December 22, 1994

Mr. J. P. O'Hanlon
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Virginia Electric and Power Company
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SUBJECT: NORTH ANNA POWER STATION, UNITS NO. 1 & NO. 2 (NA-1&2) - INDIVIDUAL PLANT EXAMINATION (IPE)/REQUEST FOR ADDITIONAL INFORMATION (RAI)

Dear Mr. O'Hanlon:

Based on the NRC ongoing review of your NA-1&2 IPE submittal, we are requesting additional information in order to complete our review. The RAI is provided in the enclosure to this letter.

The RAI is related to the internal event analyis in the IPE, the containment performance improvement program, and the proposed resolution of Generic Safety Issue (GSI)-23, "Reactor Coolant Pump Seal Failures."

We request that your response be provided within 60 days of your receipt of this letter.

This requirement affects fewer than 10 respondents and, therefore, is not subject to Office of Management and Budget review under P.L. 96-511.

Sincerely

(Original Signed By)

Leon B. Engle, Project Manager
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Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket Nos. 50-338 and 50-339

cc: See next page

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ENCLOSURE

QUESTIONS ON NORTH ANNA INDIVIDUAL PLANT EXAMINATION (IPE) SUBMITTAL

North Anna IPE Review

1. North Anna is a two unit site with several shared systems; offsite power, service water (SW), instrument air, and component cooling water (CCW). The submittal states that the following initiating events modeled in the IPE result in tripping both units: loss of offsite power, loss of instrument air, and loss of SW. While the submittal contains information on the guidelines for modeling these dual unit interactions, it does not report the estimated dual unit core damage frequency (CDF). Please discuss those dual unit initiating events which may evolve into dual unit core damage. Include the estimated CDF (if available) due to such events.

2. The submittal indicates that loss of offsite power was considered as dual unit loss of offsite power, i.e., loss of power to the whole site. Please explain how single unit loss of offsite power was modeled and how its frequency was incorporated into the model.

3. It is not clear from the submittal that the modeling of the CCW system i.e., two pumps for each unit and each unit isolated from each other, represents the only plant operating configuration. Please discuss the operational configuration of the CCW system and, if different from indicated in the IPE (i.e., operated with cross-connect open between units), discuss the expected impact of the configuration difference on CDF, if any, and possible contribution to dual unit CDF.

4. Please address the following questions related to success criteria and the event trees:

   a. The IPE credits operator action to cooldown and depressurize the reactor coolant system (RCS) with the secondary as a method to prevent reactor coolant pump (RCP) seal loss of coolant accident (LOCA). The use of depressurization in other IPEs is credited with reducing the magnitude and likelihood of RCP seal LOCA, but not with preventing it completely. This action (top event O) appears in event trees for flooding, loss of SW, loss of RCP seal cooling, and loss of emergency switchgear cooling (ESGR) and transfers from other trees, for example, loss of offsite power to the ESGR tree. Please discuss the basis and the impact of this assumption on the estimated CDF and its impact on the contribution to CDF from RCP seal LOCA. Include the flooding event tree in your discussion since it is not clear that the human error probability (HEP) sensitivity analyses nor the importance calculations took the flooding events into account.

   b. For small LOCA events in which high head safety injection (HHSI) fails, the IPE credits operator action to depressurize with the secondary and use low head safety injection (LHSI) to mitigate a small

LOCA. This success path was not credited in the NUREG-1150 study, in which sequences where HHSI failed were considered to go to core damage. From discussions about the HEP on page D-172, the time available to take this action is based on the steam generator (SG) dryout time of about 91 minutes for a 2" break. However page B-2 indicates that the timing used for core cooling recovery is the time to core uncovery for a 1" break with no safety injection (SI), i.e., 2.2 hours. Please discuss the following:

(1) The rationale for use of the SG dryout time and not the core uncovery time, considering that for small break sizes larger than 1" and up to 2", the core uncovery time may be significantly less; possibly as limiting as 0.5 hours. This reduced time would cause the HEP to be significantly higher, increase the contribution of small LOCA and the total CDF. Discuss the impact.

(2) The success criteria in the submittal for small LOCA indicate that secondary side heat removal can be accomplished with AFW and either the steam dumps to the condenser or through the atmospheric dump valves. It is also indicated that an SI signal is assumed to be present for all LOCAs; consequently it appears that credit for the steam dumps should be eliminated unless an operator action to defeat the signal is considered. However, this type of action does not appear in the estimates for time available to depressurize. Since there is a significant difference of relief capacity between the steam dumps to the condenser and the atmospheric dumps (about 1/4 the capacity of the steam dump valves) which would affect the time to cooldown (identified in the submittal as 5 minutes) and since the fault trees appear to credit both paths, please identify and discuss (i) if both paths were given credit, (ii) the effect on estimated time to cooldown for each path and the assumptions used, and (iii) the impact on the HEPs and CDF due to the different paths.

c. For plant damage state delineation the event trees separate recirculation spray from the containment sump (top event Rs), and containment heat removal by cooling of the recirculation spray heat exchangers with SW (top event Ch). The success criteria for large, medium, and small LOCAs require containment heat removal; that is, success of both events Rs and Ch. The event trees indicate that loss of containment heat removal leads to core damage for LOCA events. However, discussions in the submittal (page 4-16) indicate that the LHSI pumps are environmentally qualified to 300° F. and will continue to operate even if the temperature gets to 350° F., at which point the containment is likely to fail due to overpressure. This indicates that core damage has not occurred at this point. This indicates that pumps are still functioning with a failed containment, but no core damage has occurred. However, an assumption listed on page A-62 of the submittal indicates that the design temperature of the pump is limited to 250° F. by the graphite bearing assembly. Please provide the basis for the assumption that the self-cooled ECCS pumps with a 250° F. design temperature (as indicated by the assumption) can operate up to 350° F. What is the

impact on the CDF of this assumption? If the pumps do fail then there would be an impact on the release from the containment, since these sequences would be core damage sequences ensuing into what would be a failed containment.

d. Given the assumption of successful operation of the LHSI pumps at elevated temperatures as discussed in c. above and since the IPE credits one heat exchanger in the recirculation spray system as sufficient to provide containment heat removal to support core cooling, (about 1/2 of the containment heat removal used in the UFSAR licensing analyses), please discuss if nominal or plant-specific heat exchanger efficiencies were used to support the use of only one heat exchanger to prevent the LHSI pumps from overheating.

e. It is stated in the discussion for recovery factor REC-CONTAINMENT, that a probability of ECCS failure from environmental qualification effects associated with containment failure was assigned a value of 0.02 and applied to sequences, as noted above, for which containment cooling was lost, containment fails, but ECCS was successful. The sensitivity analysis results, wherein the value of REC-CONTAINMENT was set to 1.0 (guaranteed failure), indicates that the resultant CDF was 7.3E-5, a 7.6% increase. However, it appears that this sensitivity analysis included the internal events, but not the flooding events, and that if the same factor was applied to the flooding events, those sequences that originally did not go to core damage, would go to core damage with a frequency of about 3E-5 from the E-FAB2 tree alone. This would increase the total CDF by the same amount and result in a CDF of about 1E-4. Please address this case and the impact of all the affected flooding sequences, for this sensitivity analysis.

5. The IPE credits operator action for continued operation of turbine driven auxiliary feedwater (TDAFW) pump following loss of dc power. How is loss of the turbine due to overfilling the SGs prevented, given a loss of SG level indication?

6. The UFSAR and Appendix A of the submittal indicate that the electric power system is not symmetric at the two units. The fault trees in the submittal indicate that cross-tie of the 4160 V. 1E buses at unit 2 is available, while at unit 1 it is not, and also shows the capability of unit 2 supplying power from bus 2J to bus 1H of unit 1 and vice versa, but not from 2H to 1J. However, the system description in Section 3.2 of the submittal states that the power system is symmetric between the two units. If the unit 1 electric power lineup was used as the model for both units, please discuss how the IPE model accounts for the plant-specific asymetries in the electric power configuration, and what is the impact, if any, on the CDF? In addition, there does not appear to be an HEP identified to account for operator failure to make such crossties.

7. Plant-specific data were used to quantify failure-to-start for numerous components, including: the TDAFW pump, HHSI pumps, and emergency diesel generators (EDGs). Given that a number of valves in the plant are normally tested, why weren't plant-specific failure on demand data for

valves used in developing failure rates for the IPE?

8. Table 3.4.3.3, dealing with contributions of decay heat removal (DHR) functions to CDF, is missing from the submittal. Please provide this information.

9. The submittal indicates that loss of instrument air is not of major concern for air-operated valves such as primary power operated relief valves (PORVs) and SG atmospheric dump valves (ADVs), due to the presence of backup air supplies. What credit for long term operation of accumulators was taken and how was long term leakage from these accumulators considered in the models for these valves?

10. The submittal indicates that the only heating ventilation air conditioning (HVAC) system modeled as required to mitigate an accident is cooling for the ESGR rooms. The UFSAR indicates that numerous HVAC systems are present in the plant. The dependency tables in the submittal indicate that there is no dependency on HVAC for the following areas: AFW, charging pumps, LHSI pumps, residual heat removal (RHR) pumps, SW pumps, and recirculation spray pumps. Please discuss the basis (calculation, test etc.) for assuming that HVAC to these areas is not required. Also, discuss the dependency of the operation of the EDGs on the ventilation louvers (it is not clear if this implies natural or forced convection and if fans are required) and how they were included in the model.

11. The submittal (Section 6) identifies a number of recommendations for plant and procedure modifications which were credited in the IPE internal events and flooding analyses. From the submittal, the increase in the estimated CDF if the recommendations were not implemented is about 3E-5/year. However, the increase in the CDF due to not implementing the recommendations identified from the flooding analysis is not provided in Section 6 of the submittal. Please identify the amount of credit attributable to these changes to the estimated CDF. Also, identify the status of the recommended modifications listed in Tables 6-1 and 6-2 of the submittal and if they have not yet been incorporated, identify the schedule for their implementation.

North Anna IPE Review Back-end Questions

1. It is not clear from the submittal whether the key figures of merit used for the North Anna containment event tree (CET) analyses such as containment pressure loads, in-vessel hydrogen generation, etc. (obtained from Surry analyses), were scaled properly to reflect the smaller containment and larger RCS volume in the North Anna plant. Please describe how the submittal scaled the results of the Surry analyses to the North Anna plant.

2. It is difficult to interpret and understand the IPE results for early

containment failure. Even though the NUREG-1150 results have been used to a large extent, the conditional probability of early and late containment failure for the North Anna submittal is about twice as large as the corresponding results from the NUREG-1150 analyses for the Surry plant. For the three important initiators, namely, transients, loss of offsite power sequences and LOCAs, please explain the differences in the CET inputs between the Surry NUREG-1150 analyses and the North Anna analyses.

3. This question concerns the quantificatio of the early containment decomposition event tree (DET) in Figure 5.2-4, page 4-175 of the submittal. The pressures listed in the above-mentioned figure for the various DET branches could not be found in NUREG/CR-4551 or in NUREG/CR-4896. Please discuss how the containment loads for the various CET branches (in node "TOTPRESS" of Figure 4.5.2-4 of the submittal) were obtained.

4. With regard to local hydrogen detonations:

   (a) To what extent have plant walkdowns been performed to determine the probable locations of hydrogen released into the containment? Discuss how the process assessed (i) local deflagrations that could translate to detonations given a favorable nearby geometry, and (ii) the containment boundary, including penetrations and associated challenge by hydrogen burns.

   (b) Please identify potential reactor hydrogen release points and vent paths, and estimates of compartment free volumes and vent path flow. Please specifically address how this information is used in your assessment of hydrogen pocketing and detonation. Your discussion (including important assumptions) should address likelihoods of local detonation and potentials for missile generation as a result of local detonations.

5. What operator recovery actions were considered in the back-end analysis? Have you considered the potential of hydrogen burn as a result of turning on containment spray when the containment is steam-inerted in a severe accident scenario? Please provide a discussion of your considerations.

6. With respect to the analysis of containment isolation failure probability, NUREG-1335 (Section 2.2.2.5, page 2-11) states that "the analyses should address the five areas identified in the Generic Letter, i.e., (a) the pathways that could significantly contribute to containment isolation failure, (b) the signals required to automatically isolate the penetration, (c) the potential for generating the signals for all initiating events, (d) the examination of the testing and maintenance procedures, and (e) the quantification of each containment isolation failure mode (including common mode failure)." Please discuss your findings related to the above five areas.

7. Please describe what consideration was given to the effect of prolonged

high temperatures on containment penetration elastomer seal materials.

8. In general, provide a concise discussion of how your IPE process treated equipment survivability during a severe accident scenario and how credit was taken for equipment exposed to severe accident conditions.

9. Describe briefly any plant-specific insights (including candidates for back-end improvements), and discuss how these insights were or will be used to enhance plant safety.

10. Generic Letter 88-20 states that: "any functional sequence that has a core damage frequency greater than or equal to 10^{-6} per reactor year and that leads to containment failure which can result in a radioactive release magnitude greater than or equal to BWR-3 or PWR-4 release categories of WASH-1400," should be reported by the IPEs. The IPE submittal does not directly address this requirement. Please provide a listing of such sequences.

North Anna IPE Review Human-factor Questions

1. It is not clear from the submittal that the impact of human error in the calibration of critical instrumentation was quantitatively evaluated. Page 3-96 of the submittal includes calibration error in the general definition of "Type A" errors (pre-accident operator actions), but no calibration errors appear in Appendix D of the submittal wherein Type A errors are addressed. Please discuss how calibration errors were considered in the IPE and if not addressed, identify the basis for not including them in the quantification. If eliminated on the basis of frequency, identify the criteria.

2. The descriptions of pre-initiator HEP calculations in Appendix D of the submittal include a line indicating an evaluation of dependency. No dependencies were identified. In addressing dependencies, whether miscalibration or failure to restore, the process utilized should consider plant conditions, human engineering, performance by the same crew at the same time and the adequacy of procedures, etc. Please provide a discussion of the potential dependencies that were considered for pre-initiator human actions and why no dependencies were addressed in the quantification.

3. The descriptions of post-initiator HEP calculations in Appendix D of the submittal indicate that dependencies were identified between some specific human errors. However, the submittal does not provide a clear explanation of the rationale for the determination of dependency in all cases where a dependency may exist, or for identifying the degree of dependency. In particular in some cases where no dependency was assessed, the comment was made that the actions were "different enough" to be considered independent. Please provide an explanation of the criteria or bases for determining the degree of dependency.

4. In most cases in which a dependency was identified, the dependency is between two HEPs which are the same action at different times in the sequence. In those cases, the second HEP is lower, because of the longer time permitted; and the quantification of dependency is to increase the second HEP (P2 and P3) so that the joint probability of the two actions is no less than the independent probability of the second HEP. It is not clear that that this approach will yield HEP values equivalent to values arrived at by assuming a high degree of dependence (e.g., using Techniques for Human Error Rate Prediction (THERP)). Please discuss the technical basis for this quantitative treatment of dependency.

5. The presentation of results in the submittal regarding the importance of recovery actions appears confusing. Page 3-129 of the submittal indicates that the dominant recovery actions are:

   REC-1OP31:1 - recovery of main feedwater
   REC-OAP10 24HR - loss of electrical power recovered in 24 hours
   REC-1OP14:1 - local opening of RHR valves to recover RHR after SGTR
   REC- 1MOP6-70 - Recovery of 1H emergency from maintenance

   Only one of these recovery actions (REC- 1OP14:1) is included in the table of recovery actions, and Table 3.4.1-12 of the submittal identifies other recovery actions than those listed above as being sensitive to increases in the failure recovery probability. Please clarify how these unlisted recovery actions were addressed in the IPE, how they were determined to be dominant, and discuss these in comparison to the other recovery actions listed in Table 3.4.1-12. In addition, please provide a description of the process used, including walkdowns and procedure reviews etc. to assure that the credit given for these recovery actions were appropriate.

Questions on Generic Safety Issue (GSI)-23, "RCP Seal Failures"

1. Section 3.1.1.1.3 states that the SW provides cooling to the charging pumps and the CCW provides thermal barrier cooling. This means that the loss of CCW alone does not cause loss of seal cooling and therefore it was not considered as an initiating event. However, the loss of CCW could cause loss of cooling to RCP motors, requiring trip of the RCPs by operator action. If the operator does not respond to trip the RCPs, the loss of cooling to motor bearings can result in a vibration induced seal LOCA. How did the submittal address a vibration-induced RCP seal LOCA? Why was the loss of CCW not considered as an initiating event?

2. For the concerns of RCP seal failure caused by loss of offsite power, Appendix B of the IPE submittal, Section B.1.4.1 states that the RCP seal LOCA model is based on the Westinghouse model in WCAP-10541, (Figure 10-3) with modifications similar to work done by Atomic Energy of Canada Limited (AECL), and is shown in Figure B.1-2. The Westinghouse model does not consider the "popping open" mode of seal failure, and furthermore, the staff does not agree with Westinghouse

assigned probability of occurrence of each failure mode. The staff would accept methodology (in particular, the seal modelling) similar to the one employed in NUREG-1150 studies, if it is properly applied and considers the "popping open" mode of seal failure. However, it should be recognized that the staff is currently assessing the significance of an error in NUREG-1150 in the application of the model since it does not include the time independent "popping open" mode of seal failure prior to 90 minutes. The staff believes that the "popping open" mode is a credible seal failure mechanism and the probability of the seal "popping open" is finite any time after the effects of a loss of cooling reach the seal faces (i.e. 10 minutes after loss of seal cooling). Figure B.1-2 indicates that the probability of seal failure during the first hour is zero, which shows that the "popping open" failure mode has not been properly addressed by the licensee. The current staff position outlined in the proposed rule for resolution of GI-23 requires either an analysis similar to one employed in NUREG-1150 to address the "popping open" mode, or a demonstration that the risk associated with RCP seal failure is sufficiently low such that further risk reduction is not justified. Please respond in accordance with the current staff position.

3. The IPE submittal contains curves from the Westinghouse seal LOCA model in Figure B.1-1. This data is "probability of core-uncovery for time t, given loss of AC power." However, the title on this figure is "Probability of non-recovery of offsite power," which is incorrect. Also this figure shows two sets of data, one for unqualified elastomers and one for qualified elastomers, but there is no discussion of which case applies to North Anna. Evidently North Anna uses unqualified elastomers based on use of data from Figure B.1-1. Please confirm that unqualified elastomers are used at North Anna.

4. Further, the IPE submittal indicates that the modification to the Westinghouse seal model involved increasing the probability of core uncovery from 0.109 at 8 hours to 1.0 at 10 hours. The modification also increased the probabilities at earlier times from those given by Westinghouse, e.g., the probability of core uncovery at 6 hours in the Westinghouse data for unqualified elastomers is about 0.04, while the probability in the modified curve in Figure B.1-2 is about 0.09. What is the reason and justification for modifying Westinghouse data for times less than 10 hours?

5. Section B.1.4.1 presents the following equation for the probability that loss of seal cooling at time 0 leads to core uncovery by time t.

$$P(B) = \frac{\int_0 f(t)\ P_{NRAC}\ (t)\ dt}{\int_0^t f(t)\ dt}$$

There is no discussion provided related to this equation. What is P_{NRAC}? What is f(t)? Why is the equation normalized by the integral of f(t)

over time? How was this equation used in the analysis? Provide complete details of this equation.

6. Section 3.4.4.2 states that overall CDF is highly sensitive to the RCP seal LOCA model used. It also states that the modifications to ensure the availability of seal injection under off-normal conditions will be installed. Please provide details of this modification and schedule of implementation. In the absence of any details of this action, the staff will be unable to assess the adequacy of seal integrity under postulated events.

7. The discussion on recovery of offsite power during station blackout (SBO) states that if offsite power is recovered prior to core uncovery, then two situations are considered: [IPE, Page 3-50]

   (1) no seal LOCA has occurred
   (2) a seal LOCA has occurred.

   For case (2), the sequence is modeled as a small LOCA. This distinction is important, but the Appendix B discussion on the details of the seal LOCA model does not address how a probability curve for "no seal LOCA" as a function of time was produced from the data presented as the basis for the seal LOCA model which is a probability curve for "no core uncovery due to a seal LOCA" as a function of time. Please discuss how the curve for "no seal LOCA" was generated.