Tennessee Valley Authority, Post Office Box 2000, Decatur, Alabama 35609-2000

Brian O'Grady
Vice President, Browns Ferry Nuclear Plant

TVA-BFN-TS-431

December 19, 2005

10 CFR 50.90

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop: OWFN, P1-35
Washington, D.C. 20555-0001

Gentlemen:

In the Matter of	)	Docket No. 50-259
Tennessee Valley Authority	)	

BROWNS FERRY NUCLEAR PLANT (BFN) – UNIT 1 - RESPONSE TO NRC ROUND 2 REQUESTS FOR ADDITIONAL INFORMATION RELATED TO TECHNICAL SPECIFICATIONS (TS) CHANGE NO. TS-431 – REQUEST FOR EXTENDED POWER UPRATE OPERATION (TAC NO. MC3812)

This letter provides TVA's response to the NRC Staff's request for additional information, which was submitted to TVA by letter dated October 3, 2005 (Reference 1), in order to support review of the BFN Unit 1 Extended Power Uprate (EPU) license amendment application.

TVA submitted the BFN Unit 1 EPU application to the NRC by letter dated June 28, 2004 (Reference 2). TVA supplemented that application by letters dated February 23, 2005 (Reference 3), April 25, 2005 (Reference 4) and June 6, 2005 (Reference 5). The enclosure to this letter provides TVA's responses to the questions contained in Reference 1.

As discussed with the NRC Project Manager for BFN Unit 1 EPU, TVA is deferring its response to two of the Round 2 requests to ensure TVA's response to these items provides sufficient information for the Staff to complete its review of those subject areas. Specifically, NRC Request EMEB-B.6 requested

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information concerning TVA's plans for vibration monitoring, procedures, hold points, evaluations, and decision criteria during and following power ascension at EPU conditions. TVA's vibration monitoring program is not yet sufficiently developed to provide the level of detail the NRC Staff requires to complete its review of this item. Accordingly, TVA is deferring its complete response to this item until the program is further developed. TVA will provide the complete response to NRC request EMEB-B.6 by February 1, 2006.

NRC Request SPSB-A.11 requested that TVA provide an assessment of the requested credit for Containment overpressure in ensuring adequate post-accident Emergency Core Cooling System pump Net Positive Suction Head against the five key principles of risk-informed decision-making identified in NRC Regulatory Guide 1.174 and NRC Standard Review Plan Chapter 19. TVA requires further time to prepare this response, particularly in regard to development of a quantitative risk assessment model that sufficiently characterizes the risk associated with the requested credit. TVA will provide the response to NRC question SPSB-A.11 by March 1, 2006.

NRC Requests EMEB-B.9 through EMEB-B-13 request detailed information concerning development of the acoustical analyses, BFN Steam Dryer loading definition, Steam Dryer stress analyses, Steam Dryer modifications planned, plans for collecting and analyzing data during power ascension, and the bases for acceptability. The responses to these questions provided in the enclosure describe the work currently ongoing to ensure the integrity of the Steam Dryers at EPU conditions. In particular, the response to NRC Question EMEB-B.9 summarizes the work being performed, including work to develop the BFN-specific acoustical circuit analysis to define the Steam Dryer loading definition, and validation of that model via testing at the General Electric scale model test facility. Completion of this work is scheduled for June 2006; TVA will provide the detailed information requested in EMEB-B.9 through EMEB-B.13 following completion of that work. TVA expects to submit this information in July 2006. TVA will submit a status report of these efforts by March 31, 2006.

TVA is providing similar information regarding the Units 2 and 3 EPU application in a separate submittal. There are no new regulatory commitments associated with this submittal. If you have any questions concerning this letter, please contact William D. Crouch, Browns Ferry Manager of Licensing and Industry Affairs, at (256) 729-2636.

I declare under penalty of perjury that the forgoing is true and correct.
Executed on this 19th day of December, 2005.

Sincerely,

Brian O'Grady

References:

1. NRC letter, M. H. Chernoff to TVA, "Browns Ferry Nuclear Plant, Unit 1 – Request for Additional Information for Extended Power Uprate (TS-431)(TAC No. MC3812)," dated October 3, 2005.

2. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 - Proposed Technical Specifications (TS) Change TS - 431- Request for License Amendment Extended Power Uprate (EPU) Operation," dated June 28, 2004.

3. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 Response to NRC's Acceptance Review Letter and Request for Additional Information Related to Technical Specifications (TS) Change No. TS-418, Request for Extended Power Uprate Operation, (TAC No. MC3812)," dated February 23, 2005.

4. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 - Response to NRC's Request for Additional Information Related to Technical Specifications (TS) Change No. TS-431– Request for Extended Power Uprate Operation (TAC No. MC3812)," dated April 25, 2005.

5. TVA letter, W. D. Crouch to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 – Response to NRC's Request for Additional Information Related to Technical Specifications (TS) Change No. TS - 431 – Request For License Amendment – Extended Power Uprate (EPU) Operation (TAC No. MC3812)," dated June 6, 2005.

Enclosure
cc (Enclosure):

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ENCLOSURE

TENNESSEE VALLEY AUTHORITY
BROWNS FERRY NUCLEAR PLANT UNIT 1
DOCKET NO. 50-259

RESPONSE TO NRC ROUND 2 REQUEST FOR ADDITIONAL INFORMATION RELATED TO TECHNICAL SPECIFICATIONS (TS) CHANGE NO. TS - 431– REQUEST FOR EXTENDED POWER UPRATE OPERATION

By letter dated June 28, 2004 (Reference 1), TVA submitted to the NRC a license amendment application requesting authorization for Extended Power Uprate (EPU) operation for Browns Ferry Nuclear Plant (BFN) Unit 1. TVA supplemented that application by letters dated February 23, 2005 (Reference 2), April 25, 2005 (Reference 3), and June 6, 2005 (Reference 4). By letter dated October 3, 2005 (Reference 5), the NRC Staff transmitted a request for additional information to support its review of the BFN Unit 1 EPU application. The responses to those questions are provided below, by NRC request number. References cited in the responses are listed at the end of this enclosure.

NRC Request EMCB-C.1

The FAC monitoring program includes the use of a predictive method to calculate the wall thinning of components susceptible to FAC. Provide a sample list of components for which wall thinning is predicted and measured by ultrasonic testing or other method. Include the initial wall thickness (nominal), current (measured) wall thickness, and a comparison of the measured wall thickness to the thickness predicted by the CHECWORKS™ FAC model.

TVA Reply to EMCB-C.1

BFN Unit 1 is in a recovery effort following an extended shutdown period. As part of that effort, TVA is developing the Unit 1 Flow-Accelerated Corrosion (FAC) program. The BFN Units 2 and 3 FAC program was developed following Unit 1 shutdown in 1985; therefore, previous information pertaining to predicted and measured wall thinning does not exist for Unit 1. However, the BFN Unit 1 program is being developed based on the BFN Units 2 and 3 programs and will be managed by the same BFN organization. Therefore, the BFN Units 2 and 3 FAC program predictive capability is representative of the BFN Unit 1 program when fully developed and implemented. The following discussion provides the requested details from the current FAC program for BFN Units 2 and 3.

A sample list of components and measured versus predicted thickness for CHECWORKS™ modeled components at current thermal power operating conditions

(prior to EPU) is provided in the table below. A total of 15 components for Units 2 and 3 were selected for this sample.

The data in the table is the measured thickness (T_{meas}) and CHECWORKS™ predicted thickness (T_{pred}) at the time of last inspection. Predicted thickness was calculated by CHECWORKS™ using operating history and thermal conditions through Refuel Outage 13 for Unit 2 (NSS input to turbine cycle 3463 MWt) and Refuel Outage 11 for Unit 3 (NSS input to turbine cycle 3463 MWt). Also shown in the table is the nominal thickness (T_{nom}) taken from standard pipe dimension tables. By design, piping is manufactured with a tolerance of ± 12.5% of T_{nom} so initial thickness is generally not the same as nominal thickness. Therefore, the table lists the estimated initial thickness (T_{init}) determined by CHECWORKS™ in calculating wear (in CHECWORKS™ this value is termed $T_{rep,}$ for representative initial thickness).

The stated accuracy of the CHECWORKS™ predictive model is ± 50% on predicted wear rate and ± 20% on wall thickness (from section 6.3.1 of EPRI document 1009599, "CHECWORKS™Steam/Feedwater Application Guidelines for Plant Modeling and Evaluation of Component Inspection Data"). The last column in the table lists the variance between T_{pred} and T_{meas} (T_{pred}/T_{meas} variance), where a positive value indicates that T_{meas} is less than T_{pred} and a negative value indicates that T_{meas} is greater than T_{pred}. Note that for nearly all components listed in the table (27 of 30) the variance between T_{pred} and T_{meas} is within the stated accuracy of the CHECWORKS™ predictive model (± 20% on wall thickness). The three components outside the accuracy of the CHECWORKS™ predictive model are due to an initial thickness greater than ± 12.5% of T_{nom} tolerance (2CON11A-4E T_{nom}=0.438" and T_{init}=0.630"; 3CON11B-13E T_{nom}=0.438" and T_{init}=0.630; 3HDV4A4-5E T_{nom}=0.375" and T_{init}=0.445").

Table EMCB-C.1-1
Predicted Versus Measured Wall Thickness at Current BFN Operating Conditions

Unit	Item	System	Component	T_{nom} (in.)	T_{init} (in.)	T_{meas} (in.)	T_{pred} (in.)	T_{pred}/T_{meas} Variance
2	1	Heater Drains: 3FWH to 4FWH	2HDV6A3-4E	0.365	0.444	0.385	0.330	-14%
2	2	Heater Drains: 3FWH to 4FWH	2HDV6B3-5P	0.365	0.437	0.359	0.338	-6%
2	3	Heater Drains: 3FWH to 4FWH	2HDV6C3-8E	0.365	0.412	0.350	0.330	-6%
2	4	Condensate: 4FWH to 3FWH	2CON11A-3P	0.438	0.480	0.399	0.409	3%
2	5	Condensate: 4FWH to 3FWH	2CON11A-4E	0.438	0.630	0.535	0.374	-30%
2	6	Condensate: 4FWH to 3FWH	2CON11A-5P	0.438	0.501	0.413	0.390	-6%
2	7	Heater Drains: 4FWH to Flash Tank	2HDV9A4-2EX	0.375	0.422	0.363	0.309	-15%
2	8	Heater Drains: 4FWH to Flash Tank	2HDV8B4-15E	0.375	0.550	0.313	0.294	-6%

Table EMCB-C.1-1 Predicted Versus Measured Wall Thickness at Current BFN Operating Conditions								
Unit	**Item**	**System**	**Component**	**T_{nom} (in.)**	**T_{init} (in.)**	**T_{meas} (in.)**	**T_{pred} (in.)**	**T_{pred}/ T_{meas} Variance**
2	9	Heater Drains: 4FWH to Flash Tank	2HDV9C4-6P	0.375	0.468	0.349	0.345	-1%
2	10	Feedwater: 2FWH to 1FWH	2RFW4A2-2P	1.031	1.092	0.995	0.993	0%
2	11	Feedwater: 2FWH to 1FWH	2RFW4B2-5P	1.031	1.090	1.004	0.945	-6%
2	12	Feedwater: 2FWH to 1FWH	2RFW4C2-8P	1.031	1.097	1.011	0.941	-7%
2	13	Heater Drains: 1FWH to 2FWH	2HDV2A1-5P	0.322	0.348	0.314	0.288	-8%
2	14	Heater Drains: 1FWH to 2FWH	2HDV2B1-3P	0.322	0.363	0.312	0.340	9%
2	15	Heater Drains: 1FWH to 2FWH	2HDV2C1-3P	0.322	0.361	0.314	0.273	-13%
3	1	Heater Drains: 3FWH to 4FWH	3HDV3A3-3P	0.365	0.420	0.369	0.332	-10%
3	2	Heater Drains: 3FWH to 4FWH	3HDV3A3-4E	0.365	0.384	0.330	0.280	-15%
3	3	Heater Drains: 3FWH to 4FWH	3HDV3B3-8E	0.365	0.392	0.343	0.326	-5%
3	4	Condensate: 4FWH to 3FWH	3CON11B-7P	0.438	0.473	0.423	0.356	-16%
3	5	Condensate: 4FWH to 3FWH	3CON11B-13E	0.438	0.630	0.551	0.361	-34%
3	6	Condensate: 4FWH to 3FWH	3CON11C-3P	0.438	0.444	0.390	0.365	-6%
3	7	Heater Drains: 4FWH to Flash Tank	3HDV4A4-5E	0.375	0.445	0.378	0.298	-21%
3	8	Heater Drains: 4FWH to Flash Tank	3HDV4A4-11E	0.375	0.444	0.352	0.333	-5%
3	9	Heater Drains: 4FWH to Flash Tank	3HDV4B4-9E	0.375	0.439	0.366	0.311	-15%
3	10	Feedwater: 2FWH to 1FWH	3RFW2A2-2P	1.031	1.106	0.981	0.900	-8%
3	11	Feedwater: 2FWH to 1FWH	3RFW2B2-5P	1.031	1.085	0.907	0.906	0%
3	12	Feedwater: 2FWH to 1FWH	3RFW2C2-8P	1.031	1.078	0.936	0.894	-4%
3	13	Heater Drains: 1FWH to 2FWH	3HDV1A1-8P	0.322	0.378	0.317	0.288	-9%
3	14	Heater Drains: 1FWH to 2FWH	3HDV1B1-13N	0.500	0.568	0.424	0.441	4%
3	15	Heater Drains: 1FWH to 2FWH	3HDV1C1-2E	0.322	0.365	0.312	0.272	-13%

NRC Request EMCB-C.2

EPU will affect several process variables that influence FAC. Identify the systems that are expected to experience the greatest increase in wear as a result of EPU and discuss the effect of individual process variables (i.e., moisture content, temperature, oxygen, and flow velocity) on each system identified.

TVA Reply to EMCB-C.2

BFN Unit 1 is in the progress of a recovery effort following an extended shutdown period. As part of that effort, TVA is developing the Unit 1 Flow-Accelerated Corrosion (FAC) program. The BFN Units 2 and 3 FAC program was developed following Unit 1 shutdown in 1985; therefore, previous data does not exist for Unit 1. However, the predicted effects of EPU on BFN Units 2 and 3 flow-accelerated corrosion are representative of that expected for BFN Unit 1.

The EPU implementation at BFN will change a number of systems water and steam flow rates, temperatures, and enthalpies, in turn changing dissolved oxygen concentration. All these factors affect Flow Accelerated Corrosion (FAC) susceptibility status and FAC wear rates. As a result of the EPU operating conditions, some lines will experience accelerated rates of FAC, while others will have reduced rates. It is noted that no lines that were previously non-susceptible to FAC became susceptible due to post-EPU operating conditions.

The relationship between each of these parameters and FAC is as follows:

Steam Quality (moisture content): Curve with maximum FAC at ~50% and decreasing FAC away from peak.

Temperature: Curve with maximum FAC for single phase at ~275°F (300°F for two-phase) and decreasing FAC away from peak.

Flow Rate: FAC increases with increasing flow rate.

Dissolved Oxygen: FAC decreases with increasing dissolved oxygen.

The table below identifies the Unit 2 and 3 systems that are expected to experience the greatest increase in wear rate as a result of EPU operating conditions. The change in wear rate was determined based on percent change as opposed to magnitude of change. Those systems that have the greatest increase in CHECWORKS™ predictive wear rate would also have the greatest increase in CHECWORKS™ predicted wear. For each unit, a comparison was performed between pre-EPU operating conditions at the current operating cycle and post-EPU operating conditions at the cycle EPU is anticipated. For Unit 2, the analysis is based on a comparison of pre-EPU CHECWORKS™ predictions at Cycle 14 (NSS input to turbine cycle 3463 MWt) and post-EPU CHECWORKS™ predictions at Cycle 15 (NSS input to turbine cycle 3964.4 MWt). For Unit 3, the analysis is based on a comparison of pre-EPU CHECWORKS™ predictions at Cycle 12 (NSS input to turbine cycle 3463 MWt) and post-EPU CHECWORKS™ predictions at Cycle 14 (NSS input to turbine cycle 3964.4 MWt).

The top five systems from each unit are included and the entries are ordered in decreasing order of percent change. The BFN FAC Program has accounted for these changes by modeling the post-EPU operating conditions in the CHECWORKS™ predictive model thereby ensuring that the model correctly reflects pre-EPU and post-EPU operating conditions when generating wear rate and remaining life predictions. In addition, the BFN FAC Program has evaluated the effect post-EPU operating conditions will have on the remaining life of previously inspected components and has adjusted the planned scheduled inspections to account for changes in remaining life based on post-EPU conditions.

Table EMCB-C.2-1
Piping Segments at EPU Conditions With Greatest Predicted Increase in Wear

Unit	Item	System	Avg Wear Rate Change[1]	Notes
2	1	Heater Drains: 3FWH to 4FWH	19.4%	This is due to an 11°F temperature increase towards the FAC peak (to 262°F) and a 20% increase in flow rate (to 4.1 Mlb/hr). The steam quality remained unchanged at 0%.
2	2	Condensate: 4FWH to 3FWH	18.5%	This is due to an 8°F temperature increase towards the FAC peak (to 249°F) and a 16% increase in flow rate (to 16.4 Mlb/hr). The steam quality remained unchanged at 0%.
2	3	Heater Drains: 4FWH to Flash Tank	7.9%	This is due to an 12°F temperature increase towards the FAC peak (to 205°F) and a 17% increase in flow rate (to 4.9 Mlb/hr). The steam quality remained unchanged at 0%.
2	4	Feedwater: 2FWH to 1FWH	6.6%	This is due to a 16% increase in flow rate (to 16.4 Mlb/hr). The steam quality remained unchanged at 0%. The temperature increased away from the FAC peak by 10°F (to 344°F); however, this was overshadowed by the flow rate increase.
2	5	Heater Drains: 1FWH to 2FWH	5.1%	This is due to a 20% increase in flow rate (to 1.1 Mlb/hr). The steam quality remained unchanged at 0%. The temperature increased away from the FAC peak by 13°F (to 357°F); however, this was overshadowed by the flow rate increase.
3	1	Heater Drains: 3FWH to 4FWH	19.0%	This is due to an 11°F temperature increase towards the FAC peak (to 262°F) and a 21% increase in flow rate (to 4.1 Mlb/hr). The steam quality remained unchanged at 0%.
3	2	Condensate: 4FWH to 3FWH	17.8%	This is due to a 7°F temperature increase towards the FAC peak (to 249°F) and a 16% increase in flow rate (to 16.4 Mlb/hr). The steam quality remained unchanged at 0%.
3	3	Heater Drains: 4FWH to Flash Tank	10.1%	This is due to an 11°F temperature increase towards the FAC peak (to 205°F) and a 19% increase in flow rate (to 4.9 Mlb/hr). The steam quality remained unchanged at 0%.

Table EMCB-C.2-1 Piping Segments at EPU Conditions With Greatest Predicted Increase in Wear				
Unit	**Item**	**System**	**Avg Wear Rate Change[1]**	**Notes**
3	4	Feedwater: 2FWH to 1FWH	7.0%	This is due to a 16% increase in flow rate (to 16.4 Mlb/hr). The steam quality remained unchanged at 0%. The temperature increased away from the FAC peak by 10°F (to 344°F); however, this was overshadowed by the flow rate increase.
3	5	Heater Drains: 1FWH to 2FWH	4.5%	This is due to a 20% increase in flow rate (to 1.1 Mlb/hr). The steam quality remained unchanged at 0%. The temperature increased away from the FAC peak by 13°F (to 357°F); however, this was overshadowed by the flow rate increase.

1. These predicted wear rates are based on BFN Units 2 and 3 FAC program predictions from current power levels (105% of Original Licensed Thermal Power [OLTP]) to EPU conditions (120% of OLTP). The predicted effects of EPU on BFN Units 2 and 3 flow-accelerated corrosion are representative of that expected for BFN Unit 1.

NRC Request EMCB-C.3

TVA's February 23, 2005, response states:

> Previous testing was performed which bounded peak accident conditions for all but one specific coating configuration. Therefore, TVA is performing confirmatory testing to ensure that all qualified coating configurations have been tested.

In regards to this statement provide a discussion explaining what the specific coating configuration is, how large the affected area is, what specific testing was performed, the results of the confirmatory testing, and how the confirmatory testing is correlated to the coating's original design basis accident qualification.

TVA Reply to EMCB-C.3

The specific coating configuration referred to in the February 23, 2005, response was the feather edge overlap of Ameron 400NT over existing coating. This configuration had not been used in the BFN Unit 1 containment. Results of the qualification testing performed indicated that this configuration was not qualified for use at BFN. Therefore, this configuration will not be used in the BFN Unit 1 containment.

NRC Request EEIB-B.1

Address and discuss the following points:

NRC Request EEIB-B.1.a

Identify the nature and quantity of Mega volt-amp reactive (MVAR) support necessary to maintain post-trip loads and minimum voltage levels.

TVA Reply to EEIB-B.1.a

The Browns Ferry Extended Power Uprate Grid Adequacy and Stability Study credits a capability of + 200/-150 MVAR per generator for Units 2 and 3 and a capability of +360/-150 MVAR for Unit 1 as the basis for analyzing the adequacy of the BFN to grid interface. This data was provided to TVA's Transmission Planning organization along with plant post-trip load data and voltage acceptance criteria so that the proper stability and loadflow/voltage studies could be run as part of the Browns Ferry Extended Power Uprate Grid Adequacy and Stability Study. This study establishes that grid voltages (both pre- and post-unit trip) satisfy the acceptable voltage ranges for the 500 kV system.

NRC Request EEIB-B.1.b

Identify what MVAR contributions BFN Unit is credited for providing to the grid.

TVA Reply to EEIB-B.1.b

The unit manufacturer's reactive capability curves along with uprated MW ratings were provided to TVA's Transmission Planning Organization so that the unit can be properly modeled for use in their planning and stability studies. This study credits a post-event contribution of +360/-150 MVAR for Unit 1 uprated.

NRC Request EEIB-B.1.c

After the power uprate, identify any changes in MVAR associated with Items a and b above.

TVA Reply to EEIB-B.1.c

As discussed in the response to EEIB-B.1.a and EEIB-B.1.b above, for post-event capability the transmission study credits a contribution of +360/-150 MVAR for Unit 1 uprated.

NRC Request EEIB-B.1.d

Address the compensatory measures that the licensee would take to compensate for the depletion of the nuclear unit MVAR capability on a grid-wide basis.

TVA Reply to EEIB-B.1.d

TVA's Transmission Planning Organization has determined that no compensatory measures are required.

NRC Request EEIB-B.1.e

Evaluate the impact of any MVAR shortfall listed in Item d above on the ability of the offsite power system to maintain minimum post-trip voltage levels and to supply power to safety buses during peak electrical demand periods. The subject evaluation should document information exchanges with the transmission system operator.

TVA Reply to EEIB-B.1.e

No MVAR shortfall has been identified.

NRC Request EEIB-B.2

Page 6-1 of Enclosure 4 of the June 28, 2004, submittal states that the study documented that no additional changes are required for BFN's offsite power system to continue to meet Title 10 the *Code of Federal Regulations* (10 CFR), Part 50, Appendix A, General Design Criteria (GDC)-17 requirements. Because the BFN construction permits were issued prior to the May 21, 1971, effective date of the GDC, compliance to these criteria may not be required as part of the BFN Units 1, 2 and 3 licensing basis.

State whether BFN Unit 1 is consistent with GDC-17 or the Atomic Energy Commission Criterion 39.

TVA Reply to EEIB-B.2

BFN conforms to the offsite power requirements of GDC 17.

NRC Request EEIB-B.3

The submittal states that transmission system operating guides will be issued to the load dispatcher prior to EPU operation, detailing any system operating constraints and any actions that may be required, including prompt communication with the control room. What protocol has been established with the transmission system operator to communicate to the licensee the availability of the transmission lines to provide sufficient voltage following a plant trip or when voltages would not be adequate?

TVA Reply to EEIB-B.3

TVA owns both the transmission system and BFN. Communication protocol between the Transmission Operator and BFNP regarding offsite power availability is established through TVA Intergroup Agreement 6. Should the transmission system not provide sufficient voltage, notification is provided to BFN Operations so that appropriate action can be taken.

NRC Request EEIB-B.4

Provide in detail and compare the existing ratings with the uprated ratings and the effect of the power uprate on the following equipment:

a. Main generator rating and power factor
b. Isophase bus, and modifications to the cooling system
c. Detailed description of the replaced main power transformers
d. Unit Auxiliary/Start-up transformers
e. Main Generator breaker

TVA Reply to EEIB-B.4

a. Main Generator

A comparison of the current versus the uprated generator ratings and power factors are provided below.

Table EEIB-B.4-1
BFN Unit 1 Generator Ratings

Parameter	Current	Uprated
Generator Output (MWe)	1098	1280
Rated Voltage (kV)	22	22
Power Factor	0.93	0.962
Generator Output (MVA)	1280	1330

b. Isophase Bus & Cooling

The Isophase Bus at BFN operates at 22kV. The bus is divided into several sections with ratings appropriate for each section depending on the location and use of each section. The isophase bus has been analyzed for operation at the new ratings. These sections are identified below with the pre-uprate and post-uprate ratings:

Table EEIB-B.4-2 Isophase Bus Ratings			
No.	Item	Original Design (Amps)	New design Specification (Amps)
1	Main Bus	35270	36740
2	Generator Bus	17635	18370
3	Delta Bus	20365	21212

c. Main Bank Transformers

The main bank transformers at BFN are being replaced due to obsolescence issues. The Unit 1, Unit 2, and Unit 1/2 spare transformers are in place and operating at this time. The current schedule is for the Unit 3 transformers to be replaced in 2010 along with the installation of a dedicated spare Unit 3 transformer.

Table EEIB-B.4-3 Main Bank Transformers		
Transformer	Old rating (65°C)	New rating (65°C)
Unit 1	3 X 448 MVA FOA	3 X 500 MVA OFAF

d. Unit Auxiliary/Start-up Transformers

The Unit Station Service Transformers (Unit Auxiliaries) and Common Station Service Transformers (Start-Up) are rated as follows:

Table EEIB-B.4-4 Unit Auxiliary/Start-up Transformers		
Transformer	Old Rating	New Rating
USST 1A	24/32/40 MVA OA/FA/FOA	No Change
USST 1B	24/32 MVA OA/FA	No Change
CSST A	21.9/29.2/36.5 MVA OA/FA/FOA	No Change
CSST B	21.9/29.2/36.5 MVA OA/FA/FOA	No Change

e. Main Generator Breakers

The main generator circuit breaker ratings are as follows:

Table EEIB-B.4-5 Main Generator Breakers		
Gen. Breaker	**Old Rating**	**New Rating**
Unit 1	Brown Boveri Type: DR36V1750D Rated Max Voltage: 24 kV Rated Continuous Current: 36 kA Rated S.C. Current: 165 kA Rated Voltage Range: 1 Impulse Withstand V: 150 kV Rated Frequency: 60 Hz Interrupting Time: 5 Cycles	Rated Continuous Current: 37 kA Rated S.C. Current: 200 kA

NRC Request EEIB-B.5

Provide the list of loads affected by the power uprate change. Identify the motor loads before and after the power uprate change.

TVA Reply to EEIB-B.5

The table below identifies the major load changes due to power uprate. These changes are limited to increased power requirements to the reactor recirculation pump, the condensate pumps and the condensate booster pumps. There are other minimal load changes but all are within the motor nameplate ratings.

Table EEIB-B.5-1 Major Changes In Browns Ferry Unit 1 Onsite AC Distribution System Loads			
System/Component	**Pre-Uprate Condition**	**Power Uprate Requirements**	**Remarks**
Reactor Recirculation Pumps	6650 HP @100% core flow @ 105% OLTP	8657 HP @ 105% core flow 120% OLTP	Note 1
Condensate Pumps	900 HP	1250 HP	Note 2
Condensate Booster Pumps	1750 HP	3000 HP	Note 2

1. Power requirement per recirculation system pump in service. Pre-Uprate Condition based on BFN Units 2 and 3 data.
2. Power requirement per pump with combination of three reactor feedwater pumps, three condensate booster pumps, and three condensate pumps.

NRC Request EEIB-B.6

Provide the coping duration and recovery time expected from a station blackout (10 CFR 50.63). Discuss whether there is any change in the coping duration and recovery time for station blackout (10 CFR 50.63).

TVA Reply to EEIB-B.6

BFN compliance to the SBO rule (10 CFR 50.63) was established in a series of docketed communications with the NRC. The NRC issued a safety evaluation report by letter dated July 11, 1991, since supplemented by letter dated September 16, 1992. BFN Unit 1 is categorized as four-hour duration plants using the methodology of NUMARC 87-00. Coping strategy is to shutdown the blacked-out unit with equipment powered from the 250-V DC battery system. Alternate AC power from diesel generators in the non-blacked-out units will be made available to power additional required HVAC and common loads. As set forth in NUMARC 87-00, Appendix B, the Alternate AC will be available within one hour through existing cross-ties. For EPU conditions, the assumptions and inputs for these assessments were evaluated and determined to have no impact on the coping duration category or alternate AC power availability for BFN.

NRC Request EEIB-B.7

Page 6-2 of Enclosure 4 of the June 28, 2004, submittal and Page 6-2 of Enclosure 5 of the June 28, 2004, submittal state that Units 1 and 2 share four independent safety-related diesel generator units coupled as an alternate source of power, to four independent 4160 volt buses. Have the design and operation changed since Unit 1 was shutdown in 1985? Describe the onsite alternating current power system for Unit 1.

TVA Reply to EEIB-B.7

Although BFN has implemented some design changes associated with the onsite electrical system, these modifications have not resulted in changes to the fundamental attributes and distribution system associated with the configuration of the offsite AC and Diesel Generator (DG) supply to the respective 4.16kV shutdown boards, 480V shutdown boards, 480V Reactor Motor Operated Valve (MOV) boards, and associated transformers since 1985. This configuration is further described in UFSAR Chapter 8.

Browns Ferry is a three unit plant, with each unit being a General Electrical Boiling Water Reactor (BWR) 4 with a Mark I containment. As shown in UFSAR Figure 8.4-1b, the standby AC supply and distribution system for Units 1/2 consists of four diesel generators (DGs), four 4.16kV shutdown boards, two shutdown buses, four 480V shutdown boards, and eight 480V Reactor Motor Operated Valve (RMOV) boards. The standby AC supply and distribution system for Unit 3 (UFSAR Figure 8.4-2) consists of four DGs, four 4.16kV shutdown boards, two shutdown buses, two 480V shutdown boards, and five 480V RMOV boards. Both of these standby AC supply and distribution

systems supply power to unitized Units 1/2 and Unit 3 electrical loads. The standby AC supply and distribution system for Units 1/2 and Unit 3 is divided into redundant divisions, so that loss of any one division does not prevent the minimum safety-related functions from being performed by the remaining division.

NRC Request EMCB-A.1

Section 10.7, Plant Life, of Enclosure 4 of the June 28, 2004, submittal identifies irradiation-assisted stress-corrosion cracking (IASCC) as a degradation mechanism influenced by increases in neutron fluence and reactor coolant flow. This section indicates that the current inspection strategy for reactor internal components is expected to be adequate to manage any potential effects of EPU operating conditions. Note 1 in Matrix 1 of Section 2.1 of RS-001, Revision 0 indicates that guidance on the neutron irradiation-related threshold for IASCC in boiling-water reactors (BWRs) is in Boiling-Water Reactor Vessel and Internals Program (BWRVIP) report BWRVIP-26. The "Final License Renewal SER [Safety Evaluation Report] for BWRVIP-26," dated December 7, 2000, states that the threshold fluence level for IASCC is 5×10^{20} n/cm^2 (E > 1 MeV).

Identify the vessel internal components whose fluence, at the end of period of operation with the EPU operating conditions, will exceed the threshold level and become susceptible to cracking due to IASCC. For each vessel internals component that exceeds the IASCC threshold, either provide an analysis that demonstrates failure of the component will not result in the loss of the intended function of the reactor internals or identify the inspection program to be utilized to manage IASCC of the component. Identify the scope, sample size, inspection method, frequency of examination and acceptance criteria for the inspection programs.

TVA Reply to EMCB-A.1

TVA has a procedurally controlled program for the augmented nondestructive examination (NDE) of selected reactor pressure vessel (RPV) internal components in order to ensure their continued structural integrity. The inspection techniques utilized are primarily for the detection and characterization of service-induced, surface-connected planar discontinuities, such as IASCC in welds and in the adjacent base material. TVA is a participant to the BWRVIP organization and implementation of the procedurally controlled program is consistent with the BWRVIP issued documents. The inspection strategies recommended by the BWRVIP consider the effects of fluence on applicable components and are based on component configuration and field experience.

Fluence calculations were performed in accordance with Regulatory Guide 1.190, March, 2001, to support the BFN Units 1, 2, and 3 license renewal applications (Reference 6). These calculations were performed for the extended period of operation (60 years), and assumed operation of each BFN unit at EPU conditions. Based on

these calculations, four reactor components exceeded the threshold of 5×10^{20} n/cm^2 (E > 1 MeV), and were determined to be susceptible during the extended period of operation to IASCC. These components will be inspected and managed in accordance with the recommendations developed by the corresponding BWRVIP program. These components and BWRVIP Programs are identified in the table below.

Table EMCB-A.1-1
Components Susceptible to IASCC

Component	Inspection & Evaluation Program	Period of Operation
Top Guide	BWRVIP-26	60 Years
Shroud	BWRVIP-76	60 Years
Core Plate	BWRVIP-25 & BFN Chemistry Control Program	60 Years
Incore Instrumentation Dry Tubes and Guide Tubes	BWRVIP-47	60 Years

In the BFN plant license renewal application, the core plate was determined to be a "plant-specific" Time Limited Aging Analysis (TLAA) that will be managed in accordance with the Boiling Water Reactor Vessel and Internals Project, and the BFN Chemistry Control Program. The BFN core shrouds are classified as "Category C" based on the core shroud classification criteria contained in Appendix B of the BWRVIP-76. The BFN BWR Vessel Internals Aging Management Program requires inspection of core shroud welds in accordance with "Category C" core shroud inspection requirements contained in BWRVIP-76.

<u>NRC Request EMEB-B.1</u>

Discuss the plans to implement an Inservice Testing (IST) Program for restart of BFN Unit 1 that is consistent with the licensee's American Society of Mechanical Engineers (ASME) Code of record and incorporates appropriate changes in light of applicable EPU operating conditions. In particular, discuss, with examples, the evaluation of the impact of EPU conditions on the performance of safety-related pumps, power-operated valves, check valves, and safety or relief valves, including consideration of changes in ambient conditions and power supplies (as applicable), and indicate any resulting adjustments to the IST Program resulting from that evaluation.

<u>TVA Reply to EMEB-B.1</u>

The ASME Inservice Test (IST) Program at BFN is common for all three units. All three units are on a concurrent Ten-Year Interval (the Third IST Ten-Year Interval) which began on September 1, 2002. The Code of Record is the 1995 Edition through 1996 Addenda of the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

The purpose of the ASME IST Program is to perform testing to assess the operational readiness of certain pumps and valves used in nuclear power plants. The OM Code specifies requirements for performing these tests based upon the design and safety-related functions of these components. These requirements are to trend pump and valve performance after establishing reference values when the components are known to be operating acceptably. When components performance varies from these reference values, the ASME IST program requires evaluation to determine the cause and to effect corrective actions.

Evaluation of the effect of changes in plant conditions on the performance of components in the ASME IST program is performed as part of the design change process. The ASME IST program takes the changes in plant conditions, establishes tests based on those conditions, and trends the test results in order to detect degrading performance. Specific changes in operating pressure and temperature for EPU conditions will result in the following:

- Increase to MSRV setpoints due to a 30 psig increase in the maximum operating pressure in the RPV. The ASME IST Program test procedures will ensure that the MSRVs are tested to verify that they open within a percentage of the required setpoints and that corrective actions are implemented if they do not.

- Increase in the pressure that HPCI and RCIC must be able to operate against due to a 30 psig increase in the maximum operating pressure in the RPV. The ASME IST Program test procedures will ensure that the HPCI and RCIC turbines are tested to verify that they meet design and Technical Specification requirements at EPU conditions. Corrective actions will be implemented if they do not.

- Increase in the reference test pressure for the SLC pumps for the 24-month test due to a 30 psig increase in maximum operating pressure in the RPV. The ASME IST Program test procedures will ensure that the SLC pumps are tested to verify that they meet design and Technical Specification requirements at EPU conditions. Corrective actions will be implemented if they do not.

The scope of the BFN ASME IST Program will not be affected by EPU changes for Unit 1. There will be no new components added or existing components deleted within the boundaries of the existing ASME IST Program. Also, no changes to any test periodicities will be needed. Therefore, no changes (except for the implementing test procedures discussed above) are anticipated in the ASME IST Program as a result of EPU for Unit 1.

NRC Request EMEB-B.2

Section 3.7, Main Steam Isolation Valves, of Enclosure 4 of the June 28, 2004, submittal states that the 24-percent increase in steam-flow rate will result in a decrease in the stroke time for the main steam isolation valves (MSIVs) but that the stroke time will continue to satisfy the Technical Specifications. Describe the basis for this assumption using design, test, and operational experience of the MSIVs.

TVA Reply to EMEB-B.2

The BFN MSIVs have design and testing features to ensure the MSIV closure time is not reduced below the lower stroke time limit during operation. The valve is required by BFN Technical Specifications to have a closing speed of 3 to 5 seconds. Valve closing time is controlled by a valve actuator hydraulic cylinder and damper piston with flow control valves installed in the external piping around the hydraulic cylinder. When closing the valve, the oil in the underside of the piston in the hydraulic cylinder must be displaced through the external piping to the top side of the piston. The rate at which this oil displacement takes place is controlled by the adjustment of the flow control valves which, in turn, control the rate of valve closure.

The BFN MSIV is a wye pattern type valve and upon actuation to close, the valve disk proceeds into the steam flow path with the main steam line flow being over the valve disk. The hydraulic damper piston attached to the valve stem senses a combined driving force which includes the steam drag force. An increased steam line flow would therefore slightly increase the drag force applied on the main disk during closure. The hydraulic damper piston modulates the disk motion. The hydraulic resistance force is proportional to the traveling velocity of the damper piston. The increase in closing force and valve speed due to EPU conditions would be partially offset by an increase in the hydraulic resistance. Therefore, the net change (reduction) to the valve closing time due to EPU conditions is negligible.

To ensure the MSIV stroke time requirements of the Technical Specifications are met, BFN Unit 1 surveillance procedures will require an MSIV fast closure test on a refueling outage frequency. This procedure is performed under a zero steam flow condition. However, it is recognized that the MSIVs should close slightly faster during reactor operation due to the mechanical configuration of the valves since the forces that are developed on the valve poppet from steam flow assist in valve closure. In order to provide margin to the low stroke time limit, the required closure time will be designated to be 4 to 5 seconds. This margin ensures that small variations in the effect of steam flow will not cause the MSIVs to exceed the 3 second minimum closure time limit.

NRC Request EMEB-B.3

Section 4.1.3, Containment Isolation, of Enclosure 4 of the June 28, 2004, submittal states that parameters for air-operated valves (AOVs) and solenoid-operated valves

(SOVs) were reviewed, and no changes to the functional requirements of any AOVs or SOVs were identified as a result of EPU operating conditions. Discuss, with examples, the evaluation of safety-related AOVs and SOVs used for containment isolation and other safety functions for potential impact from EPU operation.

TVA Reply to EMEB-B.3

The Unit 1 AOV and SOV primary containment isolation valves have been evaluated for the effects of EPU. This evaluation examined the valve pressures and temperatures at EPU conditions and concluded:

- Performance is equivalent to or bounded by the design inputs, analytical scenarios and methodologies of the existing analyses; and
- Existing design pressures and temperatures are adequate.

Evaluation of the Unit 1 AOV and SOV containment isolation valve capability included consideration of valve functional characteristics and potential changes to operating requirements. Valve capability was confirmed by comparing valve design pressures/ temperatures to calculated EPU accident conditions. Unit 1 EPU Containment and Reactor Coolant System pressures and temperatures are bounded by the current Units 2 and 3 design bases (uprated to 105% of the original licensed thermal power, with an associated 30 psig increase in reactor pressure). The design temperatures and pressures of each Unit 1 AOV and SOV containment isolation valve were compared to the design requirements of the corresponding Units 2 and 3 valves and determined to be equivalent to, or bounded by the design requirements for the corresponding Units 2 and 3 valves. Through this comparison, the existing valve design was determined to be acceptable. Flow remained unchanged with the exception of the MSIVs, which experience a 20% increase in steam flow. See Section 3.7 of Enclosure 4 of the initial application (Reference 1) and the response to EMEB-B.2 for further discussion concerning the MSIVs. The table below provides examples of the evaluation performed.

Table EMEB-B.4-1 Unit 1 Primary Containment AOV/SOV Evaluations[1]					
Valve ID	Valve Description	Accident temperature (°F) Current/EPU	Accident pressure (psig) Current/EPU	Valve Type	Evaluation
FCV-77-2A	Drywell Floor Drain Sump Discharge	335.9/335.4	50.6/48.5	Air Operated Gate Valve	This valve is in a system that may interface with containment atmosphere. Design pressure rating is 100 psig.
FSV-84-49	Control Air Supply	335.8/335.4	50.6/48.5	Solenoid Operated Globe Valve	This valve is in a system that may interface with containment atmosphere. Design pressure rating is 100 psig.

1. As discussed above, the BFN Unit 1 AOV/SOV evaluations were based on a comparison of BFN Unit 1 valve design requirements to the corresponding BFN Units 2 and 3 valve design requirements. The information contained in this table was extracted from the BFN Units 2 and 3 AOV/SOV evaluations.

NRC Request EMEB-B.4

Section 4.1.4, Generic Letter (GL) 89-10 Program, of Enclosure 4 of the June 28, 2004, submittal states that process and ambient parameters for motor-operated valves (MOVs) were reviewed, and no changes to the functional requirements of GL 89-10 MOVs were identified as a result of EPU operating conditions. In support of the EPU review, discuss, with examples, the evaluation of safety-related MOVs for the potential impact from EPU operation, including the impact of increased process flows on operating requirements and increased ambient temperature on motor output.

TVA Reply to EMEB-B.4

Since BFN Unit 1 was in an extended shutdown when Generic Letter 89-10 was issued, TVA is performing its initial implementation of GL 89-10 as part of restart activities. TVA described development of the BFN Unit 1 GL 89-10 program in a letter dated May 5, 2004 (Reference 7). Consistent with implementation of the BFN Units 2 and 3 GL 89-10 programs, many BFN Unit 1 GL 89-10 MOVs have been or are being modified to ensure valve operability. Since operation at EPU conditions was planned as part of Unit 1 restart activities, GL 89-10 calculations were performed at EPU conditions. Therefore, BFN Unit 1 pre-EPU MOV capability data does not exist, quantitatively, to identify the specific impact on these valves due to the change associated with EPU.

The BFN MOV Program is established and prior to restart of BFN Unit 1, will be procedurally implemented. Evaluation of each MOV in the GL 89-10 program is documented in a controlled calculation. Operation at EPU can affect MOV capability due to changes in the following process conditions:

- Line pressure
- Differential pressure
- Fluid flow
- Fluid temperatures
- Normal environmental temperature
- Accident environmental temperature

Each MOV is the BFN GL 89-10 program has been evaluated at EPU conditions. The table below provides examples of the MOV evaluations performed, and represents evaluations performed on the valves, as-modified for Unit 1 restart as applicable.

Table EMEB-B.4-1
Examples of BFN Unit 1 Safety-Related MOV Evaluations

Valve	Valve description	Safety function	Parameter Affected	Current Value	EPU Value
FCV-70-47	RBCCW Primary Containment Outlet Valve	Close	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	102 psig 102 psid 240°F 6,568 lbs 37,345 lbs 469%
FCV-74-47	RHR Shutdown Cooling Supply Outboard Containment Isolation Valve	Close	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	133 psig 133 psid 128°F 28,131 lbs 50,074 lbs 78%
FCV-74-53	RHR System Loop I Inboard Injection Valve	Open	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	495 psig 495 psid 128°F 181,062 lbs 246,018 lbs 36%
FCV-75-50	Test Return Line Isolation	Close	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	407 psig 377 psid 120°F 32,533 lbs 75,693 lbs 133%

Table EMEB-B.4-1 Examples of BFN Unit 1 Safety-Related MOV Evaluations					
Valve	**Valve description**	**Safety function**	**Parameter Affected**	**Current Value**	**EPU Value**
FCV-01-55	Main Steam Drain Line Isolation valve	Close	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	1169 psig 1169 psid 140°F 8,696 lbs 15,051 lbs 73%
FCV-73-03	HPCI Steam Line Primary Containment Isolation Valve	Close	Line Pressure Differential Pressure Accident Temperature Required thrust Operator Capability Margin	NA	1169 psig 1169 psid 207.1°F 70,419 lbs 75,211 lbs 7%

A similar evaluation was performed for all of the valves in the GL 89-10 program. All of the MOVs are capable of operation at EPU conditions after the necessary modifications are implemented. Fourteen design changes (DCNs) were prepared to upgrade/replace Unit 1 GL 89-10 MOVs. All of the modifications will be implemented before Unit 1 restart.

NRC Request EMEB-B.5

Section 4.1.6, GL 95-07, of Enclosure 4 of the June 28, 2004, submittal states that MOVs used for containment or high energy line break isolation have been reviewed for the effects of operations at EPU conditions, including pressure locking and thermal binding. The licensee provided a response to GL 95-07, Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves, in a submittal dated May 11, 2004. Discuss with examples, the evaluation of safety-related power-operated gate valves in light of any changes in ambient temperature on the potential for pressure locking or thermal binding resulting from EPU operation.

TVA Reply to EMEB-B.5

For the restart of Unit 1, a review of all of the safety related power operated valves was performed to determine which valves might be susceptible to pressure locking and thermal binding. The scope of the TVA Unit 1 GL 95-07 program, evaluations and evaluation results was provided to the NRC in the May 11, 2004 letter (Reference 8). The review identified the following:

- One High Pressure Coolant Injection System valve was susceptible to thermal binding. This valve will be replaced with a double disc valve prior to Unit 1 restart. Double disc gate valves are not susceptible to thermal binding.

- Five safety related power operated gate valves will be modified prior to Unit 1 restart to preclude the potential for pressure locking. The reactor side disc face of these valves will be modified by drilling a hole in the disc face into the cavity between disc faces to avoid pressure locking.

These modifications will ensure that the pressure locking and thermal binding concerns described in GL 95-07 are resolved prior to Unit 1 restart.

The following example discusses valves that were modified for GL 95-07 and how EPU affects them. The Low Pressure Coolant Injection valves 1-FCV-74-53(67) are subject to pressure locking. These valves are a flex wedge design, are normally closed and have to open to perform their safety function. The reactor side is exposed to high pressure and temperature conditions while the reactor is in operation. This may cause potential pressure locking when the valve has to open. Therefore, the reactor side disc faces of these valves are being modified by drilling a ¼" hole in the disc face into the cavity between the disc faces to avoid pressure locking. These valves are not subject to thermal binding. The modifications to these valves are being performed to support Unit 1 restart and are similar to the modifications performed for Units 2 and 3. The modifications were developed based on EPU design parameters (ambient temperature, operating pressure and temperature), and therefore, will support operation at EPU conditions.

<u>NRC Request EMEB-B.6</u>

Section 10.4.3, Main Steam Line, Feedwater and Reactor Recirculation Piping Flow Induced Vibration Testing, of Enclosure 4 of the June 28, 2004, submittal discusses the plans for vibration monitoring during initial plant operation for the new EPU operating conditions. Discuss in more detail, the procedures for avoiding adverse flow effects during power escalation and after achieving EPU conditions, including specific hold points and duration, inspections, plant walkdowns, vibration data collection methods and locations, planned data evaluation, and decision criteria for reducing plant power level or initiating plant shutdown.

<u>TVA Reply to EMEB-B.6</u>

TVA has not yet developed detailed procedures for EPU vibration monitoring and evaluation. The following discussion provides a general response to the NRC request; a more detailed response will be provided in a future submittal as discussed in the cover letter accompanying this response.

However, when developed, these procedures will specify:

- Reactor power hold points and duration,
- Required inspections and plant walkdowns,

- Vibration data collection methods and locations,
- Data evaluation methods and procedure, and
- The decision criteria for reducing plant power level or initiating plant shutdown

Specific Hold Points and Duration

The testing procedures will specify hold points for EPU vibration testing at 5% power increments above the Current Licensed Thermal Power level through EPU. The duration of the hold points will be the time required to obtain the specified data, complete the required evaluations, and obtain restart organization approval.

Inspections and Plant Walkdowns

Vibration inspection/walkdown testing will be performed in areas accessible during power operation and will be conducted utilizing plant inspection/walkdown procedures.

Vibration Data Collection Methods and Locations

Piping inside containment will be monitored using remote sensors and piping outside containment will be monitored with remote sensors, cameras and/or hand-held instruments.

Monitoring locations for the piping inside containment will be based on time history analyses that apply loading similar to the loading due to steady-state vibration. Monitoring locations will be selected where significant analytical responses occur relative to other locations and such that the general overall piping response will be reflected in the data. Monitoring locations for large bore Main Steam and Feedwater piping outside containment will be determined based on inspection/walkdowns performed during power operation.

Monitoring locations for small bore piping will be based on time history analyses as well as inspection/walkdowns that were completed to identify relative vibration susceptibility.

Planned Data Evaluation

Evaluation of the vibration data at each hold point will be performed based on established acceptance criteria. The acceptance criteria will be in accordance with the ASME OM guideline for piping steady-state vibration monitoring and evaluation.

Decision Criteria for Reducing Plant Power Level or Initiating Plant Shutdown

In the event that measured vibrations at a given power level exceed the acceptance criteria, the power level would be reduced to a level where vibration amplitudes were

previously shown to be acceptable until further evaluation of the data could be completed.

NRC Request EMEB-B.7

In the submittal dated February 23, 2005, the licensee lists modifications planned to support EPU operation on pages E1-17 to 22. Discuss the modifications planned to safety-related pumps and valves and the actions to provide assurance of their capability to perform the applicable safety functions under EPU conditions.

TVA Reply to EMEB-B.7

Since the February 23, 2005, submittal, TVA has supplemented its response regarding modifications and testing in our April 25, 2005, letter (Reference 3). In Reference 3, planned EPU modifications were addressed in accordance with NUREG-0800, Standard Review Plan (SRP), Section 14.2.1, Draft, Revision 0, "Generic Guidelines for Extended Power Uprate Testing Programs." Section III.B of the Enclosure addressed the modifications planned for EPU and the actions to provide assurance of the capability of these components to perform the applicable safety functions under EPU conditions.

NRC Request EMEB-B.8

In the submittal dated February 23, 2005, the licensee indicates on page E1-21 that the GL 89-10 MOVs will be modified to accommodate the 30 psi increased reactor operating pressure. The licensee states that MOV setup will be accomplished per MOVATS. Address its implementation of GL 89-10 and GL 96-05 for the safety-related MOVs.

TVA Reply to EMEB-B.8

By letter dated May 5, 2004 (Reference 7), TVA described implementation of GL 89-10 for BFN Unit 1. That letter identified the valves included within the scope of the program, which is consistent with the BFN Units 2 and 3 MOV program scope.

BFN Unit 1 is implementing the GL 89-10 program as part of plant restart activities. In conjunction with implementation of GL 89-10, TVA is engaged in design and modification activities to support the restart of Unit 1. Accordingly, the scope of design and modification activities associated with GL 89-10 MOVs include evaluations and changes necessary to support fulfillment of GL 89-10 program requirements, evaluations and changes necessary to support operation of Unit 1 at EPU conditions, and evaluation and modifications as necessary to support closure of any other restart commitments potentially affecting GL 89-10 program valves. GL 89-10 modifications implemented previously for BFN Units 2 and 3 were used as inputs to the BFN Unit 1 GL 89-10 MOV design process, in addition to evaluation of requirements to support operation at EPU conditions. Therefore, modifications and replacements were selected

to address known issues identified during resolution of GL 89-10 for BFN Units 2 and 3, and ensure operability of GL 89-10 MOVs at EPU conditions.

Resolution of GL 89-10 for BFN Units 2 and 3 resulted in modification or replacement of many of the GL 89-10 program MOVs. Additionally, BFN Units 2 and 3 GL 89-10 program MOVs were evaluated during the 105% power uprate, to address changes in process conditions, and environmental temperature increases associated with that uprate effort, including the 30 psig increase in reactor operating pressure. As discussed above, these changes have been addressed in the design evaluation of BFN Unit 1 GL 89-10 program valves to support BFN Unit 1 restart and operation at EPU conditions.

A total of 14 design changes (DCNs) were prepared to upgrade/replace Unit 1 GL 89-10 MOVs to ensure that they can perform their design functions at EPU conditions and meet the requirements of GL 89-10, as well as GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." 17 MOVs are being replaced; 34 MOVs are having their actuators replaced; and all GL 89-10 MOVs are receiving SMARTSTEMs to facilitate future testing. The new Limitorque operators are being furnished with long life grease. All valves modified will be tested as part of the post modification testing program before being declared operable. Diagnostic equipment to be utilized in the performance of static and differential pressure testing will be determined by the specific application. Testing equipment to be used may include, but is not limited to the MOVATS Torque Thrust Cells, Stem Strain Transducer, Stem Strain Ring, and MCC data analysis system. As discussed in Reference 7, BFN Unit 1 will implement the Joint Owners Group recommended Generic Letter 96-05 Motor Operated Valves Periodic Verification Program, as described in Topical Report NEDC 32719 (MPR Report 1807), and begin testing during the first refueling outage after restart.

NRC Request EMEB-B.9

In the submittal dated February 23, 2005, the licensee states on page E1-26 that acoustical circuit analyses have been developed to identify the contributions to flow-induced vibration effects from main steam line components, junctions, and connections. Discuss the capability of such analyses to identify the excitation sources for flow-induced vibration effects in light of recent industry experience, and discuss possible alternative methods to identify excitation sources.

TVA Reply to EMEB-B.9

Requests EMEB-B 9, 10, 11, and 13 address the actions and plans regarding the BFN steam dryers under EPU conditions. The following discussion provides an overview of the actions planned to ensure that the BFN steam dryers will adequately perform under EPU conditions.

Initially, a steam dryer evaluation for EPU conditions was performed for BFN and the evaluation was provided as Enclosure 9 to the June 28, 2004 EPU license amendment submittal. The evaluation consisted of a stress analysis which utilized the GE generic dryer load definition for both static equivalent and response spectrum.

Since the time of the initial steam dryer evaluation, considerable developments have taken place with respect to analysis methodologies and the acquisition of additional plant operating data for dryer loads. BFN has been actively participating in the steam dryer evaluation efforts being conducted by Exelon, Vermont Yankee, and the BWROG. These efforts have included the development of scale model testing, acoustical analysis, main steam line monitoring, and the design and replacement of the two Quad Cities steam dryers. The initial Quad Cities replacement steam dryer was fully instrumented in order to monitor steam dryer loads during power ascension up through EPU operation.

This information is being used to develop the additional actions that BFN will perform to complete the steam dryer evaluations for EPU conditions, determine necessary modifications, and establish monitoring plans for power ascension testing. The current plans for the EPU steam dryer program are delineated below:

- Perform inspection of steam dryer in accordance with BWRVIP-139,
- Collection of as-built configurations of the main steam lines and components,
- Development of a 3D CAD model of the steam dryer, reactor vessel, main steam lines and components,
- Development and testing of a BFN Scale Model Test (SMT) configuration (1/17 scale) utilizing the methodologies developed by GE to operate under the BFN EPU conditions,
- Development of acoustical analyses utilizing GE methodologies and the SMT loading conditions to be utilized in the determination of EPU loading conditions. This effort will include lessons learned based on the completion of the GE benchmarking effort for the Quad Cities measured loads,
- Development of acoustical analyses utilizing Continuum Dynamics Inc. methodologies and the SMT loading conditions to be utilized in the determination of EPU loading conditions and monitoring of EPU loading conditions during power ascension,
- Performance of a stress analysis to demonstrate compliance of the steam dryer stresses against allowable limits,
- Determination of steam dryer design modifications based on the stress analysis to replace or structurally reinforce steam dryer components for the expected loads with adequate margins for reliable performance,

- Development of a power ascension monitoring plan to monitor main steam line and component vibration and pressure loads,
- Monitoring of plant conditions will be conducted per the guidance of GE SIL 644, supplements and revisions to determine steam dryer integrity, and
- Inspection of the steam dryer will be performed following successful completion of the first EPU operating cycle to assure that its structural condition is acceptable for continued operation.

TVA's approach is to utilize the GE Scale Model Test Facility (SMT) to develop BFN EPU operating conditions through the Reactor, Main Steam Lines (MSL) and MSL components, HPCI and RCIC piping. The GE SMT is being designed and constructed to replicate precisely the BFN Unit 1 configuration. To increase the SMT accuracy, BFN Unit 1 laser scans have been utilized for MSL inside Containment. System walk-down measurements and component design drawings have been employed for MSL configurations outside Containment. This information has been integrated into a 3D CAD Model, which enhanced the development of the SMT fabrication design. Additionally, internal dimensions and details for piping wall thickness, and MSL components have been developed for Safety Relief/Valves (SR/Vs), Main Steam Isolation Valves (MSIVs), Flow Elements, and Turbine Stop & Control Valves (TS & CVs). The SMT replication will contain this increased level of detail in order to measure fluctuating pressure loads from potential MSL sources. SMT characterization tests are conducted to obtain data used to correlate the acoustic Finite Element Model of the BFN plant steam system.

GE has previously reported in Reference 9, the contributions to the test measured fluctuating acoustic loads from various sources from these above referenced MSL components from SMT investigations. GE's sensitivity tests in this referenced document demonstrated the frequency ranges of response attributed to these potential sources. This approach is applicable to the BFN configuration. Due to the highest acoustical loads being attributed to the high frequency contribution from the SR/V (ERVs, SVs, SR/V in QC terminology) additional 1/6 subscale testing has been conducted to further investigate the SR/V source contributions related to these different valves. BFN has a single SR/V design rather than an assortment of different designs. Similar subscale tests will be conducted for BFN SR/Vs to compare frequency response with the SMT.

BFN's SMT will incorporate sensitivity tests focused on key parameters in order to determine bounding conditions for similarity between BFN Units 1, 2, 3. The BFN SMT will represent the most accurate and detailed replication performed to date for use in determining dryer load definition.

GE has subsequently provided an interim report, Reference 10, regarding the accuracy of the GE SMT methodology to reflect the frequency content of loading expected to act on the dryer. The overall SMT loadings have been found to be conservative when compared to measured dryer loads on the replacement dryer for QC 2. Further SMT

facility changes were required to directly compare the QC 2 dryer measured data with a QC 2 SMT model and to demonstrate the benchmark qualification.

GE has performed the SMT facility modifications and additional testing and is now preparing the benchmark qualification report relative to QC 2. This benchmark will incorporate use of the SMT facility and the GE finite element acoustical analysis to predict EPU loads on the dryer.

In order to further investigate the BFN dryer loading, TVA will also be performing an acoustical circuit analysis utilizing the Continuum Dynamics (CDI) methodologies. SMT MSL pressure loadings will be obtained and dryer loads developed for comparison. The CDI methodology will also be utilized for EPU power ascension to validate the dryer loads under actual plant operation.

Both methodologies rely on benchmarking against the measured dryer loads from the replacement dryer installed at QC2.

With this approach, TVA is confident that appropriate BFN source contribution will be adequately included in the dryer load definition and expected dryer modifications.

During power ascension, vibration monitoring will be conducted to determine flow induced vibration effects from EPU increased flow. Data obtained will provide additional component response behavior during the EPU power ascension that can be used to further evaluate source contribution.

The current schedule is to complete scale model testing and development of the acoustic circuit model by June 2006.

NRC Request EMEB-B.10

In the submittal dated February 23, 2005, the licensee states on page E1-27 that TVA had performed a detailed peer review of the General Electric Steam Dryer load definition methodology and analysis, and that the peer review had provided TVA with assurance that all phases of the analysis were adequate. Describe the design-load definition for its steam dryer at BFN Unit 1 and the basis for the adequacy of the load definition.

TVA Reply to EMEB-B.10

See the reply to EMEB-B.9 for a discussion of the EPU Steam Dryer Program for BFN.

At the time of the BFN submittal, industry data indicated that steam dryer loads could be correlated to individual plant steam line steam velocity and loading could be derived from historical data from a small number of BWRs. As discussed in the reply to EMEB-B.9, BFN has expanded the actions that are planned for the evaluation of BFN steam dryers. The EPU Steam Dryer Program for BFN will include testing, analyses, and monitoring that will ensure that necessary modifications will be made to provide

adequate structural margin for flow induced vibration and acoustical loads for EPU conditions.

NRC Request EMEB-B.11

On page E1-28 of the submittal dated February 23, 2005, the licensee states that the uncertainty in its steam dryer analysis will be reduced by the collection of plant-specific data during power ascension. On page E1-30, the licensee states that benchmarking of the acoustic circuit analysis for determining plant-specific loads is in process against a scale model test facility. Provide the details of acoustic circuit methodology and analysis, including validation, results, and uncertainty range of the methodology and analysis. Also, discuss the modifications made to its acoustic circuit model based on lessons learned from recent industry operating experience.

TVA Reply to EMEB-B.11

See the reply to EMEB-B.9 for a discussion of the EPU Steam Dryer Program for BFN.

As discussed in the reply to EMEB-B.9, the EPU Steam Dryer Program for BFN will include testing, analyses, and monitoring that will ensure that necessary modifications will be made to provide adequate structural margin for flow induced vibration and acoustical loads for EPU conditions.

The current schedule is to complete scale model testing and development of the acoustic circuit model by June 2006. When completed, BFN will submit a summary of this effort that includes the details of the acoustic circuit methodology and analysis, including validation, results, and uncertainty range of the methodology and analysis.

NRC Request EMEB-B.12

On page E1-28 of the submittal dated February 23, 2005, the licensee states that power ascension information will be collected at each of the EPU power ascension test plateaus and compared against the stresses in the design analysis of record. Discuss the specific process for collecting, evaluating, and incorporating plant data into the design stress analysis for the steam dryer during the planned EPU power ascension.

TVA Reply to EMEB-B.12

See the reply to EMEB-B.9 for a discussion of the EPU Steam Dryer Program for BFN.

As discussed in the reply to EMEB-B.9, the EPU Steam Dryer Program for BFN will include testing, analyses, and monitoring that will ensure that adequate structural margin for flow induced vibration and acoustical loads for EPU conditions.

The current schedule is to complete scale model testing and development of the acoustic circuit model by June 2006.

NRC Request EMEB-B.13

On page E1-30 of the submittal dated February 23, 2005, the licensee lists proposed modifications to the steam dryer based on lessons learned from recent BWR dryer modifications. Provide detailed descriptions and diagrams of the proposed modifications to the steam dryer. Also, describe the stress analysis performed for the modified steam dryer, and the resulting changes in predicted stress in comparison to the licensee's acceptance criteria at significant locations on the steam dryer.

TVA Reply to EMEB-B.13

See the reply to EMEB-B.9 for a discussion of the EPU Steam Dryer Program for BFN.

As discussed in the reply to EMEB-B.9, the EPU Steam Dryer Program for BFN includes testing, analyses, and modeling to identify whether modifications are necessary to ensure adequate structural margin for flow induced vibration and acoustical loads at EPU conditions.

The current schedule is to complete scale model testing and development of the acoustic circuit model by June 2006. The requested details for any required modifications will be provided following completion of this effort.

NRC Request EMEB-B.14

On pages E1-33 to 36 of the submittal dated February 23, 2005, the licensee discusses the potential impact of temperature changes from resulting from EPU operation on mechanical equipment environmental qualification. The discussion focuses on the impact of temperature changes on non-metallic materials. Discuss the evaluation and potential impact of temperature changes on motor output of applicable safety-related MOVs resulting from EPU operation.

TVA Reply to EMEB-B.14

Each MOV in BFN's GL 89-10 program has a "Operator Requirements and Capabilities" calculation. These calculations determine the required thrust/torque that the MOV will need to perform its safety function and also calculate the motor output of the MOV. The ambient temperature in some areas will increase due to EPU. This increase may impact on the actuator thrust/torque output because some motors lose capability at elevated temperatures. For EPU, an evaluation (utilizing the same methodology that was used to create the "Operator Requirements and Capabilities" calculations) was performed to determine the required thrust and the motor capability of the MOV under EPU conditions. Examples of the temperature conditions and MOV capability are provided in the table below.

Table EMEB-B.14-1 Examples of Impact of Environmental Temperature on BFN Unit 1 Safety-Related MOVs[1]					
Valve	**Function**	**Safety action**	**Ambient temperature EPU**	**Thrust Output in the safety direction EPU**	**Notes**
1-FCV-01-55	Main Steam Drain Line Isolation Valve	Close	140°F	15,051 psi	The motor has adequate margin to close this valve under EPU conditions.
FCV-23-46	RHRSW Throttle Valve to RHR B Heat Exchanger	Open	170°F	60,327 psi	The motor has adequate margin to open this valve under EPU conditions.
FCV-70-47	RBCCW Primary Containment Isolation Valve	Close	240°F	37,345 psi	The motor has adequate margin to close this valve under EPU conditions.
FCV-71-25	RCIC Lube Oil Cooling Water Supply Valve	Open	247°F	10,053 psi	The motor has adequate margin to open this valve under EPU conditions.

1. BFN Unit 1 has developed its GL 89-10 program as part of restart activities, and has evaluated MOV capability based on operation at EPU conditions. Therefore, BFN Unit 1 pre-EPU MOV capability data does not exist, quantitatively, to identify the specific impact on these valves due to the change associated with EPU.

Each MOV in the Unit 1 GL 89-10 program was evaluated assuming operation at EPU conditions. With the modifications being performed as part of the Unit 1 GL 89-10 program, all of the MOVs maintained positive margins and, accordingly, the impact of increased ambient temperature associated with operation at EPU conditions will not impact capability of the MOVs to perform their safety functions.

NRC Request IPSB-B.1

Section 8.6, Normal Operations Off-Site Doses, of Enclosure 4 of the June 28, 2004, submittal states that radiation from shine (offsite) is not presently a significant exposure pathway and is not significantly affected by EPU. This conclusion is based on the experience of earlier 5-percent power uprates for Units 2 and 3. Also, Section 8.2.2, Offsite Doses at Power Uprate Conditions, of the Environmental Report states that N-16 activity in the Turbine Building will increase linearly with EPU.

The magnitude of the N-16 source term in the Turbine Buildings is not a simple linear increase with reactor power. The equilibrium concentration of N-16 in the Turbine

Building systems will be effected (an inverse exponential function) by the decreased decay resulting from the increased steam/feed flow between the reactor and the Turbine Building. Implementation of hydrogen injection water chemistry also increases N-16 concentrations in reactor steam independently of reactor power.

Provide the present nominal value for the skyshine external dose component (assuming all three units operating at current licensed power levels), the corresponding estimated dose component following EPU (assuming all three units operating at the requested power, and design basis steam activity, levels). Include all parameters (i.e., flow rates, system component dimensions, etc.) used in calculating these values and specify the calculational method used. Identify the limiting dose receptor (i.e., is the dose receptor a member of the public located offsite and, therefore, subject to the dose limits of 40 CFR Part 190) or a member of the public working onsite (subject to the dose limits of 20.1301)). Describe any increases in doses for onsite spaces (i.e., Administrative offices, guard stations, etc.) continuously or routinely occupied by plant visitors or staff.

TVA Reply to IPSB-B.1

External gamma radiation levels are measured at BFN by thermoluminescent dosimeters (TLDs) deployed around BFN as part of the offsite Radiological Environmental Monitoring Program (REMP). TLD readings from 1996-2001 (which included, during this time frame, data taken with two units operating at original licensed power (3293 MWt), with two units operating at currently licensed thermal power (3458 MWt), and with two units operating at currently licensed thermal power (3458 MWt) with one unit operating with Moderate HWC) were compared. No discernible increase in radiation at onsite or offsite locations were indicated during this time. During this time period, onsite TLD measurements ranged from 15.5 to 16.5 mrem/quarter and offsite TLD measurements ranged from 13.25 to 14.3 mrem/quarter. Fluctuations in natural background dose rates and in TLD readings tend to mask any small increments which may be due to plant operations. Thus, there was no identifiable increase in dose rate levels attributable to direct radiation from plant equipment and/or gaseous effluents.

Pursuant to the Offsite Dose Calculation Manual (ODCM)section 7.7.5, reviews are performed to determine the highest dose to a member of the public at the site boundary. This review assumes that onsite TVA employees engaged in work activities not associated with nuclear power electric generation were considered as members of the public. The dose to a member of the public consists of the sum of dose commitments from effluent releases as well as any direct radiation dose. The effluent dose commitment is normally negligible compared to the direct radiation dose. The direct radiation dose is determined from area TLDs located onsite. It consists of gamma dose from the plume, ground contamination and from equipment sources (i.e., tanks, turbine shine, radioactive material storage areas, etc.).

As an example, for 2004, the highest direct radiation dose accounting for background and occupancy was 4.8 mrem (Reference 11). This can be compared to the limit of 100

mrem of 10 CFR 20.1301. Although EPU evaluations assumed a 20% increase in doses, it can be seen that even for a doubling of doses (~ 5 mrem to ~ 10 mrem), the dose rate to a member of the public working onsite would remain well within the limits of 10 CFR 20.1301.

NRC Request IPSB-B.2

Section 8.5.3, Post Accident, of Enclosure 4 of the June 28, 2004, submittal states that plant specific analysis for NUREG 0737, Item II.B.2. "have been performed" but gives no results or indication they meet the NUREG 0737 acceptance criteria. For each BFN Unit 1 vital area (as defined in Item II.B.2.), provide the calculated pre-uprate and post-uprate mission doses to an operator performing vital tasks following a loss-of-cooling accident (LOCA). Verify that the mission doses to personnel in these vital areas, as well as the calculated dose estimates for personnel performing required post-accident duties in the plant's Technical Support Center, are within the dose guidelines of GDC-19 (10 CFR Part 50, Appendix A). Is restoring spent fuel cooling a vital action required to mitigate the effects of a design basis LOCA at Unit 1?

TVA Reply to IPSB-B.2

Mission dose analyses for NUREG-0737, Item II.B.2, were evaluated utilizing the Alternative Source Term (AST) in accordance with 10 CFR 50.67. The results of this evaluation were provided in the AST license amendment submittal (Reference 12). AST for BFN Units 1, 2, and 3 was approved by the NRC in Reference 13. The AST analyses, including mission doses, were performed at EPU conditions and, therefore, did not require re-performance as part of the EPU license amendment. Restoration of spent fuel pool cooling is not an action required to mitigate the effects of a design basis LOCA at BFN.

As previously provided in Enclosure 4, Section 3.1.4 of Reference 12, the results of the revision of post-accident mission doses demonstrated that the previous calculated doses (based on TID-14844 source terms) at 100% OLTP conditions bound the doses calculated at EPU conditions based on AST source terms. The evaluated mission doses for BFN remain less than 5 rem TEDE.

NRC Request IPSB-B.3

Section 8.4.2, Activated Corrosion Products, of Enclosure 4 of the June 28, 2004, submittal states that the increase in the activated corrosion product activity will be 3-percent higher than the original design basis activity. Provide the basis for this estimated increase. Since Unit 1 has been shutdown for 20 years, how was the quantity of loose corrosion products (i.e., available for transport into the reactor) estimated?

The increased steam EPU flow is likely to result in an increased moisture carryover in the steam, resulting in an increased transport of non-volatile fission products, actinides, and activated corrosion and wear products from the reactor coolant to the balance of the plant. Provide the levels of moisture carry over expected at the EPU steaming rates, and discuss its potential impact on activity buildup and resultant dose rates in the balance of plant.

TVA Reply to IPSB-B.3

Calculation of activated corrosion and fission products in the reactor coolant was performed in accordance with ANSI/ANS-18.1-1984, "Radioactive Source Term for Normal Operation of Light Water Reactors." Input parameters that change as a result of EPU conditions include core power, weight of water in reactor vessel, cleanup demineralizer flow rate, and steam flow rate. Based on the methodology in ANSI/ANS-18.1-1984, calculated values for activated corrosion products and fission products for EPU conditions is provided in the table below. Design basis values based on GE design specifications is provided for comparison. The noble radiogas release after 30 minutes delay is 3.16E+04 μCi/sec (well below the original design basis of 0.35 curies/sec).

Table IPSB-B.3-1
Activated Corrosion and Fission Products

Item	Design-Basis Reactor Water (μCi/ml[1])	EPU Reactor Water (μCi/g)
Fission Products	5.73E+00	1.07E-01
Activated Corrosion Products	6.36E-02	6.52E-02
Total	5.79E+00	1.72E-01

[1]The mass of 1 ml of water is 1 g at 4°C.

The determination of activated corrosion products in the reactor coolant was performed the same way for all three units. Although Unit 1 has been shutdown for 20 years, this is considered adequate based on several reasons. Unit 1 is currently undergoing reactor pressure vessel and system cleaning efforts. The Unit 1 reactor core will have at least 672 assemblies of new fuel with the balance of no more than 92 assemblies of once and twice burned, but ultrasonically cleaned, fuel. During normal operation and refueling outages, the fuel serves as a significant source of corrosion products for release to the water. Also, Unit 1 plans to use the same micron-rated condensate demineralizer filters as Units 2 and 3 so the corrosion product source from the feedwater system is expected to be consistent with Units 2 and 3. Unit 1 has also taken significant steps in the reduction of the cobalt source term. These steps include

removing stellite (cobalt) from approximately 74 valves and using flame-hardened turbine blades in lieu of cobalt-faced blades.

Evaluation of the expected carryover rate for EPU conditions do not result in moisture carryover values above 0.13 wt%. This magnitude of moisture carryover would have an insignificant effect on activity carryover, especially as compared to the design basis margins. As discussed in the reply to IPSB.9, radiation zonings in the turbine building adjacent to steam affected areas were reviewed and monitoring is part of the planned EPU testing.

NRC Request IPSB-B.4

Section 6.3.2, Crud Activity and Corrosion Products, of Enclosure 4 of the June 28, 2004, submittal indicates that the expected increase in spent fuel pool (SFP) crud is 2 percent, based on the expected increase of crud in the reactor coolant system (RCS) due to increased feed flow. Since Unit 1 has been shut down for 20 years, how were the pre-EPU crud levels determined? Describe the impact of a 20-percent increase in feedwater flow has on condensate demineralizer efficiency.

TVA Reply to IPSB-B.4

The crud in the SFP would increase by less than 2% assuming that all residual crud in the reactor cooling system is transported to the SFP. This increase was calculated using an approach based on a contaminant removal efficiency of 90% for the RWCU system and an approximately 15% increase in feedwater flow for EPU ((100 - 90%) x 15% = 1.5%). This approach is also applicable to Unit 1 since any differences in initial crud levels in the RCS associated with the extended shutdown will be addressed during the cycle operation prior to refueling activities. Therefore, it would be anticipated that the crud levels in the RCS at the end of cycle operation at EPU would be similar for all three units.

The condensate demineralizers are discussed in Section 7.4.3 of the PUSAR. As part of EPU, an additional condensate demineralizer vessel is being installed for each unit. This additional vessel will allow an additional condensate demineralizer to be placed in service during full power operation while allowing one vessel to be taken out of service for backwashing and pre-coating. With EPU, the system will experience slightly higher loadings resulting in slightly reduced condensate demineralizer run times.

NRC Request IPSB-B.5

Describe the controls implemented throughout the extended shutdown of Unit 1 to minimize the corrosion of reactor water systems.

TVA Reply to IPSB-B.5

Detailed information concerning the BFN Unit 1 Plant Lay-up and Equipment Preservation Program (BFN Unit 1 Lay-up Program) was provided in several submittals to the NRC in support of the BFN Units 1, 2, and 3 license renewal applications. An overview of the program is provided below. Further information is available in the references identified.

Unit 1 systems and the Unit 1 portion of common systems not involved in the operation of Units 2 and 3 were placed in lay-up during the extended outage. Some of the BFN Unit 1 systems were maintained in the Plant Lay-up and Equipment Preservation Program (BFN Unit 1 Lay-up Program); other systems were maintained outside of this program. The Unit 1 systems were placed in one of the following four environments during lay-up:

- Components maintained under the BFN Unit 1 Lay-up Program in dry lay-up where the target environment was < 60 percent relative humidity;
- Components maintained under the BFN Unit 1 Lay-up Program in wet lay-up with an internal environment of flowing, air-saturated demineralized water;
- Components not maintained under the BFN Unit 1 Lay-up Program with an internal environment of moist air. For these components there were no moisture controls during lay-up; and
- Components not maintained under the BFN Unit 1 Lay-up Program with an internal environment of either treated or raw water for an extended period of time.

The reactor vessel and internals were maintained under the BFN Unit 1 Layup Program in wet layup. One Reactor Water Cleanup System filter demineralizer was in service at approximately 100 gpm to maintain reactor coolant water quality per TVA Procedure CI-13.1 "Chemistry Program." The wet lay-up flow path was Reactor Water Cleanup System suction from the 'A' Recirculation Loop through a short section of Residual Heat Removal System piping with a small portion of Reactor Water Cleanup System suction flow coming from the Reactor Vessel bottom head drain line, through Reactor Water Cleanup System inlet piping to the Reactor Water Cleanup System filter demineralizer returning via the Reactor Water Cleanup System effluent piping which returns to the Reactor Pressure Vessel via the 'B' Feedwater line. A portion of the Reactor Water Cleanup System effluent flow was routed to provide flow through Control Rod Drive System components. Chemistry limits for the wet layup components for conductivity, chloride and sulfate were 1.5 μS/cm, 15 ppb, and 15 ppb respectively.

Further details are provided in the following references:

TVA letter dated February 19, 2004 (Reference 14) provides a detailed discussion of the BFN Unit 1 Layup Program, identifies the system layup condition maintained during

the shutdown period, and compares the aging effects and aging management programs of the Unit 1 layup configuration to the Units 2 and 3 operating configurations.

TVA letter dated July 19, 2004 (Reference 15) clarified that the Unit 1 Spent Fuel Pool Cooling System remained in operation during the shutdown limit, subject to the chemistry limits in the BFN Unit 1 Technical Requirements Manual.

TVA letter dated October 8, 2004 (Reference 16) provided further details concerning BFN Unit 1 systems, including chemistry controls maintained during plant shutdown, and inspections planned to assess system material condition.

TVA letter dated January 31, 2005 (Reference 17) provided additional information concerning chemistry controls, and identified inspections, replacements, and refurbishments being performed to support BFN Unit 1 restart.

TVA letter dated May 18, 2005 (Reference 18) provided further information concerning chemistry controls and impacts on the systems in wet layup within the BFN Unit 1 Layup Program, and details concerning system piping examinations performed on BFN Unit 1 systems.

TVA letter dated May 27, 2005 (Reference 19) provided further information concerning potential corrosion mechanisms in BFN Unit 1 systems, and further details concerning inspections being performed prior to restart of the unit under the BWRVIP program, specifically in regard to crevice locations.

TVA letter dated June 6, 2005 (Reference 20) provided additional information concerning the BFN Unit 1 suppression pool layup during the plant shutdown period, and inspections and repairs made to suppression pool coatings.

NRC Request IPSB-B.6

Also, the estimate of the increase in RCS activity does not appear to include pre-outage crud bursts. Recently, a number of BWRs that have implemented hydrogen water and Zinc injection chemistry, have experienced large, unprecedented, crud bursts. Describe any contingencies that will be implemented to compensate for any unexpected build-up and release of crud in Unit 1.

TVA Reply to IPSB-B.6

When the Reactor Coolant chemistry is changed from Normal Water Chemistry to Moderate Hydrogen Water Chemistry (HWC) or Noble Metal Chemical Application (NMCA) with HWC, the crud in the reactor pressure vessel (primarily on the fuel) can restructure causing crud to be released into the water during power changes and on unit shutdowns. Since Units 2 and 3 have been operating under NMCA with HWC for at least five years, significant crud restructuring and release is not expected to occur at

EPU conditions. Since Unit 1 is restarting with relatively low levels of crud on the fuel (i.e. at least 672 new assemblies of the 764 total assemblies) and the feedwater crud source should be similar to Units 2 and 3 due to use of similar condensate demineralizer filters and the addition of a tenth condensate demineralizer vessel for all three units, crud bursts should not be a significant problem. However, should a crud burst be experienced on any unit, possible contingencies to reduce personnel radiation dose could include maximizing RWCU and Fuel Pool demineralizer operation, additional temporary filters (Tri-Nuc), bleed-and-feed operations and temporary shielding.

NRC Request IPSB-B.7

Section 6.3.3, Radiation Levels, of Enclosure 4 of the June 28, 2004, submittal states that the normal radiation levels around the SFP may increase slightly, primarily during fuel-handling operations. Explain the reason for, and the magnitude of, these postulated increases in dose rate levels in the area of the SFP. Verify that these postulated dose-rate increases will be bounded by the current radiation zone designations in the SFP area. If this postulated dose-rate increase is due to higher activation of spent fuel assemblies, discuss any effects that the storage of these spent fuel assemblies in the SFP may have on dose rates in accessible areas adjacent to the sides or bottom of the SFP.

TVA Reply to IPSB-B.7

Assuming that the normalized core and fuel bundle activity inventory (Curies/MWth) remains approximately constant from original conditions to EPU conditions, an increase in thermal power would result in a proportional increase in fuel bundle activity. An increase in bundle activity would lead to an increase in bundle dose rates. It is estimated that a core thermal power increase of 20% would result in a 20% increase of dose rates related to spent fuel pool operations. Similarly, the increased dose rates at the SFP could potentially have proportionally increased dose rates in accessible areas adjacent to the SFP.

The radiation zonings in the areas adjacent to the SFP were reviewed. Generally, the dose rates on the refuel floor are less than 10 mrem/hr (typically less than 30 mrem during refueling activities) and the doses rates in the accessible areas adjacent to the sides or bottom of the SFP are less than 1.0 mrem/hr. Zoning in these areas are not expected to change as the result of EPU conditions. Any increase in dose rates around the SFP associated with EPU would not be seen until the first refueling outage following EPU implementation. Further, dose rates at the surface of the pool are primarily due to the presence of radionuclides suspended in the cooling water. These dose rates are controlled by the frequency of the backwash and precoats of the fuel pool demineralizers. Radiation protection surveys in accordance with the current radiation protection program will ensure that refueling activities will continue to be appropriately monitored during these activities.

NRC Request IPSB-B.8

Section 8.5.1, Normal Operations, of Enclosure 4 of the June 28, 2004, submittal states that, due to the conservative shielding design, the increase in radiation levels resulting from EPU will not affect the radiation zones for the various areas of the plant. This appears to be based on an assumed linear increase in radiation source term with power level. However, the increase in N-16 activity in the turbine building is an inverse exponential function with decay time, not a linear function of reactor power. Verify that the radiation zoning in all areas containing the steam and feed systems will be unaffected by EPU.

TVA Reply to IPSB-B.8

Historical data was reviewed to evaluate the relationship between reactor power level and dose rates in steam affected areas. Also, a study was performed analyzing the effects of EPU conditions at BFN relative to hydrogen injection rates. The study found that although N16 production increases with reactor power due to increased neutron flux, the steam flow also increases, which tends to balance this increased production such that the concentration of N16 per gram of steam stays approximately the same as long as moisture carryover does not significantly increase. With the increase in steam flow rate, and correspondingly reduced travel time from the vessel nozzle to the turbines, less radioactive decay occurs in the process flow from the vessel to the turbine. Accordingly, the concentration of N16 in the turbines is larger. Feedback obtained from several EPU recipients indicates that the increase generally runs about 14-15% instead of the assumed 20%.

The radiation zonings in the turbine building adjacent to steam affected areas were reviewed. Generally, the dose rates in the walkways of the turbine buildings adjacent to steam affected areas are less than 1.0 mrem/hr. Most of the steam-affected areas are currently posted as "Locked High Radiation Area," with the exception of the reactor feedpump turbine rooms. These rooms are currently posted as "High Radiation Areas." The existing shield walls surrounding the steam-affected areas will provide adequate shielding to mitigate any predicted dose increases. Zoning in these areas are not expected to change; however, dose rates in these areas will be monitored during power ascension as part of the planned EPU testing.

NRC Request IPSB-B.9

Section 8.5.2, Normal Post-Operations, of Enclosure 4 of the June 28, 2004, submittal states that the post-operation radiation levels in most areas of the plant are expected to increase by no more than the percentage increase in power level. This section also states, however, that there are a few areas near the reactor water piping and liquid radwaste equipment where the expected radiation level increase could be slightly higher. Provide the specific locations of these areas where higher dose rates are

predicted, give the reasons for the expected increase in radiation levels in these areas, and state the percentage increase in dose rates expected.

TVA Reply to IPSB-B.9

Post operation dose rate increases are expected in areas of the plant due to the increase in the production of activated corrosion products. Since activated corrosion products are the primary contributors to crud buildup, it is expected that the dose rates near these areas will increase under post shutdown conditions in proportion to the increase in the activated corrosion products. These corrosion products will be deposited on piping and components containing reactor water. The following systems piping and components are expected to have increased dose rates: recirculation system, reactor water clean up (RWCU) and radioactive waste. Most of this piping is located in the drywell, RWCU heat exchanger room, RWCU pump room, reactor building steam tunnel, pipe tunnels, radwaste building or is embedded. Access to these areas during post operation (outages) is strictly limited by existing Radiation Protection procedures and is controlled by BFN's ALARA program.

NRC Request IPSB-B.10

Enclosure 8, Table 2 of the June 28, 2004, submittal states that the objective of test STP 1, Chemical and Radiochemical, is not applicable to EPU and is not required. The Table 1 entry for STP 1 states that "samples will be taken and measurements will be made at selected EPU power levels...." Describe which samples and measurements will be made and at what power levels. Considering that Unit 1 has been shut down for approximately 20 years, justify why the original full startup test STP 1 is not appropriate.

TVA Reply to IPSB-B.10

Note that Enclosure 8 of the original submittal (Reference 1) was replaced in its entirety by the submittal dated April 25, 2005 (Reference 3). Additional detail regarding STP 1 is provided in Table 1 of that submittal and continues to indicate that parts (b) & (c) of the original test (determination of adequacy for equipment, procedures, and techniques & evaluation of fuel, equipment, and instrument calibration) are not intended to be performed for EPU.

Samples and measurements will be measured at 90, 100, 105, 110, 115 percent of 3293 MWt and at EPU conditions (approximately 120 percent of 3293 MWt). These include the sampling of reactor water and feedwater and analyzing for chemical and radiochemical properties and determining gaseous effluent releases.

For Unit 1, parts (b) & (c) of the original STP 1 (determination of adequacy for equipment, procedures, and techniques & evaluation of fuel, equipment, and instrument calibration) are not intended to be performed as part of EPU. These items were intended to ensure readiness for the initial plant startup and are not associated with

EPU conditions. Appropriate startup test activities during Unit 1 startup from the extended shutdown up to CLTP will be performed as part of the restart testing program for Unit 1 (see Reference 21). The information provided in Reference 1 and Reference 3 is intended to identify those tests required for EPU conditions.

NRC Request IPSB-B.11

Enclosure 8, Table 2 of the June 28, 2004, submittal states that the objective of test STP 2, Radiation Measurements, is not applicable to EPU and is not required. The Table 1 entry for STP 2 states that "Gamma dose rate measurements...will be made at specific limiting locations throughout the plant..." Describe the limiting locations for which measurements will be made and at what power levels. Considering that Unit 1 has been shut down for approximately 20 years, and the uncertainties of predicting the activated corrosion source term, justify why the original full startup test STP 2 is not appropriate to provide a new baseline for dose data on activity buildup.

TVA Reply to IPSB-B.11

Note that Enclosure 8 of the original submittal was replaced in its entirety by the submittal dated April 25, 2005 (Reference 3). Additional detail regarding STP 2 is provided in Table 1 of that submittal and continues to indicate that part (a) of the original test (demonstration of background radiation levels prior to operation) is not intended to be performed for EPU.

Dose rate measurements will be measured at 90, 100, 105, 110, 115, and 120 percent of 3293 MWT. These measurements will be made at locations susceptible to dose rate increase due to increased N16 and neutron doses as a result of the increase in power level.

General area dose rates will be measured in the following areas. Also, specific survey points will be established in the following survey areas:

- Walkways in the turbine buildings adjacent to steam affected areas,
- General area adjacent to the reactor building steam tunnel,
- Access to the RWCU heat exchanger and pump rooms,
- Drywell penetrations at the core spray penetrations (RXB EL 604) and top of the TIP room (neutron surveys),
- Drywell clean room at the personnel access (neutron surveys),
- Drywell equipment access plugs and drywell CRD access plugs ,
- Turbine building roofs,
- Turbine buildings EL 575 near the condensate demineralizers,

- Turbine building near the condensate booster pumps and in the condensate pump pits,
- Feed water pumps and FW pump rooms,

Further, remote monitoring will be placed in steam affected areas throughout the turbine building during power ascension to establish a data base for increasing dose rates at the above power levels.

For Unit 1, part (a) of the original STP 2 (demonstration of background radiation levels prior to operation) is not intended to be performed as part of EPU. The current radiation surveys which are maintained for Unit 1 establish the background radiation levels in the plant prior to Unit 1 operation. Additionally, appropriate radiation surveys during Unit 1 startup from the extended shutdown up to the Current License Thermal Power level will be performed as part of the restart testing program for Unit 1 (see Reference 21). The information provided in initial application (Reference 1) and revised in TVA's April 25, 2005 submittal (Reference 3) is intended to indicate those tests required for EPU conditions.

<u>NRC Request IPSB-B.12</u>

Summarize the major Unit 1 plant hardware or system modifications involved in the requested EPU and discuss the change in occupational doses associated plant operation with the modifications in place.

<u>TVA Reply to IPSB-B.12</u>

Table 3, entitled "Browns Ferry EPU Planned Modifications, Setpoint Adjustments and Parameter Changes," provided in TVA's April 25, 2005 submittal (Reference 3), lists the planned modifications for EPU. That list was reviewed for occupational dose impacts. None of the modifications or setpoint changes would have an impact on occupational dose during plant operation. Parameter changes associated with increased steam flow and increased feedwater flow result in increased N16 sources in the turbine building and increased activation products in plant systems. These are discussed in responses to questions IPSB-B.8 and IPSB-B.9.

<u>NRC Request SPLB-A.1</u>

Section 10.5.5 of the Updated Final Safety Analysis Report (UFSAR), Revision 17 dated August 30, 1999, revised the discussion from the UFSAR that was previously provided regarding the maximum SFP heat load for batch and full core offloads. In order to facilitate NRC review of the capability of the SFPCCS to perform its function for EPU conditions, provide a discussion on the safety-related systems required to maintain fuel pool cooling within design bases temperature limits.

TVA Reply to SPLB-A.1

As discussed in BFN UFSAR Section 10.5.5, spent fuel pool cooling is normally provided by the Spent Fuel Pool Cooling and Cleanup System (SFPCCS). The system for each fuel pool consists of two circulating pumps connected in parallel, two heat exchangers, one filter demineralizer subsystem, two skimmer surge tanks, and the required piping, valves, and instrumentation. The SFPCCS transfers heat to the Reactor Building Closed Cooling Water (RBCCW) System. In addition, the Residual Heat Removal System can be operated in parallel with the fuel pool cooling system (supplemental fuel pool cooling) to maintain the fuel pool temperature if a full core off load is performed. The RHR System transfers heat to the Residual Heat Removal Service Water (RHRSW) System, and provides a source of seismic Class 1 makeup water via the RHR/RHRSW intertie. The design capacities of the SFPCCS and RHR heat exchangers operating in fuel pool cooling assist mode are provided in BFN UFSAR Table 10.5-1.

Further, the Auxiliary Decay Heat Removal (ADHR) System provides a non-safety related means to remove decay heat and residual heat from the spent fuel pool and reactor cavity of BFN Unit 2 or Unit 3. The ADHR is being modified as part of Unit 1 restart activities to provide this capability to Unit 1.

Analysis of the cooling capability of these systems is provided in the response to SPLB-A.2 below.

NRC Request SPLB-A.2

For EPU conditions, explain how the SFP water temperature will be maintained below 150 degrees Fahrenheit (F) for the worst-case normal (batch) and full core offload scenarios assuming a loss of offsite power and (for the batch offload only) a concurrent single active failure considering all possible initial configurations that can exist. Include a description of the maximum decay heat load that will exist in the SFP for each case, how these heat loads were determined, such that they represent the worst-case conditions, and what the cooling capacity is for the systems that are credited, including how this determination was made. Also:

a. Describe any operator actions that are required, how long it will take to complete these actions, and how this determination was made; and

b. Describe the maximum core decay heat load that will exist at the onset of fuel movement, how this determination was made, how this heat load will be accommodated while also satisfying the SFP cooling requirements over the duration of the respective fuel offload scenarios, and including the situation where the SFP is isolated from the reactor vessel cavity.

TVA Reply to SPLB-A.2

As described in UFSAR Section 10.5, the capacity of the SFPCCS and ADHR systems is utilized to maintain the fuel pool temperature at or below 125°F during normal refueling outages. The RHR system can be operated in parallel with the SFPCCS system to maintain the fuel pool temperature less than 150°F if a full core off load is performed. To assure adequate makeup under all normal and off normal conditions, the RHR/RHRSW crosstie provides a permanently installed seismic Class I qualified makeup water source for the spent fuel pool. This ensures that irradiated fuel is maintained submerged in water and that reestablishment of normal fuel pool water level is possible under all anticipated conditions. Two additional sources of spent fuel pool water makeup are provided via a standpipe and hose connection on each of the two EECW headers. Each hose is capable of supplying makeup water in sufficient quantity to maintain fuel pool water level under conditions of no fuel pool cooling.

Table 6-3 of the PUSAR provides the limiting analyses that were performed for batch and full core offloads considering either one train each of SFPCCS and ADHR systems or one train each of SFPCCS and RHR supplemental fuel pool cooling systems in service.

The maximum decay heat loadings for the SFP were calculated using the ANSI/ANS 5.1-1979 Standard with two-sigma uncertainty. The heat load in the SFP is the sum of previous fuel offloads and the recent batch (or full core offload) decay heats at the time of transfer. Batch offloads consist of one batch of 332 fuel bundles offloaded to an almost full SFP. The pool is assumed loaded with 2375 bundles allowing space for a full core offload (764 cells). The 2375 bundles are offloaded in eight batches, discharged at 24-month intervals. Full core offloads assume the same as the batch offload case plus 332 additional fuel assemblies, all of which have cooled for 24 additional months, along with the full core (764 bundles) which have operated for 24 months. The initiation of fuel offloading was a minimum of 50 hours after plant shutdown based upon SDC requirements, head removal time and refueling preparation. Actual times were determined based on the calculated heat removal capacity of the cooling mode. Fuel transfer time was estimated for the batch and full core offload cases based on a transfer rate of 14 bundles per hour to the fuel pool. These decay heat and offload time estimates establish the limiting case maximum heat loads for fuel pool cooling batch and full core offload cases. The maximum peak heat load calculated for each case is provided in Table SPLB-A.2-1.

Cooling of the fuel pool for each scenario conservatively assumes that only one heat exchanger/pump combination is available for the respective system credited (i.e. SFPCCS, ADHR, RHR). The heat exchanger effectiveness is based upon original design specifications including standard value fouling factors and tube plugging criteria. The original design specifications for each heat exchanger is provided in Table SPLB-A.2-2. The evaluation only considers the mass of water in the fuel pool and assumes

no circulation of water between the fuel pool and the cavity for the period of time that fuel pool gates are open while the fuel is being transferred to the pool.

For each combination of cooling systems (SFPCCS/AHDR or SFPCCS/RHR), the SPF temperature is maintained below 125°F for the batch offload cases and below 150°F for the full core offload cases.

The design and analysis basis for the spent fuel pool cooling system does not specifically address scenarios assuming a loss of offsite power and a concurrent single active failure considering all possible initial configurations. Configurations that are considered are those described above. Any other configurations/failures are addressed by the complete loss of SFPCCS as described in the reply to SPLB-A.3.

a. Operation in the SFPCCS mode is a planned evolution. Prior to each refueling outage, calculations are performed to determine the actual pool heat load and determine which equipment must be placed in service to maintain pool temperature. Administrative controls are used to ensure that the fuel pool cooling capacity is not exceeded during core offload. Operator actions required in the event of a total loss of SFPCCS are discussed in the reply to SPLB-A.3.

b. The maximum core decay heat load that will exist at the onset of fuel movement is determined using ANSI 5.1-1979 with 2 sigma decay heat methods for a core operated at EPU conditions for 24 months. Fuel movement occurs when the decay heat loads (core and spent fuel pool with previous core offloads) are within the capability of the FPC systems aligned for cooling. The evaluation only considers the mass of water in the fuel pool and assumes no circulation of water between the fuel pool and the cavity for the period of time that fuel pool gates are open while the fuel is being transferred to the pool.

Table SPLB-A.2-1
Browns Ferry Spent Fuel Pool Peak Heat Load[1]

Conditions / Parameter	Batch Offload	Limiting Full Core Offload
Configuration 1: One train each of FPCC and ADHR in Service		
Peak Heat Load (Mbtu/hr)	27.6	57.4
Configuration 2: One train each of FPCC and RHR supplemental fuel pool cooling mode in service		
Peak Heat Load (Mbtu/hr)	23.7	44.0

[1] See PUSAR Table 6-3 for applicable notes.

Table SPLB-A.2-2 Browns Ferry Original Heat Exchanger Design Specifications	
Heat Exchanger	**Original Design Heat Removal Capacity (Mbtu/hr)**
SFPCCS HX Design Heat Removal Capacity @ 125°F SFP temperature / 100°F RBCCW water temperature (single HX)	4.4
RHR HX Design Heat Removal Rate @ 125°F and 5Mlb/hr on shell side and 80°F and 2.25 Mlb/hr on tube side)	44.0
ADHR HX Design Heat Removal Rate @ 125°F and 3420 gpm on process fluid side and 75.4°F and 3420 gpm on coolant side	70.3

NRC Request SPLB-A.3

Discuss how adequate SFP makeup capability is assured for EPU conditions in the unlikely event of a complete loss of SFP cooling capability, including how the maximum possible SFP boil-off rate compares with the assured makeup capability that exists, operator actions that must be taken, how long it will take to complete these actions and how this determination was made, and boron dilution considerations.

TVA Reply to SPLB-A.3

As discussed in Section 6.3.1 of Enclosure 4 (PUSAR) of the initial application (Reference 1), the maximum boil off rate for the bounding full core offload scenario is 104 gpm. Assuming the SFP is initially at 125°F, the time to boiling following a loss of all SFP cooling would be approximately four hours. After the SFP reaches boiling, a much greater period of time is required to reduce FPC level to a level of minimum shielding.

A permanently installed, seismic Class I qualified source of makeup water is provided through the RHR/RHR Service Water crosstie to the fuel pool cooling system. The makeup capability via this path is > 150 gpm. Alignment and operation of this feature involves verifying the position of two manual valves in the field, racking out of 2 circuit breakers located in the electrical board rooms and operation of pumps and valves from the main control room. These actions can be performed well within the needed timeframe. There are no boron dilution considerations for a BWR SFP.

NRC Request SPLB-A.4

Provide justification and/or details of the evaluation which concludes that the SFP cooling and makeup systems continue to meet the requirements of draft GDC-4 for EPU conditions, in so far as it requires that reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

TVA Reply to SPLB-A.4

The spent fuel pool cooling and makeup system for each unit's fuel pool are separate systems except for a spare filter demineralizer which can be aligned to any of the three units. When utilized, the spare demineralizer is aligned to one unit only. Therefore, the spent fuel pool cooling and makeup system for each unit remains separate.

The ADHR system provides a non-safety related means to remove decay heat and residual heat from the spent fuel pool and reactor cavity. This system is aligned to only one unit at a time and, therefore, is not shared simultaneously between the units.

Separation of the spent fuel pool cooling and makeup systems and the ADHR system will not be affected by EPU. The operation and alignment of these systems will not be changed under EPU conditions.

NRC Request SPLB-A.5

In Section 6.4.1.1, of Enclosure 4 of the June 28, 2004, submittal regarding the emergency equipment cooling water (EECW) system, it is stated that: "EPU does not significantly increase equipment cooling water loads, and thus, the capacity of the EECW system remains adequate." Discuss, in more detail, the impact of the proposed EPU on EECW heat loads, flow rates, and flow velocities for the worst-case conditions, including limiting assumptions, input parameters, and available margin that will remain.

TVA Reply to SPLB-A.5

System configuration and operation of the EECW system is not modified for EPU conditions. The EECW system continues to take suction from the UHS and provide cooling water to the required systems. System flow rates and, therefore, flow velocities, will not change with EPU implementation. Heat loads to the RHR and CS room coolers will slightly increase due to post-LOCA increases in room temperatures for these areas. The increase in room temperatures in these area were determined using the current EECW system flows and room coolers. This increase in room temperatures will slightly increase the EECW discharge temperatures of the room coolers but will not be significant since room temperatures increase by less than 3°F.

NRC Request SPLB-A.6

In Section 6.4.1.1.2, of Enclosure 4 of the June 28, 2004, submittal regarding the residual heat removal service water (RHRSW) system, it is stated that:

> The post-LOCA containment and suppression pool responses have been calculated based on an energy balance between the post-LOCA heat loads and the existing heat removal capacity of the RHR and RHRSW systems. As discussed in Sections 3.11 and 4.1.1, the existing

suppression pool structure and associated equipment have been reviewed for acceptability based on this increased suppression pool temperature...The RHRSW system flow rate is not changed.

Discuss, in more detail, the impact of the proposed EPU on the RHRSW system heat loads (including SFP cooling considerations), flow rates, and flow velocities for the worst-case conditions, including limiting assumptions, input parameters, and available margin that will remain.

TVA Reply to SPLB-A.6

The Containment spray/Suppression Pool cooling mode post-accident containment system response is based on the RHRSW system design requirements. The RHRSW system design requirement to supply the RHR heat exchangers with 4,000 gpm per RHR heat exchanger is unchanged. The RHRSW maximum inlet temperature corresponds to an ultimate heat sink temperature of 95°F. The EPU containment system response results in an increase in the maximum Suppression Pool temperature from 177°F to 187.4°F. The containment cooling analysis results in an increase in the total heat load rejected to the RHRSW system due to post-accident suppression pool cooling from 67.84×10^6 BTU/hr to 75.47×10^6 BTU/hr. The maximum RHRSW fluid outlet temperature from the RHR heat exchanger increases from 126.3ºF to 132.7ºF due to the suppression pool temperature increase. The maximum outlet temperature of 132.7ºF remains below the current design limit of 150ºF RHRSW outlet temperature. With the exception of the maximum RHRSW outlet temperature increase, system flow rates, flow velocities, and system margins remain the same as for pre-EPU operation. There is no effect on the system capacity for spent fuel pool cooling considerations (see the response to SPLB-A.2).

NRC Request SPLB-A.7

Provide a description of any impacts that the proposed EPU will have on the issues described in GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions," and GL 96-06, Supplement 1, including the basis for your determination. In particular, confirm that the assumed heat transfer capabilities of heat exchangers are consistent with heat exchanger performance testing that has been completed in accordance with GL 89-13 and corrected for worst-case conditions; and that water-hammer and two-phase flow analyses that were completed in accordance with GL 96-06 continue to be valid.

TVA Reply to SPLB-A.7

The BFN systems within the scope of GL 89-13 are the Emergency Equipment Cooling Water System (EECW) and the Residual Heat Service Water System (RHRSW). These are the only systems that transfer heat from safety related systems, structures and

components to the ultimate heat sink. These systems were evaluated under EPU conditions and there are no changes to the flow rates of these systems, therefore the key heat exchanger parameters (such as fouling factors, effectiveness and tube plugging analysis) used in the EPU analysis remain consistent with the existing GL 89-13 program. Current evaluations, testing, and monitoring performed by the TVA Heat Exchanger Program to meet the commitments related to GL 89-13 will support operation at EPU conditions. There are slight increases in some of the system heat exchanger outlet temperatures, but the design of the heat exchangers is not affected and remains within the existing design parameters.

The Browns Ferry response to Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," was accomplished using the peak drywell temperature of 336ºF. This value bounds the peak Unit 1 EPU drywell temperature of 335.4°F.

GL 96-06 addresses three issues:

- Water hammer during a loss of coolant accident (LOCA) or a main steam line break (MSLB)
- Two-phase flow during a LOCA and MSLB
- Thermally induced over pressurization of isolated water filled piping sections in containment that could jeopardize the ability of accident-mitigating system to perform their safety functions and could lead to a breach of containment integrity through bypass leakage.

The system that is potentially impacted for water hammer and two-phase flow is the RBCCW system. An evaluation of the RBCCW coolers was performed and determined that two phased flow and water hammer during a LOCA or MSLB with a concurrent loss of offsite power is not a concern for EPU.

All of the primary containment penetrations were evaluated for susceptibility to thermal overpressurization. Several penetrations were identified as being susceptible to overpressurization. These were evaluated on a case-by-case basis. Several modifications to valves and changes to procedures will be required to ensure that the penetrations will acceptable (for example the drywell floor and equipment drain sump discharge lines are susceptible to overpressurization). This condition will be alleviated by drilling holes in the respective valve discs for the implementation of the BFN GL 96-06 program). All modifications will be implemented before Unit 1 restart.

NRC Request SPLB-A.8

For EPU conditions, provide justification and/or details of the evaluation which concludes that the safety-related service water systems will continue to meet the

requirements of draft GDC-4, in so far as it requires that reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing.

TVA Reply to SPLB-A.8

Unit sharing and interactions for BFN are discussed in UFSAR Appendix F.

The safety-related service water systems at BFN include the EECW system, the RHRSW system, and the UHS (which provides the source of water for the EECW and RHRSW systems). The effects of EPU on the EECW and RHRSW systems are discussed in PUSAR Section 6.4.1.1. These changes are minor and will not result in a change to the system configuration or operation and, therefore, will not have an effect on the sharing of these systems.

The UHS is the Wheeler Reservoir/Tennessee River. Although the maximum temperature assumed in DBA analyses was increased for EPU, there is no change in how the UHS is utilized or shared between the units.

NRC Request SPLB-B.1

Discuss whether any administrative controls or fire protection responsibilities of plant personnel are affected by an increase in decay heat. Also, address why an increase in decay heat will not result in an increase in the potential for a radiological release from a fire.

TVA Reply to SPLB-B.1

Administrative controls associated with fire protection in the Technical Specifications, the Technical Requirements Manual, and the Nuclear Quality Assurance Plan were reviewed and there are no changes required for EPU.

As indicated by the results of the Appendix R analyses, all Appendix R acceptance criteria are met under EPU; therefore, there is no increase in the potential for a radiological release resulting from a fire.

NRC Request SPLB-B.2

Section 6.7.1, of Enclosure 4 of the June 28, 2004, submittal states that:

> ...a plant-specific evaluation was performed to demonstrate safe shutdown capability in compliance with the requirements of 10 CFR 50 Appendix R assuming EPU conditions.... The results of the Appendix R evaluation for EPU provided in Table 6-5 demonstrate that fuel cladding integrity, reactor vessel integrity, and containment integrity are maintained and that

sufficient time is available for the operator to perform the necessary actions.

Upon reviewing Table 6-5, Browns Ferry Appendix R Fire Event Evaluation Results, the NRC staff was able to find references for all but the following values in the EPU submittal:

- Cladding Heatup (peak clad temperature (PCT)), degrees F = 1428 (EPU)
- Suppression Pool Bulk Temperature, degrees F = 227 (EPU), ≤ 227 (Appendix R Criteria), including Note 3 [*sic*]
- Primary Containment Pressure, pounds per square inch gage = 13.6 (EPU)

Provide references, including appropriate extracts from the UFSAR, plant-specific Appendix R evaluation, etc., for these values in Table 6-5, including Note 3 [*sic*].

TVA Reply to SPLB-B.2

The analysis to determine the EPU effect on compliance with Appendix R Fire is documented in BFN Calculation MDN-0999-980113, "Appendix R Fire Protection Evaluation." As indicated in PUSAR Table 6-5, key evaluation results included the calculated PCT, the peak bulk suppression pool temperature, and the peak containment pressure shown to be below their respective design limits. In system piping analysis, the EPU Appendix R maximum suppression pool temperature is established as the limiting condition for which the affected piping is evaluated, and Note 4 was intended to clarify that the 227°F criteria is designated as the limit for the torus attached piping required for the Appendix R case.

NRC Request SPLB-B.3

Section 6.7.1 of Enclosure 4 of the June 28, 2004, submittal states that :

> ...[f]or this [bounding PCT] case, the time available to the operator to open three MSRVs [main steam relief valves] is reduced from 30 minutes to 25 minutes at the EPU conditions. This reduction in the time available does not have any effect because the current procedures require this action to be completed within 20 minutes. Although the analysis assumes the time available to perform this operator action is reduced by five minutes ..., five minutes of margin remain compared to the present analysis.

Discuss the time-line analyses, including any assumptions, that may have been made in determining that the action can confidently be accomplished within 20 minutes, such that the 5-minute reduction in available time "does not have any effect."

TVA Reply to SPLB-B.3

BFN Units 2 and 3 Safe Shutdown Instructions currently require operators to depressurize the reactor within 20 minutes following initiation of the fire event. As part of the BFN Unit 1 restart effort, these Appendix R BFN Safe Shutdown Instructions, currently BFN Unit 2/Unit 3 procedures, are being revised to ensure safe shutdown capability with all three BFN units operating. As documented in the NRC's November 2, 1995 Safety Evaluation of the post-fire safe shutdown capability of BFN Units 2 and 3 (Reference 22), TVA performed walkdowns of the BFN Safe Shutdown Instructions for the 34 fire areas/zones to confirm the ability of the operators to perform actions both inside and outside of the control room. For a fire in the Control Building, which would require evacuation of the Control Room, TVA performed a timed walkdown of the required actions. The actions were evaluated for feasibility and included adequacy of emergency lighting, labeling, accessibility, logical grouping and sequencing for the operators, and time restraints. TVA concluded that the actions could be successfully completed within the specified time requirements, which included depressurization of the Unit 2 reactor as required within 20 minutes. Additionally, simulated fires in the Control Building and five additional fire areas were selected and included in operator requalification training based on complexity of the manual actions required, uniqueness of the actions required, and number of time-critical sections contained in the shutdown instructions. Therefore, TVA has verified, and continues to confirm that operators can accomplish the required depressurization within 20 minutes.

NRC Request SPLB-B.4

The June 6, 2005, Reply 6 of Enclosure 4, states that:

> ...the plant is compartmentalized and protected in accordance with Appendix R requirements such that a fire in one area will not affect the equipment in another area or, alternate shutdown paths capable of controlling each of the units are available.

Discuss whether that latter phrase "alternate ... available" is intended as additional to the former phrase "a fire ... area" or as a contingency if the first phrase does not apply. That is, does Volume 1 of the BFN Fire Protection Report (FPR) ensure "that a fire in one area will not affect the equipment in another area" exclusively, or does it do so only if "alternate shutdown paths capable of controlling each of the units are [not] available?"

TVA Reply to SPLB-B.4

As discussed in Paragraph 4.4.5, Section 1, Volume 1 of the BFN Fire Protection Report (FPR), BFN Units 1, 2, and 3 are divided into a number of fire areas/zones (compartments) to comply with Appendix R requirements. These compartments and associated fire barriers, including fire seals, fire dampers, fire doors, fire wrap, and structural steel protection provide adequate assurance a fire will be contained within

one area and not propagate to an adjacent fire area. The BFN Units 1, 2, and 3 Fire Hazards Analysis and Appendix R Safe Shutdown Analysis were performed based on this compartmentalization. Each fire area/zone is evaluated to ensure one train of the minimum safe shutdown systems is available for a postulated fire within the area of concern. As documented in Section 3 of the BFN Fire Protection Report, the Control Building (Control Room and the Cable Spreading Room (Fire Area 16)), is the only BFN fire area/zone where "alternative or dedicated shutdown capability" is required in accordance with Appendix R, Section III.G.3). The remaining fire areas/zones satisfy Appendix R separation criteria III.G.1 and III.G.2 by ensuring one train of the minimum safe shutdown systems is available following a fire in that area/zone. The term "alternative shutdown" applies only to Fire Area 16.

NRC Request SPLB-B.5

Section 6.7.1 of Enclosure 4 of the June 28, 2004, submittal as supplemented by the reply dated June 6, 2005 (including the discussion for the ATRIUM-10 fuel), states that "spurious operation of HPCI [high pressure coolant injection] was reviewed in accordance with [Volume 1 of the BFN FPR]. The HPCI system was assumed to initiate at the onset of the Appendix R event, and flow at its normal flow rate. The time at which the reactor vessel water level would reach the MSLs [main steam lines] is greater than 6 minutes. Therefore, the procedures will require HPCI isolation prior to 6 minutes during an Appendix R event." Volume 1 of the BFN FPR addresses pre-EPU conditions, so the conclusion regarding the greater than 6-minute time for the reactor vessel water level to reach the MSLs presumably applies to pre-EPU conditions.

Discuss whether the conclusion with regard to the timing for isolation of HPCI still remains valid at EPU conditions.

TVA Reply to SPLB-B.5

The conclusion with regard to securing the HPCI System within six minutes following a spurious initiation during an Appendix R event remains valid at EPU conditions.

The current BFN Appendix R analysis determined that a spurious actuation of HPCI would fill the reactor vessel to up to the Main Steam Lines in just over six minutes. Therefore, BFN Appendix R Safe Shutdown Instructions were written to ensure that operators secure HPCI injection within six minutes should a spurious initiation of the HPCI System occur.

As discussed in Section 6.7.1 of Enclosure 4 of TVA's June 28, 2004, EPU application (Reference 1), the EPU Appendix R analysis for GE-14 fuel determined that the time required for HPCI to fill the reactor vessel to the Main Steam lines during an Appendix R event and following spurious actuation was greater than six minutes. Therefore, based on the analysis for GE fuel, the required operator response time of six minutes was unchanged.

NRC Request SPLB-B.6

Enclosure 13 of the June 28, 2004, submittal states,

> Because the BFN construction permits were issued prior to the May 21, 1971, effective date of the GDC, compliance to these criteria [i.e., the acceptance criteria contained in RS-001] is not required as part of the BFN Units 2 and 3 licensing basis.

Correspondingly, the submittal contains a modified version of Section 2.5.1.4, Fire Protection, of Insert 5 for "Section 3.2 - BWR Template Safety Evaluation" from RS-001. However, Section 1.3, Basis of the Fire Protection Plan, of Volume 1 of the BFN FPR, states the following.

> This Fire Protection Plan has been developed for BFN to satisfy the requirements of General Design Criterion (GDC) 3 of Appendix A to 10 CFR 50.... On November 19, 1980, the Nuclear Regulatory Commission (NRC) published its final 10 CFR 50.48, 'Fire Protection,' which established fire protection requirements for operating nuclear power plants. This regulation, which imposed the requirement to have a fire protection plan to satisfy GDC 3, became effective on February 17, 1981. This regulation is applicable to BFN.

Furthermore, Section 6.7.1 presents an analysis based on the BFN FPR, which acknowledges GDC 3 as the basis for the current Fire Protection Program. Address the discrepancy between the submitted information and the FPR.

TVA Reply to SPLB-B.6

The BFN Fire Protection Plan complies with GDC 3. A revised RIS-001 Section 2.5.1.4 is included in Appendix A of this enclosure to reflect this. (Note that the RIS-001 markup provided in the initial EPU License Amendment Requests was replaced in its entirety in the February 23, 2005 submittals).

NRC Request SPLB-B.7

Some plants credit aspects of their Fire Protection System for other than fire protection activities (e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems). Identify the specific situations and discuss to what extent, if any, the EPU affects these "non-fire-protection" aspects of the plant Fire Protection System.

TVA Reply to SPLB-B.7

BFN does not take credit in any safety analyses for the fire protection system in other than fire protection activities. Procedures are provided under Emergency Operating Instructions (EOI) and Severe Accident Management Guidelines (SAMG) that provide instructions for utilizing fire protection system pumps to provide water to the reactor, the drywell, or the suppression chamber if necessary. However, this use of the non-safety related fire protection system is not credited in analyses and EPU operation will not require any changes to these procedures regarding the utilization of the fire protection system.

NRC SPSB Branch Requests

Introduction

The PRA information provided in Section 10.5 of Enclosure 4 of the June 28, 2004, EPU submittal (Reference 1), and subsequently updated in References 23 and 24, reflects the Unit 1 operation at EPU operating conditions. The model was developed consistent with the guidance contained in ASME Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications (Reference 25), and considers the concurrent operation of BFN Units 1, 2, and 3 at EPU conditions. TVA's responses to the NRC Staff's Requests for Additional Information (RAIs) regarding the Unit 1 PRA are based on the latest update, described in Reference 24. To facilitate the NRC Staff's review of the RAI responses by NRC, the PRA tables originally provided in Section 10.5 of Enclosure 4 of the June 28, 2004, submittal have been revised to reflect the latest Unit 1 PRA model results and are provided below.

Table 10-3
BFN Unit 1 Summary of CDF and LERF

Parameter	Initial Licensing Request For EPU (Reference 1)	Updated PRA Values Provided To NRC In August 2004 (Reference 23)	Latest PRA Values Provided To NRC In September 2005 (Reference 24)
Total CDF (yr^{-1}, mean value)	1.66E-6	1.86 E-6	1.77 E-6
LERF (yr^{-1}, mean value)	2.93E-7	1.87 E-7	4.40 E-7

Table 10-4 Summary Of Initiator Contributions to CDF and LERF for Browns Ferry Unit 1			
Initiator Category	**Mean frequency (events per year)**	**CDF**	**LERF**
Transient initiator categories			
Inadvertent Opening of One SRV	1.36E-2	3.70E-9	4.65E-10
Spurious Scram at Power	8.76E-2	2.85E-8	3.43E-9
Loss of 500kV Switchyard to Plant	1.02E-2	2.42E-8	6.43E-9
Loss of 500kV Switchyard to Unit	2.37E-2	5.18E-8	1.51E-8
Loss of Instrumentation and Control Bus 1A	4.27E-3	9.76E-10	1.30E-10
Loss of Instrumentation and Control Bus 1B	4.27E-3	3.06E-8	2.61E-9
Total Loss of Condensate Flow	9.45E-3	3.88E-8	5.96E-9
Partial Loss of Condensate Flow	1.93E-2	5.71E-9	7.11E-10
MSIV Closure	5.52E-2	9.34E-8	3.57E-8
Turbine Bypass Unavailable	1.95E-3	3.08E-9	1.19E-9
Loss of Condenser Vacuum	9.70E-2	1.67E-7	6.41E-8
Total Loss of Feedwater	2.58E-2	4.55E-8	1.67E-8
Partial Loss of Feedwater	2.47E-1	8.55E-8	1.01E-8
Loss of Plant Control Air	1.20E-2	6.58E-8	7.44E-9
Loss of Offsite Power	7.87E-3	2.70E-7	5.03E-9
Loss of Raw Cooling Water	7.95E-3	1.18E-7	4.96E-9
Momentary Loss of Offsite Power	7.57E-3	1.90E-9	2.46E-10
Turbine Trip	5.50E-1	1.90E-7	1.70E-8
High Pressure Trip	4.29E-2	1.32E-8	1.63E-9
Excessive Feedwater Flow	2.78E-2	8.20E-9	1.02E-9
Other Transients	8.60E-2	2.79E-8	3.37E-9
ATWS Categories			
Turbine Trip ATWS	5.50E-1	5.58E-8	5.34E-8
LOSP ATWS	7.87E-3	1.32E-9	1.27E-9
Loss of Condenser Heat Sink ATWS	1.52E-1	6.27E-8	6.04E-8
Inadvertent Opening of SRV ATWS	1.36E-2	1.14E-9	1.07E-9
Loss of Feedwater ATWS	3.02E-1	1.00E-7	9.64E-8
LOCA initiator categories			
Breaks Outside Containment	6.67E-4	3.12E-8	6.97E-9

Table 10-4 Summary Of Initiator Contributions to CDF and LERF for Browns Ferry Unit 1			
Initiator Category	**Mean frequency (events per year)**	**CDF**	**LERF**
Excessive LOCA (reactor vessel failure)	9.39E-9	9.09E-9	4.16E-11
Interfacing Systems LOCA	3.15E-5	5.00E-8	5.20E-9
Large LOCA – Core Spray Line Break			
Loop I	1.68E-6	4.49E-9	1.55E-10
Loop II	1.68E-6	4.49E-9	1.55E-10
Large LOCA – Recirculation Discharge Line Break			
Loop A	1.18E-5	1.38E-8	1.20E-9
Loop B	1.18E-5	1.38E-8	1.20E-9
Large LOCA – Recirculation Suction Line Break			
Loop A	8.39E-7	4.67E-9	8.11E-11
Loop B	8.39E-7	4.67E-9	8.11E-11
Other Large LOCA	8.39E-7	8.56E-10	7.30E-11
Medium LOCA Inside Containment	3.80E-5	2.02E-8	3.99E-9
Small LOCA Inside Containment	4.75E-4	9.05E-11	1.50E-11
Very Small LOCA Inside Containment	5.76E-3	1.38E-9	1.79E-10
Internal flooding initiator categories			
EECW Flood in Reactor Building – shutdown units	1.20E-3	7.38E-11	3.19E-11
EECW Flood in Reactor Building – operating unit	1.85E-6	1.19E-9	2.10E-12
Flood from the Condensate Storage Tank	1.22E-4	1.38E-9	3.63E-10
Flood from the Torus	1.22E-4	3.98E-8	2.89E-10
Large Turbine Building Flood	3.65E-3	5.52E-8	2.29E-9
Small Turbine Building Flood	1.65E-2	1.54E-8	1.50E-9

Table 10-5 Frequency-Weighted Fractional Importance to Core Damage of Operator Actions Used in Browns Ferry Unit 1 PRA		
Database Variable	**Operator Action Description**	**Frequency-Weighted Fractional Importance to Core Damage**
HPRVD1	OPERATOR FAILS TO INITIATE DEPRESSURIZATION	2.8033E-1
HPWWV1	OPERATOR FAILS TO OPEN WETWELL VENT	2.4139E-1
HRSPC1	OPERATOR FAILS TO LOCALLY RECOVER SP COOLING FAILURE	1.3564E-1
HRRHRX	OPERATOR FAILS TO ALIGN THE RHR UNIT 1/UNIT 2 CROSSTIE	4.0855E-2
HPHPE1	OPERATOR FAILS TO CONTROL LEVEL WITH HPCI/RCIC – THIS IS A NON ATWS SCENARIO	2.4758E-2
HPHPR1	OPERATOR FAILS TO CONTROL LEVEL WITH HPCI/RCIC FOLLOWING LEVEL 8 TRIP	1.8028E-2
HOSV1	OPERATOR FAILS TO PREVENT MSIV CLOSURE DURING ATWS	1.7257E-2
HPTAF1	OPERATOR FAILS TO CONTOL LEVEL AT TAF DURING ATWS – UNISOLATED VESSEL	1.4605E-2
HOAL2	OPERATOR FAILS TO LOWER AND CONTROL LEVEL DURING ATWS (ISOLATED VESSEL)	1.2427E-2
HPSPC1	OPERATOR FAILS TO ALIGN SUPPRESSION POOL COOLING – THIS IS A NON ATWS SCENARIO	1.0432E-2
ORVD2 (Split fraction)	OPERATOR FAILS TO INITIATE DEPRESSURIZATION GIVEN FAILURE TO CONTROL HIGH PRESSURE LEVEL CONTROL	6.4582E-3
HODWS1	OPERATOR FAILS TO ALIGN FOR DRYWELL SPRAY. THIS IS A NON ATWS SCENARIO.	5.5943E-3
HPTAF2	OPERATOR FAILS TO CONTOL LEVEL AT TAF DURING ATWS– ISOLATED VESSEL	4.8371E-3
HREEC1	OPERATOR FAILS TO ALIGN SWING RHRSW PUMPS FOR EECW (SCENARIO REQUIRES 2 PUMPS TO BE ALIGNED)	3.7452E-3
HOAL1	OPERATOR FAILS TO LOWER AND CONTROL LEVEL DURING ATWS (NON ISOLATED VESSEL)	3.6761E-3
HPSLC2	OPERATOR FAILS TO INITIATE STANDBY LIQUID CONTROL – VESSEL IS ISOLATED FROM CONDENSER	1.3186E-3

Table 10-5 Frequency-Weighted Fractional Importance to Core Damage of Operator Actions Used in Browns Ferry Unit 1 PRA		
Database Variable	**Operator Action Description**	**Frequency-Weighted Fractional Importance to Core Damage**
HOREE2	OPERATOR FAILS TO ALIGN SWING RHRSW PUMPS FOR EECW (SCENARIO REQUIRES 1 PUMP TO BE ALIGNED)	5.6522E-4
HPRTB1	OPERATOR FAILS TO PROVIDE BACKUP TRIP SIGNAL	5.1220E-4
HOSL1	OPERATOR FAILS TO INITIATE STANDBY LIQUID CONTROL – VESSEL IS NOT ISOLATED FROM CONDENSER	4.1747E-3
HOX2	OPERATOR FAILS TO CROSSTIE 4 KV SHUTDOWN BOARD	4.0820E-4
HOX1	OPERATOR FAILS TO ALIGN BATTERY CHARGER 2B TO 250V DC BATTERY BOARD	3.6289E-4
HPADS1	OPERATOR FAILS TO INHIBIT ADS (ISOLATED VESSEL)	3.4901E-4
HPHPL1	OPERATOR FAILS TO CONTROL HPCI/RCIC LONG TERM (6-24 HOURS)	2.3943E-4
HPADS2	OPERATOR FAILS TO INHIBIT ADS (NON ISOLATED VESSEL)	1.5692E-4
HODSB1	OPERATOR FAILS TO ALIGN DIESEL BOARD FOR DIESEL C	8.6858E-5
HOR480	OPERATOR FAILS TO RECOVER 480 SHUTDOWN BOARD	5.8085E-5
HPLPC1	OPERATOR FAILS TO CONTROL LPCI/CS INJECTION	1.8690E-5

NRC Request SPSB-A.1

The second paragraph of Section 10.5 of Enclosure 4 of the June 28, 2004, submittal indicates that all associated plant modifications were systematically reviewed to identify their effect on the elements of the probabilistic risk assessment (PRA) model. Provide the details of these systematic reviews, including the effect of each modification on the PRA model.

TVA Reply to SPSB-A.1

TVA reviewed the EPU Design Change Notice (DCN) packages to identify any effect on the PRA model. This review determined that the PRA model was not affected by the EPU modifications.

The PRA is a model that reflects the design and operation of the BFN plant. An inherent feature of PRAs is the tacit assumption that components are designed to perform the associated functions. For example, an MOV is designed to open against a certain pressure differential. If the pressure differential is changed and the MOV is modified to accommodate the change, there is no effect on the PRA. Likewise, the substitution of an equivalent component qualified for the associated design conditions does not affect the PRA.

It is not necessary to model all plant components in the PRA. In general, components that are non-safety related and do not support or affect power operation are not included in the model. However, non-safety related components such as the high and low -pressure turbines, and the generator and associated cooling are modeled in the PRA because they can affect the initiating event frequencies. The PRA models this impact by including plant data associated with such components in determining associated initiating event frequencies.

The following table is the list of EPU modifications transmitted to the NRC by letter dated February 23, 2005 (Reference 2), annotated to provide the results of the PRA review.

Table SPSB-A.1-1

Modification	PRA Review Results
High Pressure Main Turbine	Modeled implicitly as turbine trip. No basis for changing frequency.
Low Pressure Turbine	Modeled implicitly as turbine trip. No basis for changing frequency.
Turbine Sealing System	Modeled implicitly as turbine trip. No basis for changing frequency.
Condensate Pumps	Increased flow of pumps does not change ability of the Condensate and Demineralizer Water systems to provide a low pressure water source for the reactor vessel. Does not impact the initiating event frequency attributes.
Condensate Booster Pumps	Increased flow of pumps does not change ability of Condensate System as a low pressure water source for the reactor vessel. Does not impact the initiating event frequency attributes.
Steam Packing Exhauster Bypass	This does not affect use of Condensate System as a low pressure water source for reactor vessel.
Condensate Demineralizers	The Demineralizers are not credited as a source of water; these modifications will not introduce any adverse effects. The modifications do not impact the initiating event frequency attributes.

Table SPSB-A.1-1	
Modification	**PRA Review Results**
Main Condenser Extraction Steam Bellows	Bellows are not explicitly modeled; this change does not affect the availability of the main condenser. This modification ensures adequate design margin is maintained.
Feedwater Pumps and Turbines	The modifications do not affect the modeling of Feedwater System as a post-trip source of high pressure water to the reactor vessel. The change does not impact the initiating event frequency attributes.
Feedwater Heaters	The modifications do not affect the modeling of Feedwater System as a post-trip source of high pressure water to the reactor vessel. The change does not impact the initiating event frequency attributes.
Moisture Separators	Modeled implicitly as turbine system. No basis for changing frequency.
Main Generator System	The main generator is modeled through the turbine trip initiating event (including load rejection events). The event is modeled statistically based on generic data and BFN operating experience. There is no basis for changing the process.
Main Bank Transformers	Does not introduce any new initiators or change frequency of existing initiators.
Isolation Phase Bus Duct Cooling	Does not introduce any new initiators or change frequency of existing initiators.
EHC Software	Does not introduce any new initiators or change frequency of existing initiators.
Technical Specification Instrumentation Respan	Does not introduce any new initiators or change frequency of existing initiators.
Balance of Plant Instrument Respan	Does not introduce any new initiators or change frequency of existing initiators.
Drywell Building Steel	Does not change structural ability of building as modeled in the PRA.
Main Steam, Recirculation, Feedwater, and Condensate Supports	No changes to the systems that impact the capability to adequately perform PRA associated functions.
Torus Attached Piping	Does not affect integrity of torus; the modifications ensure design margin is maintained.
Main Steam Isolation Valves	Does not affect reliability or function of the MSIVs ability to close or to remain open.
Reactor Recirculation Pump Motors	The recirculation pump motors are modeled as a required trip for ATWS sequences. Modifications do not impact this function.
Jet pumps	This is an operational improvement not related to safety.
Local Power Range Monitors	The replacements reflect higher power operation. They provide the same function and information; not explicitly modeled.
ICS/SPDS	The replacements reflect higher power operation. They provide the same function and information; not explicitly modeled.

Table SPSB-A.1-1	
Modification	**PRA Review Results**
Main Steam Relief Valves	No affect on MSRV challenges and subsequent reseating.
Motor Operated Valves	The modifications do not adversely affect the reliability of the MOVs as modeled in the PRA.
High pressure Coolant Injection System	System features modified are not modeled explicitly; will ultimately manifest in reliability statistics.
Steam Dryer	The steam dryer is not explicitly modeled. This change provides no basis for changing the model.
Vibration monitoring	Operational feature; not modeled. Monitoring equipment.

NRC Request SPSB-A.2

Provide the following information related to the treatment of a loss of offsite power (LOOP) in the PRA model:

NRC Request SPSB-A.2.a

Describe how the frequencies of LOOP events were determined.

TVA Reply to SPSB-A.2.a

The data from Units 2 and 3 was used as plant-specific data for Unit 1. Note that during the time period used for data collection (January 1996 to March 2003) there were no loss of offsite power or loss of station power (LOOP or LOSP) events at BFN. BFN Units 1, 2 and 3 are a common facility with a common switchyard. Even though Unit 1 has been in a non-power production mode, several Unit 1 systems and components have remained operational both to support fuel pool cooling and Units 2 and 3 operation. At the time of restart, Unit 1 will be the same functionally as Units 2 and 3. All three units will have the same Updated Final Safety Analysis Report and operators will be licensed on all three units. Therefore, it is appropriate to use Unit 2 and 3 LOOP data for Unit 1.

A loss of offsite power (LOOP) (or LOSP) is defined in the PRA as the concurrent loss of the 500kV systems and the 161kV systems. In this situation, AC power is supplied by the onsite DGs. For BFN, the Station Blackout (SBO) is defined as the complete loss of AC power to one unit and limited AC power provided onsite by the diesel generators (DGs) to the other two units.

The calculation of LOOP frequencies are based on the BFN design in which there are no dependencies between the 500kV system and the 161kV system with respect to

plant-centered and switchyard events. Complete dependencies are modeled for grid and severe weather events.

The BFN PRA partitions loss of offsite power events (sustained loss of offsite power for more than 2 minutes) into four categories of initiating events (IEs):

- Loss of the 500kV supply to a single unit (L500U),
- Loss of the 500kV supply to the plant (L500PA),
- Grid related LOSP events (LOSPG), and
- Severe weather related LOSP (LOSPW).

Note that LOSPG and LOSPW events are combined to form the initiator LOSP. For completeness, a fifth initiating event category is also used, momentary loss of offsite power (MLOSP). Momentary loss of offsite power events are those events that are recovered either manually or automatically in less than two minutes, as defined in NUREG/CR-5496 (Reference 26). Momentary loss of offsite power events do not require the modeling of the emergency diesel generators, but require modeling of the restart demand for any operating equipment powered from the emergency buses.

For all other initiating events, top events representing the 500kV system (OG5) and the 161kV system (OG16) are questioned. The approach used to evaluate these top events is consistent with the discussion in the previous paragraph.

There have been a number of publications prepared by or for the NRC related to LOSP frequency and recovery times. They are summarized as follows:

- NUREG-1032 (Reference 27) was published in June 1988. It documents the findings of technical studies performed as part of the program to resolve the "Station Blackout," Unresolved Safety Issue A-44. Important factors analyzed include: LOSP frequency, reliability of emergency AC power supplies, capability and reliability of decay heat removal systems independent of AC power, and the likelihood of restoring offsite power before core damage could be initiated. The effects of different switchyard designs, plant locations, and operational features on the estimated station blackout events are also addressed. NUREG-1032 can be seen as definitive in addressing station blackout, and subsequent studies were based on the format and structure developed in NUREG-1032.

- INEEL/EXT-97-00887 (Reference 28) was published in November 1997. Its primary objective is to update the NUREG-1032 LOSP frequency and recovery time, using plant event data from 1980 to 1996. It also extends the scope by considering LOSP events at shutdown.

- NUREG/CR-5496 (Reference 26) was published in November 1998 as the final version of INEEL/EXT-97-00887.

Generic Data

The BFN PRA models use the data and information from NUREG/CR-5496 to develop prior distributions. NUREG/CR-5496 continued the practice from NUREG-1032 of classifying LOSP events into one of the following categories:

> *Plant-centered LOSP* events are those in which the design and operational characteristics of the plant itself play a role in the likelihood of LOSP. Plant-centered failures typically involve hardware failures, design deficiencies, human errors (maintenance and switching), and localized weather-induced faults (lightning and ice), or combinations of these types of failures. Switching or repairing faulted equipment at the site can recover plant-centered failures.
>
> *Grid-related LOSP* events are those attributed to the intrinsic grid unreliability. Grid unreliability has traditionally been the most prominent factor associated with a loss of offsite power at nuclear power plants. Factors affecting recovery include the existence and implementation of appropriate procedures and the capability and availability of power sources that can supply power during grid blackout.
>
> *Severe weather LOSP* events occur due to local or area-wide storms. Severe weather only includes weather events that cause severe or extensive damage at or near the site. In such cases, the recovery time is relatively long due to the extensive repair work required. Severe weather does not include weather events that do not cause extensive damage and therefore does not affect the recovery time. Such events may be classified as either grid-related or plant-centered LOSP events.

The following paragraphs describe the development of frequencies for LOSP, MLOSP, L500U, and L500PA events based on the data in NUREG/CR-5496. The sustained plant-centered frequency is partitioned into L500U and L500PA frequencies. Sustained grid-related and severe weather events are mapped into LOSP events. The momentary frequencies from grid-related, severe weather and plant-centered events are combined into the MLOSP frequency. Table SPSB-A.2-1 provides the results of the analysis.

Plant-Centered L500U (single unit) and L500PA (entire plant, multi-unit) Frequency

The plant-centered events are further partitioned into sustained and momentary events. The momentary events are included in the MLOSP initiating event and only the sustained plant-centered events (i.e. L500U and L500PA) are considered here. Table B-4 in NUREG/CR-5496 lists the industry distribution that was developed for sustained plant-centered LOSP events. This reference constitutes the generic data used.

The process for developing the sustained plant-centered event distributions is as follows:

> In step 1, calculate a generic industry beta factor for L500PA events by assuming the occurrence of L500PA events can be modeled as the fraction of sustained plant-centered LOSP events that result in loss of power to more than one unit, at multi-unit sites. This is analogous to the event by event reviews performed to derive common cause hardware failures. For step 2, develop the generic industry (sustained plant-centered) distributions for L500U and L500PA by using the beta factor calculated in step 1 and the sustained plant-centered LOSP distribution in step 1. In step 3, perform Bayesian updates on the generic distribution to develop plant specific distributions for L500U and L500PA.

The generic industry frequency distribution for sustained plant-centered events in Table B-4 of NUREG/CR-5496 is a gamma distribution with α= 1.844 and β= 46.12 and a mean of 4.00E-2, per year.

The next step is to calculate a common cause beta factor for plant-centered LOSP events. Only the statistics for multi-unit sites are used in the development of the beta factor. The common cause beta factor is then estimated as $2N_2/(N_1+2N_2)$, where N_1 is the number of events affecting only one unit and N_2 is the number of events affecting two or more units. As shown in Table SPSB-A.2-2, N_1 is 26 and N_2 is 5. Thus the point estimate for the LOSP beta factor is approximately 0.278.

The resulting generic prior distributions are presented in Table SPSB-A.2-3.

<u>Plant-Specific Data</u>

Between late 1984 and mid 1985, all three units were shut down and have undergone substantial changes to design, equipment, maintenance, procedures, and operating policies. It was judged that the old data (prior to this shutdown period) are not applicable to the BFN units, so only data from the period following the shutdowns are used in the development of initiating event frequencies. Due to the fact that the NUREG/CR-5750 (Reference 29) is used as the source document and since that document includes all LERs through 1995, the initiating event collection starts in 1996.

All three units are similar in design (with respect to initiating events) and Unit 1 will be operated with similar procedures and management philosophy as the other units. Unit 1 has been shutdown during the entire period since mid 1985. Hence, there is no Unit 1 initiating event data available. Unit 2 and Unit 3 data through March 2003 are pooled to form a pseudo plant specific database for Unit 1. There are a total of 13.78 calendar years of data for Unit 2 and Unit 3 combined between January 1996 and March 2003.

Since the frequencies in NUREG/CR-5750 are given in terms of critical hours, the calendar years for BFN must be converted to equivalent units. Browns Ferry total critical hours is estimated from NRC operating experience data and the BFN Scram Database (Reference 30). A criticality factor of 0.944 is the average of Units 2 and 3 during the years 1996 through 2002.

Historical losses of offsite power events are recorded in the database regardless of plant power level. In the actual event sequence quantification, the initiating event categories related to losses of offsite power [i.e. loss of offsite power (LOSP), loss of 500-kV line to a single unit (L500U), loss of 500-kV line to the plant (L500PA), and momentary losses of offsite power (MLOSP)] are modified by a scalar factor of 0.944 to account for the average plant availability factor over the data collection period. The resulting, updated distributions for losses of offsite power are indicated in Table SPSB-A.2-4.

Table SPSB-A.2-1
Browns Ferry Generic Prior Loss of Station Power (LOSP) Frequency Distributions (per Calendar Year)

Category	Mean	Distribution
Sustained LOSP		
Severe-Weather LOSP	5.20E-3	Gamma(0.197, 37.93)
Grid-Related LOSP	3.00E-3	Gamma(3.14, 1048.3)
Sustained L500PA		
Total Sustained L500PA	1.11E-2	Gamma(1.844, 165.9)(1)
Sustained L500U		
Total Sustained L500U	2.89E-2	Gamma(1.844, 63.88)(2)
Momentary MLOSP		
Plant-Centered MLOSP	3.82E-3	Gamma(4.50, 1178.6)
Severe-Weather MLOSP	2.39E-3	Gamma(2.50, 1048.2)
Grid-Related MLOSP	1.43E-3	Gamma(1.50, 1048.2)
Total Momentary MLOSP	7.64E-3	Gamma(8.24, 1078.7) (3)
Total LOSP	5.58E-2	

(1) Gamma(1.844, 46.12) scaled by 0.722 (1 – beta factor).
(2) Gamma(1.844, 46.12) scaled by 0.278 (beta factor).
(3) Best fit distribution for the sum of the three types of MLOSP.

Table SPSB-A.2-2 Multi-Unit Station Loss of Station Power (LOSP) Events		
Multi Unit Station	**Single Unit LOSP Events**	**Multi-Unit LOSP Events**
Arkansas	0	1
Beaver Valley	1	1
Braidwood	1	
Browns Ferry	0	
Browns Ferry	0	
Brunswick	2	
Byron	0	
Calvert Cliffs	0	1
Catawba	1	
Comanche Peak	0	
Cook	1	
Diablo Canyon	1	
Dresden	2	
Farley	0	
Hatch	0	
Indian Point	1	
Lasalle	1	
Limerick	0	
McGuire	3	
Millstone	1	
Nine Mile Point	0	
North Anna	0	
Oconee	1	
Palo Verde	2	
Peach Bottom	0	
Point Beach	1	
Prairie Island	0	1
Quad City	1	
Salem	0	
San Onofre	1	
Sequoyah	0	1
South Texas	0	
St. Lucie	1	
Surry	0	
Susquehanna	1	
Turkey Point	2	
Vogtle	0	
Zion	1	
Totals	**26.00**	**5.00**
LOSP Beta Factor	**0.278**	

Table SPSB-A.2-3 Generic Prior Distributions				
		Prior Distribution		
			Gamma	
BFN IE	Description	Mean (per calendar year)	Alpha (no units)	Beta (critical years)
LOSPG	Loss of Offsite Power Grid Related	2.85E-03	3.14	1048.3
LOSPW	Loss of Offsite Power – Weather Related	4.93E-03	0.197	37.93
L500PA	Loss of 500kV to Plant	1.1E-02	1.84	165.9
L500U	Loss of 500kV to One Unit	2.7E-02	1.84	63.9
MLOSP	Momentary Loss of Offsite Power	7.26E-03	8.24	1078.7

Table SPSB-A.2-4 BFN Unit 1 Initiating Event Plant-Specific Updates and Posterior Distributions for Losses of Offsite Power									
			BFN Data		Posterior				
BFN IE	Description	Prior Mean (per calendar year)	No. of Events	Exposure Time (critical years)	Mean (per calendar year)	Alpha	Beta (critical years)	5th %ile (per calendar year)	95th %ile (per calendar year)
LOSPG	Loss of Offsite Power – Grid Related	2.85E-03	0	13.78	2.81E-03	3.14	1062.08	7.96E-4	5.82E-3
LOSPW	Loss of Offsite Power – Weather Related	4.93E-03	0	13.78	3.62E-03	0.197	51.71	2.98E-9	1.9E-2
L500PA	Loss of 500kV to Plant	1.1E-02	0	13.78	9.73E-03	1.84	179.68	1.55E-3	2.4E-2

BFN IE	Description	Prior Mean (per calendar year)	BFN Data		Posterior				
			No. of Events	Exposure Time (critical years)	Mean (per calendar year)	Alpha	Beta (critical years)	5th %ile (per calendar year)	95th %ile (per calendar year)
L500U	Loss of 500kV to One Unit	2.7E-02	0	13.78	2.3E-02	1.84	77.68	3.59E-3	5.5E-2
MLOSP	Momentary Loss of Offsite Power	7.26E-03	0	13.78	7.17E-03	8.24	1092.48	3.61E-3	1.2E-2

Table SPSB-A.2-4
BFN Unit 1 Initiating Event Plant-Specific Updates and Posterior Distributions for Losses of Offsite Power

NRC Request SPSB-A.2.b

Describe how the recovery of offsite power is modeled in the PRA (e.g., use of specific representative times, probabilistic convolutions).

TVA Reply to SPSB-A.2.b

The recovery of offsite power is modeled in the PRA by a probabilistic convolution of DG failures by time with offsite power non-recovery curves. The model is a mathematical approximation of the integral evaluated over the time interval from zero to 24 hours of the unavailability of onsite power, times the frequency of not recovering *offsite* power.

NRC Request SPSB-A.2.c

Describe how the probabilities of offsite power recovery events were determined.

TVA Reply to SPSB-A.2.c

The non-recovery of offsite power is accounted for in the sequence models via top events [EPR30] and [EPR6]. These top events account for the time-dependent failure of the DGs. Of interest here is the portion of the recovery model related to recovery of power from offsite sources. No credit is given for recovery of the failed DGs.

NUREG/CR-5496 provides generic industry data representing the time to recovery from losses of offsite power (LOSP) at nuclear power plants for actual incidents that occurred

from 1980-1996 caused by plant-centered losses, grid losses, or severe weather losses. Earlier analyses (Reference 31) of nuclear plant incidents through 1985 categorized plant-centered causes of offsite power failure into three plant groups, depending on the plant design factors regarding independence of the offsite power sources, and automatic and manual transfer schemes for class 1E buses. The later analysis of plant incidents through 1996 in NUREG/CR-5496 (Reference 26) indicated no statistically significant unit-to-unit variability for the plant-centered initiating events and recovery times, and hence, this trend was not modeled. Therefore, as shown in NUREG/CR-5032 (Reference 31), the frequency of offsite power non-recovery is obtained or interpolated from the values used to represent the figures and data for the recovery of offsite power due to plant-centered, weather, and grid-related causes.

Plant specific data was not used to adjust the generic industry curves for offsite non-recovery. The values used in the analysis for these three curves are reported in NUREG/CR-5496, Table SPSB-A.2-5. For intermediate times, linear interpolation was used to obtain the non-recovery probability.

Table SPSB-A.2-5
Probabilities Derived From Data Presented in NUREG/CR-5496

Hours After Offsite Power is Lost	Plant-Centered Events	Weather Related Events	Grid Related Events
0.	1	1	1
0.8333	0.3999	-	-
1.667	0.23351	0.783	0.99617
2.5	0.15758	-	0.52875
3.333	0.11487	0.59622	0.34578
5	0.069683	-	0.19429
6.667	0.04699	0.38391	0.12848
10	-	0.2708	0.07010
13.333	-	0.20214	-
16.667	0.010696	0.15685	0.03091
21.667	-	0.11287	-
35	0.004368	0.08491	0.01361

NRC Request SPSB-A.2.d

Describe how the probability of consequential LOOP was determined.

TVA Reply to SPSB-A.2.d

Generic historical data was used to calculate the loss of the 500kV supply to the unit subsequent to a turbine trip. The value of 3.34E-04 is assigned to this event based on the PLG-0500 database (Reference 32). Note that BFN has not experienced any LOOPs since the recovery of Units 2 and 3. There is insufficient evidence to support a loss of the 500kV grid from a simultaneous trip of two or more units at the site. The concept of multi-unit trips occurring simultaneously is, with the exception of some categories of LOOPs, a PRA simplification. The trips, although expected to be closely spaced, will not occur simultaneously. There may be time for the grid operators to take actions to prevent loss of the grid. Additionally, it is uncertain whether the loss of the three units will endanger the grid. Given these uncertainties, a value of 0.1 was used in previous BFN PRAs. That value is repeated here.

NRC Request SPSB-A.2.e

Provide the contribution to the total core damage frequency (CDF) from consequential LOOP events.

TVA Reply to SPSB-A.2.e

The quantification process involves both single unit and multi-unit LOOP initiators. As discussed in TVA Reply to SPSB-A.2.d, the probability of a conditional LOOP is dependent on the type of initiator. For a single unit initiator, a value of 3.34E-4 is used for the subsequent LOOP. For the multi-unit initiator, a value of 0.1 is used. Utilization of these values result in the contribution to the CDF from consequential LOOPs for Unit 1 being 1.5E-11.

NRC Request SPSB-A.3

Section 10.5.1 of Enclosure 4 of the June 28, 2004, submittal indicates that the Unit 1 PRA uses more detailed initiating event categories as compared to the Unit 2 and Unit 3 PRAs in order to facilitate the tracing of success criteria in the PRA model. Explain why it was necessary to adopt this approach for the Unit 1 PRA and describe (in terms of the PRA modeling) how the approach actually facilitates the tracing of success criteria. Explain why it was not necessary to use more detailed initiating event categories in the Unit 2 and 3 PRA models.

TVA Reply to SPSB-A.3

It was necessary to use more detailed initiating event categories for Unit 1 as compared to Unit 2 and Unit 3 PRAs in order to be consistent with the ASME PRA Standard (Reference 25).

The ASME PRA Standard approach facilitates the tracing of success criteria in that more detailed categories can remove conservative assumptions. As an example, the Unit 2 and 3 loss of feedwater initiating event was changed for Unit 1 by being partitioned into a total loss of feedwater and a partial loss of feedwater. The partial loss of feedwater implies that feedwater was available at the time of the scram and that HPCI and RCIC may not be required.

It was not necessary to use more detailed initiating event categories in the Unit 2 and 3 PRA models because they have not been updated to the ASME PRA standard (Reference 25). Also, the Unit 2 and 3 initiating event categories represent a complete set of internal initiators. This set was developed prior to the availability of RG 1.200. These categories are an evolution of the event categories developed initially for the Unit 2 IPE and minor refinements accomplished as the BFN PRA models evolved. Additionally, they were evaluated as part of the BWROG Certification process and found acceptable. They are sufficient for calculating CDF and LERF values and supporting risk-informed decisions.

NRC Request SPSB-A.4

Identify the specific sources of the data used in the Unit 1 PRA (including initiating event frequencies, basic event failure probabilities, split fractions, and common cause data). If any data based on the operating experience of Unit 1 has been used, justify its applicability to the post-EPU plant, considering that Unit 1 has been shut down for almost two decades. If any data based on the operating experience of Units 2 and 3 has been used, justify its applicability to Unit 1.

TVA Reply to SPSB-A.4

Initiating Events Data

The sources of the data used in the Unit 1 PRA for initiating event frequencies are discussed below:

- The primary source of initiating event generic distributions is NUREG/CR-5750 (Reference 29). These generic distributions were updated using BFN experience from the beginning of 1996 through March, 2003.

- NUREG/CR-5496 (Reference 26) was used for LOSP related initiating events.

Unit 1 will be operated with the same or similar procedures. All three units are similar in design (with respect to initiating events) and Unit 1 will be operated with the same procedures and management philosophy as the other 2 units. Hence, Unit 2 and Unit 3 plant data used in the updating of the initiating event frequencies are applicable to Unit 1.

Basic Event Failure Probabilities and Split Fraction Data

The sources of the data used in the Unit 1 PRA for component failure rates and maintenance unavailability's are discussed below:

- In general, data was obtained from Units 2 and 3. For the CRD and RHR pumps, Unit 1 data was also included. These Unit 1 components can be cross-tied to Unit 2 and were kept operable.

- The time period in the development of the database for Unit 2 and 3 PRA was from June 1994 through May 1999. For the Unit 1 PRA, the failure rate and maintenance unavailability for the major components were updated with additional experience through March 2003.

- For selected components, the failure rate and maintenance unavailability data sources are the data in support of either the Maintenance Rule (10 CFR 50.65) or EPIX (Reference 33). The priors used for updating the failure rates are from NUREG/CR-4639 (Reference 34) and EPRI NP-6780-L (Reference 35), and the priors used for updating the maintenance unavailability parameters are from PLG-0500 (Reference 32).

- For the other components, the generic failure rates are taken from PLG-0500 (Reference 32).

The Units 2 and 3 component failure rate and maintenance unavailability data was determined to be applicable to the Unit 1 PRA due to the following factors:

- The equipment has the same function,
- The equipment has same design, maintenance and operational practices,
- The system procedures for operation, maintenance and testing are or will be similar,
- The same staff/personnel will be used for testing and maintenance of equipment, and
- The plants have similar training and management approach.

Common Cause Data

The sources of the data used in the Unit 1 PRA for common cause parameters are discussed below:

- The source of common cause data used for the development of the common cause failure parameters is NUREG/CR-6268 (Reference 36).
- The screening of the common cause events was done for applicability to Units 1, 2 and 3.
- Additionally, common cause was modeled for HPCI and RCIC pumps based on data from INEEL (Reference 37).

The basis for the screening of events for all the three units was that all three units are similar in design and all the units will be operated with the same or similar procedures and management philosophy.

<u>**NRC Request SPSB-A.5**</u>

The following questions/requests relate to the internal flooding initiating event frequencies:

<u>**NRC Request SPSB-A.5.a**</u>

For "emergency equipment cooling water (EECW) flood in reactor building – shutdown units," the Unit 1 frequency is given as 1.2E-3. For Unit 2, this frequency is given as 1.2E-5, and for Unit 3, as 1.2E-2. Provide an explanation and bases for these widely different estimates.

<u>**TVA Reply to SPSB-A.5.a**</u>

The 1.2E-5 value for Unit 2 is a typographical error and should be 1.2E-2. The correct value of 1.2E-2 is used in the Unit 2 PRA model.

The IE frequencies are based on the assumption that maintenance can occur any time a unit is shutdown, so with the Unit 1 return to power operation, the probability of a unit being shutdown drops dramatically.

The Unit 1 IE frequency value has been updated to reflect the likelihood that one of the other two units was shutdown. This accounts for the IE value used for Unit 1.

The Units 2 and 3 model initiating event values for EECW flood in the turbine building were not revised in the recent model updates to reflect the restart of Unit 1. The existing Units 2 and 3 IE value is acceptable based on the fact that when the IE is changed to reflect the operating states of the other units, the IE goes from 1.2E-2 to 1.2E-3. Also the contribution of the postulated event "Emergency cooling water (EECW) flood in reactor building – shutdown units," to the total CDF is not significant. Taking these factors into consideration, the existing model results are conservative.

NRC Request SPSB-A.5.b

For the remaining flooding initiators (EECW flood in reactor building – operating unit, flood from the condensate storage tank, flood from the torus, large turbine building flood and small turbine building flood), the Unit 1 frequencies are higher than the corresponding Unit 2 and 3 frequencies. Explain and provide a basis for these differences.

TVA Reply to SPSB-A.5.b

Each of the IEs are discussed below.

EECW Flood in the RB – Operating Unit

The Unit 2/3 values (from the IPE) were calculated based on zero events in 1081 plant years. The Unit 1 frequency was based on a prior frequency distribution based on 0.5 (consistent with recommended practice with zero events) events in 740 reactor operating years. The 1081 plant years included shutdown data not applicable to this initiator. The impact was to slightly increase the flood frequency. A Bayesian update was then performed to incorporate BFN plant specific data (0 events in 13.78 plant operating years) and the plant availability factor was applied. The failure probability for the operator action to isolate the flood was not changed. The result is a Unit 1 initiator frequency approximately 10% higher than the IPE values used in the Unit 2 and Unit 3 models.

Flood from the Condensate Storage Tank

The Unit 2/3 values (from the IPE) were calculated based on one event in 1081 plant years. The Unit 1 frequency was based on a prior frequency distribution based on 1 events in 740 reactor operating years. The impact was to slightly increase the flood frequency. A Bayesian update was then performed to incorporate BFN plant specific data (0 events in 13.78 plant operating years) and the plant availability factor was applied. The failure probability for the operator action to isolate the flood was not changed. The result is a Unit 1 initiator frequency approximately 25% higher than the IPE values used in the Unit 2 and Unit 3 models.

Flood from the Torus

The Unit 1 frequency is consistent with the IPE calculation (i.e., 16 pipe segments, 7.5E-6 rupture frequency per segment year). The IPE value of 9.6E-5 is raised to 1.2E-4 for the Unit 1 model based on revising the availability factor from 0.8 (IPE) to 0.95 (Unit 1 PRA). Updated data was used to obtain the value of 1.34E-5 frequency (cited for the Unit 2/3 PUSAR).

Large and Small Turbine Building Floods

The Unit 2 and Unit 3 large and small turbine building flood frequencies were developed under the condition that Unit 1 was in lay-up (Unit 2 PRA with Unit 3 Operating). The Unit 1 initiating event frequencies were developed, as part of the Unit 1 PRA, under the condition that both Units 2 and 3 are operating. This leads to an increase in both large and small turbine building flood initiating event frequencies since the frequencies are directly correlated to the number of units assumed in operation.

The Units 2 and 3 model initiating event values for the large turbine building flood were not revised in the recent model updates to reflect the restart of Unit 1. The existing Units 2 and 3 IE values are acceptable based on the fact that when the IE is changed to reflect the operating state of Units 1, the IE goes from 2.2E-3 to 3.6E-3. Also the contribution of the postulated event "Large Turbine Building Floods," to the total CDF is not significant. Taking these factors into consideration, the existing model results are appropriately representative of the effects of the postulated large turbine flooding for Units 2 and 3.

Several other factors also account for small changes in the initiating event frequencies calculated for the Unit 1 PRA. The prior distribution for the small turbine building flood was based on 6 events in 740 reactor operating years. The prior distribution for the large building flood was based on one event in 740 reactor operating years. A Bayesian update was then performed to incorporate BFN plant specific data. The prior distributions were both updated with zero events in 13.78 plant operating years (instead of zero in 1.69). Also, an availability factor of 0.95 was applied (in place of 0.8).

NRC Request SPSB-A.6

Section 10.5 of Enclosure 4 of the June 28, 2004, submittal states that the Unit 1 PRA assumes that Units 2 and 3 are operational at EPU power levels. Provide the following information related to the treatment of multi-unit interactions in the Unit 1, 2, and 3 PRA models:

NRC Request SPSB-A.6.a

Describe how various combinations of plant operating states (at-power, shutdown, transition) are addressed.

TVA Reply to SPSB-A.6.a

The BFN PRAs are structured to address the plant operating states appropriately. The risk models focuses on identifying and quantifying the scenarios that could potentially occur when each of the three BFN units are at-power. The status (at-power, startup, shutdown) of each unit was evaluated to determine the potential impact on the availability of shared systems that have a role in responding to postulated events. The

availability of such equipment would be impacted if the configuration of the part of the system that could support another unit is changed (e.g., through maintenance or alignment changes). This scenario is addressed in the PRA models by considering this case in the IE probabilities. Another situation is that the mode of a unit could impact the shared systems success criteria. In practice, for this case regarding shared systems, the limiting success criteria are if each of the three BFN units is at-power.

The systems potentially impacted by configuration are under the control of each units technical specifications (e.g., RHR cross-connect) or, in practice, minimally impacted (e.g., diesel generators).

Multiple diesel generators are not voluntarily removed from service simultaneously (the same personnel at BFN perform maintenance on each generator in series). Moreover, a situation where such a need would be required is extremely unlikely. BFN historical evidence justifies a very low frequency for unplanned maintenance in general.

There is one unique situation and that is the modeling associated with the common accident signal. The logic model in the unit 1 PRA does explicitly track the status (at-power or not) of unit 2.

<u>**NRC Request SPSB-A.6.b**</u>

Describe which initiating events impact more than one unit and describe how these are modeled.

<u>**TVA Reply to SPSB-A.6.b**</u>

Multi-unit interactions have been modeled in each of the Unit 1, 2, and 3 PRA models. This modeling approach provides realistic and comprehensive PRA results for the three BFN units. Table SPSB-A.6-1 below provides information regarding the multi-unit initiating events (IEs) and how each of these IEs is modeled.

Table SPSB-A.6-1
BFN Multi-Unit Initiating Events

Initiating Event	Probabilistic Failures	Modeling
Loss of Plant Control Air	Plant Control Air Failure resulting in complete loss of control air	Fails the following components for three Units: - Drywell Control Air (Unit 3 only, Unit 2 Drywell Control is supplied from Containment Inerting System; Unit 1 will be modified prior to restart) - Outboard main steam isolation valves - Primary Containment air-

Table SPSB-A.6-1 BFN Multi-Unit Initiating Events		
Initiating Event	**Probabilistic Failures**	**Modeling**
		operated isolation valves fail based on the associated failure mode for a loss of air event - Control Rod Drive Hydraulic System flow control valves - Temperature control valves in Raw Cooling Water System
Loss of Raw Cooling Water	Raw Cooling Water System failure resulting in complete loss of the system	Fails the following for three Units: - Plant Control Air - Control Rod Drive pumps
Large Turbine Building Flood	Large pipe failure resulting in fluid loss and impact on associated equipment	Fails affected systems - Raw Cooling Water and Plant Control Air
Loss of Offsite Power	Complete loss of offsite power	All DGs challenged
Loss of 500kV Switchyard to the Plant	500kV failure	161kV system and associated transfer challenged.

NRC Request SPSB-A.6.c

Identify the systems that are shared among units and describe how these shared systems are modeled in the PRA. Specifically address when credit is taken to recover failed key safety functions by using cross-connects among units.

TVA Reply to SPSB-A.6.c

Table SPSB-A.6-2 below provides information regarding the BFN PRA modeling approach for the shared systems defined in UFSAR Appendix F. A column is included in the table to address the situations where credit is taken for shared systems to fulfill key safety functions.

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Normal Auxiliary Power (Includes Offsite and Station Sources)	500kV and 161kV are modeled	500kV and 161kV are modeled.	500kV and 161kV are modeled.	Modeling approach is consistent with the shared system configuration and operational approach.	No
Environmental Radiological Monitoring	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Control and Service Air	Control and Service Air System is modeled.	Control and Service Air System is modeled.	Control and Service Air System is modeled.	Each unit's air supplied equipment share common system components including compressors, receivers, etc. Modeling approach is consistent with the shared system configuration and operational approach.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Condenser Circulating System	Normally operated as a unitized system.	Normally operated as a unitized system.	Normally operated as a unitized system.	Modeling approach is consistent with the shared system configuration and normal operational configuration.	No
Raw Cooling Water	Common to Units 1, 2, and 3 operational loads.	Common to Units 1, 2, and 3 operational loads.	Common to Units 1, 2, and 3 operational loads.	Modeling approach is consistent with the shared system configuration and normal operational configuration.	No
Raw Service Water	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Radioactive Waste Control	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Drywell Equipment and Floor Drain	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Fire Protection	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Condensate Storage and Transfer	Normally operated as a unitized system.	Normally operated as a unitized system.	Normally operated as a unitized system.	Modeling approach is consistent with the normal operational configuration.	No
Potable Water and Sanitary	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Auxiliary Boiler	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Plant Communications	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Lighting	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Plant Preferred and Nonpreferred AC	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Auxiliary DC Power Supply and Distribution	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Demineralized Water	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Reactor Building and Closed Cooling Water System	Modeling not required.	Modeling not required.	Modeling not required.	Normally operated as unitized with a common spare pump and heat exchanger. A loss of RBCCW would result in a unit trip. It is not uniquely modeled but tacitly included the unit trips are evaluated as IEs on a statistical basis.	No
Reactor Building Equipment and Floor Drain	Modeling not required.	Modeling not required.	Modeling not required.	A common drain header is the only portion of the system that is shared.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Hardened Wetwell Vent	In the PRA model as a unitized feature.	In the PRSA model as a unitized feature.	In the PRA model as a unitized feature.	Shared portioned in common header to the stack.	No
Control Bay HVAC	Modeling not required.	Modeling not required.	Modeling not required.	Loss of Control Bay HVAC not modeled due to low frequency and remote shutdown facilities.	No
Spent Fuel Storage Facilities	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Reactor Building Crane	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No
Process Radiation Monitoring	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Standby AC Power Supply and Distribution	Shared equipment includes the 4160-kV Shutdown Boards and Shutdown Buses. Also a portion of the electrical distribution configuration is unitized including the 480-V boards.	Shared equipment includes the 4160-kV Shutdown Boards and Shutdown Buses. Also a portion of the electrical distribution configuration is unitized including the 480-V boards.	Shared equipment includes the 4160-kV Shutdown Boards and Shutdown Buses. Also a portion of the electrical distribution configuration is unitized including the 480-V boards.	Modeling approach is consistent with the shared system configuration and operational approach.	Yes – Credit is taken in the PRA model for shared systems between units consistent with the physical configuration, procedures, and operator training.
250V DC Power Supply and Distribution	Shared equipment includes the 250V DC Batteries. Also the portion of the 250V electrical distribution configuration in unitized including the 250V boards.	Shared equipment includes the 250V DC Batteries. Also the portion of the 250V electrical distribution configuration in unitized including the 250V boards.	Shared equipment includes the 250V DC Batteries. Also the portion of the 250V electrical distribution configuration in unitized including the 250V boards.	Modeling approach is consistent with the shared system configuration and operational approach.	Yes – Credit is taken in the PRA model for shared systems between units consistent with the physical configuration, procedures, and operator training.
Subsections of the Heating and Ventilating, Ventilation, and Air-Conditioning Systems	Modeling not required.	Modeling not required.	Modeling not required.	This is Control Building cooling which is not modeled due to low occurrence probability and affect.	No
Control rod Drive (shared portion not Class I)	Units 1 and 2 share a pump.	Units 1 and 2 share a pump.	Unit 3 has 2 dedicated pumps.	Each unit models CRD injection.	No

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Gaseous Radwaste	Modeling not required.	Modeling not required.	Modeling not required.	Not modeled because the system does not provide a causal relationship that supports safe operation or shutdown of the unit	No
Standby Coolant	Unit 1 and Unit 2 shared piping modeled in PRA.	Unit 1, Unit 2, and Unit 3 shared piping modeled in PRA.	Unit 2 and 3 shared piping modeled in PRA.	Modeling approach is consistent with the shared system configuration and operational approach.	Yes – Credit is taken in the PRA model for shared systems between units consistent with the physical configuration, procedures, and operator training.
RHR Service Water	System is configured to support all three units and is modeled consisted with the physical configuration.	System is configured to support all three units and is modeled consisted with the physical configuration.	System is configured to support all three units and is modeled consisted with the physical configuration.	Modeling approach is consistent with the shared system configuration and operational approach.	Yes – Credit is taken in the PRA model for shared systems between units consistent with the physical configuration, procedures, and operator training.

Table SPSB-A.6-2 BFN Shared System Modeling Approach					
Shared System (From UFSAR Appendix F)	**Unit 1 Modeling Approach**	**Unit 2 Modeling Approach**	**Unit 3 Modeling Approach**	**Basis for Modeling Approach**	**Credit Taken for Shared System?**
Emergency Equipment Cooling Water System	System is configured to support all three units and is modeled consisted with the physical configuration.	System is configured to support all three units and is modeled consisted with the physical configuration.	System is configured to support all three units and is modeled consisted with the physical configuration.	Modeling approach is consistent with the shared system configuration and operational approach.	Yes – Credit is taken in the PRA model for shared systems between units consistent with the physical configuration, procedures, and operator training.
Standby Gas Treatment	Modeling not required.	Modeling not required.	Modeling not required.	Does not have any use regarding core damage scenarios.	No

NRC Request SPSB-A.7

Provide the detailed human reliability analysis (HRA) calculation sheets, (e.g., as generated by the Electric Power Research Institute (EPRI) HRA calculator) for all human interactions ("operator actions") that have a Fussell-Vesely importance measure greater than 0.005 or a risk-achievement worth greater than 2. Include a discussion of how performance shaping factors were modified for the Unit 1 human reliability analysis to account for new procedures, lack of familiarity with Unit 1 equipment, the potential for "wrong unit" errors, and other factors unique to starting up a plant that has not operated in almost two decades.

TVA Reply to SPSB-A.7

Table SPSB-A.7-1 below lists the BFN Unit 1 actions with a Fussell-Vesely importance measure greater than 0.005 or a risk-achievement worth greater than 2.

The human failure events (HFEs) for Unit 1 actions were evaluated utilizing the Electric Power Research Institute (EPRI) HRA Calculator®, whereas those for Units 2 and 3 had been evaluated using a combination of a failure likelihood index methodology and manual application of methodologies now incorporated into the EPRI HRA calculator. The EPRI HRA calculator provides a structured means of recording and applying performance shaping factors. Therefore, it constitutes an improvement in the HRA task,

and the Unit 2 and 3 performance shaping factors were not used as a basis for Unit 1 HFEs

Performance shaping factors were not required to be modified for the Unit 1 human reliability analysis to address issues associated with the Unit 1 restart. The Unit 1 PRA is not a "startup" PRA. It is a PRA that estimates the annual average CDF and LERF just like the Unit 2 and 3 PRAs. The operators at BFN are not unit specific. They are trained and qualified on all three units. The operators for Unit 1 will be drawn from a pool experienced in operating Units 2 and 3. Only minor differences exist between the three units as reflected in a common Updated Final Safety Analysis Report (UFSAR) and similar Technical Specifications (TSs). The training emphasizes differences between the units. The procedures for Unit 1 are the same or similar to the Units 2 and 3 procedures. It is not necessary to modify the performance shaping factors for Unit 1 operation. The Human Reliability Analysis Sheets for these actions are provided in Appendix B of this response.

Table SPSB-A.7-1
BFN Unit 1 Significant Human Failure Events

Basic Event Name	Fussell-Vesely Importance	Risk Achievement Worth	Basic Event Description
HPRVD1	2.97E-01	1462	OPERATOR FAILS TO INITIATE DEPRESSURIZATION
HRWWV1	2.22E-01	6.31	OPERATOR FAILS TO ALIGN WETWELL VENT PATH
HRSPC1[1]	1.31E-01	1793	OPERATOR LOCAL RECOVERY OF SP COOLING FAILURE
HRRHRX	2.45E-02	< 2	OPERATORS ALIGN THE RHR UNIT 1/UNIT 2 CROSSTIE
HPHPE1	2.05E-02	8.39	OPERATOR FAILS TO CONTROL LEVEL WITH RCIC/HPCI (EARLY - 6 HOURS)
HPHPR1	1.65E-02	5.58	OPERATORS FAIL TO RECOVER AND CONTROL HPCI/RCIC AFTER L8
HPTAF1	1.40E-02	2.05	OPERATORS MAINTAIN LEVEL ABOVE TOP OF ACTIVE FUEL (ATWS)
HPSIV1	1.00E-02	< 2	OPERATORS DEFEAT MSIV INTERLOCK DURING ATWS
HPSPC1	9.07E-03	2.23	OPERATOR FAILS TO ALIGN RHR FOR SUPPRESSION POOL COOLING (NON-ATWS)

1. The HRA Calculator Report format was not used for this action. This is the local action to align suppression pool valves, given HPSPC1 succeeds (operators attempt to align), but the valve motor failure is recoverable. Screening Value = 0.1 was assigned to account for the fraction of valve failures that the operators will be unable to recover through local actions, either because the valve stem is broken or the valve is jammed, or the operators encounter physical difficulties they can not overcome in the time available. The action is not discussed explicitly in the HRA, since the success of HPSPC1 indicates the operators are trying to establish cooling and hours are available to manually align the required valves.

NRC Request SPSB-A.8

Provide a discussion of large early release frequency (LERF) from external events or a basis for concluding that any increases due to EPU are not significant.

TVA Reply to SPSB-A.8

Potential vulnerabilities due to external events were formally evaluated in accordance with the guidance contained in Generic Letter 88-20, Supplement 4, as part of the BFN IPEEE program. The table below lists the industry sanctioned and acceptable approach used at BFN to evaluate each category of external event.

Table SPSB-A.8-1
External Events Evaluation Methodology

External Event Category	Methodology
Seismic Events	EPRI Seismic Margins
Internal Fire	EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology
High winds	Progressive screening and plant walkdown leading to a bounding analysis
External Floods	Progressive screening and plant walkdown
Transportation and nearby facility accidents	Progressive screening and plant walkdown

Regarding seismic events, the implementation of EPU does not adversely impact the conclusion previously made regarding seismic margins. Please refer to the BFN response to NRC Request SPSB-A.14 for additional information.

BFN uses the EPRI Fire Induced Vulnerability Evaluation (FIVE) process to evaluate internal fires. Please refer to the BFN response to NRC Request SPSB-A.13 for additional information.

For the last three external event categories, the IPEEE evaluation found that no plant-unique accident sequences different from those determined by the IPE for internal events were predicted or identified. In addition, any impacts of potential maximum physical impact fell below the screening criteria for further evaluation. Therefore, it was concluded that no additional containment performance assessment was needed, and absolute numerical values for CDF and LERF were not required.

NRC Request SPSB-A.9

The frequency-weighted fractional importance to core damage of operator action HORVD2, Manual depressurization of reactor pressure vessel using MSRVs, for the post-EPU plant is 55 percent for Unit 2 and 43 percent for Unit 3 CDF. For Unit 1, the corresponding operator action appears to be HPRVD1, Operator fails to initiate depressurization, which has a frequency-weighted fractional importance to core damage of 26.7 percent. Explain, in detail, why these apparently similar events have such different importance to core damage in light of the similarity of the PRA models. Also, describe the programmatic activities (e.g., training) intended to make this operator action reliable.

TVA Reply to SPSB-A.9

Because the post-EPU models showed a relatively high importance for manual depressurization, sequences where manual depressurization failed were scrutinized for the Units 1, 2, and 3 PRAs. The sequences are characterized by:

1. A loss of feedwater,
2. A common cause failure (CCF) of HPCI and RCIC, and
3. A failure to depressurize.

The Unit 1 operator action corresponding to Units 2 and 3 action HORVD2 is HPRVD1.

Additional information regarding the HRA analysis approach and results is provided in the response to NRC Request SPSB-A.7.

Each of the BFN PRAs was updated since the original EPU licensing applications to incorporate enhancements. As a result of these updates, the fractional importance and Fussell-Vesely (FV) importance values have changed.

The Fractional importance and Fussell-Vesely (FV) importance both reflect the "weight" of a variable in the CDF sequences. In the revised Units 1 and 2 PRAs, the fractional importance for the operator action to depressurize are similar and now have values of 0.280 for Unit 1 and 0.293 for Unit 2. Unit 3 has a slightly higher CDF than the other Units, principally due to LOOP sequences, and this accounts for the Unit 3 value of 0.166. These values reflect an acceptable variation between the units and also represent absolute values that are consistent with the relative importance of this human action.

Licensed operator training at Browns Ferry reviews the circumstances and events that would require emergency depressurization in the classroom annually. In addition, the operator requalification training includes a number of scenarios run over the course of the training cycle that require emergency depressurization. Therefore, BFN is assured

that operators are adequately trained to recognize and perform emergency reactor vessel depressurization if required.

NRC Request SPSB-A.10

Section 10.5.3 of Enclosure 4 of the June 28, 2004, submittal states:

> Recovery actions take credit for those actions performed by the on-shift personnel either in response to procedural direction or as skill-of-the-craft to recover a failed function, system or component that is used in the performance of a response action in dominant sequences.

Does this include repair of failed equipment? If yes:

a. Provide a list of repair events credited in each PRA model, including the basis for the non-recovery probabilities used.

b. How have these repair human error probabilities been adjusted as the result of EPU?

c. Provide a sensitivity of CDF and LERF to repair activities, if credited, by removing all credit for repair of failed equipment.

TVA Reply to SPSB-A.10

The recovery actions in accident sequences of the PRA take no credit for repair of systems or components that failed earlier in that sequence.

NRC Request SPSB-A.11

As part of its EPU submittal, the licensee has proposed taking credit (Unit 1) or extending the existing credit (Units 2 and 3) for containment accident pressure to provide adequate net positive suction head (NPSH) to the ECCS pumps. Section 3.1 in Attachment 2 to Matrix 13 of Section 2.1 of RS-001, Revision 0 states that the licensee needs to address the risk impacts of the extended power uprate on functional and system-level success criteria. The staff observes that crediting containment accident pressure affects the PRA success criteria; therefore, the PRA should contain accident sequences involving ECCS pump cavitation due to inadequate containment pressure. Section 1.1 of Regulatory Guide (RG) 1.174 states that licensee-initiated licensing basis change requests that go beyond current staff positions may be evaluated by the staff using traditional engineering analyses as well as a risk-informed approach, and that a licensee may be requested to submit supplemental risk information if such information is not submitted by the licensee. It is necessary to consider risk insights, in addition to the results of traditional engineering analyses, while determining the regulatory acceptability of crediting containment accident pressure.

Considering the above discussion, please provide an assessment of the credit for containment accident pressure against the five key principles of risk-informed decision-making stated in RG 1.174 and SRP Chapter 19. Specifically, demonstrate that the proposed containment accident pressure credit meets current regulations, is consistent with the defense-in-depth philosophy, maintains sufficient safety margins, results in an increase in core-damage frequency and risk that is small and consistent with the intent of the Commission's Safety Goal Policy Statement, and will be monitored using performance measurement strategies. With respect to the fourth key principle (small increase in risk), provide a quantitative risk assessment that demonstrates that the proposed containment accident pressure credit meets the numerical risk acceptance guidelines in Section 2.2.4 of RG 1.174. This quantitative risk assessment must include specific containment failure mechanisms (e.g., liner failures, penetration failures, primary containment isolation system failures) that cause a loss of containment pressure and subsequent loss of NPSH to the ECCS pumps.

TVA Reply to SPSB-A.11

As discussed in the cover letter, this response will be provided in a future submittal.

NRC Request SPSB-A.12

Section 10.1.3 of Enclosure 4 of the June 28, 2004, submittal states that the mass release for reactor water cleanup breaks was calculated using the 30-psi reactor pressure increase, and that the safety-related equipment was evaluated for effects. Was the PRA flooding study updated to reflect this flooding rate? Was the impact of the flood on non-safety related equipment credited in the PRA determined and factored into the risk assessment?

TVA Reply to SPSB-A.12

The RWCU system does not release sufficient inventory of fluid prior to automatic isolation to cause damage to equipment due to flooding. Therefore, the PRA does not model flooding from the RWCU. The PRA does include consideration of flooding from sources of large quantities of fluids from postulated pipe breaks from systems such as the EECW system and the CST piping inside the reactor building. This approach bounds the fluid loss from the RWCU system for flooding considerations. The EECW system and the CST piping inside the reactor building do not experience any flow rate or pressure changes as a result of EPU implementation.

NRC Request SPSB-A.13

The existing fire risk evaluations are based on the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology, which uses a quantitative screening criterion of 10^{-6} per year. This screening criterion appears too large because the core-damage frequency

from internal events is of the same order of magnitude. As the fire risk evaluations for Units 2 and 3 have not been updated since the individual plant external event evaluation was performed, provide an updated FIVE analysis for Unit 1 that reflects the post-EPU plant configuration and uses an appropriate screening criterion.

<u>TVA Reply to SPSB-A.13</u>

The EPRI FIVE methodology calls for 1E-6 as a quantitative screening criterion to distinguish critical fire area/zones vs. non-critical fire area/zones for fire vulnerability. This EPRI quantitative screening criterion remains valid when compared to the CDF from internal events calculated for BFN. However, TVA performed an evaluation of the fire area/zones previously screened out to respond to this concern, and determined that the use of 1E-6 as a quantitative screening criterion had no adverse impact on the FIVE analysis results.

The BFN Unit 1 FIVE analysis was transmitted to the NRC by letter dated January 14, 2005, (Reference 38) and was performed based on Unit 1 post-EPU configuration. Quantitative screening was performed for each fire area/zone assuming all the fire initiating components as well as "target" cables and equipment are damaged by fire. If the fire induced core damage frequency (CDF) was less than 1E-6 for a fire in a particular area/zone, no further analysis was performed. If it was greater than 1E-6 for a fire area/zone, then detailed fire analyses for fire initiating components were performed, resulting in component related fire scenarios and associated CDF. When the total fire-induced frequency was summed, the CDF contributions from both "screened" fire area/zones and fire area/zones with detailed analysis were included.

The CDF contributions for the "screened" fire area/zones were typically well below the quantitative screening criteria of 1E-6. The table below contains excerpts from Table 5-2 (Reference 38) identifying the CDF contributions for the screened fire area/zones. As shown in the below table, the CDF associated with the screened fire area/zones range from 1E-9 to 1E-7, with four fire area/zones having CDF contribution values greater than 1E-7. It can be observed that Fire Area/Zone 24, 4kV tie board room has the highest CDF of 6.6E-7.

Upon further examination of the analysis performed for Fire Area/Zone 24, there is no Unit 1 related equipment in this fire area/zone. However, during review of the potential failure modes of the 4kV tie board, it was identified that a conceivable failure of shutdown buses 1 and 2 could occur, similar to a loss of offsite power, though offsite power would remain available to the balance of plant loads. For this level of analysis, all fires in this area are therefore conservatively modeled as a loss of all offsite power (initiating event LOSP). It can be argued that the "true" CDF associated with Fire Area/Zone 24 should be less than 6.6E-7. Hence, "screening" this fire area/zone from detailed analysis is justified.

Excerpt from Table 5-2 (Reference 38) Fire Induced CDF Summary for Screened Fire Area/Zones		
Fire Area/Zone	**Description**	**Fire Area CDF**
6	**480V Shutdown Board Room 1A (Unit 1 Reactor Building, 621' Elevation)**	1.11E-07
8	4kV Shutdown Board Room D (Unit 2 Reactor Building, 593' Elevation)	5.83E-09
10	480V Shutdown Board Room 2A (Unit 2 Reactor Building, 621' Elevation)	1.07E-08
11	480V Shutdown Board Room 2B (Unit 2 Reactor Building, 621' Elevation)	4.39E-09
12	Shutdown Board Room F (Unit 3 Reactor Building, 593' Elevation)	1.09E-08
13	Shutdown Board Room E (Unit 3 Reactor Building, 621' Elevation)	5.41E-09
14	480V Shutdown Board Room 3A (Unit 3 Reactor Building, 621' Elevation)	4.83E-09
15	480V Shutdown Board Room 3B (Unit 3 Reactor Building, 621' Elevation)	5.17E-09
17	**Unit 1 Battery and Battery Board Room, Control Building 593' Elevation**	2.35E-07
18	Unit 2 Battery and Battery Board Room, Control Building 593' Elevation	1.43E-08
19	Unit 3 Battery and Battery Board Room, Control Building 593' Elevation	2.62E-08
20	Unit 1 and 2 Diesel Generator Building	4.56E-08
21	**Unit 3 Diesel Generator Building**	1.09E-07
22	4kV Shutdown Board Room 3EA and 3EB, 583' Elevation, Unit 3 Diesel Generator Building	7.01E-09
23	4kV Shutdown Board Room 3EC and 3ED, 583' Elevation, Unit 3 Diesel Generator Building	1.03E-08
24	**4kV Bus Tie Board Room, 565' Elevation, Unit 3 Diesel Generator Building**	6.60E-07

NRC Request SPSB-A.14

Enclosure 7 of the June 28, 2004, submittal identifies planned modifications of the drywell building steel (building steel beams and connections), main steam supports, and torus attached piping (supports and snubbers) due to the EPU conditions. With respect to these planned modifications, address the following issues:

NRC Request SPSB-A.14.a

Confirm that these planned modifications will not change the high confidence of low probability of failure values used in the seismic margins analysis.

TVA Reply to SPSB-A.14.a

The analysis of building steel (beams and connections), main steam supports, and torus attached piping (supports and snubbers) have been or will be performed in accordance with the BFN design criteria for the planned modifications. The design criteria specifies the loads and load combinations to apply in the design calculations. The loads associated with EPU are being incorporated into the analyses of these features, in combination with the other applicable loading as prescribed by the design criteria. Consequently, the planned modifications will not change the high confidence of low probability of failure (HCLPF) values as determined by the seismic margins analysis.

NRC Request SPSB-A.14.b

Describe the impact that the proposed modifications have on the probability distribution function of containment strength used in the LERF analysis.

TVA Reply to SPSB-A.14.b

A probabilistic containment failure analysis for Unit 1 was performed to determine the probability distribution function of containment strength used in the LERF analysis. Proposed structural modifications to the torus and drywell structural steel have no impact on the dominant failure modes for this analysis, because these modifications are being performed to maintain sufficient design margin in these components at EPU conditions.

NRC Request SPSB-A.15

Explain why LERF is less than CDF for interfacing system LOCAs.

TVA Reply to to SPSB-A.15

The IE ISLOCA accident sequence analysis includes an end-state of "core damage with small bypass" of primary containment. Therefore, some of the CDF sequences go to the

"core damage with small bypass' end-state and not the LERF end-state. This modeling approach is consistent with the guidance provided in the ASME Standard for PRA (Reference 24) and results in the situation where the CDF is greater than LERF.

NRC Request SPSB-A.16

TVA has previously requested a full-scope application of an alternative source term. As part of this request, it was proposed that the standby liquid control system be used to help control suppression pool pH during severe accidents. Has suppression pool pH control been credited in the LERF analysis? If so, provide the details.

TVA Reply to SPSB-A. 16

Suppression pool pH control using the Standby Liquid Control (SLC) System has not been credited in the LERF analysis for BFN. SLC injection of sodium pentaborate solution assists in buffering suppression pool pH thereby preventing accident iodine fission product re-evolution from the pool to the containment. This use of the SLC system does not adversely impact the BFN severe accident management program, i.e., it has no effect on initiating events or equipment requirements to mitigate core damage. Therefore, it is not relevant to the concept of core damage and large releases as analyzed in the BFN PRA.

NRC Request SPSB-A.17

Describe the operator actions considered in the estimation of LERF. How are the Severe Accident Management Guidelines accounted for in the LERF analysis?

TVA Reply to SPSB-A.17

The operator actions considered in the LERF analysis are all associated with implementing the Severe Accident Management Guidelines (SAMGs). These actions are provided in the table below.

Table SPSB-A.17-1
Operator Actions Considered In LERF Analysis

Action	Comment
Depressurize Reactor Pressure Vessel (RPV)	Late depressurization or maintaining successful depressurization from level 1. This allows use of low pressure injection systems to inject to the RPV to prevent or mitigate continued core melt progression and, prevention of high pressure blowdown induced failure modes of containment if the RPV is breached.
RPV Injection	Post core damage injection with Core Spray or RHR in the LPCI mode. Injection of water into the vessel can mitigate the consequences of a core melt by preventing or substantially mitigating containment challenges.

Table SPSB-A.17-1 Operator Actions Considered In LERF Analysis	
Action	**Comment**
Drywell Spray	RHR in the Drywell Spray mode. The spray system can be employed to accomplish two important functions: (1) scrubbing fission products that are not otherwise scrubbed and, (2) providing water to cool the core debris on the drywell floor to limit non-condensable gas generation and to limit drywell heating and the associated temperature induced failures that can lead to containment failure.
Containment Flooding	Entry into the SAMGs calls for flooding of containment from external water sources. Prior to vessel breach, limitations are imposed to maintain the pressure suppression function by terminating containment flooding within the torus. After vessel breach has been identified, the operators are requested to once again flood containment. Flooding of containment has desirable effects of cooling the core debris, maintaining a low drywell temperature, and scrubbing airborne fission products and fission products from the melt release.

NRC Request SPSB-A.18

Address the questions in the SRP, Chapter 19, Table III-1 concerning low power and shutdown PRA.

TVA Reply to SPSB-A.18

BFN does not have a low power or shutdown PRA. Therefore, the SRP questions relating to low power and shutdown PRA are not applicable. BFN uses the EPRI Outage Risk Assessment and Management (ORAM) technology software. This evaluation process assists with maintaining adequate defense-in-depth of safety functions when planning and conducting outages.

NRC Request SPSB-A.19

With respect to the technical adequacy of the Unit 1 PRA, the letter from T. E. Abney, TVA, to the U.S. Nuclear Regulatory Commission, "Browns Ferry Nuclear Plant (BFN) - Unit 1 - Response to Request for Additional Information Related to Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerability," dated August 17, 2004, states:

Since the Unit 1 PSA was built from the Units 2 and 3 PSAs, which incorporate the resolution of the peer review comment, the Unit 1 PSA has incorporated the findings of the Units 2 and 3 PRAs Peer Review. Thus, the previously conducted Peer Review was effectively an administrative and technical Peer Review of the Unit 1 PSA. Similar models, processes, policies, approaches, reviews, and management oversight were utilized to develop the Unit 1 PSA.

RG 1.174, Section 2.2.3.3, states

> In the current context, technical acceptability will be understood as being determined by the adequacy of the actual modeling and the reasonableness of the assumptions and approximations.

In order to assess the "adequacy of the actual modeling" in the Unit 1 PRA, it is necessary to review the actual Unit 1 PRA model.

Provide an assessment of the PRA's technical adequacy as discussed in RG 1.200. Note that it is acceptable to perform the assessment by making either (a) a direct assessment against the requirements of the ASME PRA Standard Addendum A (ASME SA-Ra-2003), or (b) a self-assessment using the guidance issued on August 16, 2002, by the Nuclear Energy Institute (NEI) that supplements NEI 00-02.

TVA Reply to SPSB-A.19

TVA has no immediate plans to perform a self-assessment of the BFN Unit 1 PRA. As discussed in Section 10.5.7 of Enclosure 4 (PUSAR) of the initial application (Reference 1), the BFN Unit 1 PSA was developed to be consistent with ASME RA-S-2002, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications." The BFN Unit 1 PRA was developed by an outside expert under the TVA Quality Assurance Program, and was independently reviewed by TVA. Accordingly, the BFN Unit 1 PRA was initially developed, and via its own internal review and approval process, already assessed against the requirements of the American Society of Mechanical Engineers (ASME) standard.

As further discussed in Section 10.5.7 of the PUSAR, and expanded upon in TVA's August 17, 2004, letter submitted to support closure of NRC Generic Letter 88-20 for BFN Unit 1 (Reference 39), the BFN Unit 1 PRA was built based on the BFN Units 2 and 3 PRAs, and modified as required to be consistent with the ASME standard. The BFN Units 2 and 3 PRAs were peer-reviewed to the BWROG peer review certification process, and the observations identified during that process resolved. The specific observations identified during that certification review were provided to the NRC in Reference 39. Accordingly, the development of the Unit 1 PRA based on the BFN Units 2 and 3 PRAs addressed and resolved at the outset, the results of the BFN Units 2 and 3 peer review process.

TVA's application for extended power uprate is not a risk-informed application as defined in Regulatory Guide 1.174, in that this application does not "go beyond current staff positions." The BFN Unit 1 application was developed consistent with NRC-established positions as documented, largely, in the PUSAR accompanying that application. Notwithstanding this position, TVA recognizes the value that risk insights, based on a high-quality PRA model, adds to the process of evaluating plant operation including evaluating plant changes. Accordingly, TVA actively uses, performs on-going

reviews, and revises the BFN PRA models. It was this process that led to TVA's update of BFN Unit 1 PRA by letters dated August 23, 2004 and September 15, 2005.

NRC Request SPSB-A.20

Provide a list of the significant basic events contained in the PRA logic model (including both the basic event name, the basic event description, the Fussell-Vesely importance measure and the Risk Achievement Worth) for the post-EPU plant configuration. Note that term "significant basic event" is defined in RG 1.200, Appendix A, Table A-1, Index Number 2.2.

TVA Reply to SPSB-A.20

The following tables provide significant basic events by Fussell-Vesely (FV) importance and by Risk Achievement Worth (RAW), respectively. Note that the list for the RAW is significantly longer than for FV. The reason for this is the definition of RAW where a highly reliable basic event is assumed to fail with a probability of 1.0. Changing a probability by orders of magnitude can have a significant impact on the results.

BFN Unit 1 Significant Basic Events by Fussell-Vesely Importance Measure			
Rank	**Basic Event**	**Description**	**Fussell-Vesely Importance**
1	HER_HPRVD1	OPERATOR FAILS TO INITIATE DEPRESSURIZATION	2.9726E-001
2	HER_HPWWV1	OPERATOR FAILS TO ALIGN WETWELL VENT PATH	2.2165E-001
3	CONDENSER_2A2B2C	MAIN CONDENSER UNAVAILABLE AFTER PLANT TRIP	1.4339E-001
4	[MOVFO1FCV0230034 MOVFO1FCV0230040 MOVFO1FCV0230046 MOVFO1FCV0230052]	COMMON CAUSE FAILURE OF RHRSW RHR VALVES	1.3587E-001
5	HER_HRSPC1	OPERATOR LOCAL RECOVERY OF SP COOLING FAILURE	1.3058E-001
6	PTSFS1PMP0730054	HPCI PUMP FAILS TO START ON DEMAND	1.0241E-001
7	PTSFR1PMP71019_6	RCIC PUMP FAILS TO RUN	1.0143E-001
8	GEL_SOV_CF_PSOVS	CCF 33% OR MORE HCU SCRAM PILOT SOVs OR BACKUP SOVs FAILS	8.5654E-002
9	PTSFS1PMP0710019	RCIC PUMP FAILS TO START ON DEMAND	7.5660E-002
10	PTSFR1PMP73054_6	HPCI PUMP FAILS DURING OPERATION	6.4956E-002
11	[DGFTS_1_DG3A]	DG 3A FAILS TO START; DG 3A FAILS TO RUN; DG 3A BREAKER 1838 FAI	5.7396E-002
12	RHR1CCF	FAILURE OF U2 RHR PUMPS AFTER ALL U1 PUMPS HAVE FAILED	5.6984E-002
13	[DGFTS_1_DGA]	DG A FAILS TO START; DG A FAILS TO RUN; DG A BREAKER 1818 FAILS	4.8775E-002

BFN Unit 1 Significant Basic Events by Fussell-Vesely Importance Measure			
Rank	**Basic Event**	**Description**	**Fussell-Vesely Importance**
14	[MOVFO1FCV0740057 MOVFO1FCV0740059 MOVFO1FCV0740071 MOVFO1FCV0740073]	COMMON CAUSE FAILURE RHR SP COOLING VALVES	4.8216E-002
15	[DGFTS_1_DGA DGFTS_1_DGB DGFTS_1_DGC DGFTS_1_DGD]	COMMON CAUSE FAILURE OF UNIT 1/2 DGS	4.0526E-002
16	[DGFTS_1_DGB]	DG B FAILS TO START OR DG B FAILS TO RUN OR DG B BREAKER 1822 FA	3.4340E-002
17	MOVFC1FCV0710034	RCIC MINI-FLOW VALVE FAILS TO CLOSE ON DEMAND	3.0063E-002
18	[MOVFO1FCV0710008]	RCIC STEAM ADMISSION VALVE FAILS TO OPEN ON DEMAND	2.7629E-002
19	[MOVFO1FCV0710039]	RCIC DISCHARGE VALVE FAILS TO OPEN ON DEMAND	2.7629E-002
20	BE_HOU11	OPERATORS ALIGN THE RHR UNIT 1/UNIT 2 CROSSTIE	2.4451E-002
21	PTSFS1CCF_RCIHPI	RCIC AND HPCI PUMPS COMMON CASUE FAILURE TO START	2.4413E-002
22	[MOVFO1FCV0740073]	RHR SP VALVE FAILS TO OPEN	2.2049E-002
23	[MOVFO1FCV0740071]	RHR SP VALVE FAILS TO OPEN	2.2049E-002
24	MOVFO1FCV0730036	HPCI TEST RETURN VALVE	2.0622E-002
25	HER_HPHPE1	OPERATOR FAILS TO CONTROL LEVEL WITH RCIC/HPCI (EARLY - 6 HOURS)	2.0466E-002
26	[MOVXC1FCV0730036]	HPCI TEST RETURN VALVE	1.8947E-002
27	MOVFO1FCV0730027	SUCTION PATH FROM SUPPRESSION POOL FAILS	1.8374E-002
28	MOVFO1FCV0730035	RETURN TEST LINE FOR HPCI FAILS	1.8374E-002
29	MOVFO1FCV0730026	PATH FROM SP RING HEADER TO HPCI SUCTION FAILS	1.8374E-002
30	MOVFC1FCV0730040	PATH FROM SP RING HEADER TO HPCI SUCTION FAILS	1.8374E-002
31	[DGFTS_1_DGC]	DG C FAILS TO START; DG C FAILS TO RUN; DG C BREAKER 1818 FAILS	1.8354E-002
32	PTSFR1CCF_RCIHPI	CCF TO RUN HPCI AND RCIC PUMPS	1.7286E-002
33	[MOVFO1FCV0730016]	HPCI STEAM SUPPLY FAILS	1.6880E-002
34	[MOVFO1FCV0730044]	HPCI PUMP DISCHARGE PATH FAILURE	1.6880E-002
35	[MOVXC1FCV0730035]	HPCI RETURN LINE TO CST FAILED	1.6880E-002
36	[MOVFO1FCV0710008 MOVFO1FCV0730016]	CCF TO OPEN FAILS RCIC AND HPCI STEAM SUPPLY	1.6796E-002
37	[MOVFO1FCV0710039 MOVFO1FCV0730044]	CCF TO OPEN CAUSES RCIC AND HPCI DISCHARGE FAILURE	1.6796E-002
38	HER_HPHPR1	OPERATORS FAIL TO RECOVER AND CONTROL HPCI/RCIC AFTER L8	1.6467E-002
39	PTSFR1PM73054_18	RCIC TURBINE PUMP FAILS TO RUN	1.4238E-002
40	[DGFTS_1_DGA DGFTS_1_DGB DGFTS_1_DGC]	CCF TO START DGS A, B, AND C	1.4208E-002

BFN Unit 1 Significant Basic Events by Fussell-Vesely Importance Measure			
Rank	**Basic Event**	**Description**	**Fussell-Vesely Importance**
41	BE_HPTAF1	OPERATORS MAINTAIN LEVEL ABOVE TOP OF ACTIVE FUEL (ATWS)	1.3959E-002
42	[MOVFO1FCV0740059]	FAILURE TO OPEN 74-57 FOR RHR LOOP I SP COOLING	1.3183E-002
43	[MOVFO1FCV0740057]	FAILURE TO OPEN 7474-57 FOR RHR LOOP I SP COOLING	1.3183E-002
44	[MOVFO1FCV0710034 MOVXC1FCV0710038 MOVXC1FCV0730035 MOVXC1FCV0730036]	MOV FAILURES RESULT IN FAIURE OF BOTH HPCI AND RCIC	1.3003E-002
45	GEL_ROD_CF_CRD	CCF 33% OR MORE RODS FAIL TO INSERT	1.2552E-002
46	[PMSFS1PMP074001B]	RHR PUMP B FAILS TO START	1.2408E-002
47	PTSFR1PM71019_18	RCIC PUMP FAILS TO RUN FOR 18 HOURS	1.2330E-002
48	[MOVFO1FCV0230034]	RHR HX RHRSW VALVE 24 FAILS TO OPEN	1.0882E-002
49	BE_HOAL2	LOWER & CONTROL LEVEL DURING ATWS (UNISOLATED RPV)	1.0872E-002
50	[MOVFO1FCV0740059 MOVFO1FCV0740071]	CCF TO OPEN RHR SUPPRESSION POOL VALVES BOTH LOOPS	1.0723E-002
51	[MOVFO1FCV0740059 MOVFO1FCV0740073]	CCF TO OPEN RHR SUPPRESSION POOL VALVES BOTH LOOPS	1.0723E-002
52	[MOVFO1FCV0740057 MOVFO1FCV0740071]	CCF TO OPEN RHR SUPPRESSION POOL VALVES BOTH LOOPS	1.0723E-002
53	[MOVFO1FCV0740057 MOVFO1FCV0740073]	CCF TO OPEN RHR SUPPRESSION POOL VALVES BOTH LOOPS	1.0723E-002
54	BE_HOSV1	OPERATORS DEFEAT MSIV INTERLOCK DURING ATWS	1.0044E-002
55	HER_HPSPC1	OPERATOR FAILS TO ALIGN RHR FOR SUPPRESSION POOL COOLING (NON-AT	9.0660E-003
56	[DGFTS_1_DG3B]	DG 3B FAILS TO START	8.7858E-003
57	TBSFDST	TURBINE BYPASS SYSTEM UNAVAILABLE FOR SHORT TERM PRESSURE RELIEF	7.2486E-003
58	BE_FRACT7	A MULTI UNIT INITIATOR AND U2 @ POWER	6.8678E-003
59	FLTPL1___032AFLT	AFTER FILTER PLUGS IN PLANT CONTROL AIR	5.9284E-003
60	FLTPL1__032PRFLT	PREFILTER PLUGS IN PLANT CONTROL AIR	5.9284E-003
61	[FN2FR1ROOM74001A FN2FR1ROOM74001B FN2FR1ROOM74001C FN2FR1ROOM74001D]	CCF RHR ROOM COOLERS FOR PUMPS A, B, C, AND D	5.8996E-003
62	GEL_ACC_CF_HCU	CCF 335 OR MORE HCU ACCUMULATORS FAIL	5.3768E-003
63	AOVFO1FCV0640222	FCV 64-222 FAILS TO OPEN ON DEMAND (HWWV)	5.2515E-003
64	AOVFO1FCV0640221	FCV 64-221 FAILS TO OPEN ON DEMAND (HWWV)	5.2515E-003

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
1	GEL_SOV_CF_PSOVS	CCF 33% or more HCU Scram Pilot SOVs or Backup SOVs Fail	4.7876E+004
2	GEL_ACC_CF_HCU	CCF 335 or more HCU Accumulators Fail	4.7876E+004
3	GEL_AOV_CF_HCU	CCF 33% or more HCU Scram Inlet/Outlet AOVS Fail to Open	4.7876E+004
4	GEL_ROD_CF_CRD	CCF 33% or more Rods Fail to Insert	4.7876E+004
5	[PMSFR1PMP074001A PMSFR1PMP074001B PMSFR1PMP074001C PMSFR1PMP074001D]	Common Cause: Group RHR Pumps Fail to Run, 4/4	2.6055E+003
6	[FN2FR1ROOM74001A FN2FR1ROOM74001B FN2FR1ROOM74001C FN2FR1ROOM74001D]	Common Cause: Group RHR Room Coolers Fail to Run, 4/4	2.6054E+003
7	[PMSFS1PMP074001A PMSFS1PMP074001B PMSFS1PMP074001C PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 4/4	2.6054E+003
8	[FN2FS1ROOM74001A FN2FS1ROOM74001B FN2FS1ROOM74001C FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 4/4	2.6053E+003
9	HER_HPSPC1	Operator Fails to Align RHR for Suppression Pool Cooling (NON-ATWS)	1.7931E+003
10	HER_HPRVD1	Operator Fails to Initiate Depressurization	1.4622E+003
11	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 6/6	1.2149E+003
12	[RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003
13	[RV2FO1PCV0010005 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003
14	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003
15	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003
16	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003
17	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 5/6	1.2149E+003

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
18	[FN2FS1ROOM74001A FN2FS1ROOM74001B FN2FS1ROOM74001C]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 3/4	1.2004E+003
19	[PMSFS1PMP074001A PMSFS1PMP074001B PMSFS1PMP074001C]	Common Cause: Group RHR Pumps Fail to Start, 3/4	1.1996E+003
20	[FN2FR1ROOM74001A FN2FR1ROOM74001B FN2FR1ROOM74001C]	Common Cause: Group RHR Room Coolers Fail to Run, 3/4	1.1991E+003
21	[PMSFR1PMP074001A PMSFR1PMP074001B PMSFR1PMP074001C]	Common Cause: Group RHR Pumps Fail to Run, 3/4	1.1985E+003
22	[MOVFO1FCV0230034 MOVFO1FCV0230040 MOVFO1FCV0230046 MOVFO1FCV0230052]	Common Cause: Group RHR Heat Exchangers, 4/4	9.4793E+002
23	SWCS	CCF (Failure to Start) of all RHRSW Pumps	6.0770E+002
24	SWCR	CCF (Failure to Run) of All RHRSW Trains	6.0770E+002
25	FCOFTO_DGABCD	Motor Operated Vent. Dampers FTO or Fans Fail to Start (Diesels)	2.8000E+002
26	[DGFTS_1_DGA DGFTS_1_DGB DGFTS_1_DGC DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 4/4	2.8000E+002
27	[MOVFO1FCV0740057 MOVFO1FCV0740059 MOVFO1FCV0740071 MOVFO1FCV0740073]	Common Cause: Group RHR Suppression Pool Cooling Valves, 4/4	2.1026E+002
28	[MOVFO1FCV0740059 MOVFO1FCV0740071]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	2.1026E+002
29	[MOVFO1FCV0740059 MOVFO1FCV0740073]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	2.1026E+002
30	[MOVFO1FCV0740057 MOVFO1FCV0740071]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	2.1026E+002
31	[MOVFO1FCV0740057 MOVFO1FCV0740073]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	2.1026E+002
32	[RL1FD1___0010K14 RL1FD1___0010K16 RL1FD1___0010K51 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 4/4	1.3889E+002
33	[RL1FD1___0010K16 RL1FD1___0010K51 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 3/4	1.3889E+002
34	[RL1FD1___0010K14 RL1FD1___0010K16 RL1FD1___0010K51]	Common Cause: Group Relays for MSIV Closure, 3/4	1.3889E+002
35	[RL1FD1___0010K51 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 2/4	1.3889E+002
36	[RL1FD1___0010K14 RL1FD1___0010K51 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 3/4	1.3889E+002
37	[RL1FD1___0010K14 RL1FD1___0010K16 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 3/4	1.3889E+002
38	[RL1FD1___0010K14 RL1FD1___0010K16]	Common Cause: Group Relays for MSIV Closure, 2/4	1.3889E+002

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
39	[RL1FD1___0010K14 RL1FD1___0010K52]	Common Cause: Group Relays for MSIV Closure, 2/4	1.3889E+002
40	[AOVFC1FCV0010037 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 2/8	1.3889E+002
41	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
42	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010051]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
43	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
44	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010037]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
45	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010027]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
46	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010026 AOVFC1FCV0010027 AOVFC1FCV0010037 AOVFC1FCV0010038 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 8/8	1.3889E+002
47	[AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 2/8	1.3889E+002
48	[AOVFC1FCV0010037 AOVFC1FCV0010038 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
49	[AOVFC1FCV0010037 AOVFC1FCV0010038 AOVFC1FCV0010051]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
50	[AOVFC1FCV0010038 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
51	[AOVFC1FCV0010037 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
52	[AOVFC1FCV0010027 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
53	[AOVFC1FCV0010014 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
54	[AOVFC1FCV0010015 AOVFC1FCV0010026 AOVFC1FCV0010027]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
55	[AOVFC1FCV0010026 AOVFC1FCV0010027]	Common Cause: Group MSIVs Fail to Close, 2/8	1.3889E+002
56	[AOVFC1FCV0010014 AOVFC1FCV0010037 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
57	[AOVFC1FCV0010027 AOVFC1FCV0010037 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
58	[AOVFC1FCV0010026 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
59	[AOVFC1FCV0010026 AOVFC1FCV0010027 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
60	[AOVFC1FCV0010026 AOVFC1FCV0010037 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
61	[AOVFC1FCV0010015 AOVFC1FCV0010037 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
62	[AOVFC1FCV0010015 AOVFC1FCV0010051 AOVFC1FCV0010052]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
63	[AOVFC1FCV0010026 AOVFC1FCV0010027 AOVFC1FCV0010038]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
64	[AOVFC1FCV0010026 AOVFC1FCV0010027 AOVFC1FCV0010037]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
65	[AOVFC1FCV0010014 AOVFC1FCV0010015]	Common Cause: Group MSIVs Fail to Close, 2/8	1.3889E+002
66	[RL1FD1___0010K16 RL1FD1___0010K51]	Common Cause: Group Relays for MSIV Closure, 2/4	1.3889E+002
67	[AOVFC1FCV0010014 AOVFC1FCV0010015 AOVFC1FCV0010026]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
68	[AOVFC1FCV0010014 AOVFC1FCV0010026 AOVFC1FCV0010027]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
69	[AOVFC1FCV0010026 AOVFC1FCV0010027 AOVFC1FCV0010051]	Common Cause: Group MSIVs Fail to Close, 3/8	1.3889E+002
70	[DGFTS_1_DGA DGFTS_1_DGB DGFTS_1_DGC]	Common Cause: Group Unit 1/2 Diesel Generators, 3/4	1.1823E+002
71	[MOVFO1FCV0230034 MOVFO1FCV0230040 MOVFO1FCV0230046]	Common Cause: Group RHR Heat Exchangers MOVs, 3/4	1.0097E+002
72	[PMSFR2___02300B1 PMSFR2___02300B2 PMSFR2___02300D1 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 4/4	8.9775E+001
73	[PMSFS2___02300B1 PMSFS2___02300B2 PMSFS2___02300D1 PMSFS2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps 4/4	8.9775E+001
74	[FN2FS1ROOM74001A FN2FS1ROOM74001C FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 3/4	7.1926E+001
75	[PMSFS1PMP074001A PMSFS1PMP074001C PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 3/4	7.0732E+001
76	[FN2FR1ROOM74001A FN2FR1ROOM74001C FN2FR1ROOM74001D]	Common Cause: Group RHR Room Coolers Fail to Run, 3/4	6.9841E+001
77	[PMSFR1PMP074001A PMSFR1PMP074001C PMSFR1PMP074001D]	Common Cause: Group RHR Pumps Fail to Run, 3/4	6.8611E+001
78	[FN2FS1ROOM74001A FN2FS1ROOM74001B FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 3/4	6.5393E+001
79	[PMSFS1PMP074001A PMSFS1PMP074001B PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 3/4	6.4202E+001
80	[FN2FS1ROOM74001B FN2FS1ROOM74001C FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 3/4	6.3836E+001
81	[FN2FR1ROOM74001A FN2FR1ROOM74001B FN2FR1ROOM74001D]	Common Cause: Group RHR Room Coolers Fail to Run, 3/4	6.3304E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
82	[PMSFS1PMP074001B PMSFS1PMP074001C PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 3/4	6.2645E+001
83	[PMSFR1PMP074001A PMSFR1PMP074001B PMSFR1PMP074001D]	Common Cause: Group RHR Pumps Fail to Run, 3/4	6.2061E+001
84	[FN2FR1ROOM74001B FN2FR1ROOM74001C FN2FR1ROOM74001D]	Common Cause: Group RHR Room Coolers Fail to Run, 3/4	6.1748E+001
85	[PMSFR1PMP074001B PMSFR1PMP074001C PMSFR1PMP074001D]	Common Cause: Group RHR Pumps Fail to Run, 3/4	6.0504E+001
86	[CB1FO0BKR0571614 CB1FO0BKR0571616 CB1FO0BKR0571718]	Common Cause: Group Unit 1/2 4kv SD Feeder Breakers FTO, 3/4	5.1145E+001
87	[CB1FO0BKR0571614 CB1FO0BKR0571616 CB1FO0BKR0571718 CB1FO0BKR0571724]	Common Cause: Group Unit 1/2 4kv SD Feeder Breakers FTO, 4/4	5.1144E+001
88	HOVXC1HCV0740085	HCV-74-85 Transfers Closed	5.0915E+001
89	HOVXC1HCV0670565	Valve 67-565 Transfers Closed	5.0915E+001
90	[FN2FS1ROOM74001A FN2FS1ROOM74001C]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 2/4	4.9186E+001
91	MOVXC1FCV0740007	FCV-74-7 Transfers Closed	4.8610E+001
92	[PMSFS1PMP074001A PMSFS1PMP074001C]	Common Cause: Group RHR Pumps Fail to Start, 2/4	4.8370E+001
93	PTSFS1CCF_RCIHPI	RCIC HPCI Pumps Common Cause Failure To Start	4.8168E+001
94	[MOVFO1FCV0710008 MOVFO1FCV0730016]	Common Cause: Group RCIC Steam Supply, 2/2	4.8168E+001
95	[MOVFO1FCV0710039 MOVFO1FCV0730044]	Common Cause: Group HPCI RCIC Pump Discharge MOV failure, 2/2	4.8168E+001
96	[MOVFO1FCV0710034 MOVXC1FCV0730035 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs, 3/4	4.8168E+001
97	[HPCI RCIC Return Lines MOVs1FCV0710034 MOVXC1FCV0710038 MOVXC1FCV0730035]	Common Cause: Group HPCI RCIC Return Lines MOVs, 3/4	4.8168E+001
98	[HPCI RCIC Return Lines MOVs1FCV0710034 MOVXC1FCV0710038 MOVXC1FCV0730035 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs, 4/4	4.8168E+001
99	[RL11RLY23A_K25 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.8168E+001
100	[RL1FD123A_K21 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.8168E+001
101	[RL11RLY23A_K25 RL1FD123A_K21 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 3/4	4.8168E+001
102	[RL11RLY23A_K25 RL1FD123A_K22 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 3/4	4.8168E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
103	[RL1FD123A_K21 RL1FD123A_K22 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 3/4	4.8168E+001
104	[RL11RLY23A_K25 RL1FD123A_K21 RL1FD123A_K22 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 4/4	4.8168E+001
105	PTSFR1CCF_RCIHPI	RCIC HPCI Pumps Common cause Failure to Run	4.8168E+001
106	[MOVFO1FCV0710034 MOVXC1FCV0710038 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 3/4	4.8168E+001
107	[MOVFO1FCV0710034 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	4.8168E+001
108	[RL1FD123A_K22 RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.8168E+001
109	ECCS_SUPPLY_TRAN	Insufficient Flow to ECCS Suction Ring Header During Transient	3.7332E+001
110	ECCS_SUPPLY_LOST	Insufficient Flow Available to Ring Header During LOCA	3.7026E+001
111	PRESS_SPRES_LOST	PSP to Quench Steam During LOCA Blowdown	3.7026E+001
112	[PMSFR1PMP074001A PMSFR1PMP074001C]	Common Cause: Group RHR Pumps Fail to Run, 2/4	3.6674E+001
113	[FN2FR1ROOM74001A FN2FR1ROOM74001C]	Common Cause: Group RHR Room Coolers Fail to Run, 2/4	3.6667E+001
114	[MOVFO1FCV0230034 MOVFO1FCV0230040 MOVFO1FCV0230052]	Common Cause: Group RHR Heat Exchangers MOVs, 3/4	3.4779E+001
115	[FN2FR1FAN098601 FN2FR1FAN098602]	Common Cause: Group FANRUN, 2/2	3.3789E+001
116	[FN2FS1ROOM74001A FN2FS1ROOM74001B]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 2/4	3.0606E+001
117	[PMSFS1PMP074001A PMSFS1PMP074001B]	Common Cause: Group RHR Pumps Fail to Start, 2/4	3.0231E+001
118	[FN2FR1ROOM74001A FN2FR1ROOM74001B]	Common Cause: Group RHR Room Coolers Fail to Run, 2/4	2.9643E+001
119	[PMSFR1PMP074001A PMSFR1PMP074001B]	Common Cause: Group RHR Pumps Fail to Run, 2/4	2.9639E+001
120	[FN2FS1ROOM74001B FN2FS1ROOM74001C]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 2/4	2.9050E+001
121	[PMSFS1PMP074001B PMSFS1PMP074001C]	Common Cause: Group RHR Pumps Fail to Start, 2/4	2.8671E+001
122	[FN2FR1ROOM74001B FN2FR1ROOM74001C]	Common Cause: Group RHR Room Coolers Fail to Run, 2/4	2.8087E+001
123	[PMSFR1PMP074001B PMSFR1PMP074001C]	Common Cause: Group RHR Pumps Fail to Run, 2/4	2.8082E+001
124	[DGFTS_1_DGA DGFTS_1_DGB DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 3/4	2.6367E+001
125	[MOVFO1FCV0230034 MOVFO1FCV0230040]	Common Cause: Group RHR Heat Exchangers MOVs, 2/4	2.6343E+001
126	HOVXC1HCV0740088	HCV-74-88 Transfers Closed	2.3682E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
127	HOVXC1HCV0670606	Valve 67-606 Transfers Closed	2.3217E+001
128	BUSFR1BUS057___1	Battery BD. 1.	2.3200E+001
129	MOVXC1FCV0740030	FCV-74-30 Transfers Closed	2.2678E+001
130	[FN2FS1ROOM74001B FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 2/4	2.2597E+001
131	[PMSFS1PMP074001B PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 2/4	2.2218E+001
132	[RL1FD1___00358A2 RL1FD1___00358B2 RL1FD1___00358C2 RL1FD1___00358D2]	Common Cause: Group Low RX Level Output Relays, 4/4	2.1454E+001
133	[RL1FD114A0750K7A RL1FD114A0750K7B]	Common Cause: Group Low RX Level Logic Relay (CSS), 2/4	2.1454E+001
134	[RL1FD1___00358B2 RL1FD1___00358C2 RL1FD1___00358D2]	Common Cause: Group Low RX Level Output Relays, 3/4	2.1454E+001
135	[RL1FD1___00358A2 RL1FD1___00358C2 RL1FD1___00358D2]	Common Cause: Group Low RX Level Output Relays, 3/4	2.1454E+001
136	[RL1FD1___00358A2 RL1FD1___00358C2]	Common Cause: Group Low RX Level Output Relays, 2/4	2.1454E+001
137	[RL1FD1___00358B2 RL1FD1___00358D2]	Common Cause: Group Low RX Level Output Relays, 2/4	2.1454E+001
138	[RL1FD1___00358A2 RL1FD1___00358B2 RL1FD1___00358D2]	Common Cause: Group Low RX Level Output Relays, 3/4	2.1454E+001
139	[RL1FD1___00358A2 RL1FD1___00358B2 RL1FD1___00358C2]	Common Cause: Group Low RX Level Output Relays, 3/4	2.1454E+001
140	[RL1FD110A0740K7A RL1FD110A0740K7B RL1FD110A0740K8A RL1FD110A0740K8B]	Common Cause: Group RELAY3, 4/4	2.1454E+001
141	[RL1FD110A074K36A RL1FD110A074K36B]	Common Cause: Group RELAY4, 2/2	2.1454E+001
142	[SWDFD1_LS003058A SWDFD1_LS003058B SWDFD1_LS003058C SWDFD1_LS003058D]	Common Cause: Group Low RX Level Bistables, 4/4	2.1454E+001
143	[SWDFD1_LS003058B SWDFD1_LS003058C SWDFD1_LS003058D]	Common Cause: Group Low RX Level Bistables, 3/4	2.1454E+001
144	[SWDFD1_LS003058A SWDFD1_LS003058B SWDFD1_LS003058C]	Common Cause: Group Low RX Level Bistables, 3/4	2.1454E+001
145	[SWDFD1_LS003058A SWDFD1_LS003058C SWDFD1_LS003058D]	Common Cause: Group Low RX Level Bistables, 3/4	2.1454E+001
146	[SWDFD1_LS003058A SWDFD1_LS003058B SWDFD1_LS003058D]	Common Cause: Group Low RX Level Bistables, 3/4	2.1454E+001
147	[RL1FD110A0740K7A RL1FD110A0740K8A RL1FD110A0740K8B]	Common Cause: Group Low RX Level Logic Relay (RHR), 3/4	2.1454E+001
148	[RL1FD110A0740K7B RL1FD110A0740K8A RL1FD110A0740K8B]	Common Cause: Group Low RX Level Logic Relay (RHR), 3/4	2.1454E+001
149	[RL1FD110A0740K7A RL1FD110A0740K7B]	Common Cause: Group Low RX Level Logic Relay (RHR), 2/4	2.1454E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
150	[RL1FD110A0740K7A RL1FD110A0740K7B RL1FD110A0740K8A]	Common Cause: Group Low RX Level Logic Relay (RHR), 3/4	2.1454E+001
151	[RL1FD110A0740K7A RL1FD110A0740K7B RL1FD110A0740K8B]	Common Cause: Group Low RX Level Logic Relay (RHR), 3/4	2.1454E+001
152	[RL1FD110A0740K8A RL1FD110A0740K8B]	Common Cause: Group Low RX Level Logic Relay (RHR), 2/4	2.1454E+001
153	[SWDFD1_LS003058B SWDFD1_LS003058D]	Common Cause: Group Low RX Level Bistables, 2/4	2.1454E+001
154	[SWDFD1_LS003058A SWDFD1_LS003058C]	Common Cause: Group Low RX Level Bistables, 2/4	2.1454E+001
155	[RL1FD114A0750K7B RL1FD114A0750K8A RL1FD114A0750K8B]	Common Cause: Group Low RX Level Logic Relay (CSS), 3/4	2.1454E+001
156	[RL1FD114A0750K7A RL1FD114A0750K7B RL1FD114A0750K8A RL1FD114A0750K8B]	Common Cause: Group Low RX Level Logic Relay (CSS), 4/4	2.1454E+001
157	[RL1FD114A0750K8A RL1FD114A0750K8B]	Common Cause: Group Low RX Level Logic Relay (CSS), 2/4	2.1454E+001
158	[RL1FD114A0750K7A RL1FD114A0750K7B RL1FD114A0750K8A]	Common Cause: Group Low RX Level Logic Relay (CSS), 3/4	2.1454E+001
159	[RL1FD114A0750K7A RL1FD114A0750K7B RL1FD114A0750K8B]	Common Cause: Group Low RX Level Logic Relay (CSS), 3/4	2.1454E+001
160	[RL1FD114A0750K7A RL1FD114A0750K8A RL1FD114A0750K8B]	Common Cause: Group Low RX Level Logic Relay (CSS), 3/4	2.1454E+001
161	PMOFR3___027__CC	Loss of All Unit 3 CCW Pumps	2.0481E+001
162	HOVXC2___0240500	Unit 1 CCW Intake Valve 2-24-500 Transfers Closed	2.0481E+001
163	HOVXC1___0240504	Crosstie Valve 1-24-504 Transfers Closed	2.0481E+001
164	HOVXC1___0240500	Unit 1 CCW Intake Valve 1-24-500 Transfers Closed	2.0481E+001
165	HOVXC2___0240521	RCW Header Isolation Valve 2-24-521 Transfers Closed	2.0481E+001
166	HOVXC2___0240524	RCW Header Isolation Valve 2-24-524 Transfers Closed	2.0481E+001
167	[PMOFR1___024001A PMOFR1___024001B PMOFR2___024002A PMOFR2___024002B PMOFR2___024002C PMOFR3___024003A PMOFR3___024003B]	Common Cause: Group Raw Cooling Water Pumps, 7/7	2.0481E+001
168	HOVXC3___0240500	Unit 3 CCW Intake Valve 3-24-500 Transfers Closed	2.0481E+001
169	HOVXC2___0240594	RCW Header Isolation Valve 2-24-594 Transfers Closed	2.0481E+001
170	HOVXC2___0240515	Crosstie Valve 2-24-515 Transfers Closed	2.0481E+001
171	PMOFR1___027__CC	Loss of All Unit 1 CCW Pumps	2.0481E+001
172	PMOFR2___027__CC	Loss of All Unit 2 CCW Pumps	2.0481E+001
173	[CB1FO0BKR0571614 CB1FO0BKR0571616 CB1FO0BKR0571724]	Common Cause: Group Unit 1/2 4kv SD Feeder Breakers FTO, 3/4	1.8722E+001
174	[CB1FO0BKR0571614 CB1FO0BKR0571616]	Common Cause: Group Unit 1/2 4kv SD Feeder Breakers FTO, 2/4	1.8722E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
175	[DGFTS_1_DGA DGFTS_1_DGC DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 3/4	1.8220E+001
176	[PMSFR2___02300B1 PMSFR2___02300B2 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 3/4	1.8125E+001
177	[PMSFS2___02300B1 PMSFS2___02300B2 PMSFS2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps 3/4	1.8103E+001
178	[DGFTS_1_DGB DGFTS_1_DGC DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 3/4	1.7732E+001
179	DIMFR1___002CODM	Insufficient Flow Thru Demin Flow Path	1.7651E+001
180	COVLK1___0020558	Condensate Booster Pump B Discharge Check Valve 2-558 Gross Reverse Leakage	1.7651E+001
181	[PMOFR1CBP002002A PMOFR1CBP002002B PMOFR1CBP002002C]	Common Cause: Group Condensate Booster Pumps, 3/3	1.7651E+001
182	MOVXC1FCV0020041	Outlet Valve FCV 2-41 Transfers Closed	1.7651E+001
183	COVFT1___0020558	Condensate Booster Pump B Discharge Check Valve 2-558 Fails to Reseat	1.7651E+001
184	COVLK1___0020517	Condensate Pump B Discharge Check Valve 2-517 Gross reverse Leakage	1.7651E+001
185	COVFT1___0020517	Condensate Pump B Discharge Check Valve 2-517 Fails to Reseat	1.7651E+001
186	[PMOFR1_CP002002A PMOFR1_CP002002B PMOFR1_CP002002C]	Common Cause: Group Condensate Pumps, 3/3	1.7651E+001
187	MOVXC1FCV0020036	Inlet Valve FCV2-36 Transfers Closed	1.7651E+001
188	HXRPL1___002OFGA	Excessive Leakage/Rupture Of Off-Gas Condenser	1.7651E+001
189	HXRPL1___002SJAE	Excessive Leakage/Rupture (SJAE)	1.7651E+001
190	HXRPL1___002EXHA	Excessive Leakage/Rupture OF Steam Packing Exhauster	1.7651E+001
191	[DGFTS_1_DG3A DGFTS_1_DG3B DGFTS_1_DG3C DGFTS_1_DG3D]	Common Cause: Group Diesel Generators, 4/4	1.7495E+001
192	FCOFTO_1_DG3ABCD	Motor Operated Vent Dampers Fail to Open or Fans Fail to Start	1.7495E+001
193	[DGFTS_1_DGA DGFTS_1_DGB]	Common Cause: Group Diesel Generators, 2/4	1.6789E+001
194	[PMSFR2___02300B1 PMSFR2___02300B2 PMSFR2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps, 3/4	1.6274E+001
195	[PMSFS2___02300B1 PMSFS2___02300B2 PMSFS2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps 3/4	1.6259E+001
196	SWYARD	Offsite Grid and Switchyard Failure	1.6168E+001
197	COVFT1___0020526	Condensate Pump C Discharge Check Valve 2-526 Fails to Reseat	1.5599E+001
198	COVFT1___0020550	Condensate Booster Pump C Discharge Check Valve 2-550 Fails to Reseat	1.5599E+001
199	COVLK1___0020550	Condensate Booster Pump C Discharge Check Valve 2-550 Gross reverse Leakage	1.5571E+001

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
200	COVLK1___0020526	Condensate Pump C Discharge Check Valve 2-526 Gross reverse Leakage	1.5571E+001
201	BUSFR0ShutDNBRDA	Shutdown Board A Bus Fault	1.4722E+001
202	E1VFD1FCV0470067	Master Trip Valve FCV 47-67 Fails to Operate On Demand	1.4193E+001
203	[MOVFO1FCV0230034 MOVFO1FCV0230046 MOVFO1FCV0230052]	Common Cause: Group RHR Heat Exchangers MOVs, 3/4	1.4158E+001
204	[DGFTS_1_DG3A DGFTS_1_DG3B DGFTS_1_DG3C]	Common Cause: Group Diesel Generators, 3/4	1.2656E+001
205	HOVXC1HCV0740033	HCV-74-33 Transfers Closed	1.0932E+001
206	HOVXC1ISV0670610	Valve 67-610 Transfers Closed	1.0932E+001
207	HOVXC1HCV0670603	Valve 67-603 Transfers Closed	1.0932E+001
208	HOVXC1ISV0670609	Valve 67-609 Transfers Closed	1.0932E+001
209	HOVXC1ISV0670602	Valve 67-602 Transfers Closed	1.0932E+001
210	HOVXC1ISV0670605	Valve 67-605 Transfers Closed	1.0932E+001
211	HOVXC1HCV0740089	HCV-74-89 Transfers Closed	1.0932E+001
212	[PMSFR2___02300B1 PMSFR2___02300B2]	Common Cause: Group South Service Water Header RHRSW Pumps, 2/4	1.0764E+001
213	[PMSFS2___02300B1 PMSFS2___02300B2]	Common Cause: Group South Service Water Header RHRSW Pumps 2/4	1.0763E+001
214	[MOVFO1FCV0230040 MOVFO1FCV0230046 MOVFO1FCV0230052]	Common Cause: Group RHR Heat Exchangers MOVs, 3/4	1.0673E+001
215	MOVXC1FCV0740024	FCV-74-24 Transfers Closed	1.0601E+001
216	CKVFO1CKV074559B	Check Valve 74-559B Fails to Open On Demand	1.0543E+001
217	CKVFO1CKV074560B	Check Valve 74-560B Fails to Open On Demand	1.0543E+001
218	[FN2FS1ROOM74001B]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 1/4	1.0490E+001
219	[PMSFR1PMP074001B]	Common Cause: Group RHR Pumps Fail to Run, 1/4	1.0405E+001
220	[PMSFS1PMP074001B]	Common Cause: Group RHR Pumps Fail to Start, 1/4	1.0403E+001
221	[FN2FR1ROOM74001B]	Common Cause: Group RHR Room Coolers Fail to Run, 1/4	1.0391E+001
222	HXRRP1SEAL67001B	Seal Heat Exchanger 1B Ruptures	1.0316E+001
223	HXRRP1HEX074901B	Heat Exchanger 1B Ruptures	1.0316E+001
224	HXRRP1HXR067001B	Pump Room Cooler 1B (Heat Exchanger Data) Ruptures	1.0316E+001
225	COVXC0___0240563	Check Valve 0-24-563 Manual Valve 0-24-562 Transfer Shut	9.4777E+000
226	COVXC0___0240577	Check Valve 0-24-577 Manual Valve 0-24-578 Transfer Shut	9.4777E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
227	HOVXC0___0240523	Manual Valve 0-24-523, -554 Transfer Shut	9.4777E+000
228	COVPL1___0322171	Check Valve 32-2171 PLUGS	9.4316E+000
229	HOVXC0___0240681	Manual Valve 0-24-681 Transfers Shut	9.4316E+000
230	HOVXC0___0241052	Manual Valve 0-24-1052 Transfers Shut	9.4316E+000
231	COVPL1___0320243	Check Valve 32-0243 Plugs	9.4316E+000
232	R2VPO0___0320556	Relief Valve 0-32-556 Premature Open	9.4316E+000
233	R2VPO0___0320551	Relief Valve 0-32-551 Premature Open	9.4316E+000
234	HOVXC1___0320211	Manual Valve 32-211 Transfers Shut	9.4316E+000
235	HOVXC1___0322370	Manual Valve 32-2370 Transfer Shut	9.4316E+000
236	HOVXC1___0322373	Manual Valve 32-2373 Transfer Shut	9.4316E+000
237	R2VPO0___0320546	Relief Valve 0-32-546 Premature Open	9.4316E+000
238	HOVXC1___0320975	Manual Valve 032-975 Transfers Closed	9.4316E+000
239	FLTPL1___032AFLT	After filter Plugs	9.4316E+000
240	RCVRP0__032RCVR1	Air Receiver1 Rupture	9.4316E+000
241	RCVRP0__032RCVR2	Air Receiver2 Rupture	9.4316E+000
242	RCVRP0__032RCVR3	Air Receiver3 Rupture	9.4316E+000
243	FLTPL1__032PRFLT	Pre-filter Plugs	9.4316E+000
244	HOVXC0___0320549	Valve 545 OR 549 Transfers Shut Given Receivers 2 and 3 Path	9.4316E+000
245	[DGFTS_1_DGA DGFTS_1_DGC]	Common Cause: Group Diesel Generators, 2/4	8.6384E+000
246	HER_HPHPE1	Operator Fails to Control Level With RCIC/HPCI (Early 6 hours)	8.3947E+000
247	[DGFTS_1_DGB DGFTS_1_DGC]	Common Cause: Group Diesel Generators, 2/4	8.1505E+000
248	[MOVFO1FCV0710008]	Common Cause: Group RCIC Steam Supply, 1/2	7.9722E+000
249	[MOVFO1FCV0710039]	Common Cause: Group HPCI RCIC Pump Discharge MOV failure, 1/2	7.9722E+000
250	MOVFC1FCV0710034	Valve 1-FCV-71-34 Fails to Close On Demand	7.9647E+000
251	[MOVFO1FCV0710034 MOVXC1FCV0710038]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	7.9641E+000
252	[MOVFO1FCV0740053 MOVFO1FCV0740067]	Common Cause: LPCI Injection MOVs 2/2	7.5151E+000
253	[MOVFO1FCV0740071 MOVFO1FCV0740073]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	7.4404E+000
254	[MOVFO1FCV0740073]	Common Cause: Group RHR Suppression Pool Cooling Valves, 1/4	7.4193E+000
255	[MOVFO1FCV0740071]	Common Cause: Group RHR Suppression Pool Cooling Valves, 1/4	7.4193E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
256	[DGFTS_1_DG3A DGFTS_1_DG3B DGFTS_1_DG3D]	Common Cause: Group Diesel Generators, 3/4	7.2844E+000
257	[MOVFO1FCV0710034 MOVXC1FCV0730035]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	7.0326E+000
258	[DGFTS_1_DG3A DGFTS_1_DG3B]	Common Cause: Group Diesel Generators, 2/4	6.9881E+000
259	RPDRP1RP71011A_6	Inboard Rupture DISC 1-RPD-71-011A Failure	6.3543E+000
260	HER_HPWWV1	Operator Fails to Align Wetwell Path	6.3063E+000
261	CKVFO1CKV0710580	Check Valve 1-CKV-71-580 Fails to Open On Demand	6.2600E+000
262	CKVFO1CKV0710499	Check Valve 1-CKV-71-499 Fails to Open On Demand	6.2600E+000
263	CKVFO1CKV0030572	RFW Line B Injection Valve 1-CKV-3-572 Fails to Open On Demand	6.2600E+000
264	CKVFO1FCV0710040	Check Valve 1-FCV-71-40 Fails to Open On Demand	6.2600E+000
265	CKVFC1CKV0030568	Check Valve 1-CKV-3-568 Fails to CLOSE On Demand	6.2600E+000
266	CKVLK1CK030568_6	Check Valve 1-CKV-3-568 Gross Backleakage	6.2524E+000
267	[RL1FD1RLY0710K22]	Common Cause: Group HPCI/RCIC Relays, 1/4	6.2499E+000
268	CSVFO1HCV0710014	Stop Check Valve 1-HCV-71-14 Fails to Open On Demand	6.2259E+000
269	MOVXC1FCV71037_6	Valve 1-FCV-71-37 Transfers Closed	6.2036E+000
270	MOVXC1FCV71019_6	Valve 1-FCV-71-19 Transfers Closed	6.2036E+000
271	MOVXC1FCV7102_6	Valve 1-FCV-71-2 Transfers Closed	6.2036E+000
272	MOVXC1FCV07103_6	Valve 1-FCV-71-3 Transfers Closed	6.2036E+000
273	MOVXO1FCV71038_6	Valve 1-FCV-71-38 Transfers Open	6.2036E+000
274	SWLFD1_LS0710029	Level Switch 1-LS-71-29 Fails to Operate On Demand	6.1845E+000
275	PTSFS1PMP0710019	RCIC Pump Fails to Start On Demand	6.1570E+000
276	PTSFR1PMP71019_6	RCIC Pump Fails to RUN	6.1079E+000
277	MOVXO1FCV71034_6	Valve 1-FCV-71-34 Transfers Open	5.9884E+000
278	MOVXC1FCV07108_6	Valve 1-FCV-71-8 Transfers Closed	5.9884E+000
279	MOVXC1FCV71039_6	Valve 1-FCV-71-39 Transfers Closed	5.9884E+000
280	HOVXC1HCV3066_6	RFW Line B Valve 1-HCV-3-66 Transfers Closed	5.9691E+000
281	MOVXC1FCV0740071	Valve FCV-74-71 Transfers Closed	5.7258E+000
282	MOVXC1FCV0740073	Valve FCV-74-73 Transfers Closed	5.7258E+000
283	RHR Neat Exchangers MOVs MOVFO1FCV0230046]	Common Cause: Group HXMOV, 2/4	5.7228E+000
284	[MOVXC1FCV0730035 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	5.6877E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
285	[MOVXC1FCV0710038 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	5.6877E+000
286	[MOVXC1FCV0710038 MOVXC1FCV0730035]	Common Cause: Group HPCI RCIC Return Lines MOVs 2/4	5.6877E+000
287	[MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 1/4	5.6819E+000
288	MOVFO1FCV0730036	MOV 1-FCV-73-36 Fails to Open On Demand	5.6785E+000
289	[MOVXC1FCV0710038 MOVXC1FCV0730035 MOVXC1FCV0730036]	Common Cause: Group HPCI RCIC Return Lines MOVs 3/4	5.6729E+000
290	HER_HPHPR1	Operators FAIL to Recover Control HPCI/RCI After L8 Trip	5.5781E+000
291	CONDENSER_2A2B2C	Main Condenser Unavailable After Plant Trip	5.5122E+000
292	HOVXC1ISV0640737	LO Manual Valve FCV-64-737 Transfers Closed During Operation	5.3644E+000
293	AOVFO1FCV0640222	FCV 64-222 Fails to Open On Demand	5.3644E+000
294	AOVFO1FCV0640221	FCV 64-221 Fails to Open On Demand	5.3644E+000
295	AOVXC1FCV0640222	FCV 64-222 Transfers Closed During Operation	5.3644E+000
296	AOVXC1FCV0640221	FCV 64-221 Transfers Closed During Operation	5.3644E+000
297	HOVXC1__032_3754	Manual Valve 32-3754 Transfers Closed	5.3644E+000
298	HOVXC1__032_2704	Manual Valve 32-2704 Transfers Closed	5.3644E+000
299	HOVXC1__032_2703	Manual Valve 32-2703 Transfers Closed	5.3644E+000
300	[PMOFR1_CP002002A PMOFR1_CP002002B]	Common Cause: Group Condensate Pumps, 2/3	5.1829E+000
301	[MOVFO1FCV0730016]	Common Cause: Group RCIC Steam Supply, 1/2	5.1630E+000
302	[MOVFO1FCV0730044]	Common Cause: Group HPCI RCIC Pump Discharge MOV failure, 1/2	5.1630E+000
303	[MOVXC1FCV0730035]	Common Cause: Group HPCI RCIC Return Lines MOVs 1/4	5.1630E+000
304	MOVFO1FCV0730027	MOV 1-FCV-73-27 Fails to Open On Demand	5.1608E+000
305	MOVFO1FCV0730035	MOV 1-FCV-73-35 Fails to Open On Demand	5.1608E+000
306	MOVFO1FCV0730026	MOV 1-FCV-73-26 Fails to Open On Demand	5.1608E+000
307	MOVFC1FCV0730040	MOV 1-FCV-73-40 Fails to CLOSE On Demand	5.1608E+000
308	RHR Neat Exchangers MOVs MOVFO1FCV0230052]	Common Cause: Group HXMOV, 2/4	5.0833E+000
309	CKVFO1CKV0730517	Check Valve 1-CKV-73-517 Fails to Open On Demand	4.8865E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
310	RHRDSGRUP0750000	RHR Discharge Fails to Remain Intact/ Rupture	4.8830E+000
311	[MOVFO1FCV0230034]	Common Cause: Group RHR Heat Exchanger MOVs, 1/4	4.7769E+000
312	MOVXC1FCV0020171	MOV 1-FCV-2-171 Transfers Closed During Operation	4.7488E+000
313	[PMSFR2___02300A1 PMSFR2___02300A2 PMSFR2___02300C1 PMSFR2___02300C2]	Common Cause: Group South Service Water Header RHRSW Pumps, 4/4	4.7393E+000
314	[PMSFS2___02300A1 PMSFS2___02300A2 PMSFS2___02300C1 PMSFS2___02300C2]	Common Cause: Group Condensate Pumps 4/4	4.7393E+000
315	COVPL1___0760551	Check Valve 076-0551 Fails to Open, Plugged, Transfers Closed	4.7300E+000
316	COVPL1___0760552	Check Valve 076-0552 Fails to Open, Plugged, Transfers Closed	4.7300E+000
317	HOVXC1___0322515	Manual Valve S 32-2515,2520, 4011, 4009, 2529 Transfer Shut	4.7300E+000
318	COVPL1___0322516	Check Valve S 32-2516, 2528, 2521 FAIL to Open, Plugged, TRAN	4.7300E+000
319	FLTPL1___032CFLT	Drywell Loads (C) Air Filter Plugged	4.7300E+000
320	COVPL1___0760405	Check Valve 076-0405 Fails to Open, Plugs, Transfers Closed	4.7300E+000
321	HOVXC1___0322253	Manual Valve S 32-2253,2160, 4010, 4008, 1736, Transfer Shut	4.7300E+000
322	COVPL1___0322163	Check Valve S 32-2163 336 FAIL to Open, Plugged, Transfer Closed	4.7300E+000
323	FLTPL1___032BFLT	Drywell Loads (B) Air Filter Plugged	4.7300E+000
324	HOVXC1___0760538	Manual Valve 076-0538 Transfers Closed	4.7300E+000
325	HOVXC1___0760310	Manual Valve 076-0310 Transfers Closed	4.7300E+000
326	CSVFO1HCV0730023	Fails to P Check Valve 1-HCV-73-23 Fails to Open On Demand	4.6911E+000
327	TBSFDST	Turbine Bypass System Unavailable for Short Term Pressure Relief	4.6891E+000
328	HOVXC1HCV0230031	Valve HCV-23-31 Transfers Closed	4.6424E+000
329	CKVFO1CKV0230510	Check Valve CKV-23-510 Fails to Open On Demand	4.6358E+000
330	HXRPL1HEX074900A	Heat Exchanger 1A Plugs	4.6319E+000
331	[SWL1_LS073056A SWL1_LS073056B]	Common Cause: Group SWTCH, 2/2	4.6311E+000
332	CKVXC1CKV0230510	Check Valve CKV-23-510 Transfers Closed	4.6302E+000
333	MOVXC1FCV0230034	Valve FCV-23-34 Transfers Closed	4.6283E+000
334	XR2FR1_C_1B_TS1B	Transformer TS1B Fails During Operation	4.5971E+000
335	BUSFR1_480VBRD1B	480V Shutdown Bus 1B Fails	4.5971E+000
336	CB1XO04KV_BD_C20	Input Breaker 20 Transfers Open	4.5971E+000
337	CB1XO1480BD1B_1C	Output Breaker 1C Transfers Open	4.5971E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
338	MOVXC1FCV73040_6	MOV 1-FCV-73-40 Transfers Closed During Operation	4.5943E+000
339	MOVXC1FCV73003_6	MOV 1-FCV-73-3 Transfers Closed During Operation	4.5943E+000
340	MOVXC1FCV73002_6	MOV 1-FCV-73-2 Transfers Closed During Operation	4.5943E+000
341	CKVFO1CKV0030558	RFW Check Valve 1-CKV-3-558 Fails to Open On Demand	4.5918E+000
342	CKVFC1CKV0030554	Feedwater Check Valve 1-CKV-3-554 Fails to Close On Demand	4.5918E+000
343	CKVFO1CKV0730603	Check Valve 1-CKV-73-603 Fails to Open On Demand	4.5918E+000
344	CKVFO1FCV0730045	Testable Check Valve 1-FCV-73-45 Fails to Open On Demand	4.5918E+000
345	CKVFO1CKV0730505	Check Valve 1-CKV-73-505 Fails to Open On Demand	4.5918E+000
346	CKVFO1CKV0730566	Check Valve 1-CKV-73-566 Fails to Open	4.5918E+000
347	[RL1FD123A_K21]	Common Cause: Group HPCI/RCIC Relays, 1/4	4.5425E+000
348	[RL1FD123A_K22]	Common Cause: Group HPCI/RCIC Relays, 1/4	4.5425E+000
349	[RL11RLY23A_K25]	Common Cause: Group HPCI/RCIC Relays, 1/4	4.5425E+000
350	[RL11RLY23A_K25 RL1FD123A_K21]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.5350E+000
351	[RL1FD123A_K21 RL1FD123A_K22]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.5350E+000
352	[RL11RLY23A_K25 RL1FD123A_K22]	Common Cause: Group HPCI/RCIC Relays, 2/4	4.5350E+000
353	CKVLK1CKV30554_6	Feedwater Check Valve 1-CKV-3-554 Develops Gross reverse Leakage	4.5286E+000
354	[PMSFR2___02300B2 PMSFR2___02300D1 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 3/4	4.4790E+000
355	[MOVFO1FCV0740057 MOVFO1FCV0740059]	Common Cause: Group RHR Suppression Pool Cooling Valves, 2/4	4.4750E+000
356	PTSFS1PMP0730054	HPCI Pump Fails to START On Demand	4.4627E+000
357	[PMSFS2___02300B2 PMSFS2___02300D1 PMSFS2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps 3/4	4.4539E+000
358	[MOVFO1FCV0740059]	Common Cause: Group RHR Suppression Pool Cooling Valves, 1/4	4.4539E+000
359	[MOVFO1FCV0740057]	Common Cause: Group RHR Suppression Pool Cooling Valves, 1/4	4.4539E+000
360	PTSFR1PMP73054_6	HPCI Pump During Operation	4.4301E+000
361	MOVXC1FCV73044_6	MOV 1-FCV-73-44 Transfers Closed During Operation	4.4113E+000
362	MOVXC1FCV73027_6	MOV 1-FCV-73-27 Transfers Closed During Operation	4.4113E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
363	MOVXC1FCV73026_6	MOV 1-FCV-73-26 Transfers Closed During Operation	4.4113E+000
364	MOVXO1FCV73040_6	MOV 1-FCV-73-40 Transfers Open AFTER SWITCHOVER	4.4113E+000
365	MOVXC1FCV73016_6	MOV 1-FCV-73-16 Transfers Closed During Operation	4.4113E+000
366	MOVXC1FCV73034_6	MOV 1-FCV-73-34 Transfers Closed During Operation	4.4113E+000
367	HOVXC1HCV73025_6	Manual Valve 1-HCV-73-25 Transfers Closed During Operation	4.3679E+000
368	HOVXC1HC30067_6	RFW Valve 1-HCV-3-67 Transfers Closed	4.3679E+000
369	[CB1FO3BKR0571334 CB1FO3BKR0571336 CB1FO3BKR0571338]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 3/4	4.3508E+000
370	[CB1FO3BKR0571334 CB1FO3BKR0571336 CB1FO3BKR0571338 CB1FO3BKR0571342]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 4/4	4.3508E+000
371	[RL11RLY23A_K25 RL1FD123A_K21 RL1FD123A_K22]	Common Cause: Group HPCI/RCIC Relays, 3/4	4.3466E+000
372	RPDRP1RP73020_6	Inboard Rupture Disc1-RPD-073- 020 Ruptures Causing HPCI Isolation	4.3372E+000
373	BUSFR1_UNITBRD1A	4KV Unit Board 1A	4.0393E+000
374	[PMSFR2___02300A1 PMSFR2___02300A2 PMSFR2___02300C2]	Common Cause: Group North Service Water Header Pumps, 3/4	4.0278E+000
375	[PMSFS2___02300A1 PMSFS2___02300A2 PMSFS2___02300C2]	Common Cause: Group North Service Water Header RHRSW Pumps 3/4	4.0277E+000
376	CSDSCGRUP0740000	Core Spray Discharge Fails to Remain Intact/Ruptures	4.0240E+000
377	CKVXC1CK30572_6	RFW Line B Injection Valve 1-CKV-3-572 Transfers Closed	3.9845E+000
378	CKVXC1CK710580_6	Check Valve 1-CKV-71-580 Transfers Closed	3.9845E+000
379	CKVXC1FCV71040_6	Check Valve 1-FCV-71-40 Transfers Closed	3.9845E+000
380	CKVXC1CK710499_6	Check Valve 1-CKV-71-499 Transfers Closed	3.9845E+000
381	CSVXC1HCV71014_6	Stop Check Valve 1-HCV-71-14 Transfers Closed	3.9706E+000
382	CB1XO1480SD1B_3B	Feeder Breaker 3B Transfers Open During Operation.	3.9668E+000
383	CB1XO1RMOV_1B_2D	BUS Feeder Breaker 2D Transfers Open During Operation.	3.9668E+000
384	BUSFR1480VRMOV1B	480V RMOV BD 1B BUS	3.9668E+000
385	[PMSFR2___02300A1 PMSFR2___02300A2 PMSFR2___02300C1]	Common Cause: Group North Service Water Pumps, 3/4	3.8951E+000
386	[PMSFS2___02300A1 PMSFS2___02300A2 PMSFS2___02300C1]	Common Cause: Group North Service Water Header RHRSW Pumps 3/4	3.8949E+000
387	CKVXC1CK730603_6	Check Valve 1-CKV-73-603 Transfers Closed During Operation	3.8252E+000
388	CKVXC1CK730505_6	Check Valve 1-CKV-73-505 Transfers Closed During Operation	3.8252E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
389	CKVXC1FCV73045_6	Testable Check Valve 1-FCV-73-45 Transfers Closed	3.8252E+000
390	CKVXC1CK030558_6	RFW Check Valve 1-CKV-3-558 Transfers Closed	3.8252E+000
391	CKVXC1CKV0730566	Check Valve 1-CKV-73-566 Transfers Closed During Operation	3.8252E+000
392	CKVXC1CK730517_6	Check Valve 1-CKV-73-517 Transfers Closed During Operation	3.8252E+000
393	CB1XO2480BD2A_1C	Output Breaker 1C Transfers Open	3.8207E+000
394	CB1XO04KV_BD_B_5	Input Breaker 5 Transfers Open	3.8207E+000
395	BUSFR2_480VBRD2A	480V Shutdown Bus 2A	3.8197E+000
396	XR2FR2_B_2A_TS2A	Transformer TS2A During Operation	3.8195E+000
397	CSVXC1HCV73023_6	Stop Check Valve 1-HCV-73-23 Transfers Closed	3.8123E+000
398	[PMSFR2___02300A1 PMSFR2___02300A2]	Common Cause: Group North Service Water Header RHRSW Pumps 2/4	3.7793E+000
399	[PMSFS2___02300A1 PMSFS2___02300A2]	Common Cause: Group North Service Water Header RHRSW Pumps 2/4	3.7792E+000
400	[SWDFD1PIS003204B SWDFD1PIS003204C]	Common Cause: Group High RX Pressure Signal Bistables, 2/4	3.6982E+000
401	[SWDFD1PIS003204B SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 2/4	3.6982E+000
402	[SWDFD1PIS003204A SWDFD1PIS003204C]	Common Cause: Group High RX Pressure Signal Bistables, 2/4	3.6982E+000
403	[SWDFD1PIS003204A SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 2/4	3.6982E+000
404	[RL1FD1___003204A RL1FD1___003204C]	Common Cause: Group High RX Pressure Signal Output Relays, 2/4	3.6982E+000
405	[RL1FD1___003204A RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 2/4	3.6982E+000
406	[RL1FD1___003204B RL1FD1___003204C]	Common Cause: Group High RX Pressure Signal Output Relays, 2/4	3.6982E+000
407	[RL1FD1___003204B RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 2/4	3.6982E+000
408	[RL1FD1___003204A RL1FD1___003204B RL1FD1___003204C]	Common Cause: Group High RX Pressure Signal Output Relays, 3/4	3.6982E+000
409	[RL1FD1___003204A RL1FD1___003204B RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 3/4	3.6982E+000
410	[RL1FD1___003204A RL1FD1___003204C RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 3/4	3.6982E+000
411	[RL1FD1___003204B RL1FD1___003204C RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 3/4	3.6982E+000
412	[SWDFD1PIS003204B SWDFD1PIS003204C SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 3/4	3.6982E+000
413	[SWDFD1PIS003204A SWDFD1PIS003204B SWDFD1PIS003204C SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 4/4	3.6982E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
414	[SWDFD1PIS003204A SWDFD1PIS003204B SWDFD1PIS003204C]	Common Cause: Group High RX Pressure Signal Bistables, 3/4	3.6982E+000
415	[SWDFD1PIS003204A SWDFD1PIS003204B SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 3/4	3.6982E+000
416	[SWDFD1PIS003204A SWDFD1PIS003204C SWDFD1PIS003204D]	Common Cause: Group High RX Pressure Signal Bistables, 3/4	3.6982E+000
417	[RL1FD1___00358C4 RL1FD1___00358C5]	Common Cause: Group RELAY2, 2/2	3.6982E+000
418	[RL1FD1___003204A RL1FD1___003204B RL1FD1___003204C RL1FD1___003204D]	Common Cause: Group High RX Pressure Signal Output Relays, 4/4	3.6982E+000
419	[CB1FO3BKR0571334 CB1FO3BKR0571336 CB1FO3BKR0571342]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 3/4	3.6103E+000
420	[CB1FO3BKR0571334 CB1FO3BKR0571336]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 2/4	3.6103E+000
421	BATFD1BAT057_SBA	Battery SB-A Fails on Demand	3.4235E+000
422	BUSFR1BUS057_SBA	SB-A BUS	3.4235E+000
423	[PMSFR2___02300B1 PMSFR2___02300D1 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 3/4	3.4170E+000
424	[MGSFR1RPSMGSET_A MGSFR1RPSMGSET_B]	Common Cause: Group Motor Generator Sets Fail, 2/2	3.4140E+000
425	[PMSFS2___02300B1 PMSFS2___02300D1 PMSFS2___02300D2]	Common Cause: Group Condensate Pumps 3/4	3.3993E+000
426	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
427	[RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
428	[RV2FO1PCV0010019 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
429	[RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
430	[RV2FO1PCV0010005 RV2FO1PCV0010022 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
431	[RV2FO1PCV0010005 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
432	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010030 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
433	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
434	[RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
435	[RV2FO1PCV0010005 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010034]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3685E+000
436	[RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3679E+000
437	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010030 RV2FO1PCV0010031]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3679E+000
438	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010031]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3679E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
439	[RV2FO1PCV0010005 RV2FO1PCV0010019 RV2FO1PCV0010022 RV2FO1PCV0010030]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3679E+000
440	[RV2FO1PCV0010005 RV2FO1PCV0010022 RV2FO1PCV0010030 RV2FO1PCV0010031]	Common Cause: Group Safety Relief Valves Fail to Depressurize, 4/6	3.3679E+000
441	[DGFTS_1_DG3A DGFTS_1_DG3C DGFTS_1_DG3D]	Common Cause: Group Diesel Generators, 3/4	3.3159E+000
442	[DGFTS_1_DGA DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 2/4	3.1903E+000
443	[MGSFR1RPSMGSET_A]	Common Cause: Group Motor generator Sets Fail, 1/2	3.0742E+000
444	BATFD1BAT057_SBC	Battery SB-C On Demand.	3.0735E+000
445	BUSFR1BUS057_SBC	SB-C BUS	3.0735E+000
446	BKRXO1RPSBUSA902	Distribution Panel Feeder Breaker 902 Transfers Open	3.0731E+000
447	CTRXO1RPSBUSA1A1	Protection Contactor 1A1 Transfers Open	3.0731E+000
448	CTRXO1RPSBUSA1A2	Protection Contactor 1A2 Transfers Open	3.0731E+000
449	BUSFR1RPSBUS001A	RPS BUS A Fails During Operation	3.0731E+000
450	BKRXO1RMOV1A013A	480V RMOV BD 1A Breaker 13A Transfers Open	3.0731E+000
451	FSWFR1M_B057__XC	Charger Output Fuse Switch Transfers Open.	3.0269E+000
452	CB1FO1M_B05717B1	Charger Input Breaker 17B1 Open.	3.0269E+000
453	CHGFR1M_B057_SBC	Charger SB-C During Operation	3.0269E+000
454	[DGFTS_1_DG3A DGFTS_1_DG3C]	Common Cause: Group Diesel Generators, 2/4	3.0194E+000
455	[PMSFR2___02300B1 PMSFR2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps, 2/4	2.8902E+000
456	[PMSFS2___02300B1 PMSFS2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps 2/4	2.8895E+000
457	[PMSFR2___02300B2 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 2/4	2.8475E+000
458	[PMSFS2___02300B2 PMSFS2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps 2/4	2.8446E+000
459	DCA_FLD	Line Break in Drywell Control Air	2.8222E+000
460	PCA_FLD	Line Break in Plant Control Air	2.8222E+000
461	RAD_MONITOR	Spurious Operation of Radiation Monitor Resulting in MSIV Closure	2.8221E+000
462	BUSFR3SHTDBRD3EA	Shutdown BD 3EA Bus Fault	2.8144E+000
463	[PMSFS1PMP074001A PMSFS1PMP074001D]	Common Cause: Group RHR Pumps Fail to Start, 2/4	2.8130E+000
464	[FN2FS1ROOM74001A FN2FS1ROOM74001D]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 2/4	2.7997E+000
465	BUSFR1CAB3PNL9_9	I&C Bus B Panel 9-9 CAB 3 Unit 1 Failure.	2.7809E+000
466	[FN2FS1ROOM74001A]	Common Cause: Group RHR Pump Room Coolers Fail to Start, 1/4	2.7733E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
467	[PMSFR2___02300B1 PMSFR2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps, 2/4	2.7656E+000
468	[PMSFS2___02300B1 PMSFS2___02300D2]	Common Cause: Group South Service Water Header RHRSW Pumps 2/4	2.7641E+000
469	[RL1FD1RLY10AK58A RL1FD1RLY10AK58B]	Common Cause: Group RLY, 2/2	2.7618E+000
470	MOVXC1FCV0740057	Valve FCV-74-57 Transfers Closed	2.7604E+000
471	MOVXC1FCV0740059	Valve FCV-74-59 Transfers Closed	2.7604E+000
472	[PMSFS1PMP074001A]	Common Cause: Group RHR Pumps Fail to Start, 1/4	2.7417E+000
473	[PMSFR2___02300B2 PMSFR2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps, 2/4	2.7242E+000
474	CKVFO1CKV074560A	Check Valve 74-560A Fails to Open On Demand	2.7224E+000
475	CKVFO1CKV074559A	Check Valve 74-559A Fails to Open On Demand	2.7224E+000
476	[PMSFS2___02300B2 PMSFS2___02300D1]	Common Cause: Group South Service Water Header RHRSW Pumps 2/4	2.7222E+000
477	FSWFR1M_B057__XA	Charger Output Fuse Switch Transfers Open	2.7141E+000
478	CB1FO1M_B05716C1	Charger Input Breaker 16C1 Open.	2.7141E+000
479	CHGFR1M_B057_SBA	Charger SB-A During Operation	2.7141E+000
480	[PMSFR2___02300B1]	Common Cause: Group South Service Water Header RHRSW Pumps, 1/4	2.7139E+000
481	[PMSFS2___02300B1]	Common Cause: Group South Service Water Header RHRSW Pumps 1/4	2.7132E+000
482	COVFO2___0230522	Check Valve 0-23-522 Fails to Open On Demand	2.7111E+000
483	HOVXC2___0230523	Manual Valve 0-23-523 Transfers Closed	2.7099E+000
484	HOVXC2___0230524	Manual Valve 0-23-524 Transfers Closed	2.7099E+000
485	COVXC2___0230522	Check Valve 0-23-522 Transfers Closed	2.7079E+000
486	CB1XO2480SD2A_3A	Feeder Breaker 3A Transfers Open During Operation.	2.7037E+000
487	CB1XO2RMOV_2A_3D	BUS Feeder Breaker 3D Transfers Open During Operation.	2.7037E+000
488	BUSFR2480VRMOV2A	480V RMOV BD 2A Bus	2.7037E+000
489	[PMSFR1PMP074001A]	Common Cause: Group RHR Pumps Fail to Run, 1/4	2.7025E+000
490	[DGFTS_1_DGB DGFTS_1_DGD]	Common Cause: Group Diesel Generators, 2/4	2.7025E+000
491	[DGFTS_1_DG3A DGFTS_1_DG3D]	Common Cause: Group Diesel Generators, 2/4	2.6978E+000
492	[FN2FR1ROOM74001A]	Common Cause: Group RHR Room Coolers Fail to Run, 1/4	2.6942E+000
493	MOVXC1FCV0740001	FCV-74-1 Transfers Closed	2.6791E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	Basic Event	Description	Risk Achievement Worth
494	[DGFTS_1_DG3A]	Common Cause: Group Diesel Generators, 1/4	2.6693E+000
495	HOVXC1HCV0740010	HCV-74-10 Transfers Closed	2.6513E+000
496	HOVXC1ISV0670567	Valve 67-567 Transfers Closed	2.6512E+000
497	HOVXC1ISV0670571	Valve 67-571 Transfers Closed	2.6512E+000
498	HOVXC1HCV0740086	HCV-74-86 Transfers Closed	2.6512E+000
499	HOVXC1ISV0670570	Valve 67-570 Transfers Closed	2.6512E+000
500	HOVXC1ISV0670574	Valve 67-574 Transfers Closed	2.6512E+000
501	HOVXC1HCV0670572	Valve 67-572 Transfers Closed	2.6512E+000
502	[FCOFO_1_FCO_230C FCOFO_1_FCO_231C]	Common Cause: Group Unit 3 DG Dampers, 2/2	2.6416E+000
503	[FN2FTS_DG3A_FANA FN2FTS_DG3A_FANB]	Common Cause: Group Unit 3 DG Fans, 2/2	2.6404E+000
504	HXRRP1HEX074901A	Heat Exchanger 1A Ruptures	2.6384E+000
505	HXRRP1SEAL74001A	Seal Heat Exchanger 1A Ruptures	2.6384E+000
506	HXRRP1HXR074001A	Pump Room Cooler 1A (Heat Exchanger Data) Ruptures	2.6384E+000
507	BUSFR1CAB2PNL9_9	I&C Bus A Panel 9-9 AB 2 Unit 1 Failure.	2.6360E+000
508	FRDXC_DG3A_1035	Fire Dampers 1035, 1031 Transfer Closed	2.6333E+000
509	CHARG_DG3ACHG3A2	Charger "3A", In/Out Fuses Fail. Charger Input, Output Breaker Transfer Open	2.6311E+000
510	BUSFD_DG3ABUS3A	125V DC BUS OR Battery OR Fused Switch to DG CONT Transfer	2.6290E+000
511	HOVXC_DG3A_862	Manual Valve S 862,699 TRANS. Closed OR EXPANSION JOINT LEAK.	2.6289E+000
512	CB1XO_DG3A_1838	DG 3A Breaker 1838 TRANS. Open OR Breaker 1334 TRANS. Closed OR	2.6244E+000
513	[CB1FO0BKR0571614 CB1FO0BKR0571718]	Common Cause: Group Unit 1/2 4kV Shutdown Board Feeder Breakers FTO, 2/4	2.6140E+000
514	[CB1FO0BKR0571614 CB1FO0BKR0571718 CB1FO0BKR0571724]	Common Cause: Group Unit 1/2 4kV Shutdown Board Feeder Breakers FTO, 3/4	2.6138E+000
515	[PMSFR2___02300B2]	Common Cause: Group South Service Water Header RHRSW Pumps, 1/4	2.6008E+000
516	[PMSFS2___02300B2]	Common Cause: Group South Service Water Header RHRSW Pumps 1/4	2.5992E+000
517	HOVXC2___0230527	Manual Valve 0-23-527 Transfers Closed	2.5989E+000
518	COVFO2___0230526	Check Valve 0-23-526 Fails to Open On Demand	2.5975E+000
519	COVXC2___0230526	Check Valve 0-23-526 Transfers Closed	2.5937E+000
520	[PMSFR1PMP074001A PMSFR1PMP074001D]	Common Cause: Group RHR Pumps Fail Fails to Run, 2/4	2.5788E+000
521	[FN2FR1ROOM74001A FN2FR1ROOM74001D]	Common Cause: Group RHR Room Coolers Fail to Run, 2/4	2.5782E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
522	[CB1FO0BKR0571614]	Common Cause: Group Unit 1/2 4kV Shutdown Board Feeder Breakers FTO, 1/4	2.5600E+000
523	[CB1FO0BKR0571614 CB1FO0BKR0571724]	Common Cause: Group Unit 1/2 4kV Shutdown Board Feeder Breakers FTO, 2/4	2.5599E+000
524	[MOVFC1FCV0740053 MOVFC1FCV0740067]	Common Cause: Group LPCI Injection MOVs, 2/2	2.5549E+000
525	CB1XC0BKR0571614	Breaker 1614 Transfers Closed	2.5441E+000
526	CKVXC1CKV074560A	Check Valve 74-560A Transfers Closed	2.5254E+000
527	CKVXC1CKV074559A	Check Valve 74-559A Transfers Closed	2.5254E+000
528	[DGFTS_1_DGA]	Common Cause: Group Diesel Generators, 1/4	2.4895E+000
529	[PMSFR2___02300A1 PMSFR2___02300C1 PMSFR2___02300C2]	Common Cause: Group South Service Water Header RHRSW Pumps, 3/4	2.4684E+000
530	[PMSFS2___02300A1 PMSFS2___02300C1 PMSFS2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 3/4	2.4682E+000
531	[PMSFR2___02300A1 PMSFR2___02300C1]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.4624E+000
532	[PMSFS2___02300A1 PMSFS2___02300C1]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.4624E+000
533	[PMSFR2___02300A1 PMSFR2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.4051E+000
534	[PMSFS2___02300A1 PMSFS2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.4050E+000
535	[PMSFR2___02300A1]	Common Cause: Group Service Water Header RHRSW Pumps, 1/4	2.4033E+000
536	[PMSFS2___02300A1]	Common Cause: Group Service Water Header RHRSW Pumps, 1/4	2.4033E+000
537	COVFO2___0230502	Check Valve 0-23-502 Fails to Open On Demand	2.4033E+000
538	HOVXC2___0230503	Manual Valve 0-23-503 Transfers Closed	2.4032E+000
539	HOVXC2___0230504	Manual Valve 0-23-504 Transfers Closed	2.4032E+000
540	COVXC2___0230502	Check Valve 0-23-502 Transfers Closed	2.4031E+000
541	[FCOFO_1_FCO_64C FCOFO_1_FCO_65C]	Common Cause: Group DG Dampers, 2/2	2.3395E+000
542	[PMSFR2___02300A2 PMSFR2___02300C1 PMSFR2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 3/4	2.3334E+000
543	[PMSFS2___02300A2 PMSFS2___02300C1 PMSFS2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 3/4	2.3332E+000
544	[FN2FTS_DGA_FANA FN2FTS_DGA_FANB]	Common Cause: Group DG A Fans, 2/2	2.3318E+000
545	[PMSFR2___02300A2 PMSFR2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.3172E+000
546	[PMSFS2___02300A2 PMSFS2___02300C2]	Common Cause: Group Service Water Header RHRSW Pumps, 2/4	2.3171E+000
547	CHARG_DGA_CHGA2	Charger "A", In/Out Fuses Fail Charger Input Output Breaker Transfers Open	2.2760E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
548	HOVXC_DGA_532	Manual Valve S 532, 861 TRANS. Closed or Expansion Joint Leak	2.2721E+000
549	BUSFD_DGA_BUSA	125V DC BD. BUS or Battery or Fused Switch to DG Control Tran	2.2672E+000
550	CB1XO_DGA_1818	DG A Breaker 1818 TRANS. Open or Breaker 1614 Transfers Closed	2.2613E+000
551	FRDXC_DGA_1023	FIRE DAMPERS 1023, 1019 Transfer Closed	2.2594E+000
552	[MOVFO1FCV0230040 MOVFO1FCV0230046]	Common Cause: Group RHR Heat Exchangers MOVs, 2/4	2.2374E+000
553	XR2FR1_A_1A_TS1A	Transformer TS1A During Operation	2.2321E+000
554	BUSFR1_480VBRD1A	480V Shutdown Bus 1A	2.2321E+000
555	CB1XO04KV_BD_A_5	Input Breaker 5 Transfers Open	2.2321E+000
556	CB1XO1480BD1A_1C	Output Breaker 1C Transfers Open	2.2321E+000
557	HER_HRSPC1	Operator Local recovery of SP Cooling Failure	2.2311E+000
558	[RL1FD1RL68118A3A RL1FD1RL68118A3B RL1FD1RL68118B3A RL1FD1RL68118B3B]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 4/4	2.2290E+000
559	[RL1FD1RL68118A3B RL1FD1RL68118B3A RL1FD1RL68118B3B]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 3/4	2.2290E+000
560	[RL1FD1RL68118A3A RL1FD1RL68118B3A RL1FD1RL68118B3B]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 3/4	2.2290E+000
561	[RL1FD1RL68118A3A RL1FD1RL68118B3A]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 2/4	2.2290E+000
562	[RL1FD1RL68118A3A RL1FD1RL68118A3B RL1FD1RL68118B3B]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 3/4	2.2290E+000
563	[RL1FD1RL68118A3A RL1FD1RL68118A3B RL1FD1RL68118B3A]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 3/4	2.2290E+000
564	[RL1FD1RL68118A3B RL1FD1RL68118B3B]	Common Cause: Group Relays for Breaker trip Coils for Recirc Pump Trip, 2/4	2.2290E+000
565	[CB1FO1BKR0681440 CB1FO1BKR0681450 CB1FO1BKR0681540 CB1FO1BKR0681550]	Common Cause: Group Recirc Pump Trip Breakers, 4/4	2.2290E+000
566	[CB1FO1BKR0681450 CB1FO1BKR0681540 CB1FO1BKR0681550]	Common Cause: Group Recirc Pump Trip Breakers, 3/4	2.2290E+000
567	[CB1FO1BKR0681440 CB1FO1BKR0681540 CB1FO1BKR0681550]	Common Cause: Group Recirc Pump Trip Breakers, 3/4	2.2290E+000
568	[CB1FO1BKR0681440 CB1FO1BKR0681450 CB1FO1BKR0681550]	Common Cause: Group Recirc Pump Trip Breakers, 3/4	2.2290E+000
569	[CB1FO1BKR0681440 CB1FO1BKR0681450 CB1FO1BKR0681540]	Common Cause: Group Recirc Pump Trip Breakers, 3/4	2.2290E+000
570	[CB1FO1BKR0681540 CB1FO1BKR0681550]	Common Cause: Group Recirc Pump Trip Breakers, 2/4	2.2290E+000
571	[CB1FO1BKR0681440 CB1FO1BKR0681450]	Common Cause: Group Recirc Pump Trip Breakers, 2/4	2.2290E+000
572	[DGFTS_1_DGC DGFTS_1_DGD]	Common Cause: Group Unit 1?2 DGs FTS, 2/4	2.1871E+000
573	[PMSFR2___02300A2 PMSFR2___02300C1]	Common Cause: Group North Service Water Pumps, 2/4	2.1342E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
574	[PMSFS2___02300A2 PMSFS2___02300C1]	Common Cause: Group North Service Water Pumps, 2/4	2.1341E+000
575	[PMSFR2___02300A2]	Common Cause: Group North Service Water Pumps, 1/4	2.1316E+000
576	[PMSFS2___02300A2]	Common Cause: Group North Service Water Pumps 1/4	2.1315E+000
577	COVFO2___0230506	Check Valve 0-23-506 Fails to Open On Demand	2.1315E+000
578	HOVXC2___0230507	Manual Valve 0-23-507 Transfers Closed	2.1314E+000
579	COVXC2___0230506	Check Valve 0-23-506 Transfers Closed	2.1313E+000
580	[CB1FO3BKR0571334 CB1FO3BKR0571338 CB1FO3BKR0571342]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 3/4	2.1304E+000
581	[CB1FO3BKR0571334 CB1FO3BKR0571338]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 2/4	2.1303E+000
582	[CB1FO3BKR0571334]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 1/4	2.1293E+000
583	[CB1FO3BKR0571334 CB1FO3BKR0571342]	Common Cause: Group Unit 3 4kV Shutdown Boards feeder Breakers FTO, 2/4	2.1292E+000
584	[MOVFO1FCV0710034]	Common Cause: Group HPCI RCIC Return Lines MOVs 1/4	2.1186E+000
585	BE_HPTAF1	Operators Fails to Lower Level to TAF and terminate Most Injection Flow	2.0514E+000
586	HOVXC1HCV0630012	Manual Valve 63-12 Transfers Closed	2.0471E+000
587	COVFO1___0630525	Check Valve 63-525 Fails to Open	2.0471E+000
588	COVFO1___0630526	Check Valve 63-526 Fails to Open	2.0471E+000
589	HOVXC1___0630524	Manual Valve 63-524 Transfers Closed	2.0471E+000
590	COVPL1___0630525	Check Valve 63-525 Transfers Closed / Plugs	2.0471E+000
591	COVPL1___0630526	Check Valve 63-526 Transfers Closed / Plugs	2.0471E+000
592	[MOVFC1FCV0690001 MOVFC1FCV0690002 MOVFC1FCV0690012]	Common Cause: Group D, 3/3	2.0471E+000
593	HOVXO1___0630013	Manual Valve 63-13 to DRAIN TANK Transfers Open	2.0471E+000
594	[PMSFS1___063001A PMSFS1___063001B]	Common Cause: Group SLC Pumps, 2/2	2.0471E+000
595	TK2RP1___0630001	Standby Liquid Control Storage Tank Ruptures	2.0471E+000
596	[PMSFR1___063001A PMSFR1___063001B]	Common Cause: Group SLC Pumps, 2/2	2.0471E+000
597	[EOVFD1___063008A EOVFD1___063008B]	Common Cause: Group SLC Explosive Valves, 2/2	2.0471E+000
598	HOVXC1___0630500	Manual Valve 63-500 Transfers Closed	2.0471E+000
599	FSWFR2M_B057__XB	Charger Output FUSE SWITCH-X Open.	2.0278E+000
600	CHGFR2M_B057_SBB	Charger SB-B During Operation	2.0278E+000
601	CB1FO2M_B057_5A2	Charger Input Breaker 5A2 Open.	2.0278E+000

BFN Unit 1 Significant Basic Events By Risk Achievement Worth			
Rank	**Basic Event**	**Description**	**Risk Achievement Worth**
602	HOVXC1___0840703	Manual Valve 703 Transfers Closed	2.0261E+000
603	HOVXC1___0840707	Manual Valve 707 Transfers Closed	2.0261E+000
604	CKVXC1___0840709	Check Valve 709 Transfers Closed	2.0261E+000
605	PCVFD1PCV0840706	PCV 84-706 On Demand	2.0261E+000
606	TK1RP0TK08400A	Nitrogen Tank A Rupture	2.0261E+000
607	[DGFTS_1_DGB]	Common Cause: Group Unit 1/2 DGs, 1/4	2.0017E+000

NRC Request SPSB-A.21

Identify the key sources of uncertainty and the key assumptions in the PRA. Note that the terms "key source of uncertainty" and "key assumption" are defined in RG 1.200, Appendix A, Table A-1, Index Number 2.2.

TVA Reply to SPSB-A. 21

The following are the key sources of uncertainty and key assumptions as defined in RG 1.200.

One SRV

The thermal-hydraulic analyses for Unit 1 indicated that a single stuck open safety relief valve (SRV) as an IE would depressurize the vessel such that low-pressure injection systems would be effective in mitigating core damage. This depressurization may not be applicable generically and is regarded as a key source of uncertainty. A key assumption is that a single stuck open SRV as an IE would depressurize the vessel such that low-pressure injection systems would be effective in mitigating core damage.

CRD for Vessel Protection

The thermal-hydraulic analyses for Unit 1 also indicated that CRD injection operated in the enhanced mode, in some circumstances, would prevent vessel melt-through. As this is not generally modeled, this is a key source of uncertainty. The key assumption made with respect to enhanced CRD injection is that no credit was taken for this in the BFN Unit 1 model.

Common Cause Failures for RHRSW Pumps

There are a total of 12 RHRSW pumps. There are four pumps normally dedicated to EECW, four pumps dedicated to RHRSW, and four "swing" pumps normally aligned to

RHRSW but capable of being aligned to EECW. The pumps are similar in design and draw from the same suction source. There is no industry consensus on modeling a common cause group of 12. The key assumption made was that these pumps are modeled in three common cause groups: the EECW pumps, the RHRSW pumps, and the swing pumps. There is no credible loss of suction event for all pumps. Further, if the EECW pumps are failed, then the RHRSW pumps are irrelevant.

Common Cause Failures for HPCI and RCIC

There is not a consensus in the industry on the extent of inter-system common cause failure (CCF) modeling. Although HPCI/RCIC common cause failure events are in the INEEL database, they may not always be modeled. A key assumption was to model CCF between HPCI and RCIC. The CCF also accounts for different failure rates for HPCI and RCIC. This raises the frequency of the dominant class of sequences where all high-pressure injection is lost and the operators fail to depressurize. Elimination of this dependency significantly reduces core damage.

NRC Request IROB-B-1

Describe how the proposed EPU will change the plant emergency and abnormal operating procedures.

TVA Reply to IROB-B-1

For BFN, Emergency Operating Procedures and Abnormal Operating Procedures are designated as Emergency Operating Instructions (EOIs) and Abnormal Operating Instructions (AOIs). The EOIs for Browns Ferry are symptom based. Changes in the EOIs and the AOIs required for EPU implementation consist of revisions to previously defined numerical values (e.g., rated reactor thermal power, heat capacity temperature limit, etc.). The definition of these parameters has not been altered, only the numerical value of the parameter has changed.

NRC Request IROB-B-2

Describe any new operator actions needed as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU.

TVA Reply to IROB-B-2

As previously stated in the PUSAR, operator responses to transient, accident and special events are not affected by EPU conditions. Accordingly, no new operator actions in the EOIs and AOIs have been created as a result of the proposed EPU for these events. Although AOIs also include actions outside of transient, accident and special events, no significant AOI revision to operator actions are expected. AOIs will

be reviewed for EPU conditions and necessary revisions will be completed as part of EPU implementation.

The change in parameter values (e.g., core decay heat, thermal power level, etc.) associated with EPU conditions could affect the timing of actions provided in the EOIs and AOIs. However, the EOIs are symptom based and the EOIs and AOIs do not contain specific times for the operator actions. Since the operator will continue to follow the sequence of actions required, there is no change in the current operator actions. Steps taken by the operator to mitigate events are not being changed as a result of EPU.

NRC Request IROB-B-3

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, or alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they could use the instruments reliably.

TVA Reply to IROB-B-3

Changes to the control room controls, displays, and alarms are being implemented as a part of the Unit 1 recovery effort. These changes are being made similar to the changes previously incorporated in the Units 2 and 3 control room design efforts. Changes associated with EPU are being implemented concurrently with this recovery effort.

There are no major changes to the control room controls, displays, or alarms planned as a result of EPU. Some changes are required to the instrumentation spans, alarm settings or actuation setpoints to accommodate increased process conditions or due to the installation of new equipment required for EPU. Where recorders, indicators, or instrumentation are changed to accommodate EPU, digital equipment may be selected where it is deemed technically acceptable; however, no such changes are currently planned. Banding will be reviewed and revised as necessary (for example, condensate booster pump ammeters).

There are various instructional aids in the main control room that will also be revised due to power uprate. These instructional aids are labels, sketches, or markings, which are posted and used as memory or instructional guidance (for example, power/flow map).

Setpoint changes as a result of EPU include the following. The Technical Specification setpoint changes are described in Section 5 of the PUSAR.

- APRM Flow Biased Scram and Rod Block Setpoints
- Turbine Stop Valve Closure and Turbine Control Valve Fast Closure Scram Bypass
- Main Steam Line High Flow Isolation

The changes in instrumentation and instructional aids in the main control room will be prepared in accordance with the plant modification process, which incorporates detailed review of the proposed control room design change package. All required changes will be implemented prior to operation at uprated conditions. The change control process includes an impact review by operations and training personnel. Training and implementation requirements are identified and tracked, including simulator impact. Verification of operator training is required as part of the design change closure process.

NRC Request IROB-B-4

Describe any changes to the safety parameter display system resulting from the proposed EPU. How will the operators be informed of the changes?

TVA Reply to IROB-B-4

The Safety Parameter Display System (SPDS) is being installed as part of the modifications required for Unit 1 restart following the extended shutdown. This system was not in place prior to the extended shutdown. The SPDS on Unit 1 will be similar to the SPDS on Units 2 and 3 and will reflect conditions associated with EPU such as rated core thermal power, reactor pressure, and changes to EOI Limit graphs. The design and intent of the SPDS remain unchanged from Units 2 and 3. The information presented on the SPDS display (top level display) and the method of presentation remain the same as before EPU on Units 2 and 3. These changes will not affect EOI execution and will be included in operator simulator training utilizing the SPDS.

REFERENCES:

1. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 - Proposed Technical Specifications (TS) Change TS - 431- Request for License Amendment - Extended Power Uprate (EPU) Operation," dated June 28, 2004.

2. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 Response to NRC's Acceptance Review Letter and Request for Additional Information Related to Technical Specifications (TS) Change No. TS-418, Request for Extended Power Uprate Operation, (TAC No. MC3812)" dated February 23, 2005.

3. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 - Response to NRC's Request for Additional Information Related to Technical Specifications (TS) Change No. TS-431– Request for Extended Power Uprate Operation (TAC No. MC3812)," dated April 25, 2005.

4. TVA letter, W. D. Crouch to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 – Response to NRC's Request for Additional Information Related to Technical Specifications (TS) Change No. TS - 431 – Request For License Amendment – Extended Power Uprate (EPU) Operation (TAC No. MC3812)," dated June 6, 2005.

5. NRC letter, M. H. Chernoff to TVA, "Browns Ferry Nuclear Plant, Unit 1 – Request for Additional Information for Extended power Uprate (TS-431)(TAC No. MC3812)," dated October 3, 2005.

6. TVA Letter, M. J. Burzynski to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3, Application for Renewed Operating Licenses," dated December 31, 2003.

7. TVA Letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) Unit 1 – Generic Letter 89-10 and Supplements 1 to 7, Safety-Related Motor-Operated Valve (MOV) Testing And Surveillance," dated May 5, 2004.

8. TVA Letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) Unit 1 – Generic Letter 95-07, Pressure Locking And Thermal Binding of Safety Related Power-Operated Gate Valves," dated May 11, 2004.

9. GE Engineering Report for Quad Cities Unit 1 Scale Model Testing, GENE-0000-0032-2219-01, April 2005.

10. Interim Comparison of Quad Cities Unit 1 Scale Model Test Data with Quad Cities Unit 2 Plant Data, GENE-0000-0042-7471-01, July 2005.

11. TVA Letter, BFN to NRC letter dated, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - Annual Radioactive Effluent Release (AREOR) Report - January Through December 2004," dated April 28, 2005.

12. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Amendment - Alternative Source Term," dated July 31, 2002.

13. NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 - Issuance of Amendments Regarding Full-Scope Implementation of Alternative Source Term (TAC Nos. MB5733, MB5734, MB5735, MC0156, MC0157 and MC0158) (TS-405)," dated September 27, 2004.

14. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2 and 3 - January 28, 2004 Meeting Follow-Up - Additional Information," dated February 19, 2004 (ML040510241).

15. TVA letter, M. Burzynski to NRC, "Browns Ferry Nuclear Plant (BFN), Units 1, 2 and 3 (TAC Nos. MC1768, MC1769, and MC1770) License Renewal Application: Response to Request for Additional Information (RAI) Regarding Lay-Up Effects of Unit 1 Structures and Component Supports," dated July 19, 2004.

16. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) Related to Aging of Mechanical Systems During the Extended Outage of Browns Ferry Nuclear Plant Unit 1 (TAC Nos. MC1704, MC1705, and MC1706)," dated October 8, 2004.

17. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3 License Renewal Application (LRA) – Relating to Section 3.0 Unit 1 Lay Up Questions – Response to Aging of Mechanical Systems During the Extended Outage of Browns Ferry Nuclear Plant Unit 1 – NRC Request for Additional Information (RAI) (TAC Nos. MC1704, MC1705, and MC1706)," dated January 31, 2005.

18. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) – Response to NRC Request for Additional Information Concerning the Unit 1 Layup Program (TAC Nos. MC1704, MC1705, and MC1706)," dated May 18, 2005.

19. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - License Renewal Application (LRA) – Response to NRC Request for Additional Information Concerning the Unit 1 Layup Program (TAC Nos. MC1704, MC1705, and MC1706), dated May 27, 2005.

20. TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) – Unit 1 – Response to NRC's Request for Additional Information Related to Technical Specifications (TS) Change No. TS - 431 – Request for License Amendment – Extended Power Uprate (EPU) Operation (TAC No. MC3812)," dated June 6, 2005.

21. TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) - Unit 1 - Response to NRC Request for Additional Information Regarding the Restart Testing Program (TAC NO. MC7208)," dated August 15, 2005.

22. NRC Letter to TVA, "Safety Evaluation of Post-Fire Safe Shutdown Capability and Issuance of Technical Specification Amendments for the Browns Ferry Nuclear Plant Units 1, 2, AND 3 (TAC Nos. M85254, N87900, M87901, and M87902) (TS 337), dated November 2, 1995.

23. TVA Letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Unit 1- Proposed Technical Specifications (TS) Change TS - 431 - Request for License Amendment - Extended Power Uprate (EPU) Operation Probabilistic Safety Assessment (PSA) Update," dated August 23, 2004.

24. TVA Letter to NRC, "Browns Ferry Nuclear Plant (BFN) Unit 1 – Update to the Probabilistic Safety Assessment (PSA)," dated September 15, 2005.

25. Standard For Probabilistic Risk Assessment For Nuclear Power Plant Applications, ASME RA-S-2002, April 5, 2002.

26. NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," U.S. Nuclear Regulatory Commission, November 1998.

27 NUREG-1032, "Evaluation of Station Blackout Accidents At Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1988.

28. INEEL/EXT-97-00887, Draft Version of NUREG/CR-5496, Idaho National Engineering and Environmental Laboratories.

29. NUREG/CR-5750, "Rates of Initiating Events at Nuclear Power Plants: 1987-1995," U.S. Nuclear Power Plants, February 1999.

30. Tennessee Valley Authority, "Browns Ferry Nuclear Plant Scram Database" Updated as of March 31, 2003.

31. U.S. Nuclear Regulatory Commission, "Modeling Time to Recovery and initiating Event Frequency for Loss of Off-Site Power incidents at Nuclear Power Plants," NUREG/CR-5032, January 1988.

32. Database For Probabilistic Risk Assessment Of Light Water Nuclear Power Plants, PLG-0500.

33. Institute of Nuclear Power Operations (INPO) Equipment Performance and Information Exchange (EPIX).

34. Nuclear Computerized Library for Assessing Reactor Reliability (NUCLARR), NUREG/CR-4639, Volume 5, Part 3, Hardware Component Failure Data, Revision 4, September 1994.

35. EPRI NP-6780-L, "Advanced Light Water Reactor Evolutionary Plant Utility Requirements Document – PRA Key Assumptions and Groundrules," Volume 2, Chapter 1, Appendix A, Electric Power Research Institute, 1990.

36. NUREG/CR-6268, "Common-Cause Failure Database and Analysis System," U.S. Nuclear Regulatory Commission, (Vols. 1, 2, 3, and 4), June 1998.

37. INEEL Common Cause Failure Database and Analysis System, NUREG/CR-6268.

38. Letter to the NRC, "Browns Ferry Nuclear Plant Unit 1 – Response to NRC Generic Letter (GL) 88-20, Supplement 4 – Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities – Submittal of Browns Ferry Nuclear Plant Unit 1 Seismic and Internal Fires IPEEE Reports," dated January 14, 2005.

39. TVA Letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) - Unit 1 - Response to Request for Additional Information Related to Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerability (TAC No. MC1895), dated August 17, 2004.

APPENDIX A

REVISED RS-001 TEMPLATE SAFETY EVALUATIONS

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the offsite power system; and the stability studies for the electrical transmission grid. The NRC staff's review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss of offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC-17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed EPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The NRC staff further concludes that the impact of the proposed EPU on grid stability is insignificant. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.5.1.4 Fire Protection

Regulatory Evaluation

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that SSCs required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire. The NRC's acceptance criteria for the FPP are based on (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant; (2) GDC-3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) draft GDC-4, insofar as it requires that reactor facilities shall not share systems or components unless it is shown safety is not impaired by the sharing. Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

[Insert technical evaluation. The technical evaluation should (1) clearly explain why the proposed changes satisfy each of the requirements in the regulatory evaluation and (2) provide a clear link to the conclusions reached by the NRC staff, as documented in the conclusion section.]

Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, GDC-3, and draft GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to fire protection.

APPENDIX B

HUMAN RELIABILITY ANALYSIS CALCULATION SHEETS FOR OPERATOR ACTIONS WITH A FUSSELL-VESELY IMPORTANCE MEASURE GREATER THAN 0.005 OR A RISK-ACHIEVEMENT WORTH GREATER THAN 2.

HPRVD1

EMERGENCY DEPRESSURIZATION, GIVEN HP INJECTION LOST

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	04/22/04
Cognitive Method:	HCR/ORE/THERP

Table 1: HPRVD1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	N/A	1.0e-07
P_{exe}	9.1e-03	1.9e-04
Total HEP		1.9e-04
Error Factor		10

HFE Scenario Description:
This action is required when the reactor has isolated and insufficient high pressure injection is available to maintain the RPV above TAF (-162"). Attempts to inject with HPCI and RCIC unsuccessful due to hardware OOS and/or failures.

Operators need to recognize that emergency depressurization will be required and take action to align available low pressure systems. Once the RPV reaches TAF, they must open MSRVs and verify that LP systems are recovering RPV level.

Failure to complete this action prior to RPV level falling to 1/3 active core height is assumed to result in core damage at high pressure.

Related Human Interactions:
Per C1-4, operators will be trying to recover HP inj. as RPV level declines to TAF
Shift supervisor will declare site emergency as RPV level declines past -122"

Performance Shaping Factors:
Operators will be trying to establish high pressure injection and could be distracted. However, their failure to obtain adequate flow from any high pressure injection system should drive them to conclude that they can not maintain the RPV level above -162." As documented in the training section, scenarios requiring emergency depressurization are addressed in simulator training 12 times per year, so the operating crew will familiar with the various situations that require it.

Procedure and step governing HI:
EOI-1 RC/L-9 transfer to C-1 and C-2

Training:

	-	None	
X	-	Classroom	Frequency: 1
X	-	Simulator	Frequency: 12

Degree of Clarity of Cues & Indications:

X	-	Very Good
	-	Average
	-	Poor

Human-Machine Interface:

X	-	Control Room Panels
	-	Local Control Panels
	-	Local Equipment

Special Requirements:

Tools	Parts	Clothing
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

	-	Skills
X	-	Rule
	-	Knowledge

Complexity of Response

		Cognitive			Execution
	-	Complex		-	Complex
X	-	Simple	X	-	Simple

Environment:

Lighting			Heat/Humidity		
X	-	Normal	X	-	Normal
	-	Emergency		-	Hot / Humid
	-	Portable		-	Cold

Radiation			Atmosphere		
X	-	Background	X	-	Normal
	-	Green		-	Steam
	-	Yellow		-	Smoke
	-	Red		-	Respirator required

Equipment Accessibility:

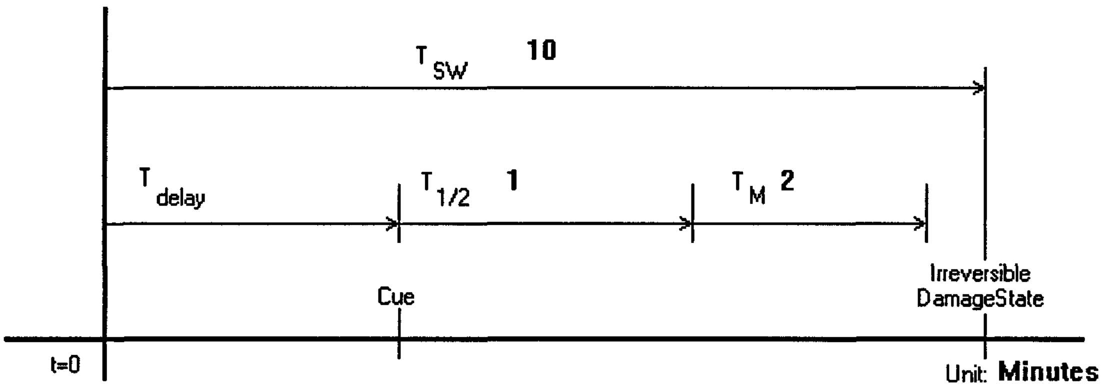
		Location	Accessibility
X	-	**Control Room Front Panels**	Accessible
	-	**Control Room Back Panels**	
	-	**Hot Shutdown Panels**	
	-	**Auxiliary Building**	
	-	**Electrical Building**	
	-	**Containment**	
	-	**Pump house**	
	-	**Switchyard**	

Stress:

	-	**Optimum (Low)**
X	-	**Moderate**
	-	**Extreme (High)**

Cognitive
HPRVD1

Cue:
RPV level lower than -45" (or -122" if initially unisolated) and decreasing. Attempts to initiate HP injection have failed and MSIVs are closed. Suppression pool temperature is rising as steam is discharged through MSRVs.



Reference for System Time: MAAP CASE01, loss of all injection into RPV. The time relates to the window available once the RPV level reaches TAF. The available to recognize the need for the action and align low pressure systems before the RPV level reaches TAF is approx 40 min.

Reference for Manipulation Time: Simulator observations indicate all six MSIVs can be opened within seconds.

Duration of time window available for action (TW): 7.00 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes		Yes
X	Rule		No		No	X	No

Sigma: 4.0e-01

HEP: 1.0e-07

Execution Unrecovered

HPRVD1

Table 2: HPRVD1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
C1-4	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Line up, start pumps, and raise injection systems to the max						Comments:						
C1-8	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Verify alignment and pumps running while waiting for RPV to reach TAF.						Comments:						
C2-7	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Open 6 ADS valves						Comments:						
C2-8 through 13	1.3E-3	20-7	1	E	5							6.5e-03
Actions: SRO Verify SRVs opened and depressurization						Comments:						
C1-13 and 14	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Verify Maximum injection into RPV and refill						Comments:						

Execution Recovery

HPRVD1

Table 3: HPRVD1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
C1-4		**Line up, start pumps, and raise injection systems to the max**	**2.6e-03**				**1.4e-04**
	C1-8	Verify alignment and pumps running while waiting for RPV to reach TAF.		2.6e-03	LD	5.2e-02	
C2-7		**Open 6 ADS valves**	**6.5e-03**				**5.4e-05**
	C2-8 through 13	SRO Verify SRVs opened and depressurization		6.5e-03	LD	5.6e-02	
	C1-13 and 14	Verify Maximum injection into RPV and refill		6.5e-03	MD	1.5e-01	
		Total Unrecovered:	**9.1e-03**			**Total Recovered:**	**1.9e-04**

HRWWV1

ALIGN HARDENED WETWELL VENT FOR SP COOLING

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	05/12/04
Cognitive Method:	CDBTM/THERP

Table 1: HRWWV1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	3.8e-03	3.8e-03
P_{exe}	3.8e-02	3.8e-02
Total HEP		4.2e-02
Error Factor		5

HFE Scenario Description:
This action is challenged when no suppression pool cooling is available and the containment pressure can not be maintained below 55 psig by other means. At the point this action is required, multiple systems will have failed.
Failure to accomplish this action is assumed to lead to loss of containment pressure control and breach.

Related Human Interactions:
As this action is not questioned unless multiple failures have occurred, the operating crew will be heavily involved in recovery actions. In addition, it is assumed that additional personnel will be arriving to support the crew.

Performance Shaping Factors:
As many systems will have failed at this point, the crew will be under high stress.

Procedure and step governing HI:
EOI-2, PC/P-13 to P-17
EOI App 13

Training:

	-	**None**	
X	-	**Classroom**	Frequency: 1
X	-	**Simulator**	Frequency: 1

Degree of Clarity of Cues & Indications:

X - **Very Good**
- **Average**
- **Poor**

Human-Machine Interface:

X - **Control Room Panels**
- **Local Control Panels**
- **Local Equipment**

Special Requirements:

Tools	Parts	Clothing
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

X - **Skills**
- **Rule**
- **Knowledge**

Complexity of Response

Cognitive	Execution
X - Complex	X - Complex
- Simple	- Simple

Environment:

Lighting	Heat/Humidity
- Normal	- Normal
X - Emergency	X - Hot / Humid
- Portable	- Cold

Radiation	Atmosphere
X - Background	X - Normal
- Green	- Steam
- Yellow	- Smoke
- Red	- Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	Control Room Front Panels	
	-	Control Room Back Panels	
	-	Hot Shutdown Panels	
X	-	Auxiliary Building	With Difficulty
	-	Electrical Building	
	-	Containment	
	-	Pump house	
	-	Switchyard	

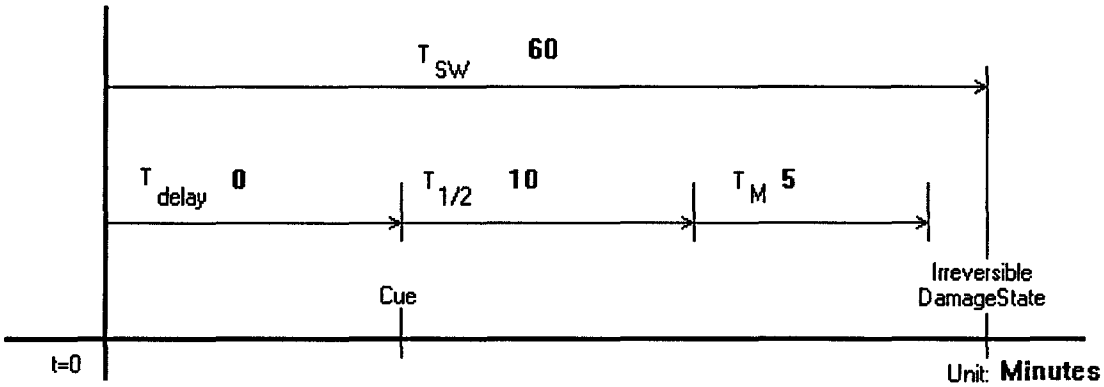
Stress:

- - Optimum (Low)
- - Moderate
- X - Extreme (High)

Cognitive Unrecovered

HRWWV1

Cue:
High containment pressure alarms. High drywell temperature



Reference for System Time: Not time sensitive. Gradual buildup of PC pressure

Reference for Manipulation Time: Simulator walk-through

Duration of time window available for action (TW): 45.00 Minutes

Table 2: HRWWV1 COGNITIVE UNRECOVERED

Pc Failure Mechanism	Branch	HEP
Pc_a: Availability of Information		
Pc_b: Failure of Attention	l	7.5e-04
Pc_c: Misread/miscommunicate data		
Pc_d: Information misleading	b	3.0e-03
Pc_e: Skip a step in procedure		
Pc_f: Misinterpret instruction		
Pc_g: Misinterpret decision logic		
Pc_h: Deliberate violation		
Sum of Pc_a through Pc_h = Initial Pc =		3.8e-03

Cognitive Recovery

HRWWV1

Table 3: HRWWV1 COGNITIVE RECOVERY

	Initial HEP	Self-Review	Extra Crew	STA Review	Shift Change	ERF Review	Recovery Matrix	DF	Multiply HEP By	Override Value	Final Value
Pc_a:		-	-	-	-	-	NC	-	1.0		
Pc_b:	7.5e-04	-	-	-	-	-	NC	-	1.0		7.5e-04
Pc_c:		-	-	-	-	-	NC	-	1.0		
Pc_d:	3.0e-03	-	-	-	-	-	NC	-	1.0		3.0e-03
Pc_e:		-	-	-	-	-	NC	-	1.0		
Pc_f:		-	-	-	-	-	NC	-	1.0		
Pc_g:		-	-	-	-	-	NC	-	1.0		
Pc_h:		-	-	-	-	-	NC	-	1.0		
										Sum of Pc_a through Pc_h = Initial Pc =	3.8e-03

Recovery Factors identified:

Execution Unrecovered

HRWWV1

Table 4: HRWWV1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
App 13,2b to 2d	3.8E-3	20-7	2	E	5							1.9e-02
Actions: Place keylock switch in Open HS-64-222B and open FCV-64-222.						Comments:						
App 13, 2e to 2g	3.8E-3	20-7	2	E	5							1.9e-02
Actions: Place keylock switch in Open HS-64-221B and open FCV-64-221.						Comments:						

Execution Recovery

HRWWV1

Table 5: HRWWV1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
App 13,2b to 2d		Place keylock switch in Open HS-64-222B and open FCV-64-222.	1.9e-02				
App 13, 2e to 2g		Place keylock switch in Open HS-64-221B and open FCV-64-221.	1.9e-02				
		Total Unrecovered:	3.8e-02			Total Recovered:	3.8e-02

HRRHRX

RECOVER RHR VIA CROSSTIE FROM UNIT 2

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	10/05/05
Cognitive Method:	HCR/ORE/THERP

Table 1: HRRHRX SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	N/A	3.0e-03
P_{exe}	1.2e-01	6.1e-02
Total HEP		6.4e-02
Error Factor		5

HFE Scenario Description:
Following successful shutdown and initiation of some form of injection has enabled the RPV level to be recovered.

At some later time the injection systems fail and the operators determine that the RPV level cannot be maintained above +2" with the preferred systems listed in EOI-1, Step RC/L-4. At this point, they transition to step RC/L-8 and determine it is necessary to crosstie RHR to another unit in order to maintain RPV level above -162".

Failure to initiate the crosstie when no other injection systems are available will result in core damage. If no other alternate means of RPV and SP cooling can be implemented, the SP will gradually heat up, resulting in over pressurization and loss of containment.

Related Human Interactions:
On going actions attempting to recover Unit 1 systems.

Performance Shaping Factors:
At the point this action is needed, multiple other systems will be unavailable and actions will be underway to recover primary systems. This action requires actions in multiple locations, including local actions in the auxiliary instrument room involving lifting and booting breaker contacts. It also requires coordinating actions between the three units. Therefore, the model can take credit for this action only if RPV injection has initially succeeded to the extent that they will get adequate time to successfully accomplish all the required actions.

Procedure and step governing HI:
EOI-1, RC/L-8, App 7C

Training:

	-	None	
X	-	Classroom	Frequency: 1
X	-	Simulator	Frequency: 1

Degree of Clarity of Cues & Indications:

	-	Very Good
X	-	Average
	-	Poor

Human-Machine Interface:

X	-	Control Room Panels
X	-	Local Control Panels
X	-	Local Equipment

Special Requirements:

Tools		Parts		Clothing	
X	Required	X	Required		Required
	Adequate		Adequate	X	Adequate
	Available		Available		Available

Type of Response:

	-	Skills
X	-	Rule
	-	Knowledge

Complexity of Response

Cognitive			Execution		
X	-	Complex	X	-	Complex
	-	Simple		-	Simple

Environment:

Lighting			Heat/Humidity		
X	-	Normal	X	-	Normal
	-	Emergency		-	Hot / Humid
	-	Portable		-	Cold

Radiation			Atmosphere		
X	-	Background	X	-	Normal
	-	Green		-	Steam
	-	Yellow		-	Smoke
	-	Red		-	Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	**Control Room Front Panels**	Accessible
	-	**Control Room Back Panels**	
	-	**Hot Shutdown Panels**	
X	-	**Auxiliary Building**	Accessible
	-	**Electrical Building**	
	-	**Containment**	
	-	**Pump house**	
	-	**Switchyard**	

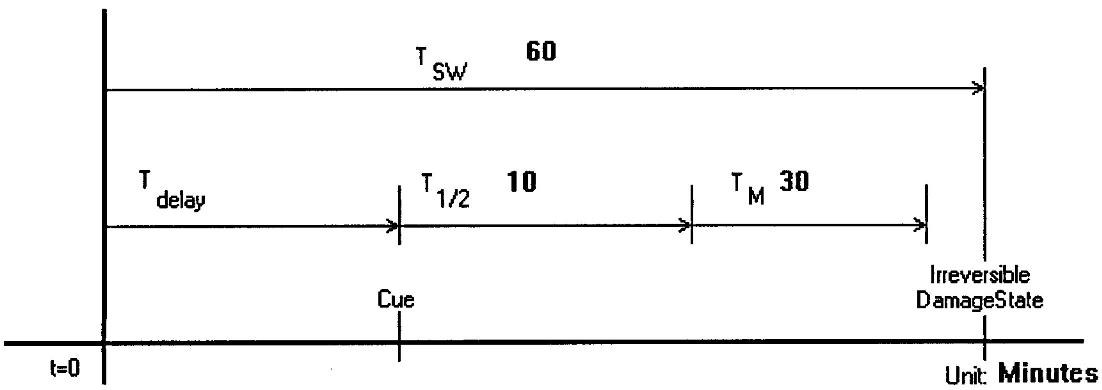
Stress:

	-	**Optimum (Low)**
X	-	**Moderate**
	-	**Extreme (High)**

Cognitive

HRRHRX

Cue:
RPV level declining and cannot be maintained above +2". Indications of failures of a variety of cooling systems.



Reference for System Time: System time of 60 minutes is assumed to be bounding, as thermal hydraulic CASE01 calculates over 60 minutes to core melt with no RPV injection following trip.

Reference for Manipulation Time: Time for local action estimated to be 30 minutes based on conversations with licensed operators.

Duration of time window available for action (TW): 20.00 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes		Yes
X	Rule		No		No	X	No

Sigma: 4.0e-01

HEP: 3.0e-03

Execution Unrecovered

HRRHRX

Table 2: HRRHRX EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
1b.	3.8E-3	20-7	2	E	5	3.8E-3	20-13	2	E	5	.076	7.6e-02
Actions: In Aux. Instr. Rm., lift and boot relay contacts to defeat RHR Pump suction Vlv interlocks						Comments: First action: requires acting carefully under pressure. Two boots must be installed. Double error rate.						
1b.3)	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Notify RO that action completed (verify by communication)						Comments:						
1c	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Locally close 2 breakers to RHR crosstie valves						Comments:						
1d.	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Unit 2 RO lines up RHR for crosstie						Comments:						
1e-h	3.8E-3	20-7	2	M	2							7.6e-03
Actions: U1 RO steps to inhibit U1 LPCI to prepare for crosstie						Comments: Includes inhibit min flow paths and closing injection valves. 2 actions.						
1i	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Locally Rack Out U1 2 RHR Pump breakers						Comments: Dispatch from control room to two separate compartments						
1j.	3.8E-3	20-7	2	M	2							7.6e-03
Actions: U1 RO open 3 crosstie valves to U1 RHR						Comments:						
1k.	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Verify U1 discharge press > 45 psig						Comments:						
1l.-o.	3.8E-3	20-7	2	M	2							7.6e-03

Actions: U2 RO open injection valve and adjust flow to control injection <5000 gpm						Comments:						
1end	3.8E-3	20-7	2	M	2							7.6e-03
Actions: Verify RPV recovers level						Comments:						

Execution Recovery

HRRHRX

Table 3: HRRHRX EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
1b.		**In Aux. Instr. Rm., lift and boot relay contacts to defeat RHR Pump suction Vlv interlocks**	**7.6e-02**				**3.8e-02**
	1b.3)	Notify RO that action completed (verify by communication)		7.6e-03	HD	5.0e-01	
1c		**Locally close 2 breakers to RHR crosstie valves**	**7.6e-03**				**3.8e-03**
	1k.	Verify U1 discharge press > 45 psig		7.6e-03	HD	5.0e-01	
1d.		**Unit 2 RO lines up RHR for crosstie**	**7.6e-03**				**3.8e-03**
	1k.	Verify U1 discharge press > 45 psig		7.6e-03	HD	5.0e-01	
1e-h		**U1 RO steps to inhibit U1 LPCI to prepare for crosstie**	**7.6e-03**				**3.8e-03**
	1k.	Verify U1 discharge press > 45 psig		7.6e-03	HD	5.0e-01	
1i		**Locally Rack Out U1 2 RHR Pump breakers**	**7.6e-03**				**3.8e-03**
	1k.	Verify U1 discharge press > 45 psig		7.6e-03	HD	5.0e-01	
1j.		**U1 RO open 3 crosstie valves to U1 RHR**	**7.6e-03**				**3.8e-03**
	1k.	Verify U1 discharge press > 45 psig		7.6e-03	HD	5.0e-01	
1l.-o.		**U2 RO open injection valve and adjust flow to control injection <5000 gpm**	**7.6e-03**				**3.8e-03**
	1end	Verify RPV recovers level		7.6e-03	HD	5.0e-01	
		Total Unrecovered:	**1.2e-01**			**Total Recovered:**	**6.1e-02**

HPHPE1

CONTROL HPCI/RCIC INJECTION TO COOL DOWN RPV, FIRST 6 HOURS

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	07/08/04
Cognitive Method:	HCR/ORE/THERP

Table 1: HPHPE1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	N/A	5.4e-04
P_{exe}	2.6e-03	2.6e-03
Total HEP		3.1e-03
Error Factor		5

HFE Scenario Description:
Transient with loss of feedwater. Successful scram and initiation of HPCI/RCIC.
The HPCI/RCIC have flow controllers that allow the operators to adjust injection. Because of its high capacity, HPCI flow must be brought under control rapidly. Once the RPV level has been stabilized, the operator must adjust HPCI pump flow against a lowering pressure due to cool down and a gradual reduction in decay heat. If left alone the HPCI pump would gradually provide more water than required and the RPV level will rise. These effects will occur over the period of a few minutes.
Trip at +51" will place a demand on the HPCI/RCIC to restart, presenting the additional possibility of a demand related failure.

Related Human Interactions:
This action includes actions to depressurize, since HPCI may be used in test flow to provide heat removal. However, operators may also cycle selected SRVs to assist in cool down.

Performance Shaping Factors:
HPCI controller is straightforward, and the operators are well trained in its use.

Procedure and step governing HI:
EOI-1 RC/L & RC/P

Training:

	-	**None**	
X	-	**Classroom**	Frequency: 1
X	-	**Simulator**	Frequency: 4

Degree of Clarity of Cues & Indications:

X - **Very Good**
- **Average**
- **Poor**

Human-Machine Interface:

X - **Control Room Panels**
- **Local Control Panels**
- **Local Equipment**

Special Requirements:

Tools	Parts	Clothing
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

- **Skills**

X - **Rule**
- **Knowledge**

Complexity of Response

Cognitive	Execution
- Complex	- Complex
X - Simple	X - Simple

Environment:

Lighting	Heat/Humidity
X - Normal	X - Normal
- Emergency	- Hot / Humid
- Portable	- Cold

Radiation	Atmosphere
X - Background	X - Normal
- Green	- Steam
- Yellow	- Smoke
- Red	- Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	**Control Room Front Panels**	Accessible
	-	**Control Room Back Panels**	
	-	**Hot Shutdown Panels**	
	-	**Auxiliary Building**	
	-	**Electrical Building**	
	-	**Containment**	
	-	**Pump house**	
	-	**Switchyard**	

Stress:

- **Optimum (Low)**

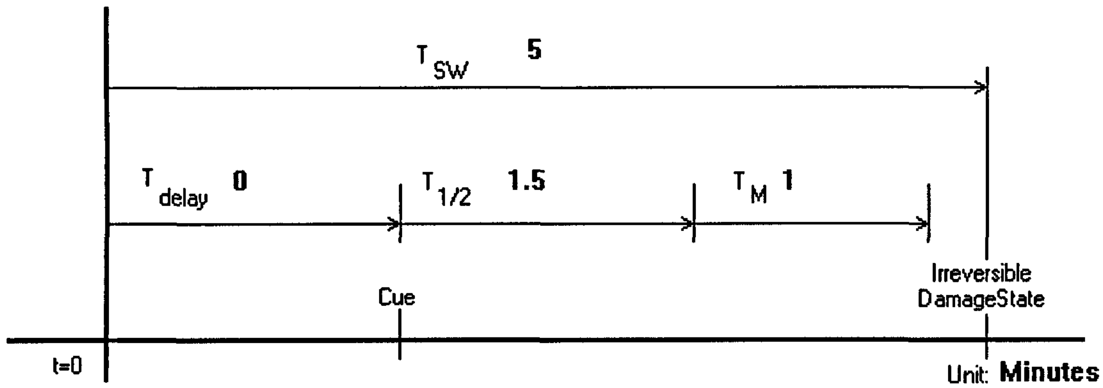
X - **Moderate**

- **Extreme (High)**

Cognitive

HPHPE1

Cue:
RPV level trending out of acceptable band. High level alarm at +39", Low level alarms at +2", -45" and -122".



Reference for System Time: Time estimated based on mismatch of HPCI flow and boiling rate based on simulator runs during walk through with operators.

Reference for Manipulation Time: Simulator Observations

Duration of time window available for action (TW): 2.50 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes	X	Yes
X	Rule		No		No		No

Sigma: 3.0e-01

HEP: 5.4e-04

Execution Unrecovered

HPHPE1

Table 2: HPHPE1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
RC/L-4, ARP High Lv	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Reduce HPI flow to bring and control level within proper range						Comments: HPCI						

Execution Recovery

HPHPE1

Table 3: HPHPE1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
RC/L-4, ARP High Lv		Reduce HPI flow to bring and control level within proper range	2.6e-03				
		Total Unrecovered:	2.6e-03			Total Recovered:	2.6e-03

HPHPR1

RESTART, CONTROL RPV LVL W HPCI/RCIC, GIVEN HIGH LVL TRIP

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	10/17/05
Cognitive Method:	HCR/ORE/THERP

Table 1: HPHPR1 SUMMARY

Analysis Results:	without Recovery	with Recovery
P_{cog}	N/A	2.6e-04
P_{exe}	5.2e-03	1.7e-03
Total HEP		1.9e-03
Error Factor		5

HFE Scenario Description:
This action is questioned after the HPCI has tripped on high level due to lack of proper adjustment of injection flow during the initial recovery of level, when flow can be maximum and operator work load is high.

Following that trip the level gradually lowers giving time for operators to restart HPCI and establish a balance of flow with decay heat boil off. If the HPCI restarts, the required actions needed to maintain control are the same as HPHPE1.

Failure to manually recover HPI is assumed to result in RPV level continuing to lower, requiring that the RPV be depressurized and low pressure injection systems be initiated. The simplifying assumption is made that the HPCI/RCIC will not start following a second trip.

Related Human Interactions:
Action HPHPE1 has failed.

Depending on how long after shutdown the trip occurred, the RPV level will gradually decline to -45" where HPCI will reinitiate. A simulator run indicates that sufficient time (tens of minutes) are required for this occur. It is judged that these time is sufficient to significantly reduce any dependence between this action and the previous failure.

Failure to manually recover HPI is assumed to result in RPV level continuing to lower, requiring that the RPV be depressurized and low pressure injection systems be initiated. The simplifying assumption is made that the HPCI/RCIC will not start following a second trip.

Performance Shaping Factors:
If they have not caught it earlier, the HPCI/RCIC trip at +51 in will alert the operators that the HPCI/RCIC turbine controller is faulty. A faulty controller could make subsequent attempts to control RPV level manually difficult. This will cause then to focus on controlling HPCI.

Procedure and step governing HI:
EOI-RC/L-4

Training:

	-	**None**	
X	-	**Classroom**	Frequency: 1
X	-	**Simulator**	Frequency: 6

Degree of Clarity of Cues & Indications:

X	-	**Very Good**
	-	**Average**
	-	**Poor**

Human-Machine Interface:

X	-	**Control Room Panels**
	-	**Local Control Panels**
	-	**Local Equipment**

Special Requirements:

Tools	Parts	Clothing
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

	-	**Skills**
X	-	**Rule**
	-	**Knowledge**

Complexity of Response

Cognitive

	-	Complex
X	-	Simple

Execution

	-	Complex
X	-	Simple

Environment:

Lighting

X	-	Normal
	-	Emergency
	-	Portable

Radiation

X	-	Background
	-	Green
	-	Yellow
	-	Red

Heat/Humidity

X	-	Normal
	-	Hot / Humid
	-	Cold

Atmosphere

X	-	Normal
	-	Steam
	-	Smoke
	-	Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	Control Room Front Panels	Accessible
	-	Control Room Back Panels	
	-	Hot Shutdown Panels	
	-	Auxiliary Building	
	-	Electrical Building	
	-	Containment	
	-	Pump house	
	-	Switchyard	

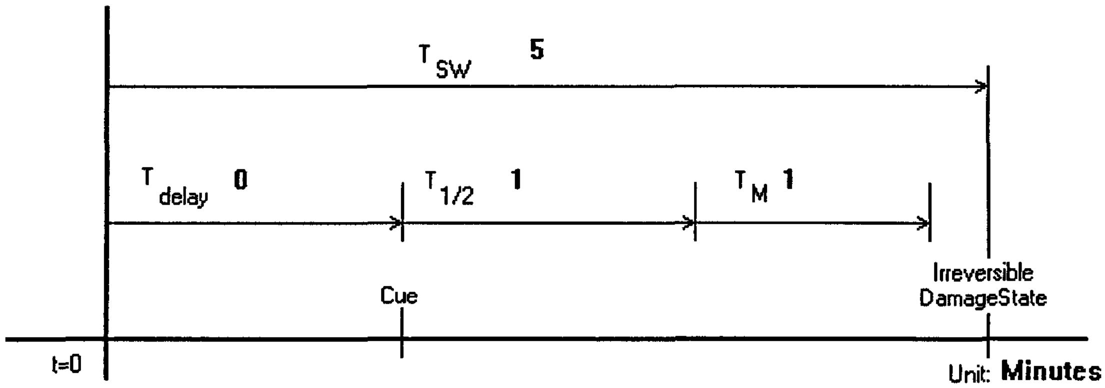
Stress:

- Optimum (Low)
- X - Moderate
- Extreme (High)

Cognitive

HPHPR1

Cue:
RPV level trending either high or low



Reference for System Time: Simulator run, 11/20/03, 40 minutes from high level trip to automatic restart. Operators also control to prevent high level trip

Reference for Manipulation Time: Simulator Observations

Duration of time window available for action (TW): 3.00 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes		Yes
X	Rule		No		No	X	No

Sigma: 4.0e-01

HEP: 2.6e-04

Execution Unrecovered

HPHPR1

Table 2: HPHPR1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
1	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Restart HPCI/RCIC						Comments:						
2	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Respond to low low RPV level and restart HPCI/RCIC						Comments:						
3	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Adjust flow as needed to keep within acceptable level						Comments:						
4	1.3E-3	20-7	1	M	2							2.6e-03
Actions: Respond to high/low RPV level alarm						Comments:						

Execution Recovery

HPHPR1

Table 3: HPHPR1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
1		**Restart HPCI/RCIC**	**2.6e-03**				**1.3e-03**
	2	Respond to low low RPV level and restart HPCI/RCIC		2.6e-03	HD	5.0e-01	
3		**Adjust flow as needed to keep within acceptable level**	**2.6e-03**				**3.8e-04**
	4	Respond to high/low RPV level alarm		2.6e-03	MD	1.5e-01	
		Total Unrecovered:	**5.2e-03**			**Total Recovered:**	**1.7e-03**

HPTAF1

CONTROL RPV LEVEL AT TAF, GIVEN ATWS WITH UNISOLATED RPV

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	07/06/04
Cognitive Method:	HCR/ORE/THERP

Table 1: HPTAF1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	N/A	2.6e-04
P_{exe}	1.3e-02	1.3e-02
Total HEP		1.3e-02
Error Factor		5

HFE Scenario Description:
ATWS has occurred without isolation. Feedwater is still operating and operators are attempting to insert rods and start SLC. This action is questioned when level control is needed to reduce power level. Failure to accomplish this action is assumed to lead to core damage.

Related Human Interactions:
Operators are injecting SLC into the core and observed RPV power level.

Performance Shaping Factors:
ATWS situation will present significant stress, but operators have trained extensively on these scenarios.

Procedure and step governing HI:
C5-8 through 13

Training:

- **None**

X - **Classroom** Frequency: 1

X - **Simulator** Frequency: 12

Degree of Clarity of Cues & Indications:

- **Very Good**
- **Average**

X - **Poor**

Human-Machine Interface:

X - **Control Room Panels**
- **Local Control Panels**
- **Local Equipment**

Special Requirements:

Tools	**Parts**	**Clothing**
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

- **Skills**

X - **Rule**
- **Knowledge**

Complexity of Response

Cognitive	**Execution**
X - Complex	X - Complex
- Simple	- Simple

Environment:

Lighting	**Heat/Humidity**
X - Normal	X - Normal
- Emergency	- Hot / Humid
- Portable	- Cold

Radiation	**Atmosphere**
X - Background	X - Normal
- Green	- Steam
- Yellow	- Smoke
- Red	- Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	Control Room Front Panels	
	-	Control Room Back Panels	
	-	Hot Shutdown Panels	
	-	Auxiliary Building	
	-	Electrical Building	
	-	Containment	
	-	Pump house	
	-	Switchyard	

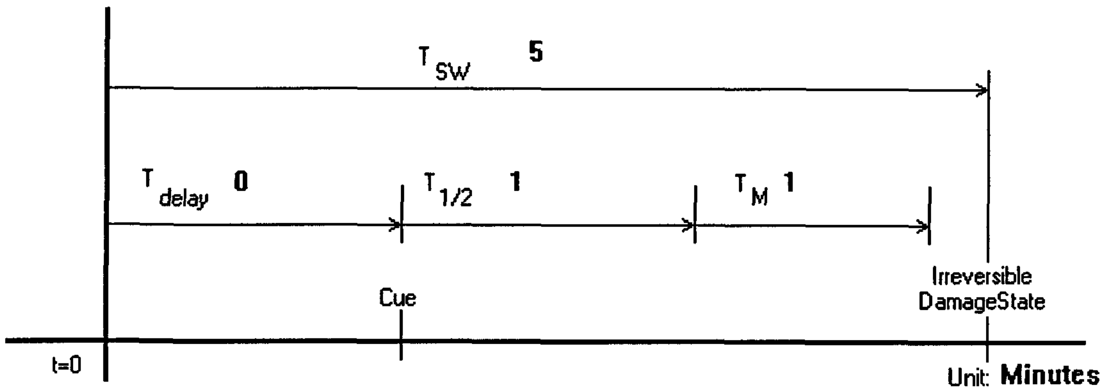
Stress:

	-	Optimum (Low)
	-	Moderate
X	-	Extreme (High)

Cognitive

HPTAF1

Cue:
RPV Level indications, reactor power level remaining above 4%



<u>Reference for System Time:</u> Calculation based on power level at TAF and 95 gal/in water within active core. (See HRA Notebook, Table 4-4). Additional one minute allowed to account for less heat deposited to SP, which delays need for level control.

<u>Reference for Manipulation Time:</u>
Simulator observations. Operator responsible for level control tracks level and power to determine first acceptable time to reinitiate injection after termination.

Duration of time window available for action (TW): 3.00 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes		Yes
X	Rule		No		No	X	No

Sigma: 4.0e-01

HEP: 2.6e-04

Execution Unrecovered

HPTAF1

Table 2: HPTAF1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
C5-10	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Terminate injection except for SLC and CRD when suppression pool > 110 F						Comments:						
C5-13	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Initiate FW as level reaches -162" and maintain above -185"						Comments:						

Execution Recovery

HPTAF1

Table 3: HPTAF1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
C5-10		Terminate injection except for SLC and CRD when suppression pool > 110 F	6.5e-03				
C5-13		Initiate FW as level reaches -162" and maintain above -185"	6.5e-03				
		Total Unrecovered:	1.3e-02			Total Recovered:	1.3e-02

HPSIV1

DEFEAT MSIV CLOSURE LOGIC, GIVEN ATWS WITH TURBINE TRIP

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	10/21/03
Cognitive Method:	HCR/ORE/THERP

Table 1: HPSIV1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{coq}	N/A	2.4e-01
P_{exe}	3.2e-02	3.2e-02
Total HEP		2.7e-01
Error Factor		1

HFE Scenario Description:
Initiating event requiring reactor trip occurred, but reactor power has not declined to decay heat levels. Reactor has not yet isolated and the operators have recognized the ATWS, initiated RPV level reduction and SLC injection into the RPV.

Related Human Interactions:
Operators are accomplishing a variety of actions related to responding to the ATWS and transient alarms.
Alternate control rod insertion underway (PSA takes no credit taken for its success)
SLC being initiated (HPSLC1=S)
If this action is not done before

Performance Shaping Factors:

Procedure and step governing HI:
EOI-1 RC/P-9, Appendix 8A
C5-4, Appendix 8A

Training:

	-	**None**	
X	-	**Classroom**	Frequency: 1
X	-	**Simulator**	Frequency: 8

Degree of Clarity of Cues & Indications:

X	-	**Very Good**
	-	**Average**
	-	**Poor**

Human-Machine Interface:

	-	**Control Room Panels**
X	-	**Local Control Panels**
	-	**Local Equipment**

Special Requirements:

Tools		Parts		Clothing	
	Required	X	Required		Required
	Adequate		Adequate		Adequate
	Available		Available		Available

Type of Response:

	-	**Skills**
X	-	**Rule**
	-	**Knowledge**

Complexity of Response

Cognitive			Execution		
X	-	Complex	X	-	Complex
	-	Simple		-	Simple

Environment:

Lighting			Heat/Humidity		
X	-	Normal	X	-	Normal
	-	Emergency		-	Hot / Humid
	-	Portable		-	Cold
Radiation			**Atmosphere**		
X	-	Background	X	-	Normal
	-	Green		-	Steam
	-	Yellow		-	Smoke
	-	Red		-	Respirator required

Equipment Accessibility:

		Location	Accessibility
	-	**Control Room Front Panels**	
	-	**Control Room Back Panels**	
	-	**Hot Shutdown Panels**	
X	-	**Auxiliary Building**	With Difficulty
	-	**Electrical Building**	
	-	**Containment**	
	-	**Pump house**	
	-	**Switchyard**	

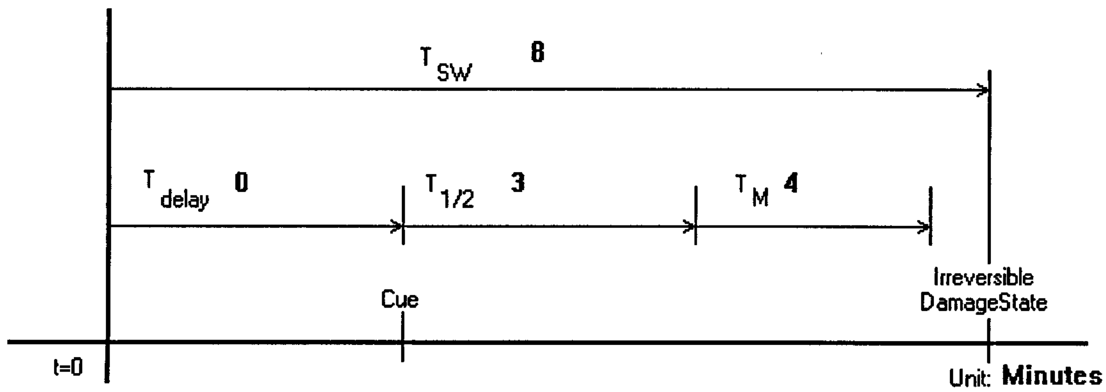
Stress:

	-	**Optimum (Low)**
	-	**Moderate**
X	-	**Extreme (High)**

Cognitive

HPSIV1

Cue:
RPV level is declining towards -122"
Power level remains above shutdown
MSIVs cycling to maintain RPV pressure at 1,050 psig



Reference for System Time: 3 to 5 min available to avoid level/ power control requirement. SP reached 170 F in 20 minutes

Reference for Manipulation Time: Simulator observations

Duration of time window available for action (TW): 1.00 Minutes

Sigma Decision Tree

	Skill vs. Rule		Procedures		Training		Stress
	Skill	X	Yes	X	Yes		Yes
X	Rule		No		No	X	No

Sigma: 4.0e-01

HEP: 2.4e-01

Execution Unrecovered

HPSIV1

Table 2: HPSIV1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
0	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Obtain four banana jack jumpers from EOI Equipment Storage Box						Comments:						
1	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Install jumper in Panel 9-15						Comments:						
2	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Install second jumper in Panel 9-15						Comments:						
3	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Install jumper in Panel 9-17						Comments:						
4	1.3E-3	20-7	1	E	5							6.5e-03
Actions: Install second jumper in Panel 9-17						Comments:						

Execution Recovery

HPSIV1

Table 3: HPSIV1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
0		Obtain four banana jack jumpers from EOI Equipment Storage Box	6.5e-03				
1		Install jumper in Panel 9-15	6.5e-03				
2		Install second jumper in Panel 9-15	6.5e-03				
3		Install jumper in Panel 9-17	6.5e-03				
4		Install second jumper in Panel 9-17	6.5e-03				
		Total Unrecovered:	3.2e-02			Total Recovered:	3.2e-02

HPSPC1

ALIGN RHR FOR SUPPRESSION POOL COOLING

Basic Event Summary

Analyst:	Dykes, AA
Rev. Date:	05/12/04
Cognitive Method:	CDBTM/THERP

Table 1: HPSPC1 SUMMARY

Analysis Results:	**without Recovery**	**with Recovery**
P_{cog}	1.2e-03	3.3e-06
P_{exe}	2.6e-03	2.8e-06
Total HEP		6.1e-06
Error Factor		10

HFE Scenario Description:
This action may be required during a transient with successful scram. The suppression pool provides the heat sink for pressure relief and the HPCI/RCIC pumps. If the RPV is isolated, or one or more the SRVs stick open during an unisolated transient, the suppression pool will gradually heat up.
Failure to accomplish this action will result in gradual heat up of the suppression pool over the course of hours, leading to eventual loss of RCIC/HPCI injection and over pressurization of the containment. If the operators fail to accomplish this action, it is assumed that they will also fail to align the wetwell vent. HRWWV1 is credited only for recovering from hardware failures leading to loss of suppression pool cooling.

Related Human Interactions:
Response activities associated with EOIs and AOI-100-1

Performance Shaping Factors:
This action is accomplished during normal cool down activities following isolation. Operators are well trained on the importance of the suppression pool as a heat sink and the necessity of removing heat from suppression pool to maintain this capacity.

Procedure and step governing HI:
EOI-2 SP/T-1, App 17A

Training:

	-	**None**	
X	-	**Classroom**	Frequency: 1
X	-	**Simulator**	Frequency: 12

Degree of Clarity of Cues & Indications:

X - Very Good
- Average
- Poor

Human-Machine Interface:

X - Control Room Panels
- Local Control Panels
- Local Equipment

Special Requirements:

Tools	Parts	Clothing
Required	Required	Required
Adequate	Adequate	Adequate
Available	Available	Available

Type of Response:

- Skills
X - Rule
- Knowledge

Complexity of Response

Cognitive	Execution
- Complex	- Complex
X - Simple	X - Simple

Environment:

Lighting	Heat/Humidity
X - Normal	X - Normal
- Emergency	- Hot / Humid
- Portable	- Cold

Radiation	Atmosphere
X - Background	X - Normal
- Green	- Steam
- Yellow	- Smoke
- Red	- Respirator required

Equipment Accessibility:

		Location	Accessibility
X	-	Control Room Front Panels	Accessible
	-	Control Room Back Panels	
	-	Hot Shutdown Panels	
	-	Auxiliary Building	
	-	Electrical Building	
	-	Containment	
	-	Pump house	
	-	Switchyard	

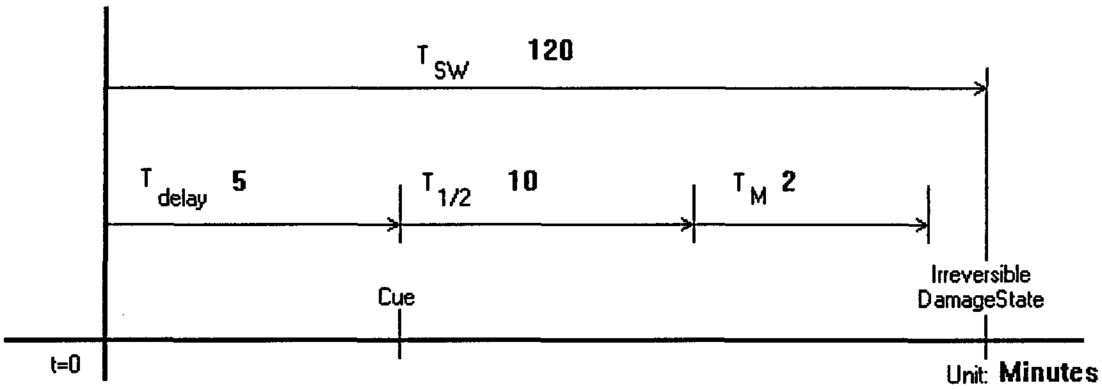
Stress:

X - Optimum (Low)
- Moderate
- Extreme (High)

Cognitive Unrecovered

HPSPC1

Cue:
Suppression pool temperature high temp alarm at +95 F. If SP continues to heat up, high temperature alarms at 110 F and again at 120 F. As SP temp rises, PC pressure also rises.



Reference for System Time: Not time sensitive - can be done over the course of hours as suppression pool gradually heats up.

Reference for Manipulation Time:
Simulator Observations: Required steps can be done within control room by one RO

Duration of time window available for action (TW): 103.00 Minutes

Table 2: HPSPC1 COGNITIVE UNRECOVERED

Pc Failure Mechanism	Branch	HEP
Pc_a: Availability of Information	A	neg.
Pc_b: Failure of Attention	D	1.5e-04
Pc_c: Misread/miscommunicate data	A	neg.
Pc_d: Information misleading	A	neg.
Pc_e: Skip a step in procedure	A	1.0e-03
Pc_f: Misinterpret instruction	A	neg.
Pc_g: Misinterpret decision logic	K	neg.
Pc_h: Deliberate violation	A	neg.
	Sum of Pc_a through Pc_h = Initial Pc =	1.2e-03

Cognitive Recovery

HPSPC1

Table 3: HPSPC1 COGNITIVE RECOVERY

	Initial HEP	Self-Review	Extra Crew	STA Review	Shift Change	ERF Review	Recovery Matrix	DF	Multiply HEP By	Override Value	Final Value
Pc_a:	neg.	-	-	-	-	-	NC	-	1.0		
Pc_b:	1.5e-04	-	-	X	-	-	1.0e-01	-	1.0e-01	1.3e-02	2.0e-06
Pc_c:	neg.	-	-	-	-	-	NC	-	1.0		
Pc_d:	neg.	-	-	-	-	-	NC	-	1.0		
Pc_e:	1.0e-03	-	X	-	-	-	5.0e-01	-	5.0e-01	1.3e-03	1.3e-06
Pc_f:	neg.	-	-	-	-	-	NC	-	1.0		
Pc_g:	neg.	-	-	-	-	-	NC	-	1.0		
Pc_h:	neg.	-	-	-	-	-	NC	-	1.0		
Sum of Pc_a through Pc_h = Initial Pc =											3.3e-06

Recovery Factors identified:

pcb and pce: Inattention and skip a step implies that other actions may initially take precedence over SP cooling. Multiple recovery opportunities account for override value of recovery factor.

1) pce only: Self check of RO in response to two additional high SP temperature alarms at 110 and120 F. Assume 0.1

2) SRO conducts periodic review of plant status against EOIs. Formally requests plant parameters for plant safety parameters: judged low dependency with operators. Assume MD

3) STA conducts independent reviews of critical plant parameters and notifies SRO of problems. Assume LD

4) Multiple opportunites to repeat the above cognitive operaitions over period of heat up. Assume HD

Estimate multiple recovery factor = 0.1*.5*.05*.5 =

Execution Unrecovered

HPSPC1

Table 4: HPSPC1 EXECUTION UNRECOVERED

Step	Omission					Commission					Total	
		Table	Item	Stress	Stress		Table	Item	Stress	Stress	Over	Per
Step No.	HEP	Ref.	Ref.	E/M/O	Value	HEP	Ref.	Ref.	E/M/O	Value	Ride	Step
2 a-c												0.0e+00
Actions: Verify/establish adequate RHRSW flow through heat exchangers						Comments: Verifies heat sink for cooling. Other top events covers its functionality. Not a critical step						
2 g.	1.3E-3	20-7	1	O	1							1.3e-03
Actions: Open RHR SYS I9II) SUPPR CHBR / POOL ISOL VLV						Comments:						
2 h.												0.0e+00
Actions: Verify desired RHR pump (s) operating						Comments: Included to show that overall functioning is continually considered. Since RHR pumps are operating, not a critical step						
2 i.	1.3E-3	20-7	1	O	1							1.3e-03
Actions: Throttle open RHR SYS I(II) SUPPR POOL CLG/TEST VLV to specified flow						Comments:						
2 i. 1)	1.3E-3	20-7	1	O	1	1.3E-3	20-10	2	O	1		2.6e-03
Actions: Verify flow within limits						Comments:						
2 k.	1.3E-3	20-7	1	O	1							1.3e-03
Actions: RO Monitor RHR Pump NPSH						Comments:						
STA	1.3E-3	20-7	1	O	1							1.3e-03
Actions: STA independent monitor of important plant safety parameters						Comments: STA records and tracks important plant safety parameters over time. The parameters that indicate failure to establish SP cooling are included on his safety parameter form.						

Execution Recovery

HPSPC1

Table 5: HPSPC1 EXECUTION RECOVERY

Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
2 g.		**Open RHR SYS I9II) SUPPR CHBR / POOL ISOL VLV**	**1.3e-03**				**1.4e-06**
	2 i. 1)	Verify flow within limits		2.6e-03	MD	1.5e-01	
	2 k.	RO Monitor RHR Pump NPSH		1.3e-03	LD	5.1e-02	
	STA	STA independent monitor of important plant safety parameters		1.3e-03	MD	1.4e-01	
2 i.		**Throttle open RHR SYS I(II) SUPPR POOL CLG/TEST VLV to specified flow**	**1.3e-03**				**1.4e-06**
	2 i. 1)	Verify flow within limits		2.6e-03	MD	1.5e-01	
	2 k.	RO Monitor RHR Pump NPSH		1.3e-03	LD	5.1e-02	
	STA	STA independent monitor of important plant safety parameters		1.3e-03	MD	1.4e-01	
2 a-c		**Verify/establish adequate RHRSW flow through heat exchangers**	**0.0e+00**				**0.0e+00**
2 h.		**Verify desired RHR pump (s) operating**	**0.0e+00**				**0.0e+00**
		Total Unrecovered:	**2.6e-03**			**Total Recovered:**	**2.8e-06**