite circuit to OPERABLE status. OR E.2 Restore required DG(s) to OPERABLE status.	 12 hours 12 hours
F. One or more required DG(s) in Train A inoperable. AND One or more required DG(s) in Train B inoperable.	F.1 Restore required DGs in Train A to OPERABLE status. OR F.2 Restore required DGs in Train B to OPERABLE status	2 hours 2 hours
G. Required Action and Associated Completion Time of Condition A, B, C, D, E or F, not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (Continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Two offsite circuits inoperable. AND One or more required DG(s) in Train A inoperable. OR One or more required DG(s) in Train B inoperable.	H.1 Enter LCO 3.0.3.	Immediately
I. One offsite circuit inoperable. AND One or more required DG(s) in Train A inoperable. AND One or more required DG(s) in Train B inoperable.	I.1 Enter LCO 3.0.3.	Immediately

BASES

ACTIONS

A.3 (continued)

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.

B.1 and C.1

To ensure a highly reliable power source remains with one or more DGs inoperable in Train A OR with one or more DGs inoperable in Train B, 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 a 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 and C.2

Required Actions B.2 and C.2 are 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 critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as the turbine driven auxiliary feedwater pump, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has inoperable DG(s).

The Completion Time for Required Actions B.2 and C.2 are 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

(continued)

BASES

ACTIONS

B.2 and C.2 (continued)

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one or more DGs inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one or more required DGs in Train A or one or more DGs in Train B inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DGs, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs 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, B.3.2, C.3.1 and C.3.2

Required Actions B.3.1 and C.3.1 provide an allowance to avoid unnecessary testing of OPERABLE DG(s). 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 other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition F of LCO 3.8.1 would be entered if the other inoperable DGs are not on the same train, otherwise, if the other inoperable DGs are on the same train, the unit is in Condition C. Once the failure is

(continued)

BASES

ACTIONS

B.3.1, B.3.2, C.3.1 and C.3.2 (continued)

repaired, the common cause failure no longer exists, and Required Actions B.3.1 and B.3.2 are satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), 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, B.3.2, C.3.1 or C.3.2, the corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 12 hour constraint imposed while in Condition B or C.

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 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.

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 restored OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on 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 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

ACTIONS

B.4 (continued)

In addition, the contingency actions listed in Bases Table 3.8.1-2 must be invoked whenever the outage period will extend beyond 72 hours.

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.

According to TVA's probabilistic safety analysis described in Reference 11, 12 hours is reasonable to confirm the OPERABLE DGs are not affected by the same problem as the inoperable DG.

C.4

According to Regulatory Guide 1.93, (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours.

In Condition C, the remaining OPERABLE DGs and offsite circuits 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. Restoration of at least one DG within 72 hours results in reverting back under Condition B and continuing to track the "time zero" completion time for one DG inoperable.

The second Completion Time for Required Action C.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 C is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to

(continued)

ACTIONS

C.4 (continued)

complete restoration of the LCO. The 6 day Completion Time provides a limit on 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 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action C.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 C was entered.

D.1 and D.2

Required Action D.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. This includes motor driven auxiliary feedwater pumps. Single train features, such as the turbine driven auxiliary pump, are not included in the list.

The Completion Time for Required Action D.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:

(continued)

ACTIONS

D.1 and D.2 (continued)

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition D (two offsite circuits inoperable) 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 D 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 (e.g., combinations that involve an offsite circuit and one DG inoperable, or one or more DGs in each train 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 plant 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

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

AC electrical power system capable of meeting its design criteria.

According to Reference 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.

E.1 and E.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 E are modified by a Note to indicate that when Condition E is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of one offsite circuit and one or more DGs in a train, 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 E for a period that should not exceed 12 hours.

In Condition E, 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 D (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)

F.1

With one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B 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 very 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, however, 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 Reference 6, with one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B inoperable, operation may continue for a period that should not exceed 2 hours.

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1 and I.1

Condition H and Condition I corresponds to a level of degradation in which all redundancy in the AC electrical power supplies cannot be guaranteed. At this severely degraded level, any further losses in the AC electrical

(continued)

BASES

ACTIONS

H.1 and I.1 (continued)

power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The plant 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 SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 9), as addressed in the FSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. 6800 volts is the minimum steady state output voltage and the 10 second transient value. 6800 volts is 98.6% of the nominal bus voltage of 6900 V corrected for instrument error and is the upper limit of the minimum voltage required for the DG supply breaker to close on the 6.9 kV shutdown board. The specified maximum steady state output voltage of 7260 V is 110% of the nameplate rating of the 6600 V motors. The specified 3 second transient value of 6555 V is 95% of the nominal bus voltage of 6900 V. The specified maximum transient value of 8880 V is the maximum equipment withstand value provided by the DG manufacturer. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Prior to performance of this SR in Modes 1 or 2, actions are taken to establish that adequate conditions exist for performance of the SR. The required actions are defined in Bases Table 3.8.1-2.

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. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the

(continued)

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion (GDC) 17, "Electrical Power Systems."

2. Watts Bar FSAR, Section 8.2, "Offsite Power System," and Tables 8.3-1 to 8.3-3, "Safety-Related Standby Power Sources and Distribution Boards," "Shutdown Board Loads Automatically Tripped Following a Loss of Nuclear Unit and Preferred Power," and "Diesel Generator Load Sequentially Applied Following a Loss of Nuclear Unit and Preferred Power."

3. Regulatory Guide 1.9, Rev. 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. Watts Bar FSAR Section 6, "Engineered Safety Features."

5. Watts Bar FSAR, Section 15.4, "Condition IV-Limiting Faults."

6. Regulatory Guide 1.93, Rev. 0, "Availability of Electric Power Sources," December 1974.

7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

8. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 18, "Inspection and Testing of Electric Power Systems."

9. Regulatory Guide 1.137, Rev. 1, "Fuel Oil Systems for Standby Diesel Generators," October 1979.

10. Watts Bar Drawing 1-47W605-242, "Electrical Tech Spec Compliance Tables."

11. TVA's letter to NRC dated August 7, 2001, Technical Specification Change TS-01-04, Diesel Generator (DG) Risk Informed Allowed Outage Time (AOT) Extension

BASES (continued)

Bases Table 3.8.1-2
TS Action or Surveillance Requirement (SR) Contingency Actions

	Contingency Actions to be Implemented	Applicable TS Action or SR	Applicable Modes
1.	The stability of the offsite power system in the vicinity of WBN shall be verified. This action establishes that the power system is within "single contingency limits" and is capable of remaining stable upon the loss of any single component supporting the system.	Action B.4	1, 2, 3, 4
2.	The expected weather conditions for the outage/maintenance/testing period shall be established.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
3.	If during the outage/maintenance/testing period, a stability problem with the offsite power system arises or inclement weather (i.e., tornado watch or warning, heavy snowfall, etc.) is experienced, the activity is to be suspended or postponed, if possible.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
4.	During the outage/maintenance/testing period the following equipment should not be removed from service concurrent with the DGs; 1) the transformer room ventilation, 2) the 6.9-kV board room ventilation, 3) the Unit 2 480V shutdown board room ventilation. If the equipment must be removed from service during a DG outage, the compensatory measures contained in System Description N3-30AB-4001, "Auxiliary Building Heating, Ventilation, Air Conditioning," shall be implemented.	SR 3.8.1.14 Action B.4	1, 2 1, 2, 3, 4
5.	During the outage/maintenance/testing period the Reactor Trip Breakers are not to be removed from service concurrent with a DG.	Action B.4	1, 2, 3, 4
6.	During the outage/maintenance/testing period the turbine-driven auxiliary feedwater pump shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4
7.	During the outage/maintenance/testing period the AFW discharge supply valves to the steam generators shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4
8.	During the outage/maintenance/testing period the opposite train RHR pump shall not be removed from service concurrent with a Unit 1 DG.	Action B.4	1, 2, 3, 4

ENCLOSURE 5

TECHNICAL SPECIFICATION CHANGE TS-01-04
DIESEL GENERATOR (DG) RISK INFORMED
ALLOWED OUTAGE TIME (AOT) EXTENSION

COMMITMENT LIST

1. Once Revision 3 of the PSA is finalized and pertinent comments dispositioned, TVA plans to compare the evaluation findings developed as a basis for this amendment to a similar evaluation based on Revision 3. The results of this review will be provided by December 14, 2001, to NRC as a supplement to this amendment request.