VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
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Docket Nos.	50-280
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Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
EVALUATION OF PRELIMINARY YELLOW FINDING AND ASSOCIATED NRC EVALUATION CONTAINED IN NRC SPECIAL INSPECTION REPORT NOS. 50-280/01-06 AND 50-281/01-06

On October 11, 2001, the NRC issued Special Inspection Report Nos. 50-280/01-06 and 50-281/01-06. This report provided the NRC's preliminary significance determination and associated evaluation related to the inoperability of the Emergency Diesel Generator (EDG) No. 3 and degraded components on EDG No. 1 at Surry Power Station. The report noted that prior to the NRC making a final decision on the preliminary finding, Virginia Electric and Power Company (Dominion) had the option of requesting a Regulatory Conference. The purpose of the Regulatory Conference is to present Dominion with the opportunity to provide its perspectives on the significance of the NRC's findings, the bases for its position, and whether it agrees with the apparent violations. Consequently, Dominion requested a Regulatory Conference in a telephone call with Mr. K. D. Landis of the NRC Region II Office. The NRC subsequently informed Dominion that a Regulatory Conference had been scheduled for November 30, 2001. In scheduling the conference, the NRC encouraged Dominion to provide its written evaluation by November 26, 2001 in an effort to make the conference more efficient and effective.

Accordingly, we have performed an evaluation of the NRC's preliminary Yellow finding relative to the condition and inoperability of EDG No. 3, the degraded components on EDG No.1, and the Phase III Analysis provided in the subject Inspection Report. Our evaluation is provided in the attachment in the form of an updated risk assessment. The updated risk assessment uses the NRC's assumptions with the additional considerations, clarifications, corrections and assumptions discussed in the attachment.

Dominion's updated risk assessment demonstrates that the NRC's preliminary Phase III Analysis was overly conservative, and that the Core Damage Probability (CDP) for Surry Unit 1 and Unit 2 would be near the mid-point of the White range of Significance Determination Process (SDP) findings as opposed to the NRC's preliminary Yellow determination. Furthermore, if the additional technical positions provided in the

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attachment are considered regarding the time of inoperability of EDG No. 3 and the common cause failure to run factor, the CDP results are even more firmly categorized as White for Units 1 and 2.

Dominion has also reviewed the two apparent violations specified in the NRC Special Inspection Report and agrees that the violations occurred as stated. Detailed root cause evaluations are still in progress. The failure to appropriately recognize and respond to the negative increasing trend of silver concentration in the EDG No. 3 oil samples is preliminarily attributed to the transition to an in-house oil analysis laboratory. The previous laboratory provided greater analytical support and alerted site personnel of adverse trends. Also, as noted in the NRC's inspection report, an incorrect action level for the silver concentration was included in the in-house laboratory's computer program designed to alert station personnel when the silver concentration in the EDG oil samples exceeded manufacturer's recommendations and required corrective action. Due to this error in change management, the potential significance of an increasing trend in silver concentration was not identified promptly. However, upon identification, activities were appropriately initiated to assess the condition and take corrective actions.

We look forward to discussing this information with you in greater detail at the Regulatory Conference on November 30, 2001. If you have any questions or require additional information prior to the Regulatory Conference, please contact us.

Very truly yours,

E. S. Grecheck
Vice President – Nuclear Support Services

Attachment

Commitments made in this letter: None.

cc: U.S. Nuclear Regulatory Commission
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Mr. R. A. Musser
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Surry Power Station

Attachment

Updated Risk Assessment of Surry EDG No. 3 Degradation

Surry Power Station Units 1 and 2

Dominion

Attachment

Updated Risk Assessment of Surry EDG No. 3 Degradation

I. Background

NRC Special Inspection Report Nos. 50-280/01-06 and 50-281/01-06 (Reference 1) document a Significance Determination Process (SDP) Phase III analysis relating to degraded components in Emergency Diesel Generator (EDG) Nos. 1 and 3 at Surry Power Station (Surry). The SDP Phase III analysis was preliminary and was based on the information and analysis capability available at that time.

An updated assessment of this finding by Dominion indicates that the preliminary Phase III analysis results were overly conservative (Reference 4). The purpose of this attachment is to describe the additional information and analysis methods that result in a more realistic assessment of the risk significance of this finding.

II. Methodology

The updated Dominion assessment uses the same general methods and data found in the NRC preliminary Phase III risk analysis. This includes use of the current updated Surry PRA model for internal initiating events and the non-updated fire analysis from the Surry Individual Plant Examination of External Events (IPEEE). The updated assessment credits additional deterministic analyses of the EDGs, includes more detailed PRA modeling, and updates information used in the preliminary Phase III analysis. The changes from the preliminary Phase III analysis include:

- Consideration of the impact of successful monthly runs of at least 2 hours for each EDG over the period that EDG No. 3's condition was degrading

- Assessments which indicate that EDG No. 1 was fully operable and not experiencing the same degradation rate as EDG No. 3 over the period that EDG No. 3's condition was degrading

- Assessments which indicate that EDG No. 2 was fully operable and not experiencing the same degradation rate that was observed in EDG Nos. 1 and 3 over the period that EDG No. 3's condition was degrading

- Crediting availability of the Alternate AC (AAC) diesel generator in the IPEEE Fire Analysis (which was installed after the IPEEE fire analysis was performed)

- Updating the status of each unit's RCP seal replacements over the period that EDG No. 3's condition was degrading (i.e., only two of three RCPs in each unit had complete high temperature endurance seal packages installed)

Mitigation of Loss of Offsite Power (LOOP) Events of 2 Hours or Less

The impact of successful monthly surveillance runs of at least 2 hours for each EDG over the period that EDG No. 3's condition was degrading is that all of the EDGs, including EDG No. 3, were fully capable of responding to loss of offsite power events lasting 2 hours or less. This was true even when EDG No. 3 was last tested on April 15, 2001, since EDG No. 3 was run for at least 2 hours on this date. (EDG No. 3 was subsequently declared inoperable and removed from service for inspection on April 23, 2001.) While the monthly surveillances were not adequate to establish the capability to run for 24 hours, they were adequate to establish the capability to run for at least 2 hours. Therefore, there was no time prior to April 15, 2001 in which any of the EDGs were incapable of mitigating loss of offsite power events lasting 2 hours or less. Inclusion of this factual observation is important to proper assessment of the risk significance of the finding.

This observation was factored into the updated internal events PRA by excluding loss of offsite power events lasting 2 hours or less from the analysis. Since there was no degradation in responding to loss of offsite power events lasting less than 2 hours, the change in risk for these initiators was zero. The frequency of loss of offsite power events greater than 2 hours (taken from References 2 and 3) was substituted in the current updated Surry PRA model for internal initiating events for use in this updated analysis.

Common Cause Factor Consideration

The NRC's Phase III Analysis provided in Attachment 3 to the Special Inspection Report assigned a "common cause failure to run factor" of 0.03 in the core damage probability assessments for Surry Unit 1 and Unit 2. We believe the assignment of this common cause failure to run factor was overly conservative in the NRC's analyses and that a nominal value should be used instead. Deterministic assessments of EDG Nos. 1 and 2 were performed that indicate that these EDGs were fully capable of performing their intended functions over the period that EDG No. 3's condition was degrading. While the conditions that led to the degradation of EDG No. 3 could also impact EDG Nos. 1 and 2, the wear rates on these EDGs were not similar to EDG No. 3. Using the silver content in the lubricating oil as the primary indicator of degradation, the wear rates among EDG Nos. 1, 2 and 3 were significantly different, even though all the EDGs used the same new lubricating oil over the period that EDG No. 3 was degrading. The increased potential for common cause failure of EDG Nos. 1 and 2 over the period that EDG No. 3's condition was degrading and due to the same degradation cause as EDG No. 3, is not supported by the data. Although there was a failure in the lube oil trending program to initiate action in a timely manner on EDG No. 3, this deficiency would not have resulted in common cause failure of the EDGs in this situation due to the significantly different degradation rates for each of the EDGs and the successful completion of the monthly surveillances of each diesel. Had the degradation rates of

the EDGs been similar, then a common cause impact from the deficiency would have been appropriate.

The 0.03 common cause factor would be appropriate for projecting the risk associated with the potential inoperability of EDG Nos. 1 and 2 with an unknown component wear condition; however, it is overly conservative to include such a factor in this case since the actual extent of component degradation is known. The condition of the wrist pin bearings in EDG No. 1 have been examined and clearly demonstrate that the EDG No. 1 bearings experienced a significantly different degradation rate and extent than EDG No. 3. Initial inspections of the EDG No. 2 bearings currently indicate that the bearings have not experienced the same degradation rate as EDG Nos. 1 or 3. Consequently, we believe that assigning a common cause failure to run factor of 0.03 was overly conservative in the NRC's analyses, and that a nominal value should be used instead.

Alternate AC Diesel and IPEEE Fire Analysis

The IPEEE fire analysis was completed prior to the installation of the AAC diesel generator. Therefore, the preliminary SDP Phase III fire analysis was very conservative since it did not credit the AAC diesel generator. The AAC diesel generator provides at least one order of magnitude reduction in core damage risk, since it can power safe shutdown loads at both units. Therefore, all applicable fire cutsets considered in the updated assessment were multiplied by a factor of 0.1 to account for availability of the AAC diesel generator.

RCP Seal Replacement Status

The preliminary Phase III SDP analysis assumed that all the Unit 1 RCP seal packages utilized the high temperature endurance seals, and two of the three RCPs at Unit 2 utilized the high temperature endurance seals. However, subsequent information indicates that one of the three Unit 1 RCPs still had a stage 1 seal that had not been replaced with a high temperature endurance seal. Due to the difficulty in determining the impact of both high temperature endurance seals and non-high temperature endurance seals in a single RCP seal package, it was conservatively assumed that the affected Unit 1 RCP did not have any high temperature endurance seals installed. This resulted in both Unit 1 and 2 having similar RCP seal configurations, which eliminates the need for separate SDP calculations for Unit 1 and 2, as was done in the preliminary SDP Phase III analysis. In addition, the RCP seal failure probabilities in the current internal events PRA model and IPEEE fire model were adjusted to account for two of three RCPs utilizing high temperature endurance seals, and one RCP utilizing non-high temperature endurance seals, as well as use of the Rhodes RCP seal model.

Exposure Time Alternatives

The NRC Special Inspection Report concluded that the maximum time period that Emergency Diesel Generator (EDG) No. 3 was not able to perform its safety function was from March 22, 2000, to April 28, 2001. This was based upon the NRC's supposition (based on increased silver content in lubricating oil samples) that degradation was beginning to occur upon return to service of EDG No. 3 on March 22, 2000. Consequently, the NRC assumed an exposure time of 201 days based on one

half of the period between the date where the EDG No. 3 lubricating oil was changed (i.e., March 22, 2000) and the date the EDG No. 3 was restored to service following repairs (i.e., April 28, 2001). The NRC's Special Inspection Report further noted that the risk models used in the SDP assume that EDG No. 3 needs to run for 24 hours to perform its safety function. However, deterministic assessments performed by an independent industry diesel expert, as well as the NRC Special Inspection Report, established that EDG No. 3 was capable of performing its safety function up to at least October 3, 2000, since the accumulated run time from October 3, 2000 to April 23, 2001 was approximately 24 hours. As noted by the independent diesel expert, beyond this point in time, the ability to run for 24 hours becomes increasingly uncertain and cannot be assured. To address this uncertainty in run time after October 3, 2000, an alternate exposure time of 104 days was also evaluated based on one half of the period between October 3, 2000 and April 28, 2001.

III. Assumptions

The assumptions used in the updated assessment were the same as those used in the NRC preliminary Phase III analysis with the following exceptions:

- The increased common cause failure potential of EDG Nos. 1 and 2 due to the silver trending deficiency and degradation of the EDG No. 3 was evaluated as a sensitivity, but is not considered the most realistic case based on the discussion above.

- The RCP seal LOCA probabilities used in the updated internal events and fire analysis were based on the Rhodes model with 2 of 3 RCPs utilizing high temperature endurance seals and 1 of 3 RCPs using non-high temperature endurance seals in both Units 1 and 2.

- Applicable fire cutsets considered in the updated assessment were multiplied by a factor of 0.1 to account for availability of the AAC EDG.

- The cumulative risk was evaluated for two different exposure times: (1) the NRC proposed exposure time of 201 days and (2) an exposure time of 104 days which assumes EDG No. 3 was able to perform its safety function up to October 3, 2000, and for an unknown period beyond this date.

IV. Results

<u>Core Damage Probability (CDP)</u>

The core damage probability (CDP) and Significance Determination Process (SDP) color associated with each case are provided in the following table:

Case	CDP (Unit 1 and 2)	SDP Color
104 days exposure time with no increased common cause impact	2.2E-6	White
104 days exposure time with NRC assumed common cause impact	3.3E-6	White
201 days exposure time with no increased common cause impact	4.2E-6	White
201 days exposure time with NRC assumed common cause impact	6.5E-6	White

The details of these calculations are documented in Reference 4.

Large Early Release Probability (LERP)

Most risk scenarios typically are more sensitive to the CDF than they are to LERF. In the station blackout scenarios, containment failure leading to a massive release typically occurs at about 20-24 hours. However, the loss of offsite power (LOOP) data in References 2 and 3 indicate that more than 96% of LOOP's are recovered within 24 hours. Thus the LERF impact would be more than an order of magnitude smaller than the CDF impact. Since the SDP LERP significance scale is an order of magnitude below the CDP significance scale, the CDP results dominate the significance of this issue.

V. Conclusions

The NRC SDP risk significance scale categorizes CDP increases between 1E-6 and 1E-5 as White findings. Based on the updated assessment, which credited the impact of successful monthly surveillances for assuring partial success of EDG No. 3 in postulated accidents, the results for all the cases support a conclusion that the inspection finding should be categorized as White for both Units 1 and 2.

VI. References

1. Letter from Mr. Victor M. McCree, NRC to Mr. David A. Christian, Dominion, "Surry Power Station – NRC Special Inspection Report Nos. 50-280/01-06 and 50-281/01-06; Preliminary Yellow Finding for Unit 1 and 2," dated October 11, 2001

2. NSAC-144, Losses of Off-Site Power at U.S. Nuclear Power Plants All Years Through 1988, April, 1989

3. EPRI Technical Report, Losses of Off-Site Power at U.S. Nuclear Power Plants - Through 1999, July 2000

4. Dominion Calculation SM-1334, Revision 1, PRA Assessment of Surry #3 EDG Inoperability, November 2001