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BGE

December 4, 1998

U. S. Nuclear Regulatory Commission
Washington, DC 20555

ATTENTION: Document Control Desk

SUBJECT: Calvert Cliffs Nuclear Power Plant
Unit Nos. 1 & 2; Docket Nos. 50-317 & 50-318
Response to Request for Additional Information; License Amendment Request: One-Time Technical Specification Change to Support the 1999 Refueling Outage

REFERENCES:

(a) Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 20, 1998, "License Amendment Request: One-Time Technical Specification Change to Support the 1999 Refueling Outage"

(b) Telephone Conferences between Mr. A. W. Dromerick, et al (NRC) and Mr. B. B. Mrowca, et al (BGE), on October 8 and 19, 1998, "Request for Additional Information Regarding the One-Time Technical Specification Change for Replacing the Service Water Heat Exchangers During the 1999 Refueling Outage

Reference (a) forwarded a request from Baltimore Gas and Electric Company for a one-time Technical Specification change. Reference (b) requested additional information concerning BGE's proposed change. Attachment (1) provides our response to Reference (b). Should you have additional questions regarding this matter, we will be pleased to discuss them with you.

Very truly yours,

for
C. H. Cruse
Vice President - Nuclear Energy

CHC/JMO/bjd

Attachment: (1) Response to Request for Additional Information; License Amendment Request for Replacing the Service Water Heat Exchangers during the 1999 Refueling Outage

A001

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ATTACHMENT (1)

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION;

LICENSE AMENDMENT REQUEST: ONE-TIME TECHNICAL SPECIFICATION

CHANGE TO SUPPORT THE 1999 REFUELING OUTAGE

Baltimore Gas and Electric Company
Calvert Cliffs Nuclear Power Plant
December 4, 1998

NRC Question 1:

Provide an evaluation of the potential risk benefit expected as a result of the new Service Water (SRW) heat exchangers.

BGE Response

Installing the new parallel plate and frame type SRW heat exchangers results in a risk decrease of approximately 1.4E-05 in annual core damage frequency (CDF) per year. This risk benefit is substantially higher than the one-time 4.8E-06 risk increase for the temporary alignments [see the response to Question 5]. Note that the risk benefit is only an estimate. The estimate is completely dependent on achieving the predicted unavailability reductions. Further, this model was based on Unit 1, which has an Emergency Diesel Generator (EDG) that is independent of saltwater. Thus, the risk benefit seen for Unit 2 is potentially greater. A Unit 2 model is not available.

The expected long-term risk impact of installing the new SRW heat exchangers has been analyzed as follows:

a. New Component Unavailabilities Determined

The expected unavailability of saltwater, SRW, containment air coolers (CACs), EDGs, Emergency Core Cooling System coolers, and component cooling after installation of the new SRW heat exchangers was determined. These unavailability estimates are based on the Unit 1 experience since the installation of the new parallel plate and frame type heat exchangers. Previously, when a SRW heat exchanger was taken out-of-service (OOS) for cleaning, the associated saltwater header had to be placed OOS. Without the SRW flow path, the saltwater pumps did not meet the minimum flow requirements. With the new heat exchanger modification, one SRW heat exchanger, at a time, can be taken OOS without taking out the associated saltwater header. Minimum saltwater pump flow is provided through a bypass line.

Prior to the modification, saltwater header maintenance "shadowed" the maintenance performed on SRW, CACs, EDGs, Emergency Core Cooling System coolers, and component cooling. Taking the saltwater header OOS took the dependent systems/components OOS. Unavailability against the "shadowed" components was counted only when it was independent of the saltwater header outage. The analysis modified the unavailability for these dependent systems to remove the "shadowing" on the systems.

b. Impact of One SRW Heat Exchanger OOS Evaluated

With one SRW heat exchanger OOS in a subsystem and one CAC isolated, sufficient cooling is available for the remaining CAC and the applicable EDGs are still operable. Current Technical Specifications do not allow for this, but design calculations have verified functionality. We are revising the Technical Specifications so that unavailability will only be applied to the OOS CAC.

c. Addressing Additional Complexity of the Modified SRW Lineup

The SRW System, after installation of the proposed modifications, does contain additional controls and components that add to the complexity of the system. The modification and the altered dependencies have not been incorporated into the Calvert Cliffs Probabilistic Risk Assessment (PRA). The modification causes new failure modes that could increase the failure

rate of the SRW subsystems. The increase is countered by the redundancy added to each SRW subsystem [i.e., failure of one heat exchanger in a subsystem provides sufficient cooling for most accident sequences except the larger loss-of-coolant accident (LOCA) scenarios]. Although these changes have not been explicitly modeled, the redundancy in the heat exchangers should provide a greater benefit than the single failure concerns for LOCA events.

d. Incorporation into PRA

The impacts of the revised maintenance unavailabilities were incorporated in the Calvert Cliffs PRA to estimate the benefit. As noted above, it does not model the added complexity or redundancy of the modified system. However, it is assumed to be a conservative estimate if the unavailabilities expected are achieved.

NRC Question 2:

Describe the risk evaluation process that will be used to monitor risk due to maintenance during the 45 days required for the evolution.

BGE Response

a. At-Power Unit (Unit 1)

The at-power unit is evaluated according to "Conduct of Plant Work Control," MN-1-202. Approximately three weeks prior to implementation of a maintenance work week, the proposed schedule is forwarded to Reliability Engineering. The proposed tests and maintenance evolutions are evaluated for potential degradation of components and the potential for increases in initiating event probabilities (such as plant trips, loss of offsite power (LOOP), or Engineered Safety Features Actuation System initiations).

Each potential lineup and test combination is quantitatively evaluated using solved Calvert Cliffs PRA sequences. The instantaneous risks and cumulative risks for the work week are calculated. When medium or high risks are noted, the schedule is evaluated to determine if changes or compensatory actions are needed. The risk analysis is updated when the schedule is updated.

The risk evaluations consider cross unit impacts. For example, since the auxiliary feedwater (AFW) motor-driven pump in each unit is capable of providing feedwater to either Unit, the shut down unit's pump affects the risk of the at-power unit. Similar logic applies to the EDGs that supply many common electrical systems (e.g., 120 VAC, 125 VDC, etc.).

b. Shut down unit (Unit 2)

Currently, Calvert Cliffs Nuclear Power Plant does not perform a probabilistic shutdown risk assessment. The outage schedule is controlled per the procedure NO-1-103, "Conduct of Lower Mode Operations." Per the procedure, Operations evaluates the outage schedule, and any subsequent changes, to ensure minimum essential equipment is available. The schedule is also evaluated for redundancy and maximum availability of reactivity control, Reactor Coolant System pressure and inventory control, decay heat removal, containment integrity, and vital auxiliaries functions. When high risk evolutions are noted, the schedule is changed or contingency plans are put into place to minimize risk.

NRC Question 3:

What compensatory measures are planned to minimize the risk due to the modified SRW lineups? Further, are these compensatory measures credited in the risk analysis?

BGE Response

The planned compensatory measures are as follows:

- To minimize the potential for a LOOP when the EDGs are not in a normal configuration, maintenance will now be restricted on all four of the offsite transmission lines. The response to Question 13 describes the restrictions.
- To ensure that an EDG resistant to weather and seismic events is available, no outage maintenance will be performed on EDG 2A during reduced inventory periods.
- To ensure that backup power is available to any of the safety-related buses, Station Blackout (SBO) Diesel Generator 0C will not be taken OOS for planned maintenance and will remain available to be connected to any of the safety-related buses.
- To ensure compressed air is available, temporary (three) diesel air compressors are to be installed on Unit 2 non-safety-related compressed air and have the capability of being cross-connected automatically to Unit 1 on loss of air pressure.

The potential decrease in LOOP probability and decrease in SBO Diesel Generator 0C unavailability are not credited in the quantitative at-power risk analysis, but they are credited in qualitative shutdown risk assessment. As a standard practice, temporary diesel air compressors are used during the outage. However, their availability was not considered in the original at-power risk assessment. See the response to Question 8 for their impact on the risk assessment.

Reference (1) notes that EDG 2A will be available during reduced inventory operations. Emergency Diesel Generator 2A will have a slightly elevated failure probability during a dual unit LOOP. This increase is due to the dependence on EDG 1B. Emergency Diesel Generator 1B powers the SRW Header 12, which is providing cooling to EDG 2A. However, as noted in Reference (1), SBO Diesel Generator 0C will not be scheduled for maintenance during this time period. Additionally, no planned maintenance will be performed on the 500 kV Switchyard that has the potential to cause a LOOP. Further, there will not be any planned maintenance on any offsite power feeds (two 500 kV Waugh Chapel lines, one 500 kV Chalk Point line, and one 69 kV Southern Maryland Electric Cooperative line). See BGE's response to Question 13 for a detailed discussion on offsite power control.

With these compensatory measures in place, the potential for a LOOP has been decreased, and there will be at least two EDGs available for emergency power during reduced inventory. The combination of the reduced likelihood of a LOOP, with at least two EDGs available, will compensate for the decrease in EDG 2A's reliability. Currently, the schedule has two EDGs (2A and 2B) and one SBO Diesel Generator (0C) available during both reduced inventory operations. The outage maintenance performed on EDGs 2A and 2B, is scheduled for the time frame when the core is off loaded.

Prior to reduced inventory operations, the steam generators will be available for natural circulation, and the time before core damage will occur due to a loss of reactor coolant is relatively long. During this time frame, at least two EDGs are scheduled to be available. Station Blackout Diesel Generator 0C will not be scheduled for maintenance, and either EDGs 2A or 2B will be available.

NRC Question 4:

Per the discussions on October 8, 1998, the LOOP frequencies discussed appear to be relatively high. Provide the single and dual unit LOOP frequencies and the basis for these frequencies.

BGE Response

Dual Unit LOOP Initiating Events:

The loss of all three 500 kV lines will result in a dual unit LOOP. Loss of one or two 500 kV lines normally has no impact. Breaker failures in the switchyard or plant switchgear can challenge a single unit's EDG, but these events are not LOOPs.

The probability of an LOOP of varying duration is:

< 1 hour	4.2E-02 per year
1 to 2 hours	5.8E-02 per year
2 to 4 hours	7.0E-03 per year
4 to 11 hours	1.5E-02 per year
> 11 hours	7.0E-03 per year
	1.3E-01 per year (TOTAL)

The frequencies were developed using a Bayesian Update process. The data window is between March 31, 1986 and December 31, 1993. The prior distributions are based on "Losses Of Offsite Power at U.S. Nuclear Plants Through 1993," NSAC/203, April 1994. The prior distribution is updated with plant-specific information, including our dual unit LOOP on July 23, 1987. The LOOP frequencies currently in use are probably conservative. In 1987, the switchyard only had two 500 kV lines. Now, the switchyard has a third 500 kV line.

Internal Events that cause power to be lost to one or more safety-related 4 kV Buses:

Although numerous external events can cause non-safety-related power to be lost to a safety-related 4 kV bus, the frequencies listed below are only those internal events which cause a direct EDG challenge:

Internal Event Label	Internal Event Description	Frequency	Basis
L13KV1	Loss of 13 kV Bus 11	3.65E-02	Based on individual component failure rates (e.g., buses, breakers, cables, etc.). Some of the individual failure rates are plant-specific, while others are generic.
L13KV2	Loss of 13 kV Bus 21 and EDG 1B	1.51E-03	Based on L13KV1 multiplied by the likelihood of an EDG failure.
L500B	Loss of 500 kV Black Bus	5.03E-02	Based on NSAC/182 (up to 1991) for the Prior Distribution, and Plant Specific Data from January 1, 1985 to March 19, 1992 for the Update.
L500R	Loss of 500 kV Red Bus and EDG 1B	2.77E-03	Based on L500B multiplied by the likelihood of an EDG failure.

These initiating events are developed from the Unit 1 perspective. Of the six Unit 1 4 kV Buses, only 4 kV Bus 14 receives power from 13 kV Bus 21 (and ultimately the 500 kV Red Bus). As a result, the failure of the bus alone does not have a credible chance of causing a plant trip. But if 4 kV Bus 14's associated EDG were to fail concurrent with the loss of 13 kV Bus 21 as an initiating event, then a plant trip is possible. When L13KV2 or L500R occurs, not only is the electrical bus lost, but EDG 1B (4 kV Bus 14's EDG) is also lost.

NRC Question 5:

What is the basis for the $4x10^{-6}$ cumulative risk noted in the License Amendment?

BGE Response

The table below shows the proposed EDG cooling configuration schedule as well as scheduled EDG outages. The schedule noted below is tentative at this time but should provide a good approximation for risks relating to the lineups proposed for the license amendment. The "Cumulative" column values are developed by the following equation:

Cumulative Risk Increase = (Cond. CDF - Base Line CDF) x (Hours in Lineup / [365 * 24])

Where the base line CDF is 3.10E-04 per year for internal and external events.

Configuration	Duration (in Days)	Hours	Cond. CDF	Cumulative
EDG 2A Normal EDG 2B OOS	1	24	3.84E-04	2.03E-07
EDG 2A OOS (12 SRW HDR OOS) EDG 2B using Cooling Tower	0.5	12	6.29E-04	4.37E-07
EDG 2A using 12 SRW HDR EDG 2B using Cooling Tower	12	288	3.30E-04	6.58E-07
EDG 2A OOS EDG 2B using Cooling Tower	5	120	3.60E-04	6.85E-07
EDG 2A using 12 SRW HDR EDG 2B OOS	6	144	4.07E-04	1.59E-06
EDG 2A using 12 SRW HDR EDG 2B using Cooling Tower	12	288	3.30E-04	6.58E-07
EDG 2A OOS (12 SRW HDR OOS) EDG 2B using Cooling Tower	0.5	12	6.29E-04	4.37E-07
EDG 2A Normal EDG 2B on Cooling Tower	2.25	54	3.19E-04	5.75E-08
EDG 2A normal EDG 2B OOS	1	24	3.84E-04	2.56E-08
Returned to Normal Configuration				
	Days	**Hours**		**Total Cumulative Increase**
Total	**40.25**	**966**	**N/A**	**4.75E-06**

As a result of your question, we have re-evaluated our sequence of steps to implement the proposed lineups. The proposed outage schedule has been refined since the time of the Reference (1) submittal. The risk numbers have been modified to address the current outage schedule and the required alignments for the outage. The cumulative risk increase is 4.8E-06. As noted in the license amendment, a typical outage would have the two EDGs removed from service at some time during the outage, which would provide a cumulative risk of approximately 2E-06. Thus, the risk increase, when compared to a "typical" outage is 2.8E-06 to the operating unit. The peak instantaneous risk increase given the above schedule is approximately two times normal. The peak instantaneous risk occurs during the two twelve hour periods where SRW 12 is OOS and EDG 2B is on the cooling tower.

Note that a detailed evaluation of the new sequences related to the modeling of the temporary alignment has been performed and is detailed in the response to Question 8. The evaluation found that many of the sequences are not valid. Therefore, the risk quantified here is conservative.

NRC Question 6:

Expand and further explain the basis for the shutdown risk evaluation.

BGE Response

Calvert Cliffs does not have a current shutdown probabilistic risk model. The risk evaluation done for the evolution is based on a qualitative evaluation.

As the proposed alignments in Reference (1) change, the EDG's support systems for the shut down unit, there is a potential for increasing the probability of a loss of power, which can impact the probability of a loss of residual heat removal (RHR), as well as increase the probability of failing to recover from a loss of RHR. Considering this, some type of risk evaluation is required.

The qualitative evaluation considers each of the major outage sections. The major sections in the outage schedule will include the following:

Milestone	Description
1	Power Operation to Start-up (Mode 1 to Mode 2)
2	Cooldown and Depressurization (Modes 3 and 4)
3	Entry into Cold Shutdown (Mode 5); shutdown cooling (SDC) placed in service; Reactor Coolant System is capable of being pressurized; natural circulation cooling is available if necessary
4	Reduced inventory (Remove Reactor Head, etc.)
5	Refueling Pool filled (Mode 6 -Refueling Operations)
6	Fuel movement (All fuel will be removed from core)
7	Core Defueled
8	Fuel Movement to load the fuel
9	Reduced Inventory (Mode 5)
10	Reactor Coolant System filled and Pressurizer Vent removed
11	Plant Startup to Power Operation (Mode 2 to Mode 1)

As EDGs 2A and 2B are only in an atypical configuration in Modes 5 and 6, Milestones 1, 2 and 11 above can be disregarded for any increase in risk. Each of the remaining milestone regions are qualitatively evaluated:

- **Milestone 3**: During this mode of operation, AFW, SDC, once-through-core-cooling (OTCC), and low pressure feed (LPF) are all viable options. Additionally, the available recovery time is much longer than would be available for an at-power event. Due to the array of cooling options available and the relatively low amount of decay heat (compared to at-power trips), EDG unavailability is considered to have a limited impact in this region.
- **Milestone 4**: During this mode of operation, SDC and OTCC are the only options available. Following a LOOP, EDG operation is critical to ensure decay heat removal. This is especially true considering the short time available for recovery. See the response to Question 3 for compensatory actions.

- **Milestone 5**: During this mode of operation, SDC, OTCC, and gravity feed are all viable options. The amount of time available for recovery is large. Having the Unit 2 EDG either in the alternative configuration, or having a single EDG OOS is considered to have a small impact on risk.
- **Milestone 6**: Bounded by Milestone 5.
- **Milestone 7**: One of the least risk significant configurations considering the large volume of water available (i.e., long recovery times).
- **Milestone 8**: Bounded by Milestone 6.
- **Milestone 9**: Bounded by Milestone 4. See the response to Question 3 for compensatory actions.
- **Milestone 10**: During this mode of operation, SDC, OTCC, and gravity feed are all viable options. The amount of time available for recovery is large. Having the Unit 2 EDG either in the alternative configuration, or having a single EDG OOS is considered to have a small impact on risk.

The risk is most significant in the early stages of the outage. In SECY 97-168, "Issuance for Public Comment of Proposed Rulemaking Package for Shutdown and Fuel Storage Pool Operation" (dated July 30, 1997), the NRC staff states that the majority of the risk involved with shutdown operations occurs prior to the initial fill of the refueling pool. Much of this risk is concentrated in the first reduced inventory portion of the outage. Per "Shutdown and Low Power Operation at Commercial Nuclear Power Plants In the United States," NUREG-1449 (draft) (dated February 1992) (page xv), the dominant risks are associated with accident sequences involving loss of RHR during operation with a reduced inventory.

The EDGs will be maintained available as much as possible during the high risk evolutions. A discussion of their availability and compensatory measures is in the response to Question 3. The increased availability of EDGs will prevent any significant risk increases, due to the modified Technical Specifications, to the shut down unit.

Although it has not been quantified numerically, the risk to the shut down unit due to the proposed modified EDG support appears negligible. Redundant EDGs will be available and the risks of a LOOP will be minimized. This proposal should not cause any significant negative impacts on sequences that could lead to core uncovery.

NRC Question 7:

Provide the following reliability factors for the Calvert Cliffs Nuclear Power Plant:

- EDG Common Cause (C/C) Factors
- EDG Fail to Start
- EDG Fail to Run
- EDG Unavailability
- EDG Mission Time

BGE Response

The failure rates and unavailabilities below are for the EDGs only and are limited to the equipment on the EDG skids. The failure rates and associated unavailabilities do not include EDG supports (e.g., SRW system, fuel oil, electrical supports, starting air, room ventilation, etc.). The failure/unavailability rates of these support systems are included in our risk models and degrade

and/or fail the EDGs as appropriate. The C/C factors are those associated with the Multiple Greek Letter Methodology that is used for C/C modeling in our risk models. All EDGs are required to run for the entire duration of the LOOP (See response to Question 4).

Fairbanks Morse EDGs (1B, 2A, and 2B)

Fails to Start	2.47E-03/demand (Based on plant-specific data (1985 - 1991)	
Beta (C/C)	2.17E-02 (Based on Electric Power Research Institute [EPRI] TR-100382 industry data, updated with plant-specific failures.)	
Gamma (C/C)	3.95E-01 (Based on EPRI TR-100382 industry data, no plant-specific c/c failures to update.)	
Fails to Run 1st Hour	3.08E-03/hour (Based on plant-specific data (1985 - 1991)	
Beta (C/C)	2.79E-02 (Based on EPRI TR-100382 industry data, updated with plant-specific failures.)	
Gamma (C/C)	3.60E-01 (Based on EPRI TR-100382 industry data, no plant-specific c/c failures to update.)	
Fails to Run after 1st Hour	2.51E-03/hour	(Based on PLG Generic Data)
Beta (C/C)	6.99E-02	(Based on PLG Generic Data)
Gamma (C/C)	2.50E-01	(Based on PLG Generic Data)
Unavailability	1.07E-02 (Based on plant-specific data (6/1985 - 10/1991)	

Societe Alsacienne De Constructions Mecaniques De Mulhouse (SACM) EDG (1A) and SBO Diesel Generator (0C)

Fails to Start	4.85E-03/demand (Based on data supplied by Electricite' de France (EdF), who has used SACM EDGs extensively.)
Beta (C/C)	1.00E-02 (PLG Generic C/C Factor)
Fails to Run 1st Hour	3.90E-03/hour (Based on data supplied by EdF, who has used SACM EDGs extensively.)
Beta (C/C)	1.00E-02 (PLG Generic C/C Factor)

Fails to Run after 1st Hour	5.76E-04/hour (Based multiplying on the generic ratio of the failure rate of an EDG in the 1st hour under the failure of an EDG beyond the 1st hour to the EdF failure rate in the 1st hour.)
Beta (C/C)	6.99E-02 (PLG Generic Common Cause Factor)
Unavailability	1.34E-02 (Based on Fairbanks Morse maintenance frequency, with increased maintenance duration (25%) to account for increased complexity of SACM EDGs.).

NRC Question 8:

What are the dominate core damage scenarios?

A. Discuss the initiating events with the largest CDF increase.

B. Discuss new sequences (specific scenarios) with highest CDF impact.

BGE Response 8A

Initiating Events - With Largest Magnitude Increase in CDF

Shown are the initiating events with the largest magnitude increase in CDF due to placing the plant in the modified EDG cooling lineups detailed in Reference (1) (see Table 8A). During evaluation of the new sequences in this lineup, it was found that many of the new sequences are not valid . These invalid sequences are screened for the reasons described below.

The majority of the screened sequences are related to the loss of Unit 2 (the shut down unit) non-safety-related air. One of the primary changes to the Unit 1 plant model, used to support the Reference (1) evaluation, is the failure of all Unit 2 SRW System components. The non-safety-related plant air compressors can be used to supply air to either Unit 1 or Unit 2, as demanded. The non-safety-related plant air compressors require SRW cooling. Since no Unit 2 SRW is available, some new Unit 1 core damage sequences are introduced that are directly related to the availability of the Unit 2 plant air compressor. However, during the outage there will be temporary diesel air compressors installed to provide Unit 2 with non-safety-related compressed air. Further, emergency cooling from fire protection will be aligned to an installed air compressor. Therefore, the contribution of each of the non-safety-related Unit 2 air-related new sequences would be decreased by the failure probability of these systems. It is estimated that each of these sequences will be decreased by at least one order of magnitude. Thus, the increased CDF for initiating events that are associated with these sequences is conservative.

A number of new sequences are overly conservative. These sequences had not been previously evaluated in the normal model. Without the guaranteed failure of Unit 2 SRW, these Unit 1 plant model sequences had a very low contribution to core damage (either truncated or a very small CDF impact). These conservative sequences have little impact in the normal model. In the modified SRW line-up model, the impact accounts for much of the increased risk.

All initiators that have a valid increase either cause a complete or partial LOOP, or cause a spurious actuation of breakers in the 500 kV Switchyard. During a LOOP, EDG 2A (supports 4 kV Bus 21) is ultimately dependent on EDG 1B, which provides 4 kV power to SRW Header 12. Since 4 kV Bus 21 requires two EDGs to function during a LOOP, the probability of core damage increases.

In addition to the more conventional forms of a LOOP, external events (such as hurricanes and seismic events) can cause both a LOOP and disable the non-safety-related temporary EDG 2B cooling tower. Some fires can cause spurious actuation of 500 kV switchyard breakers, which effectively causes a LOOP. Additionally, some fires are large enough that the fires are assumed to deplete the pretreated water storage tank (PWST). The PWST provides the makeup to the cooling tower. Thus, EDG 2B is assumed to lose cooling within two hours.

It is also important to recognize that there are several initiating events (and sequences) that benefit from the temporary alignment due to the decreased EDG dependency on Unit 2 Saltwater and SRW Systems.

BGE Response 8B

Provided are the top ten new core damage sequences that result from the modified EDG cooling lineup noted in Reference (1) (see Table 8B). All ten sequences noted are due to initiating events which result in non-safety-related power being lost to one or more safety-related 4 kV buses. Thus, the EDGs must provide power to the safety-related 4 kV buses. None of the new sequences involve loss of Reactor Coolant System inventory control. All ten sequences are due to a loss of RHR. The Calvert Cliffs PRA credits these methods for RHR from the core and preventing core damage:

- Heat Removal via the steam generators:

  1. Main Feedwater (MFW) - MFW is the preferred method of RHR. Unfortunately, MFW is lost in all ten sequences due to the loss of 500 kV power to the Switchyard. In the fire-related internal events, power is lost due to the spurious actuation of switchyard breakers. In the other scenarios, the switchyard is most likely lost due to weather-related concerns. Without the non-safety-related buses, MFW will not function.

  2. Auxiliary Feedwater - AFW is the next option used for RHR. Units 1 and 2 each have two turbine-driven AFW pumps (turbine-driven AFW pumps) and one motor-driven AFW pump (motor-driven AFW pump). The motor-driven pump is capable of feeding either unit through cross-connection piping. Success of the AFW requires at least one pump to successfully provide feed to a steam generator.

  3. Low Pressure Feed - Low pressure feed is the last option attempted to feed the steam generators. The condensate and condensate boosters pumps can be used to provide condensate to the steam generators. The ultimate source of water for this option is the non-safety-related condensate storage tank that provides make-up to the hotwell from which the condensate pumps take a suction. Unfortunately, as with MFW, this option is not possible when the non-safety-related 4 kV buses are lost.

- OTCC: Without AFW being available in the short-term, OTCC would require the successful opening of two power-operated relief valves (PORVs), operation of two high-pressure safety injection (HPSI) pumps, and two of three charging pumps.

Part of the risk increase submitted in Reference (1) is also associated with loss of inventory control. These sequences are not presented below. In our risk evaluation, the entire Unit 2 SRW System is considered removed. This results in all of the associated support systems failing with the exception of those systems explicitly mentioned in Reference (1) (i.e., EDGs and spent fuel pool cooling). The key systems affected are the Unit 2 instrument and plant air systems. The reactor coolant pump seals are cooled by component cooling water through a fail closed air-operated containment isolation valve. Without non-safety-related air, these valves fail closed. Since, Unit 2 is a back-up source of air to Unit 1, the unavailability of Unit 2 air causes a risk increase. However, during the outage three temporary diesel air compressors will be in place, as well as emergency cooling for an installed air compressor. If the temporary air compressors had been credited in the risk evaluation, the stated risk increase would be noticeably lower. Since, these sequences are not very relevant considering the amount of Unit 2 air support available during the Unit 2 outage, these sequences are not shown within the top ten sequences.

The top ten valid Core Damage sequences that result from the modified EDG cooling lineup in Reference (1) are below. Note that the core damage frequency noted for each is the annual frequency of this sequence in the modified EDG cooling lineup. The Delta Risk shown is the cumulative risk increase over the 41 day time period as compared to the base line risk model.

SEQUENCE 1

Initiating Event - Unit 2 Steam Generator Feedwater Turbine Pump fire

Sequence - Random Failure of EDG 1A
Random Failure of both turbine-driven AFW pumps

Core Damage Frequency - 1.56E-06

Delta Risk - 1.11E-07

MFW - This fire causes spurious actuation of 500 kV switchyard breakers which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - A random failure of EDG 1A causes power to be lost to AFW Pump 13. The turbine-driven AFW pumps fail due to a random failure (probably a common cause failure). Normally, motor-driven AFW Pump 23 could be used to prevent core damage. In the modified SRW line-up, EDG 2B is cooled by a cooling tower. The cooling tower receives make-up from PWSTs. The PWSTs also provide the Fire Protection System with water. During the larger fires, the PWSTs are not credited with being able to provide make-up to the cooling tower, which is assumed to result in the failure of EDG 2B. Without EDG 2B, motor-driven AFW Pump 23 cannot function.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - With the random failure of the EDG 1A, power is initially lost to reactor motor control center (MCC) 114R. This MCC provides power to a PORV. The EDG 1A also provides power to Charging Pumps 11 and 13. Although MCC cross-connection is credited to open the second PORV, no credit is taken for aligning the disconnects on Charging Pump 13 to get the second charging pump running (Charging Pump 12 is running). With only one charging pump available, OTCC is assumed to fail.

This sequence is probably conservative as the depletion of the PWST and the subsequent loss of cooling tower make-up will probably take some time to cause the failure of the EDG 2B. This means that the AFW Pump 23 will probably operate for several hours prior to failure. The longer AFW availability would allow time for the operators to align the second charging pump. Normal OTCC must be aligned within 20 minutes. However, if AFW has been providing water to the steam generator for several hours, the time is dramatically increased.

SEQUENCE 2

Initiating Event - Hurricane

Sequence -

- Random Failure of EDG 1A
- Random Failure of EDG 1B
- Operators fail to control AFW allowing steam generator overfill
- Operators fail to recover the standby turbine-driven AFW pump following the steam generator overfill

Core Damage Frequency - 7.65E-07

Delta Risk - 7.49E-08

MFW - The hurricane is assumed to cause a 24-hour LOOP that results in the loss of non-safety-related power to the 4 kV buses; MFW cannot function without non-safety-related 4 kV power.

AFW - Random failures occur on EDG 1A (fails 4 kV Bus 11) and EDG 1B (fails 4 kV Bus 14). Emergency Diesel Generator 2A is dependent on SRW Header 12 which is powered by 4 kV Bus 14 [new impact from the SRW configuration]. Thus, EDG 2A is lost (fails 4 kV Bus 21). The hurricane is also assumed to fail SBO Diesel Generator 0C (can power any of the 4 kV Buses) and EDG 2B's (fails 4 kV Bus 24) cooling tower [new impact from the SRW configuration]. As a result, all EDGs are failed and a SBO exists. When the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult but possible. The operators fail to control AFW flow causing the steam generators to overfill. The overfill condition is assumed to fail the operating turbine-driven AFW pump. Although difficult, it is possible for the operators to recover from this condition using the standby turbine-driven AFW pump and clearing the feed lines. In this sequence, the operators fail to do this prior to core damage.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 3

Initiating Event - Hurricane

Sequence -

- Random Failure of EDG 1A
- Random Failure of both turbine-driven AFW pumps

Core Damage Frequency - 6.41E-07

Delta Risk - 4.91E-08

MFW - The hurricane is assumed to cause a 24-hour LOOP which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - A random failure occurs on EDG 1A and both Unit 1 turbine-driven AFW pumps fail (probably common cause). The failure of EDG 1A causes the loss of 4 kV Bus 11 which provides power for the Unit 1 motor-driven AFW pump. The EDG 2B cooling tower is failed by the hurricane which means 4 kV Bus 24 is without power. The Unit 2 motor-driven AFW pump receives power from 4 kV Bus 24. Thus, there are no AFW pumps which can be used to feed the Unit 1 steam generators.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - With the random failure of the EDG 1A, power is initially lost to reactor MCC 114R. This MCC provides power to a PORV. The EDG 1A also provides power to Charging Pumps 11 and 13. Although MCC cross-connection is credited to open the second PORV, no credit is taken for aligning the disconnects on Charging Pump 13 to get the second charging pump running (Charging Pump 12 is running). With only one charging pump available, OTCC is assumed to fail.

SEQUENCE 4

Initiating Event - Unit 2 steam generator feedwater turbine pump fire

Sequence -

- Random Failure of EDGs 1A, 1B, and SBO Diesel Generator 0C
- Operators fail to control AFW allowing steam generator overfill
- Operators fail to recover the standby turbine-driven AFW pump following the steam generator overfill

Core Damage Frequency - 5.65E-07

Delta Risk - 5.82E-08

MFW - This fire causes spurious actuation of 500 kV switchyard breakers that results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - A random failure of EDG 1B occurs, as well as failure of EDG 1A and SBO Diesel Generator 0C (probably a common cause failure). As mentioned earlier, when 500 kV power is not available, EDG 2A fails with the failure of EDG 1B. The EDG 2B cooling tower receives make-up from PWSTs. The PWSTs also provide the Fire Protection System with water. During the larger fires, the PWST are not credited with being able to provide make-up to the cooling tower, which is assumed to result in the failure of EDG 2B. As a result, all EDGs are failed and an SBO exists. When the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult but possible. The operators fail to control AFW flow causing the steam generators to overfill. The overfill condition is assumed to fail the operating turbine-driven AFW pump. Although difficult, it is possible for the operators to recover from this

condition using the standby turbine-driven AFW pump and clearing the feed lines. In this sequence, the operators fail to do this prior to core damage.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 5

Initiating Event - Unit 2 steam generator feedwater turbine pump fire

Sequence - Random Failure of EDG 1A
Random Failure of the Main Steam Isolation Valves

Core Damage Frequency - 1.56E-06

Delta Risk - 2.84E-08

MFW - This fire causes spurious actuation of 500 kV switchyard breakers, which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - A random failure of EDG 1A (fails 4 kV Bus 11) causes power to be lost to AFW Pump 13. The turbine-driven AFW pumps require steam to function. The large Unit 2 fire is considered to disable Unit 1 ability to trip the turbine. This causes a large steam demand. The steam generator isolation signal demands that the main steam isolation valves be closed, but the main steam isolation valves fail. This is considered to fail both of the turbine-driven AFW pumps. This leaves only Unit 2 motor-driven AFW Pump 23 to supply Unit 1 with steam generator feed. The motor-driven AFW Pump 23 receives power from 4 kV Bus 24 which requires EDG 2B when the 500 kV Switchyard is de-energized. In the modified SRW line-up, EDG 2B is cooled by a cooling tower. The cooling tower receives make-up from PWSTs. The PWSTs also provide the Fire Protection System with water. During the larger fires, the PWST water storage tanks are not credited with being able to provide make-up to the cooling tower which is assumed to result in the failure of EDG 2B. Without EDG 2B, motor-driven AFW Pump 23 cannot function.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - With the random failure of the EDG 1A, power is initially lost to reactor MCC 114R. This MCC provides power to a PORV. The EDG 1A also provides power to Charging Pumps 11 and 13. Although MCC cross-connection is credited to open the second PORV, no credit is taken for aligning the disconnects on Charging Pump 13 to get the second charging pump running (Charging Pump 12 is running). With only one charging pump available, OTCC is assumed to fail.

This sequence is probably conservative as the depletion of the PWST and the subsequent lost of cooling tower make-up will probably take some time to cause the failure of EDG 2B. This means that the motor-driven AFW Pump 23 will probably operate for several hours prior to failure. The longer AFW availability would allow time for the operators to align the second charging pump. Normal OTCC must be aligned within 20 minutes, but if AFW has been providing water to the steam generator for several hours, this time is dramatically increased.

SEQUENCE 6

Initiating Event - LOOP for 24 hours

Sequence -

- Random Failure of EDGs 1A, 2B, 1B, and SBO Diesel Generator 0C
- Operators fail to control AFW allowing steam generator overfill
- Operators fail to recover the standby turbine-driven AFW pump following the steam generator overfill

Core Damage Frequency - 2.94E-07

Delta Risk - 2.06E-08

MFW - The LOOP results in the loss of non-safety-related power to the 4 kV buses. The MFW cannot function without non-safety-related 4 kV power.

AFW - Random failures of EDGs 1A, 2B, 1B and SBO Diesel Generator 0C, occur. These failures are probably two sets of common cause failures. One common cause failure between the SACM EDG (1A) and SBO Diesel Generator (0C) and the other being the Fairbanks Morse EDG failures (1B and 2B). The EDG 2A is dependent on SRW Header 12 [new impact from the SRW alignment], which is powered from 4 kV Bus 14. As 4 kV Bus 14 is lost (EDG 1B failure), EDG 2A loses cooling and is failed. All EDGs are failed at this point and an SBO occurs. After the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult, but possible. The operators fail to control AFW flow causing the steam generators to overfill. The overfill condition is assumed to fail the operating turbine-driven AFW pump. Although difficult, it is possible for the operators to recover from this condition using the standby turbine-driven AFW pump and clearing the feed lines. In this sequence, the operators fail to do this prior to core damage.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - Per the discussion in AFW above, all safety-related 4 kV power is also lost. Thus, power required for OTCC is not available. (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 7

Initiating Event - Unit 2 steam generator feedwater turbine pump fire

Sequence -

- Saltwater Header 12 OOS
- Random Failure of EDG 1A and SBO Diesel Generator 0C
- Operators fail to control AFW allowing steam generator overfill
- Operators fail to recover the standby turbine-driven AFW pump following the steam generator overfill

Core Damage Frequency - 2.67E-07

Delta Risk - 2.82E-08

MFW - This fire causes spurious actuation of 500 kV switchyard breakers which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - Saltwater Header 12 is OOS for cleaning. Without Saltwater Header 12, EDG 1B is OOS. Emergency Diesel Generator 1A and SBO Diesel Generator 0C experience a random failure (probably a common cause failure EDG 2A fails with the failure of EDG 1B [new impact from the SRW alignment]. The EDG 2B cooling tower receives make-up from PWSTs. The PWSTs also provide the Fire Protection System with water. During the larger fires, the PWSTs are not credited with being able to provide make-up to the cooling tower, which is assumed to result in the failure of EDG 2B. As a result, all EDGs are failed and an SBO exists. When the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult, but possible. The operators fail to control AFW flow causing the steam generators to overfill. The overfill condition is assumed to fail the operating turbine-driven AFW pump. Although difficult, it is possible for the operators to recover from this condition using the standby turbine-driven AFW pump and clearing the feed lines. In this sequence, the operators fail to do this prior to core damage.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 8

Initiating Event - Hurricane

Sequence -

- Random failure of EDG 1A
- Random failure of EDG 1B
- Operators fail to control AFW allowing steam generator overfill
- Backup turbine-driven AFW pump randomly fails

Core Damage Frequency - 2.30E-07

Delta Risk - 2.17E-08

MFW - The hurricane is assumed to cause a 24-hour LOOP which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - Random failures occur on EDG 1A (fails 4 kV Bus 11) and EDG 1B (fails 4 kV Bus 14). Emergency Diesel Generator 2A is dependent on SRW Header 12 which is powered by 4 kV Bus 14 [new impact from the SRW configuration]. Thus, EDG 2A is lost (fails 4 kV Bus 21). The hurricane is also assumed to fail EDG SBO Diesel Generator 0C (can power any of the 4 kV Buses) and EDG 2B's (fails 4 kV Bus 24) cooling tower [new impact from the SRW configuration]. As a result, all EDGs are failed and an SBO exists. When the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult, but possible. The operators fail to control AFW flow causing the steam generators to overfill. The overfill condition is assumed to fail the operating turbine-

driven AFW pump. The standby turbine-driven AFW pump is then lost due to a random failure. There is no power available to a motor-driven AFW pump due to the SBO.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 9

Initiating Event - Hurricane

Sequence -

- Random failure of EDG 1A
- Random failure of EDG 1B
- Operators fail to control AFW flow and underfill steam generators

Core Damage Frequency - 2.17E-07

Delta Risk - 2.05E-08

MFW - The hurricane is assumed to cause a 24-hour LOOP, which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - Random failures occur on EDG 1A (fails 4 kV Bus 11) and EDG 1B (fails 4 kV Bus 14). Emergency Diesel Generator 2A is dependent on SRW Header 12, which is powered by 4 kV Bus 14 [new impact from the SRW configuration]. Thus, EDG 2A is lost (fails 4 kV Bus 21). The hurricane is also assumed to fail SBO Diesel Generator 0C (can power any of the 4 kV Buses) and EDG 2B's (fails 4 kV Bus 24) cooling tower [new impact from the SRW configuration]. As a result, all EDGs are failed and an SBO exists. When the 125 VDC Batteries deplete, 120 VAC power is lost. Without 120 VAC power, steam generator water level indication is lost. During this portion of the SBO, AFW flow control is difficult, but possible. The operators fail to control AFW flow, underfilling the steam generators allowing core damage (error of commission). There is no power available to a motor-driven AFW pump due to the SBO.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

SEQUENCE 10

Initiating Event - Hurricane

Sequence -

- Random failure of EDG 1A
- Random failure of EDG 1B
- Operators fail to recover the failed steam admission line to AFW following the steam generator overfill

Core Damage Frequency - 1.93E-07

Delta Risk - 1.83E-08

MFW - The hurricane is assumed to cause a 24-hour LOOP, which results in the loss of non-safety-related power to the 4 kV buses. Main feedwater cannot function without non-safety-related 4 kV power.

AFW - Random failures occur on EDG 1A (fails 4 kV Bus 11) and EDG 1B (fails 4 kV Bus 14). Emergency Diesel Generator 2A is dependent on SRW Header, which is powered by 4 kV Bus 14 [new impact from the SRW configuration]. Thus, EDG 2A is lost (fails 4 kV Bus 21). The hurricane is also assumed to fail SBO Diesel Generator 0C (can power any of the 4 kV Buses) and EDG 2B's (fails 4 kV Bus 24) cooling tower [new impact from the SRW configuration]. As a result, all EDGs are failed and an SBO exists. When the 125 VDC Batteries deplete, the AFW steam admission valves fail closed. This stops both turbine-driven AFW pumps. The operator fails to open the steam admission valves prior to core damage.

LPF - Low pressure feed cannot function without non-safety-related 4 kV power.

OTCC - As noted in AFW above, an SBO occurs. Thus, power required for OTCC is not available (i.e., power to PORVs, HPSI pumps, or charging pumps).

The steam admission valves fail open on loss of air, but fail closed on loss of 125 VDC power. It is possible that the air is depleted to the AFW accumulators by the time the 125 VDC power fails. Under this circumstance, the AFW steam admission valves would not close. Therefore, this sequence may have some conservatism.

Results of Sequence Evaluation

As a result of the detailed review of the sequences, it is obvious that the increased risk calculated in SRW License Amendment Request, Response to Additional Information Response 5 above is overly conservative. If the trend seen in the top sequences is consistent through all sequences, then actual risk increase may be as low as 1.0E-06. This is based on the 2.8E-06 risk increase shown in the response to Question 5, and the ratio of valid to invalid delta risk shown on the Top New Sequences Table (Table 8B).

NRC Question 9:

What is the station battery lifetime in an SBO? Which batteries power the AFW trains?

BGE Response

Battery Lifetime

In the Calvert Cliffs PRA, the station batteries are credited with maintaining power for four hours without charging. The Calvert Cliffs PRA does not credit existing procedures to shed less important battery loads to prolong battery life.

AFW System Modeling in the Calvert Cliffs PRA

During an SBO, each unit relies on the turbine-driven AFW pumps to provide decay heat removal. Each Unit has two turbine-driven AFW pumps, either of which is capable of providing adequate flow. The turbine-driven AFW pumps are supplied steam from two redundant air-operated control valves. These valves fail open on loss of air, but fail closed on loss of 125 VDC power. One of the control valves is supplied from 125 VDC Bus 11 (1D01) and the other is

supplied from 125 VDC Bus 21 (2D01). Although it is possible that air to the control valves will not be available when 125 VDC power is lost during a long duration SBO, it is assumed that the valves fail closed and the Operators must manually vent the air from the control valves. The turbine-driven AFW pumps provide flow to a common supply point, which diverges to two separate feed trains for each steam generator. Each feed train has a flow control valve. The flow control valves require power from 120 VAC Panel 12 (1Y02) to maintain the throttle position. Panel 1Y02 is ultimately powered from 2D01.

In addition to these hardware dependencies, the AFW system requires 125 VDC power to provide indicator for critical AFW human actions. The Operators required some form of steam generator water level indication. The most reliable form is the steam generator water level indications on 1C03. The four indicators on 1C03 are each powered from the four 120 VAC Panels associated with each unit (e.g., 1Y01, 1Y02, 1Y03, and 1Y04 for Unit 1). The 120 VAC Panels are powered from the four 125 VDC Buses. Condensate Storage Tank 12 indication is also important. The indication for Condensate Storage Tank 12 is provided by either 1Y01 and 1D01; or 1Y02 and 2D01. It is possible that AFW can be controlled without Control Room indication, but the likelihood of success is significantly affected.

NRC Question 10:

Updated Final Safety Analysis Report says SRW is required for AFW room air coolers. Is AFW cooling important for the PRA model?

BGE Response

The turbine-driven AFW pump room for each unit can be cooled by one-of-three options. All three options are modeled in the Calvert Cliffs PRA. The room is normally cooled by an non-safety-related air conditioning (A/C) unit. The non-safety-related A/C unit requires SRW cooling from the Turbine Building. The second preferred cooling option is the emergency ventilation cooling. The emergency ventilation system consists of two redundant fans and associated duct work. The emergency ventilation system discharges to the Mechanical Equipment Room in the Auxiliary Building. The design basis for the emergency ventilation system is to provide AFW turbine-driven pump room cooling during a LOCA. During a LOCA, safety injection actuation signal isolates SRW to the Turbine Building. Although designed for a LOCA, the emergency ventilation system can be used as needed. The emergency ventilation cooling requires manual alignment and is powered from the safety-related reactor MCCs. The final method of cooling is to open the AFW turbine-driven pump room double wide doors. Opening the doors provides the AFW turbine-driven pump room equipment adequate cooling. Due to the redundancy and simplicity of the cooling options, AFW turbine-driven pump room cooling is not risk significant.

NRC Question 11:

For a single or dual LOOP, what is the train level success for the EDGs, station batteries, and AFW?

BGE Response

At-Power Unit Success Criteria (Unit 1)

Following a LOOP without a LOCA, a single AFW pump is capable of providing adequate decay heat removal. The AFW pump could either be turbine-driven or motor-driven. During a LOOP, the

motor-driven AFW pump requires an EDG (125 VDC is required to start the EDG) to provide motive power. The 125 VDC Bus availability does improve the likelihood of LOOP mitigation, but 125 VDC is not required to avert core damage.

Following a LOOP with an induced LOCA (the most likely possibility is a reactor coolant pump seal LOCA), a single AFW pump is required for decay heat removal, and a single EDG (125 VDC is required to start the EDG) is required to support a safety injection train.

Shut Down Unit Success Criteria (Unit 2)

In the early part of the outage when the steam generators are available, a single turbine-driven AFW pump can provide adequate decay heat removal. Later when the steam generators are not available, a single HPSI pump can provide adequate heat removal. A single EDG and 125 VDC Bus is required to support the HPSI pump and injection flow paths during a LOOP.

NRC Question 12:

Discuss flooding considerations during the SRW heat exchanger replacement.

BGE Response

Potential Flooding Concern

A further review of flooding has caused a concern regarding a catastrophic Turbine Building flood, due to a ruptured expansion joint in the operating unit's circulating water system. Due to the modification in progress, it is very likely that it will not be possible to rapidly close the Unit 2 SRW Pump Room doors. Although many of the components in the Unit 2 SRW Pump Room will be OOS, there is a door in the SRW Pump Room to the Auxiliary Building that is not watertight. Thus, the Turbine Building flood could propagate into the Auxiliary Building. Since the Auxiliary Building contains the safe shutdown equipment and is at a lower elevation than the Turbine Building, this was a significant concern.

There are a number of options being considered to make the risk due to this flood acceptable. Included in the options is temporary hardware modifications to block the flood paths or dedicated watches to alert the Control Room of catastrophic flooding. These and additional options are being evaluated. The option used will be analyzed to ensure that the risk associated with the modification is not significantly increased by the flooding concern.

The actual work being performed in the Unit 2 SRW Pump Room is not considered to be a significant source of flooding. The saltwater headers will have at least one "Class 1" isolation valve between the operating header and the work at all times. There will be personnel working 24 hours a day in the room. Any flooding would be reported immediately.

Operating Unit Risk Assessment

The CDF increase to the operating unit, due to the propagation of the flood into the Unit 2 SRW Pump Room, will be approximately 1E-07 or less. This relatively small risk increase is based on implementing compensatory measures that terminate the circulating water flood prior to reaching the Auxiliary Building. Examples, of compensatory measures are:

- Dedicated Flood Watch to ensure that the circulating water pumps are tripped in a timely fashion;
- Designing the Unit 2 SRW Pump Room doors such that the doors can be closed in a timely fashion; or
- Blocking the flood paths into the Auxiliary Building from the Unit 2 SRW Pump Room.

If a non-hardware option is used, and the actions to promptly trip the circulating water pumps or close the SRW Pump Room doors fail, core damage will be assumed to occur. If the option to block the flood paths into the Auxiliary Building from the SRW Pump Room is used, the increase in risk (to the operating unit) is due to the loss of the Unit 2 motor-driven AFW pump during the circulating water flood event. Note that all flooding events were analyzed in the PRA analysis documented in the response to Question 5 above.

Shut Down Unit Risk Assessment

As with the operating unit assessment above, core damage is assumed to occur if the relevant human actions fail on the catastrophic flood. The probability of the flood occurring and the human action failure will be maintained to be approximately 1E-07 or less.

The option to block the flood path into the Auxiliary Building leaves the Unit 2 saltwater air compressors and the motor-driven AFW pump susceptible to flooding damage. The impact on the shut down unit, due to the potential loss of the Unit 2 saltwater air compressors and motor-driven AFW pump on the catastrophic circulating water flood, is evaluated qualitatively.

During the majority of the time frame the Unit 2 SRW Pump Room doors will remain open, the only loads on the Unit 2 Saltwater System will be the component cooling heat exchangers. In this configuration the only saltwater air compressor supplied components of concern are the saltwater control valves to the component cooling heat exchangers. As these valves fail open on loss of air, there is no loss of cooling due to the loss of saltwater air compressors. Thus failing the Unit 2 saltwater air compressors, during the SRW modification, is not risk significant.

The motor-driven AFW pump is only of concern to the shut down unit during Milestones 3 and 10 (see the response to Question 6 above). These are the only applicable milestones where steam generators are available for heat removal. The loss of the motor-driven AFW pump will reduce some redundancy during this time frame, but the turbine-driven AFW pumps will still remain available, as well as the Unit 1 motor-driven AFW pump. Further, the option of OTCC exists. Thus, the potential loss of motor-driven AFW Pump 23 due to a flooding incident is not considered to be risk significant.

NRC Question 13

Reference (1) commits to no planned maintenance on three-of-the-four offsite power feeds. Can this commitment be changed to four-of-four offsite power feeds?

BGE Response

Baltimore Gas and Electric Company will not plan any maintenance on any of the offsite power feeds during the time frame that the modified EDG cooling lineups are in place. It should be noted that Baltimore Gas and Electric Company does not have complete control over two of the offsite feeds in question. We do not have direct control over Chalk Point, which provides the power to 500 kV

Transmission Line 5072. This is operated by Potomac Electric Power Company (PEPCO). We have informal agreements with PEPCO regarding testing and maintenance on this line during high risk periods. We will inform PEPCO that this is a high risk time frame and request that no testing or maintenance on 500 kV Transmission Line 5072 be performed. There is a relatively high degree of confidence that PEPCO will comply. A similar request will be made to Southern Maryland Electric Cooperative, which provides 13 kV power from a 69/13 kV substation. Given these the constraints, we will attempt to ensure that no planned maintenance will be performed on the four offsite power feeds while the EDGs are in the modified cooling configuration.

References:

1. Letter from Mr. C. H. Cruse (BGE) to NRC Document Control Desk, dated July 20, 1998, "License Amendment Request: One-Time Technical Specification Change to Support the 1999 Refueling Outage"