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BECo Ltr. #2.96- 080

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555

Docket No. 50-293
License No. DPR-35

Response To Request For Additional Information Regarding Emergency Diesel Generator Allowed Outage Time Technical Specification Change (TAC No. M95277)

Attached is our response to your Request for Additional Information (RAI) regarding Technical Specification changes submitted April 25,1996 (BECo Letter No. 96-040). The proposed change included provisions for allowing 14 day outage times on each emergency diesel generator during plant operation. In addition, as requested by RAI Question No. 2, revised Technical Specification pages 3/4.5-7 and B3/4.5-6 are being submitted that do not affect our previous finding of no significant hazard consideration determination pursuant to 10CFR50.92(c).

Commitments

This letter includes commitments to revise plant procedures 1.2.2 and 8.C.34.

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Attachment A: Response to NRC RAI
Attachment B: Revised T.S. Pages 3/4.5-7, and B3/4.5-6
Attachment C: PNPS Procedure 1.2.2 "Administration Operations Requirements"

A001/,

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Executive Summary

In our April 25, 1996, TS Change Request letter to the NRC, we requested to change the EDG Allowed Outage Time from 3 days to 14 days. NRC reviewed our submittal, and requested additional information, asking us to include SBO-DG in the EDG LCO.

This letter responds to NRC questions and provides revised TS and Basis pages. ORC reviewed the revised TS pages on August 8. These pages reflect NRC's requirement resulting from their review, and thus, do not required to be reviewed by the NSRAC and do not invalidate the previous findings under 10 CFR 50.92(c).

The inclusion of SBO-DG in the EDG LCO provides the effect of having two DGs available during the 14-day LCO, and limits one DG unavailability to 3 days (the current LCO). (The net effect of the 14-day LCO with SBO-DG " verified operable" is very close to the existing 3-day LCO with no SBO-DG.) This is very conservative.

The supporting PSA results are derived using PNPS equipment performance data, which includes EDG reliability of 0.99. Our SBO Rule commitment for EDG reliability is 0.975. The PSA result using 0.99 envelops the result for 0.975 reliability data.

There are specific commitments in the letter, which would require revisions to several procedures. We (Pat Sears and Walter Lobo) have reviewed these procedures, and changes are being made at this time.

ATTACHMENT A

RESPONSE TO NRC RAI

Response To Request For Additional Information
Emergency Diesel Generator Allowed Outage Time
Pilgrim Nuclear Power Station

Question 1. *Provide details of scheduled periodic inspection with approximate time required and frequency of performing each action. Also, provide total maximum time required in the past to complete inspections and overhaul.*

Response:

Scheduled periodic inspections and overhaul are performed together in accordance with station procedure 3.M.3-61.5, "Emergency Diesel Generator Refuel Outage Preventive Maintenance." The major portions of this procedure cover the following areas:

- Wear indication measurements such as gear backlash, crankshaft deflection and clearances
- Rebuilding/inspecting the air start motors
- Fuel injector cleaning, testing, fuel pump timing, and rack inspection
- Generator inspection and insulation resistance measurement

Historically, it takes approximately 6-7 days to complete this procedure. These activities are performed at a frequency of once every 2 years. Use of LCO AOT is governed by station procedure 1.2.2, "Administrative Operations Requirements," which limits LCO use to 50% of its total allowable AOT.

Question 2. *Because of the potential safety impact of the extended emergency diesel generator (EDG) allowed out-of-service time (AOT) for preventive maintenance (PM), the staff believes that the plant should have an alternate ac (AAC) power source which can be substituted for the inoperable EDG. Additionally, certain compensatory measures are needed during the extended EDG AOT to assure safe operation of the plant. Provide a discussion of how you would address each condition listed below as related to Pilgrim Nuclear Power Station.*

a. *The Technical Specifications (TS) should include verification that the systems, subsystems, trains, components, and devices that depend on the remaining EDG as a source of emergency power are operable before removing an EDG for PM. In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components, and devices while the EDG is inoperable.*

Response:

Proposed Technical Specification 3.9.B.3 and the technical specification it references require verification that systems, subsystems, trains, components and devices that depend on the remaining EDG are operable.

Surveillance 8.C.34, " Operations Technical Specification Requirements for Inoperable Systems/Components", will be revised to include the Blackout Diesel as the alternate AC power supply. This will include verifying the quarterly surveillance for the Blackout Diesel is current and equipment surveillances due prior to the end of the AOT shall be run prior to taking the EDG out of service. Procedure 1.2.2, "Administrative Operations Requirements", (Attachment 11, "LCO Maintenance Planning Checklist" Item # 7) provides a positive measure to preclude subsequent maintenance/testing on redundant and backup equipment while the EDG is inoperable.

b. *Before taking an EDG out for an extended period to perform maintenance, the AAC source should be verified functional and is capable of being connected to the safety bus associated with the EDG to be taken out of service prior to the start of PM and once every shift thereafter.*

Response:

The attached Technical Specification pages are revised to include compensatory measures for the AAC source before taking an EDG out of service for an extended period of time. These measures will require the AAC source to be verified operable and capable of being connected to the safety bus associated with the EDG to be taken out of service prior to the start of PM and once every shift thereafter.

c. *Voluntary entry into a limiting condition of operation (LCO) action statement to perform PM should be contingent upon a determination that the decrease in plant safety is small enough and the level of risk is acceptable for the period and is warranted by operational necessity.*

d. *Voluntary entry into an LCO action statement should not be abused by repeated entry into and exit from the LCO.*

e. *Voluntary removal from service of safety systems and important non-safety equipment, including offsite power sources, should be precluded during the outage of the EDG for PM.*

Response:

LCO entry conditions and the relationship of interfacing safety systems and important non-safety systems are addressed as operating philosophies in procedure 1.2.2, Attachment. 11, Items [2], [3], [4]. These items confirm the above NRC positions.

f. *Component testing or maintenance that increases the likelihood of a plant transient should be avoided; plant operation should be stable during the EDG PM.*

Response:

This policy is implemented by procedure 1.2.2, Attachment. 11, Item [6].

Question 3. *As stated in the April 25, 1996, letter from the licensee, the purpose of the requested amendment is to allow an increased outage time during plant power operation for performing EDG inspection and overhaul, which would include disassembly of the EDG. The staff is concerned that disassembly of an EDG would require subsequent pre-operational testing of the EDG (such as full load rejection tests) following this maintenance. This would imply that such testing would have to be performed while the plant is operating instead of during shutdown, which has been the past practice. In order to resolve this concern, the following should be addressed:*

a. *What would be the typical and worse-case voltage transients on the 4160-V safety buses as a result of a full-load rejection?*

Response:

EDG overhauls are performed in accordance with procedure 3.M.3-61.5. Although procedure 3.M.3-61.5 is described as an "overhaul", very little overhauling is performed. Full disassembly of the EDG is not done. The bulk of the procedure inspects and records the condition of the system. Any major components such as a governor would only be replaced if its condition indicated that this was necessary. We would look for signs of worn gears, excessive leaking of oil, or less than optimum control to name a few.

The testing that would be conducted after the overhaul would be an extended surveillance of procedure 8.9.1, "Manually Start and Load the EDGS." This post work testing is done at power by paralleling the EDG to its associated 4.16 KV bus that is powered from the unit auxiliary transformer. During this run, the firing pressures and other operating parameters would be recorded. Successful completion of procedure 8.9.1 is the only criteria for declaring the EDG operable following completion of an overhaul. Full load rejection tests are not routinely performed on EDGs at PNPS.

Performance of procedure 8.9.1 once per month is used to comply with T.S. 4.9.A.1.a. Therefore, the post work test itself poses no additional risk of EDG load rejection. The only additional risk of an inadvertent EDG load rejection is presented by the maintenance itself. This is more thoroughly discussed in response to item "c".

b. *If a full-load rejection test were used to test the EDG governor after maintenance, what assurance would there be that an unsafe transient condition on the safety bus (i.e., load swing or voltage transient) due to improperly performed maintenance on or repair of a governor would not occur?*

Response:

As already stated, full load rejection tests are not routinely performed on EDGs at PNPS. However, following postulated replacement of a governor (during current normal operation or an outage), some form of load rejection testing would likely be performed. In this situation, though, it would be preferable to parallel the EDG to the grid for required loading versus starting safety-related loads on the bus. The voltage transient produced by this test would be less than the conditions observed in item "c" below.

c. Using maintenance and testing experience on the EDG, identify any other possible transient conditions caused by improperly performed maintenance on the EDG governor and voltage regulator. Predict the electrical system response to these transients.

Response:

No unacceptable voltage transients have occurred at PNPS as the result of improper maintenance activities. However, on March 25, 1991, while performing a monthly surveillance, the following conditions were observed as a result of an in-service failure of the automatic voltage regulator on the B EDG:

-The KW indication increased to approximately 3500 KW
-The unit auxiliary transformer breaker to A6 tripped due to phase B overcurrent which caused a lockout on bus A6 (i.e., bus A6 de-energized requiring manual resetting of equipment)
-The EDG shutdown on overspeed and the EDG "B" output breaker 152-609 tripped.

This incident was the result of the voltage regulator failing in service but shows the response of the system to the worst case transient. The voltage transient produced by this event had no negative effect on the 4160 V safety buses or loads.

Also, the licensee should provide a description of the tests to be performed after the overhaul to declare the EDG operable and provide justification for performing those tests at power.

Response:

As stated in response to item "a", procedure 8.9.1 is the only post-overhaul test required to declare the EDG operable. This procedure is currently performed monthly to satisfy T. S. 4.9.A.1.a.

Question 4. Provide the calculated total core damage frequency (CDF) resulting from all probabilistic safety assessment (PSA) sequences involving station blackout (SBO) before and after the SBO Rule (10 CFR 50.63)implementation. Also provide the calculated total CDF from all SBO sequences after accounting for the increase in EDG unavailability due to the extended allowed outage time requested. Provide the instantaneous change in the CDF value for the worst-case plant configuration allowed under the proposed Specification. Explain how the EDG PM and subsequent on-line operability testing is treated in the CDF calculation.

Response:

Prior to implementation of the SBO Rule, there were no detailed PSA models nor Pilgrim specific data with which to quantify the SBO contribution to CDF. However, an estimate of the SBO sequences prior to implementation of the SBO rule was made by removing the SBO diesel generator from the model, and requantifying the SBO sequences. The results are as follows:

SBO CDF (prior to SBO Rule implementation) = 8.01E-06 /year

As discussed in our response to the RAI regarding our IPE submittal (BECo Letter No. 95-127, dated December 28, 1995) the current SBO sequence contribution to CDF is 9.58E-07/year. This represents a decrease in risk of 7.05E-06/year in SBO sequence contribution to CDF with the implementation of the SBO Rule.

Assuming that each EDG will be unavailable for 14 days each year in addition to its historical maintenance unavailability, the expected total CDF contribution from SBO sequences is 1.23E-06/year as calculated below:

SBO CDF with one EDG failed = 4.48E-6/year

SBO CDF with one EDG failed integrated over 14 days = 4.48E-06/year*14/365 = 1.72E-07

SBO CDF (14 day EDG AOT)=9.58E-07(337/365) +2(1.72e-07) = 1.23E-06/year

The instantaneous change in the CDF value for the worst-case plant configuration allowed under the proposed specification is provided in the quantification section of Question 7. This represents a modest increase of 2.70E-07/year in SBO contribution of CDF.

The CDF calculation does not differentiate between EDG PM and subsequent online operability testing. Rather, it conservatively assumes that each EDG will be unavailable for the full duration of the proposed 14 day AOT in addition to the historical corrective maintenance unavailability.

Question 5. Provide the EDG reliability and availability values used in the PSA analysis to calculate the SBO CDF values requested in Question 4 above. Discuss these in relation to any goals associated with the implementation of the maintenance rule and in comparison with actual past performance of the EDG's at the plant. Also compare the values used in the PSA analysis to the target values committed to for SBO.

Response:

The EDG reliability and availability values used for this calculation are provided in the quantification section of Question 7. The Maintenance Rule at PNPS has adopted the SBO reliability goal of 0 .975 for the EDG reliability for performance criteria. The EDG reliability program is controlled by PNPS procedure 1.5.16. We have performed better than this goal for the past few years.

The reliability assumed by the PSA is consistent with our current performance (approximately 0.99). Use of this value in the PSA versus the EDG reliability goal is inconsequential.

Question 6. *The condition of offsite sources of electrical power prior to and during an extended EDG outage have additional importance. Discuss what considerations should be given to not performing a proposed extended maintenance when the offsite grid condition or configuration is degraded or when adverse or extreme weather conditions (e.g., high winds, lightning, icing conditions) are expected. Discuss how planning of an extended EDG maintenance should consider the time needed to complete the extended EDG maintenance and the ability to accurately forecast weather conditions that are expected to occur during the maintenance. Discuss what, if any, contingency plans should be developed to restore the inoperable EDG in the event of unanticipated adverse weather or degraded grid conditions occurring which can significantly increase the probability of losing offsite electrical power.*

Response:

Considerations for not performing the proposed maintenance during degraded grid and extreme weather conditions are discussed in the "Guidelines" Section of 1.2.2, Attachment. 11, the last guideline. The Nuclear Watch Engineer (NWE), with as much guidance from "outside sources" as practicable, (weather reports, REMVEC, security, tour operators, other plant staff, etc.) has the authority to ensure that concurrent activities/conditions will not compromise plant safety or performance. The NWE decision would be supported by senior plant management. All the "Guidelines" in 1.2.2 support prudent scheduling taking into account all activities that would likely extend a given maintenance activity. National weather service forecasts are available to Pilgrim and are considered when planning maintenance activities. These are usually quite accurate. Since coastal weather can sometimes be unpredictable, we will add an additional guideline in Attachment 11 of 1.2.2 for contingency plans to restore inoperable standby power quickly if necessary. This would include progressively staging the necessary conditions, tools, procedures, parts, etc. to quickly reverse the disassembly process.

Question 7. *The NRC staff expects that licensees will have addressed three aspects, or tiers, in proposing risk-informed modifications and associated amendments.*

In the first tier, the licensee is expected to determine the change in plant operational risk (specifically, the change in core damage frequency (CDF) and core damage probability (CDP)) as a result of the proposed TS modification and discuss its significance. Credit for any compensatory actions should be explicitly quantified and substantiated. In addition, in order to better understand the impact of the amendment on containment performance, the staff expects the licensee to perform an analysis of the large early release frequency (LERF) under the modified TS conditions and discuss the results or, if applicable, an analysis of offsite consequences.

The second tier should provide reasonable assurance that risk significant plant equipment outage configurations will not occur while the plant is subject to the Limiting Condition for Operation (LCO) proposed for modification.

The third tier should assure that, before performing maintenance activities including removal of any equipment from service, the licensee will perform a thorough assessment of the overall impact on safety functions of related TS activities, as required by the proposed Maintenance Rule. This should be an intrinsic part of all maintenance scheduling, and involve risk insights.

The staff's review consists of an assessment of (1) the appropriateness of licensee activities in each tier, (2) the applicability of the licensee's probabilistic risk assessment (PRA) methodology to support the proposed TS change, and (3) an evaluation of the impact of the proposed TS change on plant operational risk and containment performance, and the adequacy of licensee proposed compensatory measures.

The staff's final recommendation will be based upon the licensee's commitment to the compensatory measure, insights and findings from the PRA model, and the adequacy of relevant portions of the licensee's program to meet the requirements of the Maintenance Rule, which will be in effect as of July 1996.

Three sets of questions that correspond to these three tiers have been developed as follows:

Question 7.a *Tier 1*

(a) *Probabilistic Safety Assessment (PSA). or Probabilistic Review Assessment (PRA)*

What are the success criteria for the station blackout (SBO) condition at Pilgrim for the three loss of offsite power (LOSP) conditions: plant centered, grids, and severe weather?

Response:

Losses of offsite power can be characterized as those resulting from plant centered faults, utility grid blackout, and severe weather-induced failures of offsite power sources. Depending on the type of loss of offsite power characteristic, various combinations of equipment failures would have to occur for a station blackout condition to exist. But, for all such station blackout conditions, the alternate ac power source, a non class 1E diesel generator, will be capable of providing power to an emergency bus within 10 minutes of the onset of the SBO condition. Additionally, Pilgrim Station is an eight hour coping plant (See TACM68585 dated January 15, 1992).

The PRA at Pilgrim does not differentiate success criteria for the plant centered, grid, and severe weather LOSP conditions. Rather the PRA considers the following two LOSP conditions: (1) the loss of preferred offsite power (LOPOP) which involves the loss of both 345 KV sources; and (2) the loss of all offsite power (LOOP) which involves the loss of both 345 KV sources and the 23 KV power source. The loss of all offsite power is generally due to severe weather conditions. The loss of preferred offsite power can be due to severe weather, hardware failures, personnel errors, and acts of God. Initiating frequency values for both LOPOP and LOOP conditions are based on Pilgrim's operating experience.

What review of the PRA has been made to ensure that the PRA represents the as-built, as-operated plant, and contains the fine structure (resolution) necessary to evaluate the proposed TS requirements? Were any changes made to the PRA due to such reviews?

Response:

The PRA is a living model that is periodically updated to reflect changes to plant configuration and performance. It is continually enhanced through on going peer reviews and the increasing skills and knowledge of our IPE analysts. PRA modeling changes are controlled via Safety and System Analysis Department procedure SB3, "Living Probabilistic Risk Assessment". The PRA model utilized for this application is the same one described and used in BECo's response (Letter No. 95-127, TAC No. M74451, dated December 28, 1995) to the NRC Request for Additional Information (RAI) regarding the IPE. It includes recovery actions for SBO situations, and uses updated plant data for the calculation of the LOSP initiation frequencies and HPCI and RCIC failure rates.

The model has the resolution necessary to evaluate the proposed AOT change to the Technical Specifications. The model structure includes the yearly unavailability of each EDG and thus, no changes to the model were deemed necessary for this application.

Your current PRA may be different from your IPE. Explain any major differences, specifically with respect to LOSP/SBO sequences. Include quantitative results and bases for any credit taken which impacted the LOSP/SBO contribution to COF and/or LERF.

Response:

The PSA model used for this application is identical to that used for the IPE RAI response. The differences between the IPE and the current model are addressed in that document. As described in our response, the LOOP non-recovery probabilities were updated and are somewhat larger than the original IPE submittal values. Consequently, the current contribution of SBO sequences (9.58E-07/year) to core damage has increased from that identified in the original IPE submittal (insignificant).

Please provide the minimal cut set truncation cutoff used to quantify the plant CDF changes. In particular, indicate what efforts were made to avoid underestimation when the impact calculated was negligible or non-existent.

Response:

All PRA model runs were made at a truncation level of 1E-09. The entire level I model was requantified each time, so as to capture all new possible failure sequences which might normally have been missed using pregenerated cutsets.

Provide a discussion of the LOSP events at your facility.

Response:

From January 1, 1975, through August 31, 1995 (20.7 years), Pilgrim has experienced twenty three (23) LOOP events. Nineteen (19) of these events involved the loss of preferred offsite power only, and four (4) events involved the loss of all offsite power. Please refer to BECo Letter No. 95-127 for more detailed discussion of the IPE quantification.

To improve the performance and reliability of the 345 KV switchyard (i.e., minimize LOSP events), improvements were made in 1995 which are discussed in NRC Inspection Report 95-03, Section 4.2. A modification replaced 345 KV air blast circuit breakers with "dead-tank" type SF6 (gas insulated) breakers. The new breaker bushings are designed with a longer creepage distance to ground, thus, reducing flashovers due to salt deposit and contamination of the bushings. The new SF6 type breakers are also expected to increase both the reliability and availability of the 345 KV offsite power supply during adverse weather (e.g., salt spray storm) conditions.

Other improvements included replacing the switchyard post insulators with extended creepage, glazed insulators. Other components (e.g., transformer bushings, line stringers), subject to degradation of the Sylgard coating intended to resist salt deposition, were recoated with a new silicone-based material and placed on a preventive maintenance program for cleaning and recoating. Measurable positive results have been observed in the winter of 1995-1996 during severe storms.

Discuss the impact of severe weather on switchyard condition and offsite power at your facility and how this was addressed in the PRA. Are you committed to any of the severe weather shutdown requirements and procedures of NUMARC 87-00? What requirements do you plan in order to avoid entering the 14 day AOT if severe weather is anticipated? What is the contribution of severe weather to SBO induced core damage.

Response:

As discussed previously, Pilgrim's LOSP initiating frequencies are not explicitly differentiated by cause, including severe weather. However, as a practical matter, the dominant cause of the events making up Pilgrim's LOOP frequency (but not necessarily the LOPOP frequency) is severe weather. Contingency actions in anticipation of, and in response to, severe weather conditions, are contained in PNPS procedure 1.2.2, "Administrative Operations Requirements".

Plant procedures, 5.3.31, "Station Blackout" and 2.2.146, "SBO Diesel Generator" specify the onsite restoration of AC power to plant systems. Plant procedure 5.2.6, "High Winds (Hurricanes)", addresses severe weather conditions. These procedures reflect guidance of Sections 4.2.2 and 3, NUMARC 87-00 (BECO Letter No. 89-57, dated April 17, 1989). Plant procedure 5.2.6 requires the plant to reduce power to 130 MWe before the arrival of high winds, and start and

load EDGs eight hours prior to the arrival of high winds. Electrical malfunctions and degraded voltage conditions are addressed by plant procedures, 2.4.16, "Distribution Alignment Electrical System Malfunctions", and 2.4.144, "Degraded Voltage". As discussed in the response to Question 6, consideration for not performing the diesel generator overhaul already exists in procedure 1.2.2.

As mentioned, Pilgrim implemented a series of switchyard improvements in 1994 and 1995 to reduce the probability of salt-buildup induced LOSPs. While no credit is taken in the calculated LOSP frequencies for these switchyard improvements, the modifications appear to be effective with no LOSPs reported since 1994. For a more detailed discussion of the station's susceptibility to, and coping mechanisms for, extended losses of offsite power, please refer to the IPE, Appendix C, Section C.2 "Loss of Offsite Power". Specifically Section C.2.3, pages C.2-6 through C.2-20, provide the LOOP event tree descriptions and quantification.

Please describe the peer reviews performed on your PRA. Indicate which reviews were performed in-house versus those performed by outside consultants. Summarize their overall conclusions and insights.

Response:

The original IPE submittal was subjected to a detailed peer review consisting of two levels; in-house and outside consultants. The results of these reviews are contained in the original IPE submittal (BECo Letter No. 92-114, dated September 30, 1992).

The peer review of this application was performed in house by PRA analysts and the Maintenance Rule Coordinator.

(b) Quantitative results

Please provide the following calculations and quantitative PRA results due to the AOT extension with and without credit taken for compensatory actions (or plant improvements) not credited in the IPE submitted to the NRC in response to GL 88-20.

(1) Change in average CDF (Δm(CDF)):

m(CDF) = average CDF (per year)

m2 (CDF) = The conditional m (CDF) with the proposed 14 day AOT in place

ml (CDF) = The original m (CDF) with the current 3 day AOT in place

Therefore, Δm (CDF) - m2 (CDF) - ml (CDF)

Response:

The comprehensive PSA calculation including methodology for the proposed EDG AOT Extension is contained in Part III of the technical specification submittal, BECo Letter No. 96-040, April 25, 1996.

The baseline CDF as described in BECo Letter No. 95-127 is 2.84E-05/year. The conditional average CDF with the proposed 14 day AOT in place, m2(CDF) is 2.87E-05. This assumes that no other equipment will be unavailable during each EDG's LCO. This is a credible assumption in that the unavailability of other equipment when in an EDG LCO would require entry into a more restrictive LCO.

The original CDF with the current 3 day AOT, m1(CDF), is the baseline of 2.84E-05. Therefore, the change in average CDF is 2.87E-05 - 2.84E-05 = 3E-07. This represents an increase of 1% over the baseline.

(2) Change in instantaneous CDF (ΔCDFi):

CDFi(2) = The conditional CDF when the plant is in the AOT

CDFi(l) = The CDF when the plant is <u>not</u> in the AOT

i =AOT configuration with one EDG unavailable

Therefore, ΔCDFi = CDFi(2) - CDFi(l)

Response:

The conditional CDF when the plant is in the AOT is 3.27E-05. This assumes that only one EDG is available and no other maintenance is being performed. The CDF when the plant is not in the AOT and no other maintenance is being performed is 2.11E-05. Therefore, the change in instantaneous CDF when entering the AOT is 3.27E-05-2.11E-05 = 1.16E-05.

(3) Change in conditional core damage probability (ΔCCDP):

CCDP(2) = The CCDP while the plant is in the AOT

CCDP(1) = The CCDP while the plant is <u>not</u> in the AOT

Therefore, ΔCCDP = CCDP(2) - CCDP(1)

Response:

The CCDP while the plant is in the AOT is 1.25E-06. The CCDP when not in the AOT is 1.09E-06. Therefore, the change in conditional core damage probability is: 1.25E-06 - 1.09E-06 = 1.65E-07

(4) *Change in average large early release frequency ($\Delta LERF$)*

LERF(2) = LERF with proposed AOT in place

LERF(1) = LERF with current AOT in place

Therefore, $\Delta LERF$ = LERF(2) - LERF(1)

Response:

The LERF with the proposed AOT in place, LERF(2), = 0.13 * 2.87E-05 = 3.73E-06. The LERF with the current AOT in place is 3.69E-06. Therefore, the change in LERF is LERF(2) - LERF(1) = 3.9E-08.

What are the projected average corrective maintenance and preventive maintenance downtimes for EDGs used in your calculations? Explain how they were obtained. Have you performed any sensitivity analyses on your corrective maintenance (CM) and preventive maintenance (PM) downtimes that affect the risk results in the previous question? If so, please discuss insights gleaned from the study.

Response:

The EDG data base of down times was obtained from actual maintenance histories at Pilgrim. These maintenance histories are provided in Appendix A, Table A.6, of the IPE submittal. A statistical analysis of the historical data shows the mean time for corrective maintenance is 27.3 hours, and that 95% of all corrective maintenance is accomplished within 145 hours.

Thus, based on historical performance, there is only a small probability that EDG corrective repairs will exceed 145 hours of down time. Given the mature nature of the EDG maintenance program, the historical distribution of maintenance down times is expected to be similar in the future.

The most conservative assumptions were made regarding preventive maintenance. It is assumed in the PRA that each EDG is down for a full 14 days each year for preventive/planned maintenance. This is an extremely conservative assumption because (1) major EDG overhauls are scheduled once every other year, not once per year, and (2) preventive maintenance is planned so as not to exceed 50% of the AOT (i.e., not exceed 7 days), per PNPS Procedure 1.2.2 guidance.

In summary, the EDG unavailability used in the PRA is composed of the historical unavailability due to corrective maintenance, plus the planned unavailability of each EDG being down 14 days per year for preventive maintenance. The distribution of corrective maintenance downtimes is enveloped by the 14 day preventive maintenance downtime assumed in the PRA.

Have you performed any sensitivity analyses for this requested AOT change? If so, discuss how the results of your evaluation, consideration and uncertainty ensure the PRA results in your application are robust and that the plant will not be subject to an unexpected sudden increase in the risk profile.

Response:

Several sensitivity analyses have been run for this requested AOT change to show how relatively risk insignificant either EDG is in relation to other equipment. For example, the model was requantified with either EDG removed for the entire year. The resulting CDF was 8.27 E-05/year. While this is considerably greater than the baseline CDF 2.84 E-05/year, it remains lower than the NRC safety goal of 1E-04/year.

The analysis conservatively assumes an additional 14 days of unavailability per year for each EDG in addition to its historical maintenance unavailability.

Question 7.b *Tier 2*

Given the AOT plant configuration, what does your PRA indicate are the other risk-significant systems? Is the significance the same for each EDG, or EDG combination? Please discuss any differences.

Response:

While in the LCO for either EDG, the other diesel, the startup, and the shutdown transformers have an increased risk importance as evidenced by Fussel Vesely (FV) and risk achievement worth (RAW) values. The risk measures are identical for each EDG.

For the other risk-significant systems you identified above, how would you ensure that no risk-significant plant equipment outage configurations would occur while the plant is subject to the LCO proposed for modification? Are the bases for this assurance reflected in your administrative procedures or FSAR?

Response:

Adherence to the technical specifications (3.9.B.1, 2 and 3.9.B.4) would assure that no risk significant plant equipment outage configurations would occur while in the AOT. The other risk significant systems identified are included in the technical specifications. Removal of any of this equipment from service while in the EDG AOT would require entry into a more restrictive technical specification.

Have you thoroughly reviewed your TS to see if there is a need for any other changes to your TS or (in addition to the TS amendment items you are currently requesting) due to your request for an EDG AOT of 14 days? Please identify any administrative procedure or FSAR changes made to ensure that the plant will not enter any risk-significant configuration while in the AOT.

Response:

The technical specifications have been thoroughly reviewed to verify there is no need for revision to accommodate an EDG AOT of 14 days besides the proposed change discussed in response to NRC Question 2.b. The FSAR and plant procedures will be revised as necessary in accordance with the T.S. amendment process.

As described above, adherence to the technical specifications will ensure that risk significant configurations will not be entered while in the LCO.

Question 7.c *Tier 3*

Describe your ability to perform a contemporaneous assessment of the overall impact on safety functions before conducting maintenance activities including removal of any equipment from service. Please explain how this tool, or other processes, will be used to ensure that risk-significant plant configurations will not be entered during the AOT

Response:

A PRA risk evaluation is performed on planned maintenance requiring the concurrent removal of multiple systems from service as part of the 12-Week Schedule Work Control Process. PNPS procedure 1.5.21, "Work Control Scheduling Activities and Guidelines," provides the administrative controls to ensure that the systems scheduled for maintenance in a particular work week window will be the only ones removed from service for planned maintenance.

A safety monitor (EOOS, equipment out of service program) has been developed and is being turned over to the plant Operations Department. This tool can be used to prioritize corrective maintenance activities in the case of emergent work. PNPS Procedure 1.2.2 provides guidance to ensure that the defense-in-depth concept is followed when removing important systems from service. In addition, Maintenance Rule performance criteria is used to ensure the long term risk associated with cumulative system unavailability is monitored, trended and controlled.

Explain how you are going to address the issue of configuration control, consistent with the Maintenance Rule, i.e., evaluate the impact of maintenance activities on plant configurations.

Response:

See the above response.