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December 6, 2004

TVA-BFN-TS-426

10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop: OWFN P1-35
Washington, D.C. 20555-0001

Gentlemen:

In the Matter of	)	Docket No. 50-259
Tennessee Valley Authority	)	

BROWNS FERRY NUCLEAR PLANT (BFN) UNIT 1 - TECHNICAL SPECIFICATION (TS) CHANGE TS 426 - REVISION TO DIESEL GENERATORS ALLOWED OUTAGE TIME

Pursuant to 10 CFR 50.90, Tennessee Valley Authority (TVA) is submitting a request for a TS change (TS 426) to license DPR-33 for BFN Unit 1. The proposed change revises the current Unit 1 diesel generators (DGs) TS seven day allowed outage time (AOT) to 14 days. The purpose of increasing the AOT is to provide additional flexibility for preventive or corrective maintenance and repair of the DGs.

TVA has evaluated the proposed extension of the Unit 1 DG TS AOT based upon both a deterministic evaluation and a risk-informed assessment. The deterministic evaluation concluded the proposed change is consistent with the defense-in-depth philosophy, in that:

- TVA's off-site power distribution is diverse and provides dependable sources of power to BFN;

- The on-site standby power system is reliable, has redundancy and is capable of compensating for an out-of-service DG; and

- BFN uses a proceduralized risk-based approach for scheduling maintenance, which limits removal of risk sensitive equipment from service during DG outages.

The deterministic evaluation concluded the proposed change will not adversely affect the reduction in severe accident risk achieved with the implementation of the Station Blackout Rule or affect any of the safety analyses assumptions or conclusions described in the Updated Final Safety Analysis Report. This ensures the protection of the public health and safety.

The risk-informed assessment concluded the increase in plant risk is small. The proposed change results in a negligible increase in the Unit 1 Core Damage Frequency and the Large Early Release Frequency. Thus, the proposed change is consistent with:

- The NRC's "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Volume 51, Page 30028 (51 FR 30028), dated August 4, 1996;

- Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1; and

- Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 0.

When taken together, the results of the deterministic evaluation and risk-informed assessment provide a high degree of assurance that the DGs will remain capable of performing their safety function with the proposed AOT.

NRC has previously approved this proposed TS change on BFN Units 2 and 3 (References 1 and 2) and this change is necessary to ensure fidelity with the Units 2 and 3 TS. As part of the application for Units 2 and 3, TVA committed to provide justification for extending the AOT prior to restarting Unit 1. Therefore, the proposed TS change is necessary to support the restart of Unit 1. TVA requests the amendment be approved by December 6, 2005 and that the implementation of the revised TS be within 60 days of NRC approval.

TVA has determined there are no significant hazards considerations associated with the proposed TS change and the change qualifies for a categorical exclusion from environmental review pursuant to the provisions of 10 CFR 51.22(c)(9). Additionally, in accordance with 10 CFR 50.91(b)(1), TVA is sending a copy of this letter and attachments to the Alabama State Department of Public Health.

Enclosure 1 provides TVA's evaluation of the proposed change. Enclosure 2 provides a mark-up of the proposed TS changes. Enclosure 3 provides retyped TS pages that incorporated the proposed change.

There are no regulatory commitments associated with this submittal. If you have any questions about this amendment, please contact me at (256)729-2636.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 6, 2004.

Sincerely,

ORIGINAL SIGNED BY:

T. E. Abney
Manager of Licensing
and Industry Affairs

References:

1. NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 2 and 3 - Issuance of Amendments Regarding Authorization of 14 day Allowable Outage Time for Emergency Diesel Generators (TAC Nos. M98205 and M98206)," August 2, 1999.

2. NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 2 and 3 - Supplement to Safety Evaluation Relating to Approval of 14 day Allowable Outage Time for Emergency Diesel Generators (TAC Nos. M98205 and M98206)," September 23, 1999.

Enclosures:
1. TVA Evaluation of Proposed Change
2. Proposed Technical Specification Changes (mark-up)
3. Proposed Technical Specification Changes (retyped)

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Enclosure 1

Ferry Nuclear Plant (BFN) Unit 1
Technical Specification (TS) Change TS 426
Revision to Diesel Generators Allowed Outage Time

TVA Evaluation of Proposed Change

INDEX

1.0 DESCRIPTION

This letter requests an amendment to Operating License DPR-33 for BFN Unit 1. The proposed change revises the current diesel generators (DGs) TS seven day allowed outage time (AOT) to 14 days. The increased AOT will provide additional flexibility for preventive or corrective maintenance of the DGs and consistency with the current Units 2 and 3 TSs. TVA previously committed to provide justification for extending the AOT prior to restarting Unit 1. Therefore, the proposed TS change is necessary to support the restart of Unit 1. TVA requests the amendment be approved by December 6, 2005 and that the implementation of the revised TS be within 60 days of NRC approval.

2.0 PROPOSED CHANGE

The proposed change revises the current Unit 1 DGs TS seven day AOT to 14 days. The specific changes are described below:

> Revise Unit 1 TS Page 3.8-3:
>
> In the COMPLETION TIME for REQUIRED ACTION 3.8.1.B.4, 14 days is substituted for the existing 7 days.

A mark-up of the TS showing the proposed changes is provided in Enclosure 2. Enclosure 3 provides retyped TS page that incorporated the proposed change.

3.0 BACKGROUND

On March 12, 1997, TVA submitted an application for BFN Units 2 and 3 to extend the AOT from seven days to 14 days for an inoperable DG (Reference 1). NRC requested and TVA provided additional information to support the amendment (References 2 through 7). On August 2, 1999, as supplemented on September 23, 1999, NRC approved the extension of the AOT (References 8 and 9).

The overall content of this submittal is based on:

- TVA's original application for Units 2 and 3;
- The subsequent responses to NRC requests for additional information; and

- The guidance contained in:
  - Regulatory Guide (RG) 1.174, Revision 1, and
  - RG 1.177, Revision 0.

This section contains:

1. The reason for the proposed Unit 1 TS change;
2. A description of TVA's offsite power distribution system for BFN;
3. The basis for the BFN station blackout off-site power group categorization;
4. A description of the BFN on-site standby power system;
5. The basis for the on-site emergency power system and station blackout category;
6. A discussion of DG testing;
7. An evaluation of possible transient conditions that could be caused by improper maintenance;
8. A description of the effect on DG unavailability due to the proposed change from a seven day to a 14 day DG AOT; and
9. A discussion of the applicability of the Maintenance Rule to the DGs.

Also included at the end of this section is a comparison of the proposed change, reason for change, background information, and technical analysis submitted in support of this proposed amendment with the information provided by TVA and approved by NRC for the Units 2 and 3 license amendments.

3.1 Reason for Proposed Unit 1 Change

The underlying reason for the Unit 1 TS change is the same as previously submitted for the Units 2 and 3 TS changes (i.e., to provide additional flexibility for performing scheduled or corrective maintenance on the DGs). Since Units 1 and 2 share four DGs, and the Units 2 and 3 TSs have already been revised to reflect a 14 day AOT, the proposed Unit 1 TS change will also ensure consistency with the current Units 2 and 3 TSs.

In general, the seven day AOT in the current Unit 1 TS is adequate for the planned and unplanned DG maintenance necessary to support the operation of Units 1 and 2. However, DGs are subject to a vendor recommended preventative maintenance (PM) program, which involves several periodic service and inspection activities, including a major PM outage every 12 years. The BFN DGs were manufactured by General Motors Electromotive Division (EMD) and the PM program is based on EMD recommendations.

The 12 year PM requires an extensive diesel engine disassembly, including removal of pistons, cylinder liners, and connecting rods. During the last BFN 12 year PM, the eight DGs were out of service for an average of 120.5 hours, with the longest diesel being out of service for 180.4 hours.

TVA's experience with the 12 year PM activities is limited by the infrequency of performance. However, the predicted schedule duration has considerably more uncertainty than routinely conducted activities and could encounter unexpected delays, thus raising the potential for exceeding the LCO. The extension of the seven day DG AOT to 14 days gives extra time for completing the task; thus reducing the risk of a TS forced reactor shutdown as a result of exceeding the seven day LCO. Partitioning the 12 year DG mechanical PM and electrical PM into two maintenance activities is not desirable from an overall DG availability perspective since this approach removes the DGs from service for a longer period of time than if performed as a combined activity. This is because setup, restoration, and post-maintenance testing associated with the maintenance are often duplicative, and must be repeated each time the DGs undergo maintenance. TVA has estimated the proposed combined outage approach can save 58 hours of outage time per DG. For the eight DGs, this is equivalent to a total of 464 hours (19.3 days), which represents a significant increase in overall DG availability.

TVA has considered scheduling the 12 year PM outages during refueling outages. However, Units 1 and 2 share four DGs and TVA does not intend to schedule simultaneous outages for these units. No more than two of the DGs could be serviced within a single refueling outage without extending the outage, since only one DG is removed from service at a time in order to minimize shutdown risk. There are also manpower constraints. Maintenance on DGs is performed by a limited number of experienced craftsmen due to the specialized nature of the maintenance. This manpower limitation likewise restricts working on more than one diesel generator at a time. Additionally, previous work experience indicates that shorter DG outages can be achieved by performing preventive maintenance while operating since work resources are focused on a single objective. This focus results in better planning of work, dedicated manpower allocation, and greater

resource availability for contingency work. For these reasons, it is desirable to be able to perform DG maintenance during power operations. A 14 day DG AOT is also justifiable as a contingency provision for major unexpected DG failures. This AOT would seldom be used since DG operating experience indicates major failures are uncommon.

3.2 Offsite Power Distribution System

TVA's offsite power distribution is diverse and provides a dependable source of power to BFN. The TVA transmission system is considered a diverse and dependable system due to the large generating capacity of TVA, the high number of transmission lines, and multiple interconnections. This results in a highly stable and reliable off-site power supply system for BFN. During more than 30 years of operation, there has never been a complete loss of off-site power event at BFN[(1)].

Off-site power is delivered to the site via seven 500-Kv and two 161-Kv transmission lines. These lines feed a 500-Kv switchyard and a 161-Kv switchyard as described in detail in Chapter 8.3 of the BFN Updated Final Safety Analysis Report (UFSAR).

The 500-Kv switchyard includes seven line bays and three transformer bays, and is designed to minimize the effects of the failure of individual items of equipment so any single probable event will not prevent the 500-Kv system from providing off-site power. The 500-Kv yard has two main buses, which are physically separated, and each bus has two sections connected by a disconnect. Each transformer can back feed from either bus. 4.16-Kv station service is provided via the unit Main Transformers and two Unit Station Service Transformers on each unit.

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1 On March 5, 1997, Unit 3 was in a refueling outage with the preferred offsite power source from the 500-kV switchyard unavailable due to scheduled maintenance of the Unit 3 Main Bank 500-kV transformer. This maintenance can only be performed when the Unit 3 generator is not in operation. In this situation, offsite power was being provided to Unit 3 exclusively via the 161-kV system. A loss of the 161-kV lines to Unit 3 was caused by a workmanship error on an unrelated piece of plant equipment and, thus, did not originate from the TVA transmission system. Details are provided in Licensee Event Report 50-296/97001 dated April 4, 1997, which states that the event had minimal impact on Unit 3. Unit 2 was at full power and was unaffected by the loss of the 161-kV supply. Therefore, the event is not considered a complete loss of power event for BFN.

Off-site power is also received from the 161-Kv TVA grid via two separate transmission lines, the Trinity and Athens lines. The 161-Kv switchyard includes four line bays with physically separated feeders to Common Station Service Transformers which step down the voltage to station service levels (4.16-Kv). The large number of 500-Kv and 161-Kv transmission lines, and the physical separation of the lines and transformer bays minimizes the likelihood of power loss due to loss of transmission lines.

3.3 Station Blackout Off-Site Power Group Categorization

The redundancy of the TVA transmission system coupled with a diverse off-site power supply and site distribution system provides highly reliable sources of auxiliary power which, in turn, minimizes the potential for Loss of Offsite Power events. This configuration, as expected, results in a favorable off-site power categorization for BFN for 10 CFR 50.63 Station Blackout (SBO) rule applicability as summarized below.

Nuclear Utility Management and Resource Council (NUMARC) 87-000 "Guidelines for and Technical Basis for NUMARC Initiatives for Addressing Station Blackout at Light Water Reactors" provides criteria for characterizing the susceptibility of plants to loss of offsite power events for the SBO rule. Application of the criteria results in categorizing plants into Off-site Power Design Characteristic Groups of P1, P2, or P3 which go from least to most susceptible to loss of offsite power events respectively. This Off-site Power Design Characteristic Group is a function of three separate subgroup factors. These are the Off-site Power System Independence (I) Group, the Severe Weather (SW) Group, and the Extremely Severe Weather (ESW) Group. The I Group relates to the site susceptibility to grid-related loss of offsite power events. The ESW and SW groups relate to the likelihood of loss of offsite power events due to abnormal weather.

NUMARC 87-000 criteria classifies BFN as an Independence Group I category site which is the least susceptible category to loss of offsite power events due to grid-related disturbances. This favorable categorization is based on physical separation of BFN switchyards and off-site transmission lines.

The SW Group relates to the likelihood of a loss of offsite power event due to severe weather conditions and is a combined factor based on snowfall, tornado frequency, severe storms, and salt spray. This factor is also influenced by having multiple right-of-ways for transmission lines. The SW category for BFN is Group 2 which is the second most favorable category out of five possible groups with respect to the probability of losing off-site power due to severe weather.

The ESW category relates to the likelihood of a loss of offsite power event due to extreme weather conditions. ESW is based on the probability of experiencing wind speeds greater than 125 miles per hour at the site. BFN is categorized as an ESW Group 1 site which places BFN in the category of plants least likely to lose off-site power because of extremely severe weather.

These three factors combine to result in an Off-site Power Design Characteristic Group of P1 for BFN which is the category of plants with the least susceptibility for loss of offsite power events. NRC has previously accepted this characterization for BFN as discussed in the July 11, 1991 and September 16, 1992, Safety Evaluation Reports for the SBO rule.

3.4 On-site Standby Power System

The on-site standby power system has redundancy and is capable of compensating for an out-of-service DG.

The on-site distribution of power is described in UFSAR Section 8.4. During normal operation station, auxiliary power is provided by the main generator through the Unit Station Service Transformers. If the unit is not operating, auxiliary power is provided from the 500-Kv switchyard through the Main Transformer and Unit Station Service Transformers. Auxiliary power is also available from the 161-Kv system via the two Common Station Service Transformers.

For Units 1 and 2, failure of a preferred off-site circuit from the 500-Kv switchyard will result in an automatic transfer of safety-related loads to the alternate units' Unit Station Service Transformers if voltage is available. Otherwise, they will transfer along with the nonsafety-related loads to the Common Station Service Transformers. For Unit 3, failure of the 500-Kv source will result in the transfer of both safety and non-safety loads to the Common Station Service Transformers. If no off-site power is available, safety-related loads only will transfer to the standby diesel generators. The large number of available power sources, switchyard arrangement, and physical separation of transmission lines, buses, and station transformers provides a highly redundant and reliable off-site and on-site power system.

3.5 Basis for the On-Site Emergency Power System and Station Blackout Category

The BFN emergency on-site power (Standby Alternating Current) system consists of eight diesel generators, and the associated distribution and transfer systems. The shutdown bus arrangement and distribution system for the diesel generators is described and shown in detail in Section 8.5 of the UFSAR.

The DGs are arranged such that four provide standby power to Units 1 and 2, and four are in standby service for Unit 3. Through use of 4-Kv Shutdown Buses 1 and 2, and the 4-Kv Bus Tie Board, any DG can be cross connected with any 4-Kv Shutdown Board. These alignment actions can be performed from the control room for the Shutdown Buses or from an electrical board room for Bus Tie Board transfers. This arrangement provides considerable flexibility in supplying emergency AC power.

With regard to the SBO rule, BFN has been categorized by NRC as an Emergency Alternating Current (EAC) Category "C" plant. This classification was based on requirements for shutting down all three units for an extended period following a loss of offsite power. This "C" category translates to a SBO coping duration of four hours and a DG target reliability of 0.95 for BFN.

3.6 Diesel Generator Testing

Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. Surveillance Requirement (SR) 3.8.1.5 demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The largest single load for each DG is a residual heat removal pump (2000 hp).

Load rejection testing would also be performed if the DG governor or voltage regulator was replaced or if major maintenance work was performed involving these devices. Load rejection testing would typically not be performed following mechanical PM activities such as the 12 year vendor recommended PM.

The DG load rejection surveillance test is performed as part of the DG Load Acceptance Test (LAT). During the DG LATs, the 480-V Accident Load Shedding Logic is initiated which, for certain DGs, adversely affects normal plant operations, since various loads essential for continued plant operation are automatically shed. Because of this, the A and C DG LATs are not performed while Unit 1 is operating and the B and D DG LATs are not performed

while Unit 2 is operating. For Unit 3, the 3A and 3C DG LATs have a similar effect and, therefore, are performed during Unit 3 refueling outages. The LATs (and associated load reject surveillance tests) for DGs 3B and 3D are performed with Unit 3 in operation.

The single largest load reject surveillance tests are performed with their respective 4-kV Shutdown Board isolated from the offsite power system and must meet the operating response criteria of TS SR 3.8.1.5 which is repeated below:

> Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and:
>
> a. Following load rejection, the frequency is ≤ 66.75 Hz; and
>
> b. Following load rejection, the steady state voltage recovers to ≥ 3940 V and ≤ 4400 V.
>
> c. Following load rejection, the steady state frequency recovers to ≥ 58.8 Hz and ≤ 61.2 Hz.

Specific DG testing requirements for PM activities and corrective maintenance activities are defined by the TS and by the nature of the maintenance activity. The ability to conduct DG tests while operating is based on plant systems response, and is not related to the TS request for a longer DG AOT. As noted above, for certain DGs, load reject testing is routinely performed with the BFN units in operation. If load rejection testing is required during operation, the DG along with its associated 4-kV Shutdown Board can be isolated and the testing performed with minimal impact on plant electrical systems.

3.7 Possible Transient Conditions Caused by Improper Maintenance

Improper operation of a DG due to improper maintenance (e.g., governor problems or voltage regulator problems) would be corrected in a similar manner whether detected after a corrective maintenance activity or during routine surveillance tests. Load rejection testing would be performed if the governor or voltage regulator was replaced or if major maintenance work was performed involving these devices, and would be completed while the DG was isolated from the plant electrical system.

If initial testing indicated that either device required adjustment, the DG would be started and adjustments would be made prior to connecting to the 4-kV Shutdown Board. The DG would then be tied to the 4-kV Shutdown Board and gradually loaded and the responsiveness checked while closely monitoring governor and voltage regulator performance. Should the DG become unstable during testing it would be promptly isolated. Any instability should be identified at minimum DG loading and isolation of the DG would not result in significant system perturbations.

Depending on the nature of a governor (or voltage regulator) malfunction, testing might also include the starting of an RHR pump motor (largest single load) and then disconnecting the RHR pump (largest load reject). These tests are conducted with the 4-kV Shutdown Board isolated from offsite power. Data obtained from this testing can then be compared to data obtained from previous similar DG tests to confirm proper governor (or voltage regulator) operation. This testing approach is straightforward and from past operating experience has proven to be a reliable means to assess DG performance while avoiding possible transients. In addition, required TS operability surveillance tests will be performed before the DG is declared fully operable.

As noted previously, the above testing is performed with the respective 4-kV Shutdown Board isolated from its offsite power source. Therefore, there will be no impact on electrical systems during the testing other than the RHR pump motor that is being started. Also, the ability to conduct DG tests while operating is based on plant systems response, and is not related to the TS request for a longer DG AOT.

3.8 Calculation of Diesel Generator Unavailability Due To 14-Day Diesel Generator Allowed Outage Time

The previously approved Units 2 and 3 submittal was based on the BFN DG unavailability statistics from the Maintenance Rule database from May 1994 through February 1999. The data utilized to support the Units 2 and 3 submittal includes the unavailability due to the 12 year vendor recommended preventive maintenance outages for all eight DGs. For this time period the data shows the total unavailability was 0.01660 per DG comprised of an average planned unavailability of 0.01374 (83%) and an average unplanned unavailability of 0.00286 (17%). The 12 year vendor recommended PM contribution to the net unavailability was an average of 120.5 hours per DG. Since the data does not include a full 12 years of data (the data includes an average of over four years), the unavailability value on an annual basis was higher than normal since the 12 year vendor outages are included. The 12 year PM is the longest of all planned PM outages.

This Unit 1 submittal is based on the BFN DGs unavailability statistics from May 1994 through May 2004. The Unit 2 and Unit 3 TSs had a seven day AOT through July, 1999 and a 14 day AOT thereafter. In the period in which experience data is available, one 12 year PM was performed on each diesel between January and March 1998 when the seven day AOT was in effect. The data for all eight DGs was pooled to develop maintenance unavailability values for three cases; seven day AOT data only, 14 day AOT data only, and the totals for all data. The results are shown below. For the comparison presented below, the 12 year PM outage time was subtracted from the seven day AOT data and total data values to make them compatible with the 14 day AOT values. There has been no 12 year PM performed under the 14 day AOT.

	UNITS 2 AND 3 SUBMITTAL WITH 12 YEAR PM	SEVEN DAY AOT DATA WITHOUT 12 YEAR PM	14 DAY AOT DATA WITHOUT 12 YEAR PM	TOTAL DATA WITHOUT 12 YEAR PM
Planned unavailability	0.01374	0.01241	0.01065	0.01093
Unplanned unavailability	0.00286*	0.00267E**	0.00177	0.00221
Total unavailability	0.01660	0.01508	0.01242	0.01315

* Data period is May 1994 through February 1999

** Data period is May 1994 August 1999

The above results show the planned and unplanned DG maintenance fractions for the most recent, 14 day AOT data, are actually lower than for the earlier seven day AOT data. This reflects plant maintenance improvements unrelated to the AOT. The relative contribution of planned and unplanned data is about the same for the three sets of data.

For the evaluation of expected total unavailability, the DG AOT is assumed changed from seven days to 14 days with Unit 1 operating. To consider the impact of this change, the most recent DG experience data for the 5 year period when the 14 day AOT was in effect (i.e. since August 1999) is used, and then modified to consider what the DG maintenance unavailability would have been if the seven day AOT was maintained. In order to conservatively maximize the impact, a seven day base case was extrapolated from the 14 day data.

UNPLANNED, PLANNED, 12 YEAR PREVENTATIVE MAINTENANCE AND TOTAL UNAVAILABILITY

	SEVEN DAY AOT BASE CASE	REQUESTED UNIT 1 14 DAY AOT CASE	COMMENT REGARDING BASE CASE AND 14-DAY
Unplanned unavailability	Scaled down actual data from most recent five years by AOT ratio (0.00177) x (14-7)/14 = 0.00089	Used actual data from most recent five years when 14-Day AOT was applied 0.00177	Maximized delta. Actual experience in recent ten years indicates this is conservative.
Planned unavailability not including 12 yr PM	Historical data when 14 day AOT was in effect 0.01065	Historical data when 14 day AOT was in effect 0.01065	No change identified. Most recent data reflects current plant maintenance policies.
12 year PM unavailability	Historical data when 7 day AOT was in effect 0.00114	Assumed the full 14 day duration 0.00320	Maximizes delta. Bounds potential increase in maintenance times due to relaxed AOT.
Total unavailability	0.01268	0.01562	

For the requested 14 day AOT during Unit 1 operation, the approach used the actual maintenance data fractions and a conservative 14 day period assumed for each 12 year PM outage. This bounding assumption is made, even though the actual experience data from 1998 indicates an average of five days for such outages. The conservative assumption bounds the possibility the relaxed AOT would lead to increased outage times. This is consistent with the previous work performed in support of the 14 day AOT for operation of Units 2 and 3.

3.9 Applicability of the Maintenance Rule to the Diesel Generators

TVAN Standard Programs and Processes (SPP) 6.6, "*Maintenance Rule Performance Indicator Monitoring, Trending and Reporting – 10 CFR 50.65*," TVAN Common Technical Procedure NETP-100, "*Emergency Diesel Generator Reliability Program*" and Technical Instruction 0-TI-346, "*Maintenance Rule Performance Indicator Monitoring, Trending, And Reporting - 10CFR50.65*," provide guidance for initiation, analysis, retrieval, trending, and reporting of data relative to plant level, function specific, and repetitive preventable functional failure indicators of performance required by the Maintenance Rule. The requirements of these procedures are in compliance with 10 CFR 50.65, "*Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*," and NUMARC 93-01, "*Industry Guideline for*

Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Specific performance criteria have been developed for the following Standby Diesel Generator system functions:

> To provide a source of power for the Engineered Safeguards Systems (ESS) such that no single credible failure can disable the core standby cooling functions or their supporting auxiliaries (Risk Significant).

Each DG is required to maintain an unavailability factor of less than or equal to 0.0342 as monitored over a 24 month rolling interval. The performance of diesel support systems (ventilation, starting air, and 125 VDC system) are included in this performance criteria since a DG is not considered operable if its supporting systems are not operable.

3.10 <u>Comparison with Previous TS Changes for Unit 2 and 3</u>

TVA has compared the proposed change, reason for change, background information, and technical analysis submitted in support of this proposed amendment with the information provided by TVA and approved by NRC in References 1 through 9 for the revision to the Units 2 and 3 DG TS AOTs. The comparison for each of these areas is provided below:

- The proposed change to the Unit 1 TS is the same change as proposed and approved for Units 2 and 3.

- The underlying reason for the Unit 1 TS change is the same as previously submitted for the Units 2 and 3 TS change (i.e., to provide additional flexibility for performing maintenance on the DGs). Since Units 1 and 2 share four DGs, TVA needs to maximize consistency between the Units 1, 2 and 3 TSs, operations and maintenance practices prior to restarting Unit 1.

- The background information provided in support of the Unit 1 TS change incorporates the same elements previously submitted in support of the Units 2 and 3 TS changes. The changes since the previous submissions are outlined below:

  - The description of the proposed amendment has been updated to reflect the timeframes associated with the most recent 12 year PM performed on the DGs;

  - The basis for the on-site emergency power system and station blackout category has not changed since the Units 2 and 3 submissions;

   - The discussion of DG testing has been updated to reflect three unit operation;

   - The Unit 1 Probabilistic Safety Assessment (PSA) used to evaluate this proposed change reflects three unit operation at Extended Power Uprate (EPU) conditions;

   - The consideration of unexpected weather or grid conditions when performing extended DG maintenance outages has been updated to reflect the current work control program; and

   - The description of the risk management program used to evaluate on-line maintenance has been updated to reflect the current work control program.

- The technical analysis submitted for this Unit 1 TS change incorporates the same elements previously submitted in support of the TS changes for Units 2 and 3. These elements and changes since the previous submissions are outlined below:

   - Operational status of Unit 1

     At the time the Units 2 and 3 submittals were made, Unit 1 was in an indefinite non-operational status. Accordingly, the eight DGs at the BFN stations were available to support two operational units. The impact of returning Unit 1 to operational status is discussed in this submittal.

   - TVA's off-site power distribution remains diverse and provides a dependable source of power to BFN

     The offsite power distribution system and the Station Blackout Offsite Power Group Categorization have not changed since the Units 2 and 3 submissions. However, the information was updated to reflect the most recent transmission system study.

   - BFN uses a proceduralized risk-based approach for scheduling maintenance which limits removal of risk sensitive equipment from service during DG outages

     The discussion of proceduralized risk-based controls for maintenance activities has been enhanced to reflect the more stringent controls implemented in response to the Maintenance Rule (10 CFR 50.65).

- PSA Results

  Core Damage Frequency, Large Early Release Frequency, Incremental Conditional Core Damage Probability and Incremental Conditional Large Early Release estimates for the 14 day DG AOT are provided based on the Unit 1 PSA model which considers three unit operation.

- Risk-informed Information

  The content of the application has been expanded to include additional information to address the guidance contained in RGs 1.174 and 1.177.

4.0 TECHNICAL ANALYSIS

The following technical analysis demonstrates a 14 day DG AOT maintains an adequate defense in depth and sufficient safety margins. The resulting increase in core damage frequency and risk are small and consistent with the intent of the Commission's Safety Goal Policy Statement and the regulatory position contained in RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

4.1 Compliance with Current Regulations

The onsite AC power system complies with the applicable NRC General Design Criteria and AEC/NRC Safety/RGs as described in the Safety Evaluation of the Tennessee Valley Authority Browns Ferry Nuclear Plant Units 1, 2 and 3, dated June 26, 1972, as supplemented, and Chapter 8 of the UFSAR. The proposed extension of the Unit 1 DG AOT to be consistent with the Units 2 and 3 DG AOT does not add or delete any safety-related systems, equipment, or DG loads, or alter the design or function of the onsite AC power system. Therefore, compliance with the applicable NRC General Design Criteria and AEC/NRC Safety/RGs as described in the above correspondence is not affected by this proposed change.

4.2 Deterministic Engineering Evaluation

4.2.1 Defense in Depth

As described below, the impact of the proposed extension of the Unit 1 DG TS AOT was evaluated and is consistent with the defense-in-depth philosophy and ensures the protection of the public health and safety. The limited unavailability of a single backup power source does not significantly change the balance

among the defense-in-depth principles of prevention of core damage, prevention of containment failure, and consequence mitigation. The BFN offsite and onsite AC Power systems are robust and diverse. Administrative controls ensure system redundancy. Independence and diversity are maintained during the increased DG AOT. The potential for a common cause failure is not increased and the independence of physical barriers is not degraded. Defenses against human errors are maintained. Compliance with the applicable NRC General Design Criteria and AEC/NRC Safety/RGs is not affected by this proposed change.

4.2.1.1 Overall Philosophy

The impact of the proposed extension of the Unit 1 DG TS AOT was evaluated and determined to be consistent with the defense-in-depth philosophy. The limited unavailability of a single backup power source does not significantly change the balance among the defense-in-depth principles of prevention of core damage, prevention of containment failure, and consequence mitigation. The proposed change does not introduce the possibility of new accidents or transients; nor increase the likelihood of an accident or transient.

4.2.1.2 Strength of Overall Plant Design

The proposed extension of the Unit 1 DG TS AOT is not being requested to compensate for a weakness in plant design. The robustness of the BFN AC Power systems is demonstrated in two ways. First, the TVA off-site power distribution system supplying BFN has diversity and provides reliable service. Second, the on-site auxiliary and standby power systems are reliable, have redundancy and compensate for an out-of-service DG.

TVA’s offsite power distribution is diverse and provides a dependable source of power to BFN. Offsite power is delivered to the site via seven 500-Kv and two 161-Kv transmission lines. The large number of available power sources, switchyard arrangement, and physical separation of transmission lines, buses, and station transformers provides a highly redundant and reliable offsite power system.

Transmission system transient stability studies are periodically performed which include an analysis of the effects of a three-phase fault on a generator terminal during which the unit is disconnected automatically from the system as a result of a disturbance, the loss of TVA's largest generating unit, and the loss of a BFN unit. These studies show the transmission system remains stable with negligible disturbance to the offsite power system. Similarly, steady-state studies show the 500-Kv and 161-Kv networks are capable of supplying offsite power requirements for normal, shutdown, and accident conditions.

Due to the large number of diverse generating units and strong interconnections, the likelihood of the transmission system causing the loss of all offsite power is considered to be extremely remote. The Unit 1 PSA uses a loss of offsite power frequency of 6.43E-03 per year for modeling purposes. This value is based on generic industry data with plant specific Bayesian updates. BFN has never experienced a complete loss of offsite power in more than 30 years of operation.

TVA's Transmission Planning Department performs comprehensive transmission system studies for all TVA nuclear plants. These studies include load flow analyses and transient stability studies, and are performed in accordance with the industry accepted guidelines for transmission system studies. This periodic study verifies the capability of offsite power supplies to each nuclear plant. The last periodic evaluation for BFN was completed in June 2004. The transmission system study was performed, considering the increase in electrical output of the three units (EPU conditions), to demonstrate conformance to General Design Criterion (GDC) 17 and to analyze for unit/grid stability. The study documented that no additional changes are required for Browns Ferry's offsite power system to continue to meet GDC 17 requirements. Analyses in the study also determined operation at EPU electrical outputs will not have a significant adverse effect on reliability of the offsite electrical system or on the stability of the BFN units (Reference 10).

The onsite standby power system is reliable, has redundancy and is capable of compensating for an out-of-service DG. Eight DGs, (four for Units 1 and 2, and four for Unit 3) are provided as a standby power supply to be used on loss of the Normal Auxiliary Power System. Each DG is assigned primarily to one 4kV shutdown board. It is possible, through breaker ties to the shutdown buses, to make any DG available to any 4kV shutdown board. All AC loads necessary for the safe shutdown of the plant under accident or non-accident conditions are fed from this distribution system.

BFN has several performance goals associated with the DGs, which emphasize minimizing DG unavailability and maximizing reliability. The target reliability for DGs under the SBO rule is 0.95. The Maintenance Rule DG unavailability performance criterion is established at 0.0342 (12.5 days per year). The results show the planned and unplanned DG maintenance fractions for the most recent, 14 day AOT data, are actually lower than for the earlier seven day AOT data. This reflects plant maintenance improvements unrelated to the AOT.

From these goals and achievements, it is clear there is considerable emphasis on maximizing DG availability which can only be achieved by minimizing DG outages. Therefore, while the proposed change increases the current seven day DG AOT, the real DG unavailability will not significantly rise due to the emphasis placed on meeting the various DG performance goals.

4.2.1.3 System Redundancy, Independence and Diversity

As described below, administrative controls ensure system redundancy, independence and diversity are maintained commensurate with the expected frequency and consequences of challenges to the on-site standby power system:

A. Restrictions are placed on simultaneous equipment outages that would erode the principles of redundancy and diversity;

B. Voluntary removal of equipment from service is not scheduled when adverse weather conditions are predicted or at times when the plant may be subjected to other abnormal conditions.

These administrative controls are described in more detail below:

A. TVA uses proceduralized risk-based approaches for scheduling maintenance for all modes of plant operation, which limits removal of risk sensitive equipment from service.

   SPP 7.1, “Work Control Process”, defines the risk assessment methodology that is used for Power Operations (Mode 1) and Startup (Mode 2). For on-line maintenance a risk assessment is performed before implementation and emergent work is evaluated against the assessed scope. For those SSCs modeled in the PSA, the following risk thresholds are established with approval/ actions described below:

   - Incremental core damage probability (ICDP) greater than 1E-05 should not be entered voluntarily(RED);

- ICDP greater than 5E-06 but less than 1E-05, assess non quantifiable factors, establish risk management actions per 3.5.2.1 (ORANGE);

- ICDP greater than 1E-06 but less than 5E-06, assess non quantifiable factors, establish risk management actions per 3.5.2.1 (YELLOW); and

- ICDP less than 1E-06, no separate risk management plans or approval are required (GREEN).

Activities requiring risk management actions include, as appropriate, actions to provide risk awareness and control, actions to reduce duration, and actions to reduce magnitude of risk increase. These actions might include:

- Discussion of activity with operating shift approval of planned evolution;

- Pre-job briefing of maintenance personnel emphasizing the risk aspects of the evolution;

- Presence of appropriate technical personnel for appropriate portions of the activity;

- Pre-staging of parts and materials;

- Walk down tagout and activity prior to conducting maintenance;

- Conduct of training and mock ups to familiarize personnel with the activity;

- Perform activity around the clock;

- Establish contingency plans to restore the out of service rapidly, if needed;

- Minimizing other work in areas that could affect event initiators (e.g. reactor protection system areas, switchyard, DG rooms, switchgear rooms) to decrease the frequency of initiating events mitigated by the safety function served by the out of service SSC;

- Minimize work in areas that could affect other redundant systems such that there is continued likelihood of the availability of the safety functions served by the SSCs in those areas;

- Establishment of alternate success paths for performance of the safety function of the out of service SSC (note; this equipment does not necessarily have to be in the scope of the Maintenance Rule per SPP-6.6); and

Risk management plans are required to be approved by senior plant management.

The process for risk assessments for outage activities is found in SPP-7.2, "Outage Management." The risk assessment process found in SPP-7.2 begins when the unit enters Hot Standby and applies to work performed during Hot Shutdown, Cold Shutdown, Refueling, and Defueled activities. However, site management may choose to continue to use the on-line process for forced outages based on duration, work scope, and other considerations if the plant does not go beyond hot shutdown.

Shutdown safety is an integral part of the Outage process. Shutdown safety is maintained and monitored by compliance with work in accordance with the outage schedule/plan. An assessment of the outage schedule/plan implementation and during the execution of the outage schedule/plan anytime the outage schedule logic is affected.

The assessment performed during the outage execution phase is performed through the plant schedule using Outage Risk Assessment Management (ORAM) software. The ORAM is an on-line computer program which qualitatively performs risk assessment and is sponsored by the Electric Power Research Institute (EPRI). This software takes the status (i.e. available, unavailable, protected, etc.) of key plant equipment and then produces an output of the relative level of safety/defense in depth of key shutdown areas (i.e., reactivity control, shutdown cooling, AC power (onsite, offsite), fuel pool cooling, inventory control, support equipment, etc.). The models which are built to support this software include fault trees which use a building block technology to identify specific components utilized to build a system utilized in maintaining a key safety function. The fault trees are then inputted into a SSFAT (Safety System Function Assessment Tree) to determine the number of required systems/components that are required to get a predetermined output for a given plant state/condition (i.e., green for adequate defense in depth [DID], yellow for slight reduction in DID, but still adequate, orange for significant reduction in DID, and a contingency plan must be in place prior to entry into this plant condition and red

for an inadequate level of DID and action must be taken to get out of this condition).

A team with broad extensive experience in the operation of the applicable unit with detailed knowledge of the applicable plant; and knowledge of shutdown safety issues affecting the nuclear industry as outlined in NUMARC 91-06 reviews the unit Outage Plan and detailed (Level 3) schedule to ensure that all shutdown safety issues are addressed and all reasonable actions have been taken to minimize shutdown risk. The assessment considers:

- TS requirements;

- The degree of redundancy available for performance of the key safety functions served by out of service Structures, Systems, and Components (SSCs);

- The duration of the activity;

- The likelihood of an initiating event or accident that would require the performance of the affected safety function;

- The likelihood that the activity will significantly increase the frequency of an initiating event requiring key safety functions;

- Component and system dependencies that are affected;

- Significant performance issues for the in service redundant SSCs;

- The risk impact of performing the maintenance during shutdown with respect to performing the maintenance at power;

- Performance of maintenance that will involve alterations to the facility or procedures for the duration of the maintenance activity. Examples of these alterations include jumpering terminals, lifting leads, placing temporary lead shielding on pipes and equipment, removal of barriers, and use of temporary blocks, bypasses, scaffolding and supports. The assessment considers the impact of these alterations on plant safety functions; and

- Whether the out-of-service SSCs could be promptly restored to service if the need arose due to emergent

conditions. This would apply to surveillance testing, or to the situation where the maintenance activity has been planned in such a manner to allow for prompt restoration. In these cases, the assessment will consider the time necessary for restoration of the SSC's function, with respect to the time at which performance of the function would be needed.

Other aspects of the shutdown risk assessment process are:

- The shutdown assessment is typically focused on SSCs "available to perform a function". Due to decreased equipment redundancies during outage conditions, the outage planning and control process may involve consideration of contingencies and backup methods to achieve the key safety functions, as well as measures that can reduce both the likelihood and consequences of adverse events;

- Assessments for shutdown maintenance activities need to take into account plant conditions and multiple SSCs out-of-service that impact the shutdown key safety functions. The shutdown assessment is a component of an effective outage planning and control process; and

- Maintenance activities that do not necessarily remove the SSC from service may still impact plant configuration and impact key safety functions. Examples could include:

  - A valve manipulation that involves the potential for a single failure to create a drain down path affecting the inventory control key safety function; or

  - A switchyard circuit breaker operation that involves the potential for a single failure to affect availability of AC power.

B. Administrative controls ensure that voluntary removal of equipments from service is not scheduled when adverse weather conditions are predicted or at times when the plant may be subjected to other abnormal conditions.

SPP 7.1, "Work Control Process", requires an assessment of scheduled activities be performed before implementation of a work window. The assessment includes external event considerations involving the potential impacts of weather or other external conditions relative to the proposed maintenance evolution if these external impacts (e.g., weather, external flooding, and other external impacts) are imminent or have a high probability of occurring during the planned out of service duration.

SPP-7.2, "Outage Management," states that emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a previously performed assessment. Examples include plant configuration or mode changes, additional SSCs out of service due to failures, or significant changes in external conditions (weather, offsite power availability). The following guidance applies to this situation:

- The safety assessment will be performed (or re-evaluated) to address the changed plant conditions on a reasonable schedule commensurate with the safety significance of the condition. Based on the results of the assessment, ongoing or planned maintenance activities may need to be suspended or rescheduled, and SSCs may need to be returned to service; and

- Performance (or re-evaluation) of the assessment should not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to restore the equipment to service or take compensatory actions.

4.2.1.4 Potential for Common Cause Failures

The proposed extension of the Unit 1 DG TS AOT does not add or delete any safety-related systems, equipment, or DGs loads, or alter the design or function of the onsite AC power system. Therefore, the potential for a common cause failure is not increased.

4.2.1.5 Independence of Physical Barriers

The proposed extension of the Unit 1 DG TS AOT does not affect fuel cladding, primary coolant systems, or containment. Therefore, the independence of physical barriers is not degraded.

4.2.1.6 Defense against Human Error

The proposed extension of the Unit 1 DG TS AOT does not affect any operator response to a postulated event. Due to the restart of Unit 1, maintenance on the Units 1/2 DGs will now have to be performed with at least one of the units in service. However, due to the highly specialized nature of DG maintenance, the same personnel would be performing the maintenance regardless of the duration of the DG AOT or whether or not the maintenance was being performed concurrent with outage activities. Therefore, defenses against human errors are maintained.

4.2.1.7 Compliance with General Design Criteria

The affect of the proposed extension of the Unit 1 DG TS AOT has no impact on compliance with General Design Criteria as discussed in Section 4.1, Compliance with Current Regulations.

4.2.2 <u>Safety Margins</u>

4.2.2.1 Codes and Standards

The proposed extension of the Unit 1 DG TS AOT remains consistent with the codes and standards applicable to the Browns Ferry AC power sources, except RG 1.93, as discussed in Section 4.1, Compliance with Current Regulations.

4.2.2.2 Safety Analysis and Final Safety Analysis Report Acceptance Criteria

The proposed extension of the Unit 1 DG TS AOT is consistent with the safety analysis and UFSAR acceptance criteria.

DG reliability and availability are monitored and evaluated with respect to Maintenance Rule (10 CFR 50.65) performance criteria to assure DG out of service times do not degrade operational safety over time. It should be noted that the DG unavailability hours incurred as a result of planned 12 year PM performed online during the proposed extended DG are exempt from reporting under the Regulatory Assessment Planned Unavailable Hours performance indicator (NEI 99-02, Revision 2).

SBO is defined as the complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. BFN is in the category of plants least likely to lose off-site power because of extremely severe weather, based on the Nuclear Utility Management and Resource Council (NUMARC) 87-000, "Guidelines for and Technical Basis for NUMARC Initiatives for

Addressing Station Blackout at Light Water Reactors", criteria for characterizing the susceptibility of plants to Loss of Off-site Power events for the Station Blackout rule. NUMARC 87-000 criteria also defines BFN as a Group I site which is the least susceptible category to loss of offsite power events due to grid-related disturbances. This favorable categorization is based on physical separation of BFN switchyards and off-site transmission lines. Therefore, BFN is unlikely to experience a loss of offsite power event due to weather or grid related phenomena.

To address the potential risk of core damage associated with an SBO event, the NRC issued the SBO Rule, which was promulgated as 10 CFR 50.63, "Loss of All Alternating Current Power," and RG 1.155, "Station Blackout." The ability to cope with an SBO for a certain time period provides additional defense-in-depth should both offsite and onsite emergency AC power systems fail concurrently.

TVA has eight DGs at the site. Three out of the eight are sufficient to achieve safe shutdown and provide power to sustain safe shutdown for an extended duration following loss of off-site power. In Reference 11, the NRC classifies the emergency alternating current group for BFN as "C" based on one out of two DGs (plus a portion of one of the other DG) required for safe shutdown during a loss of offsite power for each unit and a SBO coping duration of 4 hours at a DG target reliability of 0.95. The proposed extension of the Unit 1 DG AOT will not impact the SBO coping analysis since the DGs are not assumed to be available during the coping period. The assumptions used in the SBO coping analysis regarding DG reliability are unaffected by the proposed change since preventive maintenance and testing will continue to be performed to maintain the reliability assumptions.

UFSAR Section 8.5 includes the safety objectives, safety design basis, system description, safety evaluation, and inspection and testing of the Standby AC Power Supply and Distribution System. UFSAR Appendix F provides additional information to support the TS and the associated operating and emergency procedures in respect to shared systems. For example, certain pumps cannot be deliberately disabled for maintenance if certain DGs are concurrently disabled. The proposed extension of the Unit 1 DG TS AOT does not alter any description or conclusion reached in the UFSAR.

4.3 Evaluation of Risk Impact

4.3.1 Three Tiered Approach

In RG 1.177, the NRC staff identified a three-tiered approach for licensees to evaluate the risk associated with proposed DG TS AOT changes.

Tier 1 is an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in core damage frequency (CDF), the incremental conditional core damage probability (ICCDP), and, when appropriate, the change in large early release frequency (LERF) and the incremental conditional large early release probability (ICLERP).

Tier 2 is an identification of potentially high-risk configurations that could exist if equipment in addition to that associated with the change were to be taken out of service simultaneously, or other risk-significant operational factors such as concurrent system or equipment testing were also involved. The objective of this part of the evaluation is to ensure that appropriate restrictions on dominant risk-significant configurations associated with the change are in place.

Tier 3 is the establishment of an overall configuration risk management program to ensure that other potentially lower probability, but nonetheless risk-significant configurations resulting from maintenance and other operational activities are identified and appropriate compensation taken. If the Tier 2 assessment demonstrates, with reasonable assurance, that there are no risk-significant configurations involving the subject equipment, the application of Tier 3 to the proposed DG TS AOT may not be necessary. Although defense in depth is protected to some degree by most current TS, application of the three-tiered approach to risk-informed TS AOT changes discussed below provides additional assurance that defense in depth will not be significantly impacted by such changes to the licensing basis. TVA has evaluated the proposed extension of the Unit 1 DG TS AOT using the guidance of RG 1.177 and the results are provided below.

A. Tier 1, PSA Capability and Insights

Tier 1 is an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in CDF, the ICCDP, and when appropriate, the change in the LERF and ICLERP. The validity of the PSA, the PSA insights and findings, and a discussion of the uncertainty associated with these results are presented below.

Validity of the PSA

As discussed in References 10 and 12, the Browns Ferry Unit 1 PSA was performed incorporating analyses inputs, results, and the applicable modifications associated with the restart of Unit 1 at EPU power level. The Unit 1 PSA assumes that Units 2 and 3 are also operational at EPU power levels.

To ensure risk-significant effects of Unit 1 operation at EPU conditions are represented in the Unit 1 PSA, associated plant modifications were systematically reviewed to identify effects on the elements of a risk assessment. Specifically, modifications were reviewed with respect to their potential effect on the PSA model.

RG 1.174 provides the guidance framework for using PSA in risk-informed decisions for plant-specific changes to the licensing basis. The acceptance guidelines consider both the magnitude and size of the changes to CDF and LERF. The direct applicability of RG 1.174 to Browns Ferry Unit 1 is uncertain as the Unit 1 PSA represents the base case rather than a change from a preexisting base case. Nevertheless, the guidance offered by RG 1.174 does offer a framework in assisting in the interpretation of the numerical results of the PSA.

As stated in RG 1.174:

- "When the calculated increase in CDF is in the range of 10^{-6} per reactor year to 10^{-5} per reactor year, applications will be considered only if it can be reasonably shown that the total CDF is less than 10^{-4} per reactor year (Region II)."

- "When the calculated increase in LERF is in the range of 10^{-7} per reactor year to 10^{-6} per reactor year, applications would be considered only if it can be reasonably shown that the total CDF is less than 10^{-5} per reactor year (Region II)."

As shown below, the total CDF for Browns Ferry Unit 1 is below the guideline value of 10^{-4} per reactor year. Also, as shown below, the total LERF for Browns Ferry Unit 1 is below the guideline value of 10^{-5} per reactor year.

As previously provided by Reference 12, Browns Ferry Unit 1 CDF and LERF are:

- Total CDF (yr-1, mean value) = 1.86 E-6

- LERF (yr-1, mean value) = 1.87 E-7

Uncertainty Analysis

An uncertainty analysis was performed to more fully quantify the core damage frequency. The mean core damage frequency is 1.86E-6 per year. The fifth percentile is 5.37E-7 while the ninety-fifth percentile is 4.80E-6.

The plant-specific MAAP model was used to support the system success criteria determination and sequence timing. The RISKMAN™ integrated PSA computer code was used to perform the necessary data and system analyses and to represent the response of the operators and plant systems to the initiators considered. The EPRI HRA Calculator™ was used to quantify all operator actions considered in the Unit 1 PSA.

Insights and Findings

The DG unavailability data was used to quantify the Unit 1 model using RISKMAN software for both the seven day AOT base case and the requested 14-day AOT case for CDF and LERF.

ICCDP is defined by RG 1.177 as:

ICCDP = [(Conditional CDF w/ equipment out of service) - (Baseline CDF w/ nominal expected equipment unavailabilities)] x (duration of single DG under consideration)

The conditional CDF is calculated by multiplying the baseline CDF by the maximum DG top event Risk Achievement Worth (RAW). The duration of the DG under consideration is seven days, which is the difference between the current DG and the requested DG (this must be adjusted for the duration on a yearly basis by dividing by 365).

Therefore, ICCDP is derived as:

ICCDP = [(RAW x (Baseline CDF)) - (Baseline CDF)] x (duration of single DG under consideration)

Similarly, ICLERP is derived as:

ICLERP = [(RAW x (Baseline LERF)) – (Baseline LERF)] x (duration of single DG under consideration)

The results of the CDF/ICCDP and LERF/ICLERP risk measures calculations are presented in these tables:

CASE	UNIT 1 CDF	UNIT 1 LERF
7 Day AOT	1.87E-6	1.87E-7
14 Day AOT	1.89E-6	1.87E-7
Absolute Change	1.7E-8	5E-11
NRC Guidance Δ CDF/LERF	< 1E-6	< 1E-7
ICCDP	6.43E-8	1.7E-10
NRC Guidance ICCDP/ICLEWRP	< 5.0E-7	< 5.0E-8
Percentage Change	0.9%	0.03%

As can be seen from the above table, the change due to extension of the current seven day DG TS AOT to 14 days is risk insignificant and well below NRC acceptance criteria specified in RG 1.174.

B. Tier 2: Avoidance of Risk Significant Configurations

As described in Section 4.2.1.3, administrative controls ensure that system redundancy, independence and diversity are maintained commensurate with the expected frequency and consequences of challenges to the on-site standby power system:

- Restrictions are placed on simultaneous equipment outages that would erode the principles of redundancy and diversity;

- Voluntary removal of equipments from service is not scheduled when adverse weather conditions are predicted or at times when the plant may be subjected to other abnormal conditions.

In summary, TVA's administrative controls and evaluations have provided reasonable assurance that risk-significant plant equipment outage configurations will not occur as a result of the proposed extension of the Unit 1 DG AOT to be consistent with the Units 2 and 3 DG AOT.

C. Tier 3: Risk-Informed Configuration Risk Management

RG 1.177 recommends that a formal Tier 3 Configuration Risk Management Program (CRMP) be developed and implemented for systems for which a PSA AOT extension has been granted to identify possible risk significant configurations under Tier 2 that could be encountered over extended periods of time. BFN complies with 10 CFR 50.65(a)(4),"Requirements for monitoring the effectiveness of maintenance at nuclear power plants," which requires that risk assessments be performed on safety-related systems and other systems important to the safe operation of the plant as part of the maintenance process. The requirements for complying with 10 CFR 50.65(a)(4) are incorporated into SPP-7.1, "Work Control Process" as discussed in Section 4.2.1.3 and are equivalent to the recommended CRMP. Hence, BFN's compliance with 10 CFR 50.65(a)(4), which applies to DGs and many other systems, supersedes the need to have a separate CRMP which applies solely to the DGs.

RG 1.177 recommends for the Tier 3 program there be an evaluation of compensator measures. As described in Section 4.2.1.3, administrative controls ensure that system redundancy, independence and diversity are maintained commensurate with the expected frequency and consequences of challenges to the on-site standby power system:

- Restrictions are placed on simultaneous equipment outages that would erode the principles of redundancy and diversity;

- Voluntary removal of equipment from service is not scheduled when adverse weather conditions are predicted or at times when the plant may be subjected to other abnormal conditions.

BFN has not identified additional TS restrictions or compensatory measures required to avoid potential risk significant configurations during a DGs outage.

4.3.2 **Evaluation of PSA Quality**

As described in References 10, 12 and 13, the Unit 1 PSA was built on more than 10 years of analysis effort associated with the Unit 2 and 3 PSAs. The Unit 2 and 3 PSAs are maintained and were updated as recently as early 2003.

TVA procedures provide the details describing the use of the PSA at Browns Ferry to support the Maintenance Rule. The PSA assists in establishing performance criteria, balancing unavailability and reliability for risk significant SSCs and goal setting and provides input to the onsite Expert Panel for the risk significance determination process when revisions to the PSA take place. Functions are potentially considered risk significant if any of the following conditions are satisfied:

- Functions modeled in the level 1 PSA have a risk achievement worth greater than or equal to 2.0;
- Functions modeled in the level 1 PSA have a risk reduction worth of less than or equal to 0.995; or
- Functions modeled in the level 1 PSA have a cumulative contribution of 90% of the CDF.

Because the PSAs are actively used at BFN, a formal process is in place to evaluate and resolve PSA model-related issues as they are identified. The PSA Update Report is evaluated for updating every other refueling outage. The administrative guidance for this activity is contained in a TVA Procedure.

During November 1997, TVA participated in a PSA Peer Review Certification of the Browns Ferry Unit 2 and 3 PSAs administered under the auspices of the BWROG Peer Certification Committee. The purpose of the peer review process is to establish a method of assessing the technical quality of the PSA for its potential applications.

The Peer Review evaluation process utilized a tiered approach using standardized checklists allowing a detailed review of the elements and the sub-elements of the Browns Ferry PSAs to identify strengths and areas that need improvement. The review system used allowed the Peer Review team to focus on technical issues and to issue their assessment results in the form of a “grade” of 1 through 4 on a PSA sub-element level. To reasonably span the spectrum of potential PSA applications, the four grades of certification as defined by the BWROG document “Report to the Industry on PSA Peer Review Certification Process - Pilot Plant Results” were employed.

The BFN Unit 2 and 3 Peer Review resulted in a consistent evaluation across all elements and sub-elements. Also, during the Unit 2 and 3 PSAs updates in 2003, the significant findings (i.e., designated as Level A or B) from the Peer Certification were resolved, resulting in the PSA elements now having a minimum certification grade of 3. A copy of the significant peer findings and their disposition was provided in Reference 13. The Unit 1 PSA has incorporated the findings of the Units 2 and 3 PSA Peer Review. The previously conducted Peer Review was effectively an administrative and technical Peer Review of the Unit 1 PSA. Similar models, processes, policies, approaches, reviews, and management oversight were utilized to develop the Unit 1 PSA.

In summary, TVA concludes the BFN PSA model, used for evaluating the risk change in the Unit 1 DG TS AOT extension request, is appropriate and adequate to support the request.

4.4 <u>Summary and Conclusion</u>

TVA has evaluated the proposed extension of the Unit 1 DG TS AOT based on both a deterministic evaluation and a risk-informed assessment. The deterministic evaluation concluded the proposed change is consistent with the defense-in-depth philosophy, in that:

- TVA's off-site power distribution is diverse and provides a dependable source of power to BFN.
- The on-site standby power system is reliable, has redundancy and is capable of compensating for an out-of-service DG.
- BFN uses a proceduralized risk-based approach for scheduling maintenance, which limits removal of risk sensitive equipment from service during DG outages.

The deterministic evaluation concluded that the proposed change will not adversely affect the reduction in severe accident risk achieved with the implementation of the Station Blackout Rule or affect any of the safety analyses assumptions or conclusions described in the UFSAR. This ensures the protection of the public health and safety.

The risk-informed assessment concluded the increase in plant risk is small. The proposed change results in a negligible increase in the Unit 1 Conditional Core Damage Probability and the Conditional Large Early Release Probability. Thus, the proposed change is consistent with:

- The NRC's "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Volume 51, Page 30028 (51 FR 30028), dated August 4, 1996;
- RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1; and
- RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 1.

When taken together, the results of the deterministic evaluation and risk-informed assessment provide a high degree of assurance the equipment required to safely shutdown the plant and mitigate the effects of a design basis accident or transient will remain capable of performing their safety function when a DG is out of service for maintenance or repairs in accordance with the proposed DG TS AOT. The results for the eight DGs show the planned and unplanned DG maintenance fractions for the most recent 14 day AOT data are actually lower than for the earlier seven day AOT data. This reflects plant maintenance improvements unrelated to the AOT.

5.0 REGULATORY SAFETY ANALYSIS

The Tennessee Valley Authority (TVA) is submitting an amendment request to license DPR-33 for the Browns Ferry Nuclear Plant Unit 1.

The proposed change revises the current diesel generators (DGs) Technical Specification (TS) seven day allowed outage time (AOT) to 14 days. The increased AOT will provide additional flexibility for preventive or corrective maintenance of the DGs and consistency with the current Units 2 and 3 TS.

5.1 No Significant Hazards Consideration

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

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

   Response: No

   The DGs are designed as backup AC power sources in the event of loss of offsite power. The proposed DG TS 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 DG TS 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.

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

   Response: No

   The proposed amendment does not introduce new equipment, which could create a new or different kind of accident.

   No new external threats, release pathways, or equipment failure modes are created. Therefore, the implementation of the proposed amendment will not create a possibility for an accident of a new or different type than those previously evaluated.

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

   Response: No

   BFN's emergency AC system is designed with sufficient redundancy such that a DG may be removed from service for maintenance or testing. The remaining DGs are capable of carrying sufficient electrical loads to satisfy the UFSAR requirements for accident mitigation or unit safe shutdown.

A conservative PSA evaluation concluded that the risk contribution of the AOT extension is non-risk significant. For the 12 year DG Preventative Maintenance work activity, it is expected that the proposed TS would actually reduce unavailability since multiple outages would not be necessary to accomplish the maintenance activity.

The proposed change does not impact the redundancy or availability requirements of offsite power supplies or change the ability of the plant to cope with station blackout events.

For these reasons, the proposed amendment does not involve a significant reduction in a margin of safety.

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

5.2 **Applicable Regulatory Requirements/Criteria**

Browns Ferry was constructed before the General Design Criteria (GDC) of 10 CFR 50 were promulgated. However, BFN meets the offsite power requirements of GDC 17 as those requirements have been addressed and approved by the NRC as part of the original facility's licensing basis. Specifically, the description of BFN's offsite power system is contained in Chapter 8 of the UFSAR and was the subject of review by the Atomic Energy Commission in March 1971. NRC's review of BFN's offsite power system's conformance to GDC 17 was based on this information and is documented in Section 7.3 of the original and Supplements 1 and 4 of the Safety Evaluation of the Tennessee Valley Authority Browns Ferry Nuclear Plant, Units 1, 2 and 3, dated June 26, 1972, December 21, 1972, and September 10, 1973, respectively. As discussed in Section 8.5 of the UFSAR, the Standby AC Power System meets or exceeds the requirements of IEEE-308 and -279. Although the DGs are not required to meet the specific load, voltage, and frequency limits of Safety Guide 9, their capacity and capability shall be adequate to meet the intent of Safety Guide 9 for the adequacy of the onsite power supply.

With regards to conformance to 10 CFR 50.63, "Loss of All Alternating Current Power" and Regulatory Guide (RG) 1.155, "Station Blackout":

- The redundancy of the TVA transmission system coupled with a diverse off-site power supply and site distribution system provides highly reliable sources of auxiliary power which, in turn, minimizes the potential for Loss of Offsite Power events. NUMARC 87-000 criteria classifies BFN as an Independence Group I category site which is the least susceptible category to loss of offsite power events due to grid-related disturbances.

- BFN has been categorized by NRC as an Emergency Alternating Current Category "C" plant. This "C" category translates to a SBO coping duration of four hours and a DG target reliability of 0.95 for BFN.

- BFN Maintenance Rule DG unavailability performance criterion is established at 0.0342 (12.5 days per year).

- The proposed extension of the Unit 1 DG TS AOT will not impact the SBO coping analysis since the DGs are not assumed to be available during the coping period.

DG maintenance activities are appropriately controlled as required by 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." SPP 6.6, "Maintenance Rule Performance Indicator Monitoring, Trending and Reporting – 10 CFR 50.65," Technical Procedure NETP-100, "*Emergency Diesel Generator Reliability Program*" and Technical Instruction 0-TI-346, "Maintenance Rule Performance Indicator Monitoring, Trending, And Reporting - 10CFR50.65," provide guidance for initiation, analysis, retrieval, trending, and reporting of data relative to plant level, function specific, and repetitive preventable functional failure indicators of performance required by the Maintenance Rule. The requirements of these procedures are in compliance with 10 CFR 50.65, and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Each DG is required to maintain an unavailability factor of less than or equal to 0.0342 as monitored over a 24 month rolling interval.

RGs 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis”, and 1.177, “An Approach for Using Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications” provide NRC guidance regarding the use of PSA to support TS changes for extended DG TS AOT and extended surveillance test intervals.

BFN has an active and comprehensive risk management program. For on-line maintenance, risk is controlled through a 12 week rolling schedule. A schedule of sequenced work windows is established for on-line periods when combinations of plant systems can acceptably be out of service to perform PM and surveillance activities. The predetermined work windows incorporate risk assessments to determine potential impacts to the safe and reliable operation of the unit and assures long-term maintenance activities are performed within required frequencies to maximize plant equipment and component availability.

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

6.0 ENVIRONMENTAL CONSIDERATION

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

7.0 REFERENCES

1. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 2 and 3 – Technical Specifications (TS) Change 376 – Extended Emergency Diesel Generator (EDG) Allowed Outage Time (Allowed Outage Time)," March 12, 1997.

2. NRC letter to TVA, "Browns Ferry Nuclear Plant Units 2 and 3 – Request for Additional Information Regarding Temporary Extension of Diesel Generator Allowed Outage Time (TAC Nos. M99061 and M99062)," July 17, 1997.

3. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 2 and 3 – Response to Request for Additional Information Regarding Temporary Extension of Diesel Generator Allowed Outage Time (TAC Nos. M99061 and M99062) and Supplement 1 to Technical Specification (TS) Change 376 and 391T – Extended Emergency Diesel Generator (EDG) Allowed Outage Time (Allowed Outage Time)," August 15, 1997.

4. NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 2 and 3 – Request for Additional Information Regarding Technical Specification Change No. 376 – Extended Emergency Diesel Generator Allowed Outage Time (TAC Nos. M98205 and M98206)," November 17, 1998.

5. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 2 and 3 – Response to Request for Information Regarding Technical Specifications Change No. 376 – Extended Emergency Diesel Generator Allowed Outage Time (TAC Nos. M98205 and M98206)," March 30, 1999.

6. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 2 and 3 – Response to Request for Additional Information (RAI) Regarding Technical Specification Change No. 376 – Extended Emergency Diesel Generator Allowed Outage Time (TAC Nos. M98205 and M98206)," April 23, 1999.

7. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 2 and 3 – Technical Specifications Change No. 376 – Extended Emergency Diesel Generator Allowed Outage Time – Amended Submittal – Addition of Configuration Risk Management Program (TAC Nos. M98205 and M98206)," June 18, 1999.

8. NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 2 and 3 – Issuance of Amendments Regarding Authorization of 14 day Allowable Outage Time for Emergency Diesel Generators (TAC Nos. M98205 and M98206)," August 2, 1999.

9. NRC letter to TVA, “Browns Ferry Nuclear Plant, Units 2 and 3 – Supplement to Safety Evaluation Relating to Approval of 14 day Allowable Outage Time for Emergency Diesel Generators (TAC Nos. M98205 and M98206),” September 23, 1999.

10. TVA letter to NRC, “Browns Ferry Nuclear Plant (BFN) – Unit 1 - Proposed Technical Specifications (TS) Change TS-431-Request for License Amendment- Extended Power Uprate (EPU) Operation,” June 28, 2004.

11. NRC letter to TVA, “Station Blackout-Browns Ferry Units 1, 2 and 3 (MPA-A022) (TAC NOS. M68517, M68518, and M68519),” September 16, 1992

12. TVA letter to NRC, “Browns Ferry Nuclear Plant (BFN) – Unit 1 - Proposed Technical Specifications (TS) Change TS-431-Request for License Amendment- Extended Power Uprate (EPU) Operation Probabilistic Safety Assessment (PSA) Update,” August 23, 2004.

13. TVA letter to NRC, “Browns Ferry Nuclear Plant (BFN) – Unit 1 - Response to Request for Additional Information to Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerability (TAC NO. MC1895),” August 17, 2004

Enclosure 2

Ferry Nuclear Plant (BFN) Unit 1
Technical Specification (TS) Change TS 426
Revision to Diesel Generators Allowed Outage Time

Proposed Technical Specification Changes (mark-up)

[Note: new text is shown in **bold** type in the shaded areas]

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s).	24 hours
	AND		
	B.4	Restore Unit 1 and 2 DG to OPERABLE status.	~~7~~ **14** days AND 14 days from discovery of failure to meet LCO

(continued)

Enclosure 3

Ferry Nuclear Plant (BFN) Unit 1
Technical Specification (TS) Change TS 426
Revision to Diesel Generators Allowed Outage Time

Proposed Technical Specification Changes (retyped)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s).	24 hours
	AND	
	B.4 Restore Unit 1 and 2 DG to OPERABLE status.	14 days AND 14 days from discovery of failure to meet LCO

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