CATEGORY 1

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9708080122 DOC.DATE: 97/08/04 NOTARIZED: NO DOCKET #
FACIL:50-261 H.B. Robinson Plant, Unit 2, Carolina Power & Light C 05000261
AUTH.NAME AUTHOR AFFILIATION
WILKERSON,T.M. Carolina Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
Document Control Branch (Document Control Desk)

See Reports

SUBJECT: Responds to 970423 RAI re review of request to implement improved STS.

DISTRIBUTION CODE: A001D COPIES RECEIVED:LTR 1 ENCL 1 SIZE: 26+106
TITLE: OR Submittal: General Distribution

NOTES:

	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL
	PD2-1 LA	1	1	PD2-1 PD	1	1
	MOZAFARI,B	1	1			
INTERNAL:	~~FILE CENTER 01~~	1	1	NRR/DE/ECGB/A	1	1
	NRR/DE/EMCB	1	1	NRR/DRCH/HICB	1	1
	NRR/DSSA/SPLB	1	1	NRR/DSSA/SRXB	1	1
	NUDOCS-ABSTRACT	1	1	OGC/HDS3	1	0
EXTERNAL:	NOAC	1	1	NRC PDR	1	1

C A T E G O R Y 1 D O C U M E N T

NOTE TO ALL "RIDS" RECIPIENTS:
PLEASE HELP US TO REDUCE WASTE! CONTACT THE DOCUMENT CONTROL DESK, ROOM OWFN 5D-5(EXT. 415-2083) TO ELIMINATE YOUR NAME FROM DISTRIBUTION LISTS FOR DOCUMENTS YOU DON'T NEED!

TOTAL NUMBER OF COPIES REQUIRED: LTTR 13 ENCL 12

CP&L

Carolina Power & Light Company
Robinson Nuclear Plant
3581 West Entrance Road
Hartsville SC 29550

Robinson File No: 13510
Serial: RNP-RA/97-0173

AUG 04 1997

United States Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261/LICENSE NO. DPR-23
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
REGARDING EMERGENCY DIESEL GENERATORS

Gentlemen:

NRC letter dated April 23, 1997, requested that Carolina Power & Light (CP&L) Company respond to a request for additional information dated February 5, 1997, to support the NRC review of the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2 request to implement improved Standard Technical Specifications. The response is provided in the attachment to this letter.

If you have any questions concerning this matter, you may contact me or Mr. H. K. Chernoff of my staff at (803) 857-1437.

Very truly yours,

Terry M. Wilkerson

T. M. Wilkerson
Manager - Regulatory Affairs

JSK/jk
Attachment
c: Mr. B. B. Desai, USNRC Senior Resident Inspector, HBRSEP
Ms. B. L. Mozafari, USNRC Project Manager, HBRSEP
Mr. L. A. Reyes, Regional Administrator, USNRC, Region II

A001

H.B. Robinson Steam Electric Plant, Unit No. 2
Response To The Request For Additional Information
On Emergency Diesel Generator On-Line Preventive Maintenance

1.0 Your individual plant examination (IPE) submittal, dated August 31, 1992, identified several improvements that could reduce the core damage frequency. Provide the status of these improvements and indicate whether credit is taken for the improvements in the plant PRA. Explain the major differences between your current PRA and the PRA used to support your IPE. Among these differences, identify anything related to loss of offsite power/station blackout (LOOP/SBO) sequences and explain the differences and impact on the SBO risk.

A. Section 6.1, "Plant Improvements," of the IPE submittal suggested areas for potential improvements and identified some items for action, other items for further consideration of the cost versus benefit and an item for evaluation during the development of the Severe Accident Management Guidance (SAMG). The status of these items was provided by letter, RNP/93-1562, dated July 2, 1993, and updated, where appropriate, by letter, RNP/94-1529, dated August 12, 1994. The status of each improvement is listed below with a citation of the more recent status letter or an updated status, where appropriate:

Item 1 A new procedure for coping with flooding events. The IPE submittal identified this item for action. This item was completed as described in RNP/93-1562 (July 2, 1993).

Item 2 Operation of the steam-driven auxiliary feedwater (AFW) pump in the self-cooling mode. The IPE submittal identified this item for action. This item has been completed. The IPE identified this change to eliminate the need for the operator action to manually change the pump to the self-cooling mode so as to lessen the operations staff burden during accident scenarios. The steam-driven AFW pump was permanently aligned for self-cooling mode as part of a plant modification.

Item 3 Modification of the plant safety-related batteries. The IPE submittal identified this item for action. This item has been canceled. The IPE identified this change to upgrade the capacity of the batteries from 1 hour to 4 hours to allow more time for offsite power recovery. Updated results from the H.B. Robinson Steam Electric Plant Unit 2 (HBRSEP) Probabilistic Safety Assessment (PSA) model demonstrated that a modification to the station batteries was not cost beneficial relative to the reduction in core damage frequency that would have been obtained. The project was therefore canceled. Additionally, emergency operating procedures were written to cope with a loss of DC power.

Item 4 Development of a more extensive preventative maintenance program for the Dedicated Shutdown Diesel Generator (DSDG). The IPE submittal identified this item for action. This item was completed as described in RNP/93-1562 (July 2, 1993).

Item 5 Revision of Safety Injection (SI) and Containment Vessel (CV) Spray System Valve Test procedure. The IPE submittal identified this item for action. This item was completed as described in RNP/93-1562 (July 2, 1993).

Item 6 Test of the Heat Ventilation and Air Conditioning (HVAC) requirements for the E1/E2 bus room. The IPE submittal identified this item for action. This item was completed as described in RNP/94-1529 (August 12, 1994).

Item 7 Induced steam generator (SG) tube rupture. The IPE submittal identified this item for evaluation per SAMG. This item has been completed. The IPE identified this item as the only change, from the analysis of containment response, that was committed to during the study and accounted for in the results. This change was described as the elimination from the procedure of the use of the Reactor Coolant Pumps (RCPs) as a last attempt to cool the core. This change involved a significant reduction in the probability of a SG tube rupture during a severe accident. This item was included in the implementation of SAMG by the Westinghouse Owners Group (WOG). A Function Restoration Procedure was revised to bypass starting the RCPs unless sufficient water is in the SG to cover the U-tubes.

Item 8 Walk-through of the long-term Emergency Core Cooling System (ECCS) recirculation procedure. The IPE submittal identified this item for consideration of cost versus benefit. This item was completed as described in RNP/94-1529 (August 12, 1994).

Item 9 Charging pumps self-cooling modification. The IPE submittal identified this item for cost consideration. This item was canceled as described in RNP/94-1529 (August 12, 1994).

Item 10 Automatic Refill of the Condensate Storage Tank (CST) Project. The IPE submittal identified this item for cost consideration. This item was canceled as described in RNP/93-1562 (July 2, 1993).

B. Credit was taken in the current PSA model for:

Item 1 A new procedure for coping with flooding events,

Item 2 Operation of the steam-driven AFW pump in the self-cooling mode, and

Item 5 Revision of SI and CV Spray System Valve Test procedure.

C. Since the IPE Submittal, the HBRSEP PSA model has undergone updates to incorporate plant-specific data, procedural changes, and plant modifications. The major differences between the current PSA and the PSA used to support the IPE were:

a) Loss Of Coolant Accidents (LOCA) probability. The LOCA frequencies used in the initial IPE were based on frequencies taken from seven other PSAs. Limited industry failure data had led to this use of conservative LOCA initiator frequencies. Methodology, developed by Electric Power Research Institute (EPRI) (EPRI TR-102266, "Pipe Failure Study Update") to compute LOCA initiating event frequencies based on plant specific parameters, was incorporated into the HBRSEP PSA.

b) Latent human interaction. The assumptions used for screening criteria for identification of latent human interactions were revised. Based on these new screening criteria, as well as procedural enhancements, several latent human interactions were removed from the PSA model.

c) Flooding Procedures Update. The new and revised flooding procedures were written to assist the operator in identifying sources of flooding and potential isolation measures. In addition, these procedures were written to limit the accumulation of water thereby limiting the potential for equipment damage. These procedure updates were used in reassessing the internal flood initiator frequency.

d) Addition of DSDG to End Path Procedures (EPPs). A procedure was written to direct the operating crew to align equipment as needed to the Dedicated Shutdown (DS) Bus and not to limit the use of the DS Bus to Appendix R or Station Blackout conditions. For the IPE, a recovery event was manually applied to SBO cutsets. The PSA model was updated to include the DSDG system components and operator actions to perform this new procedure.

e) CST refill analysis for 80% nominal average. Historical data were reviewed to determine the actual level that was maintained in the CST. The average available inventory was greater than the inventory assumed in the IPE. An analysis with the MAAP code predicted the time for core uncovery based on CST depletion with no makeup. The MAAP analysis indicated that, with the Reactor Coolant Pumps (RCPs) not running, CST inventory was sufficient to assure core integrity past 24 hours. This was a sufficient time for recovery, and therefore, no CST depletion and refill failure was modeled with LOOP sequences.

f) Emergency Core Cooling System (ECCS) Motor Operated Valves (MOVs) Update. At the time of the IPE, ECCS MOV active failures were modeled as non-time dependent demand failures. Because many of these MOVs were only stroke tested once per refueling cycle, their demand failure probability value was increased based on the time dependent standby failure rate and the exposure time.

g) Frequencies of transient initiating events update. The transient initiating event frequencies were updated to reflect the most recent operating experience through 1995. The IPE evaluated many years of operational data to develop plant specific transient initiating event data. The transient initiating event frequencies were updated because HBRSEP had experienced a significant reduction in plant trips following the replacement of the SGs in 1984.

h) Frequency of LOOP. The LOOP initiating event analysis was updated as part of the transient event update, because HBRSEP had experienced a LOOP in 1992, and because the EPRI TR-106306, "Losses of Off-Site Power at U.S. Nuclear Plants - Through 1995," had been revised and was available. This revision incorporated a change in the methodology used to determine the LOOP frequency compared to the methodology used in the IPE. The new methodology counted specific LOOPs per unit rather than per site. This change was incorporated into NSAC-166, "Losses of Off-Site Power at U.S. Nuclear Power Plants - Through 1990." According to this document, for industry LOOP events from 1980 to 1990, the LOOP per unit year frequency was 0.035 and the per site year frequency was 0.047. The current EPRI document, EPRI-TR-106306, indicated that the industry value for LOOP per unit year was 0.036 for years 1980 through 1995. This value was essentially equivalent to the plant specific Bayesian updated LOOP frequency. The resultant plant specific LOOP initiating event frequency represented an overall reduction over the IPE value.

i) Update of Plant Specific Data. Data for components using plant specific data, major pumps and diesels, were updated through a review of the control operator logbooks and work tickets. Data used in the IPE covered operational history from 1985 through 1990. The first update brought initiating event data and Emergency Diesels Generators (EDGs) up to date through 1992. A more recent update brought the plant specific data up to date through 1995.

j) EDG update. The plant specific diesel start and run data were updated in order to remove conservatisms from the data used in the IPE Submittal. For the IPE, any diesel trip was counted as a failure. A majority of the trips experienced during testing were due to faulted trip signals that were defeated during normal standby operation. Under normal operational conditions, the diesel would not have tripped and would have continued to run without any problems. The data update screened out the nonapplicable trips and used only actual diesel run and start failures.

k) Reactor Coolant System (RCS) Pressure Challenge Update. Unavailability of the RCS Power Operated Relief Valves (PORVs) to mitigate a pressure challenge may lead to a RCS Safety Relief Valve (SRV) challenge. Challenges to the RCS SRVs increase the likelihood of an SRV LOCA. Two updates were performed to remove conservatisms associated with transient induced SRV LOCAs. The first update was a review of the operational history of running with closed block valves. Improvements in the method of blocking open the PORVs during refueling had virtually eliminated the occurrence of PORV leakage and subsequent block valve closure. Thus, the conditional probability of PORV block valve closure in the IPE model was updated accordingly.

The second model update involved removal of battery depletion events from the RCS PORVs support system fault trees following a LOOP event. The IPE model allowed battery depletion to fail power to the PORVs irrespective of timing considerations. Battery depletion was modeled to occur one hour after a loss of the battery chargers and not fail the PORVs at the time of the transient and subsequent pressure challenge. The model was updated accordingly to give the net effect of a reduction in LOOP contribution.

l) AFW Common Cause Failure Update. The IPE model included a common cause failure of the three AFW pumps based on other reference PSAs. A determination was made that, since there was no similarity in design, manufacturer, or location of the AFW Steam Driven Pump (SDP), this common cause event was invalid. The PSA model was updated to only include a common cause failure of the AFW Motor Driven Pumps (MDPs).

m) Update of Cold Leg Recirculation Model. At the time of the IPE, an emergency operating procedure was written such that, for any size LOCA, the high pressure SI pumps were always aligned to take suction from the Residual Heat Removal (RHR) pumps during recirculation mode. The procedure was revised such that, for any size LOCA, low head recirculation was initiated first with one SI pump continuing to take suction from the Refueling Water Storage Tank (RWST) flow until low pressure flow to the RCS could be verified. For inadequate low head flow, the SI pump was stopped to establish the recirculation path and then restarted to initiate high head recirculation. Thermal hydraulic analyses indicated that high head recirculation would only be required for small break LOCAs with size ranging from 3/8 inch to 5 inches. Breaks sizes larger than 5 inches, medium and large LOCAs, were determined to be mitigated by low pressure recirculation. The PSA was updated to remove the requirement for high head pumps during recirculation for medium and larger break LOCAs.

n) Update of Loss of DC Bus Events. A review of new and existing procedures was made to evaluate the most current procedural response to a loss of DC Bus. Two recoveries were found and included in the model. The first was the ability to recover a loss of AFW flow by manually closing the Emergency Bus E-2 output breaker for AFW pump B following a loss of DC Bus B. The second recovery was the ability to open locally the Main Feedwater (MFW) Regulator by-pass valves to establish feed flow from the available Feedwater/Condensate train after a loss of either DC Bus A or B. Both recoveries were included in a procedure.

o) Addition of Charging Pump C. For conservatism, the IPE only credited two charging pumps available, pumps A and B. To be more realistic, the PSA model was updated to include the three charging pumps.

p) Incorporation of AFW steam-driven pump modification. The steam-driven AFW pump was permanently aligned for self-cooling mode as part of a plant modification. Prior to this change, procedures had the operator place the pump in self-cooling mode upon a loss of service water cooling. The IPE included failure of the operator to perform this action as a pump failure mechanism. The model was updated to remove this action.

q) Alternate cooling of SI pumps with fire water. An abnormal operating procedure was revised to instruct the operator to use fire water as alternate cooling for the thrust bearing coolers on a loss of service water. The PSA model was updated to include the firewater components and operator actions. Because service water was required to cool Component Cooling Water (CCW) during ECCS recirculation mode, the model update was not credited to reduce Core Damage Frequency (CDF) but only to delay core damage from the injection mode to the recirculation mode for Level 2 consideration

r) Alternate cooling to AFW MDPs with fire water. An abnormal operating procedure was revised to instruct the operator to use fire water as an alternate means for cooling the AFW MDP oil coolers on a loss of service water. In the IPE, a recovery action was manually added to the cutsets based on engineering judgment. The PSA model was updated to include the firewater components and the operator action for dependency assessment.

s) SI reset switch for MFW. The modification added a key lock switch on the Reactor Turbine Generator Board (RTGB) to override the SI signal relays for the MFW system. Previously, the operator had to hold down the SI reset button until the safeguards relays were defeated by removing power. This time consuming action was considered not feasible during the Human Reliability Analysis (HRA) for the IPE and was not credited. With completion of this modification, the PSA was updated to credit use of MFW under scenarios that actuate an SI signal.

t) Addition of high head SI pumps recirculation line strainers. A modification was performed to add strainers to each SI pump's recirculation line to the RWST in order to prevent foreign materials from plugging the recirculation line flow element. The PSA model was updated to include a potential plugging event of these strainers.

u) Alternate compressed gas supply for SG PORVs. A modification was installed to cross connect the SG PORV instrument air header to the steam dump nitrogen accumulator. The PSA model was updated by the addition of steam dump nitrogen components and operator action to recover SG PORVs on a loss of instrument air.

v) Containment Isolation Failure Revision. Two changes were made to the containment isolation fault tree. The first change was revision of the latent human errors affecting the containment spray system. These latent human errors were a containment bypass mechanism following containment spray pump failure or SBO. The second change was a removal of the conservatism that a failure of either containment manway door would fail containment isolation. The success criterion was changed to require failure of both doors for containment isolation failure.

w) Core Debris Cooling. The IPE used information contained in Generic Letter 88-20, "INDIVIDUAL PLANT EXAMINATION FOR SEVERE ACCIDENT VULNERABILITIES - 10 CFR 50.54(F)." Of interest was the conclusion that debris cooling was assured if the debris thickness was less than 25cm and water covered the debris. More recent experimental information tended to increase the uncertainty of this conclusion. A more conservative debris cooling model was developed and incorporated into the Level 2 model.

D. Among the differences listed above, those related to LOOP/SBO sequences and an explanation for the differences and a qualitative assessment of the impact on the SBO risk were listed below:

a) CST refill analysis for 80% nominal average This reduced LOOP sequence risk because analysis results showed that sufficient CST inventory would be available to sustain decay heat removal and assure core integrity longer than the mission time of 24 hours. This was found to be true only for the case when the RCPs were not running, specifically the LOOP case. Therefore, sequences composed of CST depletion and failure to refill were remove, thereby lowering the CDF contribution for the LOOP.

b) EDG Data update This lowered SBO risk because EDG failures caused by non-emergency trip signals, i.e. trips due to instrumentation which is defeated during emergency start demands, were removed from the EDG failure database. This decreased the EDG start and failure to run probabilities. Therefore, the SBO frequency decreased.

c) Frequency of LOOP This update reduced the IPE value because favorable industry experience reduced the generic failure rate as did a change in the methodology which applied these data on a per unit basis rather than a per site basis.

d) Addition of DSDG to EPPs This reduced the estimated CDF from LOOP/SBO sequences because an explicit procedure was written to direct the operating crew to align equipment as needed to the Dedicated Shutdown (DS) Bus and not to limit the use of the DS Bus to Appendix R or Station Blackout conditions. For the IPE, a recovery event was manually applied to SBO cutsets only. Modeling of the DSDG system components and operator actions to perform this new procedure provided more realistic estimates for these and additional cutsets than the recovery event method.

e) Reactor Coolant System (RCS) Pressure Challenge Update This reduced the estimated CDF from LOOP/SBO sequences because the second model update removed battery depletion events from the RCS PORVs support system fault trees following a LOOP event. The IPE model had allowed battery depletion to fail power to the PORVs irrespective of timing considerations. Battery depletion was modeled to occur one hour after a loss of the battery chargers and not fail the PORVs at the time of the transient and subsequent pressure challenge. The model was updated accordingly to give the net effect of a reduction in LOOP contribution.

2.0 Describe any review of the PRA that has been made to ensure that the PRA represents the as-built, as operated plant. Discuss any changes made to the PRA due to such reviews.

As part of the IPE process, the PSA model was peer reviewed as described in the IPE submittal to ensure that the PSA represented the as-built, as operated plant. Since that time, the HBRSEP PSA was changed to incorporate plant procedure revisions, plant modifications and plant specific operational data. Of the changes discussed in the response to Question 1:

a) The following changes were due to plant modifications:
- Addition of high head SI pumps recirculation line strainers.
- Steam driven AFW pump in self-cooling mode.
- SI reset switch for MFW.
- Alternate compressed gas supply for SG PORVs.

b) The following changes were due to procedure changes:
- Inclusion of DSDG for non-SBO events.
- Internal Flood Mitigation.
- Alternate cooling of SI pumps with fire water.
- Reduction of latent human errors.
- Alternate cooling to AFW MDPs with fire water.
- Recovery from Loss of DC Bus

c) The following changes were due to operational history:
- Frequencies of Transient Initiating Events.
- Frequency of LOOP.
- Update of Plant Specific Component Data.
- CST refill analysis.

3.0 Provide a description of the peer reviews performed on your current PRA. Identify which reviews were performed in-house and which were performed by outside consultants. Summarize overall conclusions and insights from the peer reviews with respect to the treatment of SBO.

A. In 1996, the PSA model was independently peer reviewed by outside consultants, from Science Applications International Corporation. The final report of the peer review was issued on July 11, 1997. The following discussion summarizes the report:

a) The scope of this peer review was to compare the PSA model against the IPE model and to:
- identify any significant differences;
- determine the impact of model changes;
- evaluate logic model changes;
- identify and evaluate the PSA methodology;
- identify potential logic model updates; and,
- review current quantification methodology.

b) The overall conclusions of this peer review included:
- The results generated by the PSA were assessed to be valid based on the identified changes to the IPE model.
- The methodology implemented in the PSA was consistent with industry practice.
- The PSA contained sufficient detail and was sufficiently accurate to support "risk-informed" decisions involving plant operation.

B. The report contained no specific conclusion or insight with respect to the treatment of SBO.

4.0 Discuss the current PRA mean core damage frequency (CDF). Include a percentage breakdown of the most important initiating events, such as loss of offsite power, and a percentage breakdown of functional groupings, specifically with respect to SBO.

A. The current mean CDF was calculated to be 4.9E-05 per year. LOCAs which could result from transients in which a pressurizer PORV or SRV failed to reseat and transients involving reactor coolant pump seal failures were combined in a grouping called transient induced LOCAs. The largest contributor to transient induced LOCAs was a reactor coolant pump seal failure which resulted from a loss of component cooling water initiated event or a loss of service water initiated event with failure to provide alternate cooling to the charging pumps. Approximately 68% of the transient induced LOCAs resulted from these two initiating events. The remaining 32% resulted from loss of offsite power events followed by loss of emergency power. The primary contributor to the LOCA events, approximately 44%, was the interfacing systems LOCA event. Small LOCA events also contributed significantly, approximately 41%, to the LOCA events. Loss of offsite power contributed approximately 47% to transient induced loss of decay heat removal sequences. The remaining 53% of loss of decay heat removal sequences was composed of Loss of Emergency Bus, Loss of a DC Bus and Loss of MFW initiated events.

B. For this CDF, the percentage breakdown of the most important initiating events was:

a) Loss of Offsite Power	20%
b) Loss of Component Cooling Water	18%
c) Internal Flooding	14%
d) Loss of Service Water	11%
e) Loss of Cooling Accident (LOCA)	10%
f) Interfacing Systems LOCA	8%
g) Steam Generator Tube Rupture	7%
h) Turbine Trip	4%
i) Loss of Feedwater	3%
j) Other	3%
k) Reactor Trip	2%

C. For this CDF, the percentage breakdown of the sequence functional groupings was:

a)	Transient induced LOCA	44%
b)	LOCA	18%
c)	Internal Flooding	14%
d)	Transient - Loss of Decay Heat Removal	11%
e)	Steam Generator Tube Rupture	7%
f)	ATWS	6%

Specifically with respect to SBO, the SBO contribution was approximately 9.0E-6 of the CDF. This was approximately 18% of the CDF and approximately 89% of the LOOP contribution. The specific SBO sequence functional grouping contributions to CDF are detailed below:

a)	LOOP induced PORV/SRV LOCA followed by SBO	4.1%
b)	SBO induced RCP seal LOCA	8.7%
c)	SBO induced loss of decay heat removal	5.6%

5.0 Provide the minimal cutset 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.

A. The minimal cutset truncation cutoff used by PSA model to quantify the plant CDF changes for the baseline calculation of risk measures (e.g., CDF, LERF) was 5E-9 which was less than or equal to four orders of magnitude below the calculated value of the risk measure as recommended by EPRI TR-105396, "PSA Applications Guide, Appendix B, section B.9.1.

B. To avoid underestimation when the calculated impact was negligible or non-existent, the method for PSA applications set the affected basic events to logical "true" in the model and then quantified the risk increase of a given component, system, or other group of components. Setting the basic events to "true" assured that representative cutsets containing those basic events showed up in the results as warranted. A truncation limit of four orders of magnitude below the nominal value of the selected risk measure was still employed in those cases.

6.0 Explain what severe weather conditions assumed for your facility and how this was addressed in the PRA LOOP frequency and duration.

A. The severe weather conditions assumed for HBRSEP were tornadoes, hurricanes, lightning, severe rain, ice and snow storms. EPRI report TR-106306 provided historical information of events that had occurred at U.S. nuclear sites. The events in the report were first examined in relation to the HBRSEP site for applicability. Events that were caused by extreme external phenomenon not possible at HBRSEP were excluded. The severe weather events that were excluded were ocean or tidal storms and salt spray causing transmission line arcing.

B. To address severe weather conditions in the PSA LOOP frequency and duration, plant specific events were Bayesian updated to the non-HBRSEP events in the data base to obtain the LOOP frequency used in the PSA. The EPRI report was considered the best event data base for LOOP and was used as the basis for estimating the LOOP initiating event frequency and duration. The restoration data for offsite power in the EPRI report were based on actual data that provided a historical time-dependent probability of non-recovery. Imbedded in these data were any delays in offsite power recovery that could have occurred due to severe weather conditions. Severe weather was not a factor in HBRSEP LOOP events, as described in Licensee Event Reports (LERs).

7.0 Discuss the LOOP events at your facility.

Two LOOP events were documented in Licensee Event Reports (LERs).

According to LER 86-005, on January 28, 1986 with HBRSEP at 80% power, Emergency Bus E-2 received a undervoltage signal because of a fuse failure on an undervoltage relay. The "B" EDG was out of service for output breaker upgrade. The undervoltage signal stripped the bus and the bus was left deenergized. With Bus E-2 deenergized, power was lost to various instruments and controls and ultimately resulted in a reactor trip and turbine trip. Upon trip of the turbine and deenergization of the unit auxiliary transformer, safety loads automatically transferred to the startup transformer. Approximately, one second after the transfer, a 115kV West Bus lockout occurred, deenergizing the startup transformer and causing a LOOP at HBRSEP. The "A" EDG started and loaded onto Bus E-1. The "B" EDG was returned to service approximately 1 hour and 9 minutes after the LOOP. The start up transformer was reenergized at approximately 1 hour and 40 minutes after offsite power was lost. With the plant in a stable condition, Bus E1 remained powered by the EDG until approximately 1 hour and 57 minutes after power was returned to the startup transformer. The cause of the E-2 bus undervoltage (i.e., vulnerability of the emergency bus undervoltage relays to a random blown fuse) was determined to be separate and independent from the cause of the LOOP (i.e., susceptibility of the startup transformer primary side current transformers to DC saturation). The susceptibility of the DC saturation was eliminated by a modification which increased the rating of each current transformer (increased turn ratio) and connected a second current transformer in parallel.

According to LER 92-017, on August 22, 1992 with HBRSEP at 100% power, the startup transformer tripped off at approximately 1007 hours. Loss of the startup transformer loads caused a turbine runback leading to high SG level and a subsequent turbine trip and reactor trip. The unit auxiliary transformer deenergized and the offsite power was lost. Both EDGs started and loaded. At approximately 1348 hours, a deviation from EPP-21, "Energizing Pressurizer Heaters from Emergency Busses," was taken in order to establish power to deepwell pumps from the DSDG as a means to supply makeup to the CST. The startup transformer trip was caused by a short circuit in the sudden pressure fault protection relay sensing circuitry. The short circuit was due to water collection in a junction box that had been positioned so water could not drain out. Repairs were implemented on the startup transformer. The EDGs were allowed to remain supplying power to the emergency busses until approximately August 23, 1992, 0050 hours. The Unusual Event was terminated at approximately 0124 hours.

8.0 Characterize how the dedicated Shutdown Diesel Generator (DSDG) and the Dedicated Shutdown (DS) Bus credited in the PRA.

A. In the PSA, the DS bus was credited for providing 480 volt AC power under non-LOOP events while being powered by offsite power.

B. In the PSA, the DSDG system was credited for providing 480 volt AC power to the dedicated shutdown bus following a LOOP. The DSDG provided 480 volt AC power for Service Water Pump D, MCC-5, Component Cooling Water pump A, and Charging Pump A. Also, the DSDG was credited with being manually started and loaded via an emergency operating procedure. MCC-5 supplied power to various loads, including:

a) North Service Water Header Isolation Valve (alternate power),
b) South Service Water Header Isolation Valve,
c) RHR Loop to RCS Cold Leg Valve,
d) RHR Heat Exchanger A Cooling Water Outlet Valve,
e) RHR Pump Suction From RCS,
f) RHR Pump A Discharge to SI Pump Suction,
g) RHR Loop RWST Isolation Valve,
h) RHR Heat Exchanger A Outlet Valve,
i) RWST Discharge,
j) Feed to Instrument Bus 1,
k) Battery Charger A-1,
l) Battery Charger A,
m) Boric Acid Transfer Pump A,
n) Instrument Air Compressor A,
o) CV Spray Pump B Discharge Valve,
p) CV Sump Recirculation Suction,
q) CV Spray Pump A Discharge Valve,
r) EDG A Room Exhaust Fan,
s) EDG A Room Supply Fan, and
t) EDG Fuel Oil Transfer Pump A.

9.0 In your response dated May 29, 1996, to a previous NRC request for additional information (RAI), you indicated in answer to question No. 4 that the value used in your PRA for the emergency diesel generator (EDG) unavailability is 2.43 percent/year and the values used for EDG reliability are: failure to run 2.3e-3/ hour and failure to start 6.8e-3/demand. Describe how the proposed change to TS 4.6.1.3 will affect these values and how you determined the new values.

A. The proposed Technical Specification change is only a clarification and not a prerequisite to performing EDG maintenance with the unit on-line. As indicated on Page 4 of Enclosure 2 to "Request for Technical Specifications Change, Emergency Power System Periodic Tests" (RNP-RA/96-0005) dated January 30, 1996.

> "The current wording of the paragraph [TS Section 4.6.1.2] allows interpretation that 'refueling' can also mean 'refueling interval.' However, revising the paragraph to state at least once every refueling interval would remove any question about the allowance of performing EDG maintenance with the unit on-line."

B. Since the proposed change represented a clarification of Technical Specifications and not a prerequisite for the performance of on-line maintenance, the proposed change to TS 4.6.1.3, per se, was judged to have no effect on EDG unavailability or reliability values. The effect of performing the T.S. 4.6.1.3 diesel inspections on-line was included in the new unavailability and unreliability values used in the current PSA model. The new PSA value for EDG unavailability was calculated to be 1.8 percent/year and the new values used for EDG reliability were calculated to be: failure to run 1.13E-3/hour and failure to start 6.52E-3/demand.

C. These values were determined from plant specific data that were collected for the interval between 1985 and 1995 and incorporated into the HBRSEP PSA model.

10.0 Provide the projected average corrective maintenance and preventive maintenance downtimes for the emergency diesel generators and DSDG used in your PRA calculations. Explain how they are obtained. Specify the duration of the inspection and tests to be performed in accordance with the proposed change to TS 4.6.1.3.

A. For the emergency diesel generators, the projected average corrective maintenance and preventive maintenance downtime were combined in the PSA for total of 1.8 percent.

B. For the DSDG, the projected average corrective maintenance and preventive maintenance downtime used in the PSA was 3.42 percent.

C. These values were obtained from plant specific data that were collected for the interval between 1985 and 1995 and incorporated into the HBRSEP PSA model.

D. The duration of inspections and tests performed in accordance with TS 4.6.1.3 at a frequency of:

a) Each refueling interval was estimated to be about 72 hours.
b) Every three years (which included those scheduled each refueling interval) was estimated to be about 96 hours.

11.0 On page 4 of Enclosure 2 of your January 30, 1996, amendment request you state:

> **Since on-line maintenance of the EDGs has already been determined not to impact the AC Power System Probabilistic Safety Assessment (PSA), the revision to TS Section 4.6.1.3 will not impact the ability of the EDGs to mitigate an accident.**

Explain how you determined that on-line maintenance of the EDGs will not impact the PSA.

This was a misstated interpretation of an analysis of the emergency diesel on-line maintenance performed in 1995 and updated in 1996 using the PSA model.

A more precise statement would have been that based on guidelines provided in EPRI TR-105396, "PSA Applications Guide," performing the EDG maintenance on-line would not be considered risk significant. The PSA Applications Guide provided two criteria for whether a temporary change could be considered non-risk significant. These criteria were:

1) The instantaneous core damage frequency must be less than 1.0E-03; and,
2) The change in core damage probability must be less than 1.0E-06.

The 1996 updated analysis indicated:

	Duration of Maintenance	Instantaneous Core Damage Probability	Change in Core Damage Probability
EDG "A"	96 hours	1.38E-4	8.52E-7
EDG "B"	72 hours	1.75E-4	9.42E-7

12.0 Using the current PRA, provide the average CDF, an assessment of the change in the plant operational risk, including the change in CDF, core damage probability, and the large early release frequency that occurs as a result of the changes proposed to TS 4.6.1.3.

A. The current mean core damage frequency was calculated to be 4.9E-05 per year and large early release frequency was calculated to be 9.7E-06.

B. Since the proposed change represented a clarification of Technical Specifications and not a prerequisite for the performance of on-line maintenance, the proposed change to TS 4.6.1.3 was judged to have no effect on: average CDF or plant operational risk, including the change in CDF, core damage probability, and the large early release frequency. Refer to the response to question number 9.0 for more detailed information.

C. To quantify the effect of performing the diesel inspections on-line, an updated analysis of the impact of taking the EDGs out of service was performed with the current PSA model. First, the PSA model was quantified with the assumption that no system was out of service for test and maintenance. Then the PSA was quantified with the assumption that EDG A was out of service and then EDG B. The following results were obtained.

Case	Core Damage Frequency (per year)	Large Early Release Frequency (per year)
No Test & Maintenance	4.1E-05	9.5E-06
EDG A Out of Service	8.7E-05	1.1E-05
EDG B Out of Service	1.2E-04	1.2E-05

Based upon the estimated time of 72 to 96 hours for performance of the refueling interval inspections, the following changes in core damage probability were obtained.

Case	Core Damage Probability Change
EDG A Out of Service for 72 Hours	3.8E-07
EDG A Out of Service for 96 Hours	5.0E-07
EDG B Out of Service for 72 Hours	6.5E-07
EDG B Out of Service for 96 Hours	8.7E-07

13.0 From your current PRA, provide the value of the CDF resulting from sequences involving SBO. Also, provide this value with the changes proposed to TS section 4.6.1.3 in place.

A. From the current PSA, the value of CDF resulting from sequences involving SBO was calculated to be about 9.0E-06 per year.

B. Since the proposed change represented a clarification of Technical Specifications and not a prerequisite for the performance of on-line maintenance, the proposed change to TS 4.6.1.3 was judged to have no effect on the value of CDF resulting from sequences involving SBO. Refer to the response to question number 9.0 for more detailed information.

C. To quantify the effect of performing the diesel inspections on-line, an updated analysis of the impact of taking the EDGs out of service was performed with the current PSA model. With EDG A out of service and no other system out for test and maintenance, the CDF was about 8.7E-05 per year of which about 56.8 percent (about 4.9E-05) resulted from sequences involving SBO. With EDG B out of service and no other system out for test and maintenance, the CDF was 1.2E-04 per year of which about 41.7 percent (about 4.9E-05) resulted from sequences involving SBO.

14.0 Provide the results of the Fussell-Vesely and Risk Achievement Worth Importance analyses for each of the HBR EDGs.

The Fussell-Vesely and Risk Achievement Worth Importance measures for the different HBRSEP EDG events and failure modes represented in the PSA were:

Failure Mode	Fussell-Vesely	Risk Achievement Worth
EDG A Out of Service for Test & Maintenance	1.94E-02	2.03
EDG B Out of Service for Test & Maintenance	2.67E-02	2.41
EDG A & B Common Cause Fail to Start	8.80E-03	26.70
EDG A & B Common Cause Fail to Run	2.42E-03	4.26
EDG A Fails to Start	6.57E-03	2.00
EDG B Fails to Start	8.48E-03	2.29
EDG A Fails to Run	3.90E-03	1.14
EDG B Fails to Run	3.75E-03	1.13

15.0 Identify the model used for representing the reactor coolant pump seals in the current PRA. Provide the percentage contribution to the CDF from an SBO-induced reactor coolant pump seal loss of coolant accident. Describe how the contribution changes as a result of the proposed changes to TS section 4.6.1.3.

A. The current PSA model represented the RCP seals with a delay time (time between the loss of RCP cooling and the initiation of seal leakage) of 1.5 hours consistent with NUREG/CR-4550, Volume 1. The PSA analysis assumed that restoration of seal cooling at any time prior to this time effectively stopped any excess seal leakage and required no additional measures.

B. SBO-induced RCP seal LOCAs contributed about 4.3E-06 per year or about 8.7% of the mean CDF.

C. Since the proposed change represented a clarification of Technical Specifications and not a prerequisite for the performance of on-line maintenance, the proposed change to TS 4.6.1.3 was judged to have no effect on the percentage contribution to the CDF from an SBO-induced RCP seal LOCA. Refer to the response to question number 9.0 for more detailed information

D. To quantify the effect of performing the diesel inspections on-line, an updated analysis of the impact of taking the EDGs out of service was performed with the current PSA model. With EDG A out of service and no other systems out for test and maintenance, the CDF for SBO-induced RCP seal LOCAs was about 2.0E-05 per year which was about 23% of the configuration specific CDF (about 8.7E-05). With EDG B out of service and no other systems out for test and maintenance, the CDF for SBP-induced RCP seal LOCAs was about 2.0E-05 per year or about 17% of the configuration specific CDF (about 1.2E-04).

16.0 Given the AOT plant configurations reflected in the change request to TS 4.6.1.3, identify the other risk-significant systems indicated by your PRA. State whether the significance is the same for each EDG. Describe any measures established to ensure that no risk-significant plant equipment outage configurations would occur while the plant is subject to the EDG limiting condition for operation.

A. The risk significant system configurations, including the AOT plant configurations in the change request to TS 4.6.1.3, were indicated in the matrix in Attachment 10.2 of OMM-048, "Work Coordination and Risk Assessment." Based upon these matrices:

a) The risk significant systems with EDG A out of service were:
- AFW Steam Driven Pump;
- AFW Pump B;
- RHR Pumps B, C and D
- EDG B
- DSDG;
- DS bus.

b) The risk significant systems with EDG B out of service were:
- AFW Pumps A and B;
- AFW SDP
- Service Water Pumps A, B, C and D;
- DSDG;
- DS bus;
- RHR Pump A;
- SI Pump A;
- SG PORV A, B and C; and
- EDG A.

B. The significance was not the same for each EDG. EDG B being out of service for maintenance had a greater impact on plant risk than EDG A being out of service.

C. To ensure that no risk-significant plant equipment outage configurations would occur while the plant was subject to the EDG limiting condition for operation, the following measures were established. OMM-048, "Work Coordination and Risk Assessment" was written, in part, to provide guidance to maximize the reliability and availability of systems and components which were identified as risk significant with the plant operating at power. OMM-048 was written to require Plant General Manager approval and a review of PSA insights for plant configurations in excess of those contained in the matrix of non-risk significant configuration.

17.0 In your RAI response dated May 20, 1996, you stated that, as provided by PLP-056, the DSDG and DS bus will be operable during the period of time an EDG is inoperable while preventive maintenance is being performed. Provide a copy of PLP-056.

A copy of PLP-056, Rev 12, "Work Control Process," is attached. However, on June 21, 1997, PLP-056 was superseded by OMM-048, "Work Coordination and Risk Assessment." A copy of OMM-048 is also attached.

18.0 Also, in your RAI response, you discuss Attachment 10.2 of PLP-056, which provides a matrix of risk significant work activities from different systems when scheduled concurrently. Describe how this matrix is incorporated into your on-line maintenance scheduling program. This matrix only provides for combinations of one or two system trains unavailable at a time. Explain how do you assess the risk insights when more complicated equipment outages occur concurrently.

A. This matrix in Attachment 10.2 of PLP-056 was superseded by the matrix in Attachment 10.2 of OMM-048. The matrix of risk significant work activities, in Attachment 10.2 of OMM-048, was incorporated into the on-line maintenance scheduling program to:

a) Apply for reactor critical and power operation,
b) Address best estimate risk and not defense in depth,
c) Identify configurations that add 1E-6 to the total cumulative risk within 72 hours,
d) Encourage the expeditious termination and limitation in occurrence of these configurations.

B. For equipment outages more complicated than those provided in the matrix, OMM-048 was written to assess risk insights via a requirement for consultation with the PSA engineer and prior approval by the Plant General Manager. OMM-048 was written to require further analysis if three or more system train functions need to be unavailable at the same time.

OMM-048
WORK COORDINATION & RISK ASSESSMENT