VIRGINIA ELECTRIC AND POWER COMPANY

RICHMOND, VIRGINIA 23261

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Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
NORTH ANNA POWER STATION UNITS 1 AND 2
RESPONSE TO ADDITIONAL INFORMATION
PROPOSED TECHNICAL SPECIFICATION CHANGE
EDG ALLOWED OUTAGE TIMES

By letter dated April 12, 1996, the NRC Staff requested additional information to continue their review of our proposed Technical Specification change for Emergency Diesel Generator Allowed Outage Times. A detailed response to each question is provided in the Attachment 1 to this letter.

Should you have any questions or require additional information, please contact us.

Very truly yours,

M L Bowling

M. L. Bowling, Manager
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Attachments

cc: United States Nuclear Regulatory Commission
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Attachment 1

Response To Request for Additional Information
Emergency Diesel Generator Allowed Outage Time
North Anna Units 1 and 2

Response To Request for Additional Information

(A) Tier 1

(a) Probabilistic safety assessment (PSA, or PRA)

- What are success criteria for the station blackout (SBO) condition at North Anna 1/2? Can any one EDG mitigate SBO? Is this modeled in the PRA? Please explain.

  Response

  The success criteria for any initiating event are the minimal number of systems that are required to function to maintain adequate heat removal from the core and containment, ultimately establishing long term stable conditions, and preventing core damage or containment failure. The station blackout event tree is developed from the loss of offsite power event tree. The loss of offsite power with a failure of both EDGs on one unit is a transfer sequence from the loss of offsite power event tree that has been developed into the SBO event tree. The success criteria require that two of the three remaining diesels start and run (2 EDGs and 1 AAC DG). One diesel is required for the unaffected unit and one diesel is required for the affected unit.

  The model considers a unit blackout following a loss of offsite power. However, both units must have RCP seal cooling to avoid a seal LOCA. Successful supply of RCP seal cooling is required for both units using the charging pumps or component cooling pumps on the unaffected unit.

  The PSA model accounts for mechanical failures in the systems on the unaffected unit, mechanical failures of the valves which must change position to permit the cross-connect of the Charging System, as well as human error associated with the system realignment. Electrical failures subsequent to the SBO on the unaffected unit are also included in the model.

- How are minor asymmetries in the Unit 1 and 2 electrical power supplies accounted for in the PRA modeling?

  Response

  A fault tree model consists of Boolean logic gates which are mathematically reduced to provide combinations of failures leading to system failure (cut sets). The fault tree for each electrical bus contains failure probability estimates for the breakers, motor control centers, transformers and other components that makeup the bus. Each emergency bus as well as the busses associated with the AAC DG are represented uniquely in the model. A front line system fault tree model includes failure probability estimates for the components from the safety system being modeled and external transfers to the support systems such as electrical power. The modeling of asymmetries is accomplished by providing an accurate front line system model. For example, there are three charging pumps and two emergency buses in the North Anna design. The fault tree models containing the charging pumps have external transfers to the electrical busses. The 1A charging pump transfers to the 1H bus. The 1B charging pump transfers to the 1J bus. The 1C charging pump transfers to the 1H bus. This asymmetry in the loading of the charging pumps is modeled properly because of the external transfer linking the component to the support system. No special modeling of asymmetries is required.

- 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

Virginia Power indicated its intention to maintain the Individual Plant Examination (IPE) model as a living PSA model in the IPE submittal (Virginia Power letter dated December 14, 1992, Serial No. 92-774). Since that time the model has been updated to incorporate significant plant modifications. The most significant plant modification since the IPE submittal has been the installation of the AAC DG.

For the IPE the assurance was generated by the peer review. The peer review team included station personnel from the engineering and operations departments. Their review concluded that the IPE did represent the as-built, as-operated plant.

In order to decide if the model is applicable to a proposed analytical effort, such as the proposed preventive maintenance inspection, the analyst must review several aspects of the model:

- First, the model must be reviewed to determine if the safety systems and support systems being analyzed are included. For the proposed preventive maintenance inspection, all of the electrical busses and diesel models were required to be included. Incorporation of the AAC DG into the PSA model was also required.

- Next, the accident sequence timing must be reviewed. For the proposed preventive maintenance inspection, it was determined that a significant timing difference existed. Since the AAC DG is manually loaded it was necessary to define the scenarios in which the AAC DG could be used for accident mitigation.

- Finally, human error probabilities must also be reviewed for applicability. A new human error probability (HEP) was required for the action of manually loading the AAC DG. This HEP was included with the hardware faults in the model upgrade for the AAC DG.

- Your current PRA is said to be different from your IPE. Explain any major differences. Among those differences, are any related to SBO sequences?

  Response

  The differences between the current PSA model and the IPE are presented in Section 3.1 of the Probabilistic Safety Assessment submitted as Attachment 4 to the proposed Technical Specification change for the EDG maintenance inspection dated September 1, 1995 (Serial No. 95-430). The last paragraph of the section discusses changes in the loss of offsite pow. event tree structure to incorporate the AAC DG model. These changes are the only significant changes that impact the SBO sequences.

- 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

  The CDF model uses several different truncation limits. Each limit is presented below:

function solution	1E-09
event tree linking	1E-10
sequence concatenation	1E-10

  Procedural guidance was established as part of the IPE to avoid underestimation due to truncation. This guidance requires the solution to be three orders of magnitude greater than the truncation limit. This assures that truncated cut sets would not contribute significantly to sequence or core damage frequency.

- Provide a discussion of the loss of offsite power (LOOP) events at your facility.

  Response

  NUREG-1032 was published by the NRC in June 1988. Appendix A of this document lists the loss of offsite power events at US nuclear power plants over a period of twenty years from 1966 to 1985. The events were grouped by cause into three categories: plant-centered, grid-related and severe-weather-induced. There were no LOOP events at North Anna in any category. A review of Licensee Event Reports (LERs) indicates that there have been no LOOP events at North Anna from 1985 to the present.

- Explain what severe weather conditions you are expecting 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? How do you plan to require avoidance of entering the 14 day AOT if severe weather is approaching?

  Response

  As discussed in the response to the previous question, NUREG-1032 considered loss of offsite power from severe-weather-induced events. The weather types found to have caused LOOP events in this study include: Snow/Ice, Tornadoes, Salt Spray, Hurricanes and High Wind. North Anna is located inland in a moderate climate. So, it is expected that ice, tornadoes, or other high winds would be the most likely severe weather to be experienced at the site. These severe weather conditions are not included in the PSA model since it is an internal events model.

  External events such as weather were considered as part of the North Anna Individual Plant Examination for External Events (IPEEE). The evaluation of high winds, tornadoes and external flooding concluded that these events could be screened from detailed analysis based on the design of the plant or simple, bounding analyses.

  North Anna has not made a specific commitment to the severe weather shutdown requirements and procedures outlined in NUMARC 87-00. However, current plant procedures do identify the actions necessary to prepare for the onset of severe weather including hurricanes and tornadoes. The actions identified by our current procedures are consistent with those outlined in NUMARC 87-00, Section 4.2.3.

Avoidance of entering the 14-day AOT based on predicted severe weather is determined by the planning process and response to impending severe weather. Administrative controls currently exist that would prevent the initiation of any maintenance activities on Technical Specification required systems, subsystems, etc., or any other risk significant system or systems during periods of electrical system instabilities including severe weather conditions. These administrative controls also address the possibility of complications due to weather and other external events that may affect electrical system stability or stable plant operations. The same controls will be used for the EDG preventive maintenance outage.

For any long term developing weather conditions that are projected onsite and could affect stable operation (i.e., major winter storms or severe weather due to tropical storms or hurricanes), actions will be taken to restore the EDG to operable status as soon as practicable. For rapidly developing weather conditions, such as severe thunderstorms, abnormal operating procedures exist that provide direction on compensatory actions to be taken by the station to minimize the potential impact of such storm conditions.

- 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.

  Response

  Currently, model updates include two types of review. One is the PSA analyst review which is the independent review of the calculation. The second review is a design review meeting. As a minimum, three PSA members participate in a design review meeting for model updates. These meetings are held at approximately 30% and 70% completion points for the model update.

  The review of the IPE included both internal and external segments. The internal review consisted of one PSA analyst independently reviewing the work of another PSA analyst. The external segment included both station personnel and independent consultants reviewing the calculation notes. Details of these reviews are provided in Attachment 2 to this response, which contains selected pages from the IPE. As a result of this review it was concluded that the IPE model represented the as-built, as-operated plant. The IPE model was developed as a full Level 2 model and has become the basis for the current PSA model.

(b) Quantitative results

- Please provide the following calculations and quantitative PRA results due to the AOT extension:

  (1) Change in average CDF $\Delta m(CDF)$):

  m(CDF) = average CDF (per year)

  $m_2(CDF)$ = The conditional m(CDF) with the proposed 14 day AOT in place

  $m_1(CDF)$ = The original m(CDF) with the current 3 day AOT in place

  Therefore, $\Delta m(CDF) = m_2(CDF) - m_1(CDF)$

  Response

  $m_2(CDF)$ = 4.21E-5 / year

  $m_1(CDF)$ = 4.08E-5 / year

  Therefore, ($\Delta m(CDF)$ = 1.30E-6 / year

  (2) Change in instantaneous CDF (ΔCDF_i):

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

  $CDF_i(1)$ = The CDF when the plant is <u>not</u> in the AOT

  i = a particular AOT configuration

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

  Response

  $CDF_i(2)$ = 5.05E-5 / year

  $CDF_i(1)$ = 3.56E-5 / year

Therefore, ΔCDF_i = 1.49E-5 / year

(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

i = a particular AOT configuration

Therefore, ΔCCDP = CCDP(2) - CCDP(1)

Response

CCDP(2) = 5.05E-5 * 14/365 = 1.94E-6

CCDP(1) = 3.56E-5 * 14/365 = 1.37E-6

Therefore, ΔCCDP = 5.7E-7

(4) Change in average large early release frequency (ΔLERF):

LERF(2) = LERF with proposed AOT in place

LERF(1) = LERF with current AOT in place

Therefore, ΔLERF = LERF(2) - LERF(1)

Response

LERF(2) = 7.61E-6/year

LERF(1) = 7.36E-6/year

Therefore, ΔLERF = 2.5E-7/year

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

Response

The projected average maintenance downtime for the EDGs is 13.4 days per year when the unit is in modes 1 and 2. The PSA model does not differentiate between maintenance unavailability due to corrective or preventive maintenance so one basic event is used to represent the sum of all maintenance downtime. The maintenance downtime is based on two contributors: the actual plant data from 1990 to 1994 (i.e., 4.1 days per year); and 9.3 days of downtime to complete the preventive maintenance inspection. The latter contribution assumes that the preventive maintenance inspection utilizes all of the time, 14 days once every 18 months, proposed in the Technical Specification change request.

One "sensitivity" analysis was performed for the proposed preventive maintenance inspection. Instead of 13.4 days per year, this study utilized a maintenance downtime of 40 days per year for each of the five diesels resulting in a core damage frequency of 4.67E-5/year. This can be compared to the CDFs presented in the response to question (A)(b)(1) of 4.08E-5/year and 4.21E-5/year for the 3-day AOT and the 14-day AOT respectively.

The insights gained from the maintenance downtime sensitivity show that the increased risk associated with increasing the annual diesel maintenance downtime is far less than the decrease in risk associated with the installation of the fifth diesel generator at North Anna Power Station. Before the AAC DG was installed there were only four EDGs available to supply backup electrical power to the four 4160 V emergency buses and the corresponding CDF was 5.42E-5/year. Hence, even with an assumed downtime of 40 days for each of the five diesels the CDF of 4.67E-5/year is much less than the CDF calculated before the AAC DG was installed.

- Have you performed any sensitivity analysis for this requested AOT change? If so, discuss how your results ensure the PRA results in your application are robust and not subject to an unexpected sudden increase in the risk profile.

Response

No "sensitivity" studies were performed utilizing pre-solved cut sets which may not include all of the proper combinations. The only "sensitivity" study performed as part of the proposed preventive maintenance inspection change request is the maintenance unavailability study provided in the previous response. For this application of the PSA model, the validity of the results is ensured by a complete model requantification including all fault trees and event trees, utilizing a sequence truncation value of 1E-10.

(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 explain the results.

  Response

  The most risk significant systems and equipment represented in the Unit 1 PSA models are shown in Attachment 3 to this letter. The risk significance of the emergency diesel generators is also discussed. Unit 2 systems and equipment are similar. The list includes equipment, along with the system names, to eliminate confusion between non-risk significant equipment and the risk significant portions of the systems.

- For the systems you identified in the previous question, 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 procedures or TS?

  Response

  A majority of the risk significant equipment identified is currently controlled by Technical Specifications which limit continued power operation to less than 72 hours for the loss of one train. Additionally, when an EDG is removed from service and any other risk significant equipment becomes inoperable, then the unit is shutdown in accordance with the equipment's action statement or within six hours as directed by Technical Specification 3.0.5. Technical Specification 3.0.5 provides for a short recovery period of one hour when a system, train, or component powered by an emergency bus becomes inoperable at the same time the redundant system, train, or component is out of service.

  Administrative procedures for on-line maintenance only allow removal of one risk significant functional equipment group for preventive maintenance. Multiple risk significant functional equipment groups can be out of service only if the combination has been previously evaluated and found to result in an acceptable level of risk based on the outage duration. Also see the response to the Tier 3 questions below.

- Have you thoroughly reviewed your TS to see if there are needs 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 once per 18 months? Please identify any TS changes made to ensure that the plant will not enter any risk-significant plant configurations while in the AOT.

Response

Yes, a thorough review of Technical Specifications was performed as part of the change request evaluation. For this application, no additional Technical Specification changes other than those previously submitted with the Technical Specification change request package are necessary to prevent entry into any risk significant plant configuration. Also see the response to other Tier 2 and 3 questions.

(C) <u>Tier 3</u>

- Are you capable of performing a "real-time" assessment of the overall impact on safety functions of related TS activities before conducting maintenance activities including removal of any equipment form 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? Please describe how this explanation will be incorporated in the TS bases.

Response

North Anna Power Station operations personnel perform a "real-time" assessment of the overall impact on safety before conducting maintenance activities through strict adherence to Technical Specifications. Licensed senior reactor operators and control room operators are aware of the current equipment status at all times. These on-duty licensed operators must approve removal of any equipment from service for maintenance activities. These licensed operators will follow the guidance of the Technical Specification action statement requirements including removing the unit from power operation.

The North Anna Management safety philosophy does not allow maintenance to be planned or performed concurrently on risk significant equipment unless it has previously been determined to be a risk acceptable combination and outage duration. This safety philosophy ensures that the on-line maintenance is appropriately evaluated and executed to ensure plant safety is maintained by limiting risk significant equipment unavailability. The Technical Specification Bases does not need to be modified to address this philosophy.

Virginia Power does not currently have the capability to perform a computer based "real-time" assessment of risk by requantifing the PSA model. Work is being completed on identifying combinations of risk significant equipment which result in acceptable risk levels when simultaneously removed from service. A computerized risk monitor is under evaluation but not committed to at this time.

- 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

  The current Maintenance Rule configuration control process relies on tracking components that are out of service. The North Anna Operations Department tracks the status of systems, subsystems, trains, components, and devices that may affect the equipment operability through a computer network that is accessible to all station personnel. If any system, subsystem, etc., is in a condition, such that it is determined to be inoperable, then the appropriate entries are made in the computer network declaring that system, subsystem, etc., in "Action" and inoperable. Before any maintenance activities or testing are performed on any other systems, subsystems, etc., it is verified that the proposed configuration is not prohibited by Technical Specifications.

  Currently, North Anna has in place specific guidance, in the form of Administrative Procedures, that address controls placed on the maintenance and testing of structures, systems, or components while the unit is on-line using sound operating judgment and PSA insights. This guidance is not limited to only safety-related structures, systems, or components, but also considers any structures, systems, or components (including balance-of-plant equipment) that are risk significant or may affect stable operation of the plant.

  Additionally, Technical Specification 3.0.5 uniquely provides a means of limiting the configuration risk of the units when an EDG is unavailable for this maintenance inspection. This specification requires all equipment powered from the emergency bus associated with the inoperable EDG to be treated as inoperable if the redundant train of safety-related equipment becomes inoperable for any reason. When the redundant train becomes inoperable, the Technical Specifications require the unit to be removed from power operation within six hours. This minimizes the time that the unit can remain in any potentially high risk configuration.

  As stated previously, Virginia Power does not currently have the capability to perform computer based "real-time" assessments of risk by requantifing the PSA model. Work is being completed to identify combinations of risk significant equipment which result in acceptable risk levels when removed from service. A computerized risk monitor is under evaluation but not committed to at this time.

Attachment 2

Selected Pages From The IPE

In order to ensure that the plant truly reflects the design and operating experience, review of the following work products was performed by North Anna plant staff.

1. The significant system models and the assumptions made concerning system design and operation were reviewed by individual station engineers.

2. The human reliability modeling and assumptions were reviewed by the simulator training staff and the Human Performance Evaluation System (HPES) coordinator.

3. The accident sequence delineation (i.e., event tree functions) were reviewed by a Shift Technical Advisor).

4. The potential improvements were reviewed by station management and the appropriate discipline area at the station, i.e., procedure development, training, maintenance, operations.

Additionally, an independent peer review of the study methodology and results was completed. This peer review team consisted of station personnel and independent PRA consultants. See Section 5 for peer review details.

2.2.2 External Events

The current study includes only core damage and fission product release assessment following internal events and internal flooding. Plant walkdowns have been conducted for the flooding analysis. The information gained from these walkdowns has been included in the appropriate analysis files and will be available when performing external event analyses.

2.2.3 Methods of Examination

The approach used for the North Anna IPE is Method 1, that is a modified Level 2 PRA using current methods and information including a Containment Building performance analysis which addresses the issues in Appendix 1 and Supplement 3 to letter 88-20. The PRA follows the method described in NUREG/CR-4550 amplified by more detailed procedures for each individual task in order to comply as closely as possible with the quality assurance requirements identified in 10CFR50 Appendix B. The PRA is based on a clearly defined plant status, which was current at the time of performing the systems analysis in 1991. As the QA for the development of the plant model has required full recording of all documentation used, it will be a straight-forward process to update the model if so desired in the future. The methodology is described in more detail in Section 2.3.

5.0 UTILITY PARTICIPATION AND INDEPENDENT REVIEW TEAM

5.1 IPE ORGANIZATION

The organizational structure for the IPE is shown in Figure 5-1. The team was put together to optimize the Virginia Power resources while meeting the requirements of Generic Letter 88-20 (NRC 1988). A consultant was retained to provide probabilistic risk assessment (PRA) technology transfer in order to produce the results in a thorough, yet efficient, fashion. Three engineers from the corporate staff were assigned to be team members. However, the consultant, Halliburton NUS Corporation, retained overall responsibility for the technical aspects of the work. The Virginia Power team members were full time participants in the process while the Halliburton NUS team members participated on as needed basis. This approach helped to optimize the IPE process because Virginia Power resources were utilized efficiently, technology transfer was achieved, and the process was completed in accordance with a schedule approved by NRC.

Each Virginia Power team member participated in several of the tasks. A breakdown of the tasks and the Virginia Power participants is provided in Figure 5-2. As shown in the table, each of the tasks had at least one significant Virginia Power participant. Therefore, technology transfer has been accomplished in an effective manner.

5.2 INDEPENDENT REVIEW TEAM AND PROCESS

As shown in Figure 5-1 the independent review team consisted of station personnel, corporate staff, and consultants. The consultants were retained for two reasons. First, among the Virginia Power members of the PRA team there was little prior experience with either core damage or accident progression aspects of a modified Level 2 PRA. Second, because the consultants possessed the detailed knowledge of PRA analysis, it was reasonable to have them act as the coordinators of the independent review. Therefore, a team of two senior analysts from Science Applications International Corporation (SAIC) were contracted to act as chairpersons of the independent review committee and to have overall responsibility for the preparation of the independent review reports. The second consultant was employed to perform the independent review of the accident progression analysis. Since Stone & Webster Engineering Corporation (SWEC) was the architect/engineer for the North Anna Power Station and has maintained cognizance of the station through numerous design change projects, it was logical to employ their services for a review of the Containment analysis. The reviewer from SWEC is a senior analyst who is very familiar with the North Anna design, with severe accident analyses, and with the MAAP code. The scope of his review included all of the accident progression analyses and a check of a limited number of MAAP runs made for success criteria analyses, accident progression analyses, and source term analyses.

The corporate staff involvement was through the normal channel for independent reviews of proposed changes at the station. The group is called Corporate Nuclear Safety (CNS) and it is organizationally independent of the Engineering group. CNS participated in the independent reviews using a variety of corporate staff including members who had worked at North Anna for several years.

The members of the independent review team from the station included licensed Senior Reactor Operators, Control Room Operators, a shift technical advisor, and a member of the procedures group. The system engineering group was represented mostly on an as needed basis during the independent review. The team members participated in a one week review conducted at North Anna. The members of the team are listed in Table 5-1.

The independent review took place during the month of August 1992. At this time the review team had access to each of the analysis files produced by the project. The list of files is presented in Table 5-2. In addition to the set of analysis files, the team had access to the draft final report issued on July 15, 1992.

In early August SAIC and SWEC personnel reviewed the draft report and prepared an outline of the team meeting. The team met at North Anna for the entire week beginning August 17th. The one week session consisted of a brief PRA training session followed by breaking up into groups lead by Messrs. Holderness and Singer. Each team member was then assigned an analysis file(s) to review. Comments were recorded on the standard review form used throughout the project.

The meeting at North Anna focused on the Level I analysis, although the interface between the Level I and the Level II analysis was also considered. Thus, the Containment Building performance analysis review was conducted during the same period of time as the Level I independent review.

In addition to the formal independent review team meetings discussed above, the models were reviewed by other corporate and station personnel at various stages of the project. For example, after the completion of each analysis file, it was reviewed and signed-off by another member of the PRA team. In addition, the system engineers at North Anna participated in a limited review of the system models prior to the independent review. Similarly, personnel from the training department participated in a review of the human reliability analysis. Finally, an STA participated in a one day review of the accident sequence delineation analysis file prior to the final sequence quantification.

5.3 AREAS OF REVIEW AND MAJOR COMMENTS

As stated above, the project analysis files were supplied to the independent review team. The analysis files were then divided among the team members for review. Document review forms were used to document the individual review comments. The overall review is documented in a report which summarizes the significant comments in addition to providing the individual document review forms. Once the document review forms were received, the PRA team responded to each comment and made the appropriate changes in the models. The document review forms were then compiled in a separate analysis file to become part of the IPE documentation.

Significant comments, summarized from the Level I independent review report (SAIC 1992), are presented below:

1. The scope of the study and the level of detail appear to meet or exceed the requirements for an IPE.

2. The models and results generally reflect the current North Anna plant configuration. There are exceptions, however. The starting point for much of the North Anna study appears to be the Surry IPE. As a result, some of the models contain references to design/operational features of Surry. In a few cases, it has been noted that these features are unique to Surry and do not apply to North Anna.

3. The documentation of the study is well organized and nearly complete at the time of the review. Many of the supporting work packages were prepared much earlier in the study and have not been maintained up to date. For example, there are references to future work activities (which have now been completed). The supporting documents also contained more erroneous references to Surry features (see above) than were actually observed in the final NAPS IPE models.

Several specific technical findings are listed in Section 2 of the final independent review report. These findings are the more significant of the comments from the document review forms. An example is the comment for the Emergency Diesel Generator and Electrical Power Distribution Systems in Section 2.3:

> Operator action is required to reclose the 4160 V stub bus breakers if a CDA signal was generated or if an RHR pump was running. Trees E1H2, E1J2, E2H2, etc., should include the CDA interlock requiring manual action if a CDA signal is expected to occur.

Each of the individual comments have been reviewed by the appropriate PRA team member to determine an appropriate resolution.

Interfaces between the core damage and accident progression analyses have been reviewed by both groups of experts. A portion of the independent review team meeting was dedicated to a discussion of this interface. The SWEC consultant was in attendance for these discussions. A sample of an interface finding is the following comment from Section 2.9 of the independent review report:

> The plant damage states for SGTR sequences P13 through P16 are listed as PDS number 25. This plant damage state apparently includes failure of SG isolation. Yet in sequences P13 through P16, the SG has been isolated.

The independent review for the North Anna Level 2 IPE is similar to that conducted for the Surry plant approximately two years ago. The review of the Surry analysis concentrated on the Level 1 support aspects (success criteria), the Plant Damage States (PDSs), and the Containment Event Trees (CETs). Since these aspects were reviewed in great detail for Surry, and since the North Anna Level 2 IPE is very similar to the Surry Level 2 IPE in regard to those aspects, the North Anna review concentrated on the release categories and source terms. However, all parts of the analysis were reviewed to the level of detail presented in Section 4 and Appendix F of the draft North Anna IPE report.

In addition to the relevant IPE report sections and analysis files, twelve supporting MAAP analyses were reviewed for North Anna, eight of them being steam generator tube rupture (SGTR) analyses (six for Level 1 success criteria and two for Level 2 source terms), and four other analyses for Level 2 source terms. The four "other" analyses are as follows:

- Case 29 - Station Blackout with 200 gpm seal leak, no Auxiliary Feedwater, early Containment rupture
- Case 33 - V Sequence (2.6" cold leg)
- Case 37 - Station Blackout with 200 gpm seal leak, no Auxiliary Feedwater, early Containment leak
- Case 39 - Station Blackout with 200 gpm seal leak, 2" Containment Isolation failure with late rupture

The accident progression analysis review was documented in a similar fashion to the Level I review. Individual review comments were generated during the review of the analysis files and these comments were included in a report which also summarizes the review (SWEC 1992). The significant comments from this review are listed below:

1. Given the importance of SGTR and the use of MAAP to analyze success criteria for these sequences, a

suggestion was made to verify that the MAAP code is capable of these calculations.

2. Caution should be used in applying flooded/unflooded split fractions from NUREG-1150 (developed for Surry) to the North Anna V Sequence analysis. There are many factors: likely break locations, location of below-grade openings to adjacent structures, sump pump location and capacity, etc., which can affect this likelihood. This split is also based on other phenomenological aspects which may be affected by how the above differences affect accident progression. It isn't clear that the North Anna analysis has been sufficiently detailed or plant-unique in this area.

3. The PDS rule for RCS pressure is a unique function of the accident sequence type, i.e., large LOCA, small/medium LOCA or transient. The assignment of CET split fractions related to both direct containment heating and in-vessel steam explosion ("alpha") containment failure modes is related to this pressure/accident sequence type designation. The problem is that the relevant RCS pressure for alpha containment failure mode is best characterized as that at the time of the initial large relocation of core debris into the lower plenum while for direct containment heating (DCH) the relevant pressure that at the time of lower head failure. The two pressures are not necessarily the same, particularly for small/medium LOCAs.

4. The source term information presented on Draft IPE report Tables 4.7.3-2 and 4.7.3-3 is incomplete in that no timing or energy of release information is provided.

5.4 RESOLUTION OF COMMENTS

The comments presented in each of the independent review reports discussed above have been resolved. The process of resolving the comments consisted of the following events. Each comment was assigned to the PRA team member responsible for the development of the model/calculation in question. The resolution of a review comment could consist of either a model change or a discussion of why the comment is not important or applicable. When the resolutions were determined, a review of the resolution was made by the PRA project manager. The review forms were then compiled in an analysis file.

The resolution of the specific comments discussed above in Section 5.3 are presented below in the order they were introduced. The PRA analyst disagreed with the review team regarding the Electrical Power Distribution System comment. The operator action was not felt to be required since the stub bus supplies the CC and RH systems. These systems are only modeled in the SGTR event tree which will not generate a CDA signal.

The review of the interface between the two analyses produced some findings. The response to the sample finding listed above was that these sequences, along with P22 through P28, are lumped together in PDS 25 because the source term impact is about the same.

In reviewing the accident sequence analysis, several comments were offered. The sample comments listed above were resolved as indicated in the following text:

1. The NAPS accident progression analysis considered SGTR cases. The results were consistent with operational data.

2. The North Anna Safeguards Building was evaluated and compared to the Surry Safeguards Building. As a result of this evaluation, the split fraction used in the Surry Analysis was found to be applicable to North Anna. This result is to be expected since the general layout of the buildings is the same.

3. MAAP analysis made for the Surry IPE indicate that the two pressures are reasonably close. The same analyses were performed for North Anna, resulting in the same conclusion.

4. The analysts agreed that the timing and energy of release information should be added to Tables 4.7.3-2 and 4.7.3-3. The tables were updated to include this information.

5.5 REFERENCES

NRC (U.S. Nuclear Regulatory Commission), Individual Plant Examination for Severe Accident Vulnerabilities, 10CFR50.54(f) (Generic Letter 88-20), Washington, D.C., 1988.

SAIC, Holderness, J. H. and Singer, B. S., Virginia Electric and Power Company, North Anna Power Station, Individual Plant Examination Independent Review, September 1992.

SWEC (Stone and Webster Engineering Corporation), Peer Review of the North Anna Nuclear Power Station Level 2 Individual Plant Examination (IPE), September 1992.

TABLE 5-1

INDEPENDENT REVIEW TEAM COMPOSITION

James H. Holderness, SAIC

Blake S. Singer, SAIC

James E. Metcalf, SWEC

James R. Roth, Virginia Power - Corporate Nuclear Safety, Shift Technician Advisor, SRO licensed.

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Robert M. Garver, Virginia Power - Station Engineering, System Engineer, Shift Technical Advisor qualified.

Ross C. Anderson, Virginia Power - Nuclear Safety Engineering, Shift Technical Advisor.

John W. Daily, Virginia Power - Operations Department, Procedure Writer.

Robert M. Neil, Virginia Power - Corporate Nuclear Safety, North Anna Licensing Engineer.

TABLE 5-2
NORTH ANNA IPE INDEPENDENT REVIEW
ANALYSIS FILE LIST

File Number	Subject
319MAF.N.1	Development of a Generic Database
319MAF.N.2	Development of Plant Specific Data (Vols. I and II)
320MAF.N.1.1	System Modeling - Accumulators
320MAF.N.1.2	System Modeling - HHSI/HHSR
320MAF.N.1.3	System Modeling - LHSI/LHSR
320MAF.N.1.5	System Modeling - SI Actuation
320MAF.N.1.6	System Modeling - CDA
320MAF.N.2	System Modeling - Charging
320MAF.N.3	System Modeling - Quench Spray
320MAF.N.4	System Modeling - Recirculation Spray
320MAF.N.5	System Modeling - Containment Isolation
320MAF.N.6.1	System Modeling - Auxiliary Feedwater
320MAF.N.6.2	System Modeling - Main Feedwater
320MAF.N.7	System Modeling - Instrument Air
320MAF.N.8	System Modeling - Main Steam
320MAF.N.9	System Modeling - Primary System Pressure
320MAF.N.10	System Modeling - Emergency Electrical
320MAF.N.11	System Modeling - Emergency Diesels
320MAF.N.12.1	System Modeling - Reactor Protection
320MAF.N.12.2	System Modeling - AMSAC
320MAF.N.13	System Modeling - Service Water
320MAF.N.14	System Modeling - Component Cooling
320MAF.N.15	System Modeling - Residual Heat Removal
320MAF.N.16	System Modeling - Containment Structure
320MAF.N.17	System Modeling - Ventilation
321MAF.1.N	Accident Sequence Delineation
322MAF.N.1	Development of Success Criteria
322MAF.N.2	Identification of Special Initiators
322MAF.N.3	deleted
322MAF.N.4	Transient Analysis
323MAF.N.1	Common Cause Analysis
324MAF.N.1	Human Error Probabilities
325MAF.N.1	Initial Sequence Quantification (Vols. I and II)
325MAF.N.2	Final Sequence Quantification (Vols. I and II)
325MAF.N.	Recovery Actions

TABLE 5-2 (Continued)
NORTH ANNA IPE INDEPENDENT REVIEW
ANALYSIS FILE LIST

File Number	Subject
326MAF.N.1	MAAP Parameter File
326MAF.N.2	- na -
326MAF.N.3	Plant Damage State Logic
326MAF.N.4	Containment Event Trees
326MAF.N.5	Accident Progression Success Criteria (Vols. I, II and III)
326MAF.N.6	Release Category/Source Terms
326MAF.N.7	MAAP Level 2 Analyses
326MAF.N.8	Level 2 Sensitivity Studies
327MAF.N.1	Analysis of Internal Flooding (Vols. I and II)
328MAF.N.1	Level I Sensitivity Analysis

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FIGURE 5-1
PROJECT ORGANIZATION CHART

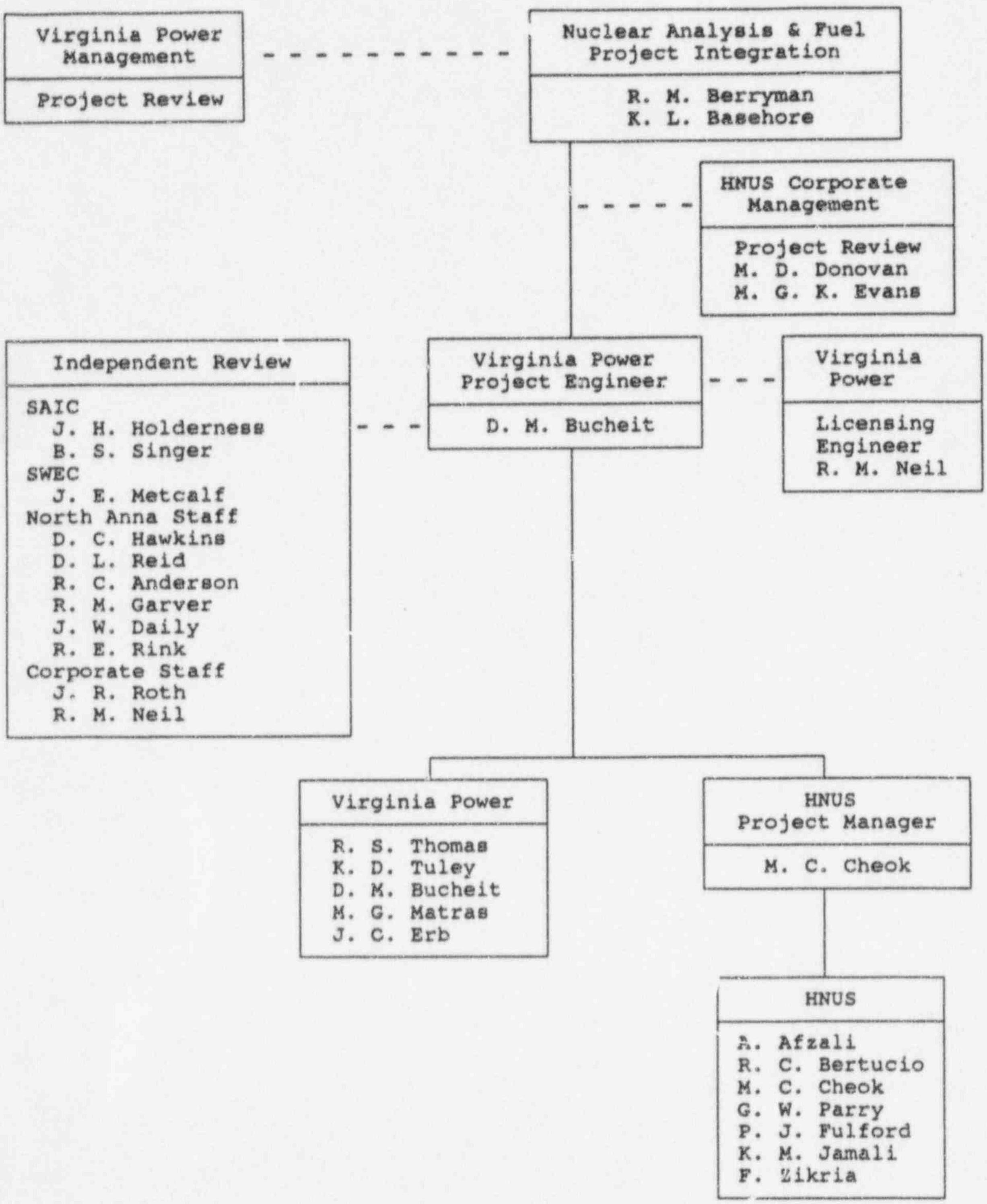
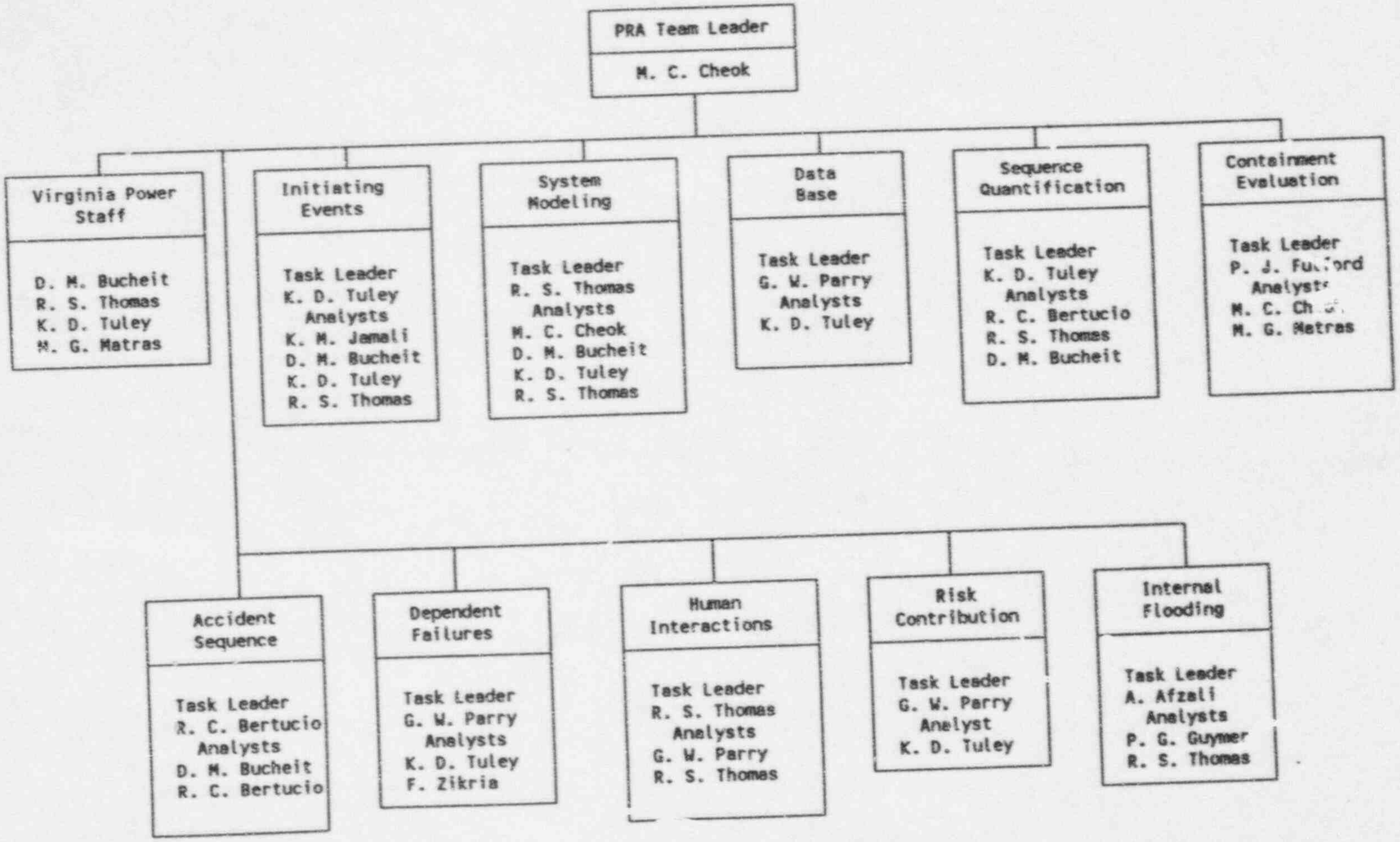


FIGURE 5-2
PROJECT TECHNICAL ORGANIZATION



Attachment 3

Risk Significant Systems and Equipment For Unit 1

Risk Significant Systems & Equipment For Unit 1			
System	**Equipment Description**	**Equipment Mark Number**	**Risk Significance**
Alternate AC Power (AAC)	Alternate AC Diesel	0-AAC-DG-0M	The risk significance increases when either EDG is removed from service. For most risk significant sequences the AAC DG is a direct substitute for either EDG.
Batteries (BY)	125 V Batteries	1-BY-B-1-I	This battery becomes risk significant when the 1J EDG is removed from service. Battery I and EDG 1J supply power to opposite train equipment.
		1-BY-B-1-III	This battery becomes risk significant when the 1H EDG is removed from service. Battery III and EDG 1H supply power to opposite train equipment.
Component Cooling Water System (CC)	Component Cooling water supply to RHR Heat exchangers	1-CC-762 1-CC-TK-1	The risk significance decreases when either diesel is removed from service. The CC system provides residual heat removal cooling which is important only during modes 1 and 2 for steam generator tube ruptures (SGTR). The SGTR accident sequences are insensitive to EDG unavailability. These sequences decrease in importance as other sequences which are sensitive to EDG unavailability become more important.
Emergency Electrical Power (EE)	4160 V Emergency Buses	1-EE-SW-1H 1-EE-SW-1J 2-EE-SW-2H	The risk significance slightly decreases when either diesel is removed from service as other equipment importance increases. These electrical buses are

Risk Significant Systems & Equipment For Unit 1			
System	**Equipment Description**	**Equipment Mark Number**	**Risk Significance**
		2-EE-SW-2J	always high risk significant equipment.
	480 V Emergency Buses	1-EE-SS-1H 1-EE-SS-1H1 1-EE-SS-1J 1-EE-SS-1J	The risk significance slightly decreases when either diesel is removed from service as other equipment importance increases. These electrical buses are always high risk significant equipment.
	480 V Motor Control Centers	1-EE-MCC-1H1-2S 1-EE-MCC-1H1-4 1-EE-MCC-1J1-1 1-EE-MCC-1J1-2N	The risk significance slightly decreases when either diesel is removed from service as other equipment importance increases. These electrical buses are always high risk significant equipment.
	Emergency Diesels	1-EE-EG-1H	The risk significance increases when the 1J EDG is removed from service. EDG 1H and 1J supply electrical power to opposite train equipment.
		1-EE-EG-1J	The risk significance increases when the 1H EDG is removed from service. EDG 1H and 1J supply electrical power to opposite train equipment.
Electrical Power (EP)	120 V Vital Buses	1-EP-CB-4A 1-EP-CB-4C	The risk significance slightly decreases when either diesel is removed from service as other equipment importance increases. These electrical buses are always high risk significant equipment.
	125 VDC Buses	1-EP-CB-12A	The risk significance increases significantly when the 1J EDG is removed from service. DC Bus I and EDG 1J supply power to opposite train equipment.

Risk Significant Systems & Equipment For Unit 1			
System	**Equipment Description**	**Equipment Mark Number**	**Risk Significance**
			The risk significance decreases when the 1H EDG has been removed from service. This electrical bus is always high risk significant equipment.
		1-EP-CB-12C	The risk significance increases significantly when the 1H EDG is removed from service. DC Bus III and EDG 1H supply power to opposite train equipment. The risk significance decreases when the 1J EDG has been removed from service. This electrical bus is always high risk significant equipment.
	Switchyard & Transfer Buses	500 kV Buses 1 & 2 34.5 kV Buses 3 & 4 4160 V Buses D, E & F	Various combinations of these electrical buses become risk significant when the either EDG is removed from service.
Feedwater (FW)	Steam Driven Auxiliary Feedwater Pump	1-FW-P-2	The risk significance increases when either EDG is removed from service. One auxiliary feedwater pump is steam driven and two are motor driven.
	Motor Driven Auxiliary Feedwater Pumps	1-FW-P-3A	The risk significance increases when the 1J EDG is removed from service, and decreases when the 1H EDG is removed from service. 1-FW-P-3A is powered from the 1H bus and EDG 1J supplies electrical power to 1-FW-P-3B.
		1-FW-P-3B	The risk significance increases when the 1H EDG is removed from service, and decreases when the 1J

Risk Significant Systems & Equipment For Unit 1			
System	**Equipment Description**	**Equipment Mark Number**	**Risk Significance**
			EDG is removed from service. 1-FW-P-3B is powered from the 1J bus and EDG 1H supplies electrical power to 1-FW-P-3A.
Quench Spray (QS)	Refueling Water Storage Tank (RWST)	1-QS-TK-1	The risk significance slightly decreases when either diesel is removed from service as other equipment importance increases. The RWST supplies flow to the low head and high head SI pumps. The RWST is always a high risk significant component.
Residual Heat Removal (RH)	Single failure RH equipment	1-RH-FCV-1605 1-RH-HCV-1758 1-RH-MOV-1700 1-RH-MOV-1701	The risk significance decreases when either diesel is removed from service. The RH system provides residual heat removal cooling which is important only during steam generator tube ruptures (SGTR) for modes 1 and 2. The SGTR accident sequences are insensitive to EDG unavailability. These sequences decrease in importance as other sequences which are sensitive to EDG unavailability become more important.
Safety Injection (SI)	LHSI suction MOVs	1-SI-MOV-1862A 1-SI-MOV-1862B	The risk significance decreases slightly when either diesel is removed from service as other equipment importance increases. This low head SI equipment is always high risk significant.
	LHSI discharge MOVs	1-SI-MOV-1864A 1-SI-MOV-1864B	

Risk Significant Systems & Equipment For Unit 1			
System	**Equipment Description**	**Equipment Mark Number**	**Risk Significance**
	LHSI recirculation MOVs	1-SI-MOV-1885A 1-SI-MOV-1885B 1-SI-MOV-1885C 1-SI-MOV-1885D	
	LHSI pumps	1-SI-P-1A 1-SI-P-1B	
	Accumulators	1-SI-TK-1A 1-SI-TK-1B 1-SI-TK-1C	