ABB

ASEA BROWN BOVERI

May 8, 1992
LD-92-064

Docket No. 52-002

Attn: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: System 80+™ Supplements to RAI Responses

References:
1. ABB-CE Letter LD-92-038, Submittal Schedule, March 25, 1992
2. ABB-CE Letter LD-92-001, Response to RAIs, January 14, 1992
3. ABB-CE Letter LD-92-024, Response to RAIs, February 18, 1992
4. ABB-CE Letter LD-92-058, Shutdown Risk, April 30, 1992
5. NRC Letter, Severe Accident Design Features, April 9, 1992

Dear Sirs:

Enclosed with this letter are a series of attachments which provide information to supplement previous RAI responses. This corresponds to the commitment in Reference 1 to provide "miscellaneous RAI responses" as they are completed.

Attachment 1 provides documentation on the size and type of modeling elements used in the analysis of the containment structure.

Attachment 2 contains a commitment to use more conservative radiological dispersion factors in order to bound approximately 90% of sites in the United States. This information supplements the response to RAI 450.09.

Attachment 3 provides a statement on compliance with Regulatory Guide 1.97 for the Heated Junction Thermocouple probe and the classification of the probe as listed in Table 3.2-1 of CESSAR-DC.

Attachment 4 provides revisions to Chapter 8 of CESSAR-DC to reflect changes to the design of the electrical distribution system resulting from meetings with NRC staff, EPRI, and ABB-CE over the past several months. These revisions replace corresponding information provided in the responses

180084

ABB Combustion Engineering Nuclear Power

Combustion Engineering Inc. 1000 Prospect Hill Road Post Office Box 500 Windsor, Connecticut 06095-0500 Telephone (203) 688-1911 Fax (203) 285-9512 Telex 99297 COMBEN WSOR

D052
1/1

to RAIs submitted in References 2 and 3.

Attachment 5 provides additional analytical results for a steam line break accident assuming no credit for operation of the turbine stop or control valves. This information supplements the responses to RAIs 440.96 and 440.100. This attachment also includes a response to a question on termination of feedwater during a steam line break.

Attachment 6 provides information on the prevention of steam generator overfill after a tube rupture event. This information supplements the responses to RAIs 440.109, 440.86(c) and 440.106(1)(k).

Attachment 7 provides information on the critical heat flux correlation used for steam line break accidents. This information supplements the response to RAI 440.97.

Attachment 8 provides information to confirm that for ATWS analysis the full-power moderator temperature coefficient provides the most adverse results. This information supplements the response to RAI 440.111.

Attachment 9 provides responses to three questions on the steam generator tube rupture event and three other questions that arose during review of the Chapter 15 safety analysis by the Reactor Systems Branch.

Attachment 10 provides a statement that the technical specifications cannot include final setpoints until specific equipment is procured.

Attachment 11 provides additional information on the sizing of the Rapid Depressurization valves in the Safety Depressurization System. This information supplements the response to RAI 440.22.

Attachment 12 provides clarification on the System 80+ Reliability Assurance Program in response to the NRC discussion paper on this program.

Attachment 13 provides a report describing the application of Probabilistic Risk Assessment in the System 80+ design process. This fulfills the commitment made at the April 28 meeting with the PRA Branch and the commitment in Reference 1 to provide this report by May 31. Also at the April 28 meeting, the need for a discussion of design features which reduce shutdown risk was identified. A discussion of those design features is presented in Section 7 of the Shutdown Risk Report which was submitted via Reference 4.

Attachment 14 provides a summary of the System 80+ approach to severe accident prevention and mitigation. While this attachment is not a complete response to Reference 5, the information provided here addresses many of the issues in Reference 5. It is expected that much of the [illegible] this attachment will facilitate the preparation of the draft Safety Evaluation Report.

Attachment 15 provides responses to those RAIs from Reference 5 which address the issue of containment bypass. Also, this attachment is related to item 4 of the NRC's April 30, 1992 letter on additional technical and policy issues.

Attachment 16 provides soil data analyzed for the System 80+ soil-structure interaction analysis. Also, included are responses to ten action items identified at the meeting with the Structural and Geosciences reviewers the week of April 27, 1992.

Attachment 17 provides responses to several questions asked at the April 22-23 meeting on piping and mechanical design. A diagram showing the process for developing equipment specifications used for procurement will be provided in a separate submittal in the near future.

Attachment 18 provides a summary of ABB-CE's program to demonstrate adequate diversity of the software used in the Nuplex 80+ design. A detailed common mode failure analysis is being performed and, as a result of this analysis, design changes will be evaluated and implemented if necessary. This attachment responds to item 1 of the NRC's April 30, 1992 letter on additional technical and policy issues. ABB requests that results of a detailed common-mode-failure analysis be a fundamental element in the NRC's policy for determining the adequacy of software diversity and the need for analog instrumentation and hard-wired controls.

If you have any questions, please call me or Mr. Stan Ritterbusch at (203) 285-5206.

Very truly yours,

COMBUSTION ENGINEERING, INC.

C. B. Brinkman

C. B. Brinkman
Acting Director
Nuclear Systems Licensing

CBB/ser
cc: J. Trotter (EPRI)
T. Wambach (NRC)

ATTACHMENT 1

Attachment to Letter ALWR-416

The NRC, Mr. Tom Cheng, has questioned the use of the ANSYS finite element type STIF63 which is used in the System 80+™ containment analysis. Mr. Cheng noted that the plot of the containment finite model had straight lines between the nodes and called Duke Engineering & Services (J.F. Snipes, J.T. Oswald and R.J. P⁄rler) to ask if the elements are plate elements or shell elements. A plot of the model is included for information.

The ANSYS element type STIF63 is called an elastic quadrilateral shell element. It is actually a 4 node plate element with 6 degrees of freedom at each node, for a total of 24 degrees of freedom for each element. The element has both bending and membrane capabilities. An assemblage of these flat elements can produce a good approximation to a curved shell element surface provided that each flat element does not extend over more than a 15 degree arc. (Reference 1, pp. 4.0.22 and 4.63.2. A copy is attached.) The System 80+ containment model is generated with elements that do not extend beyond a 10 degree arc, with most elements closer to a 5 degree arc.

Isoparametric elements exist such as the ANSYS STIF93 element. This is an 8 node isoparametric shell element which is better suited to model shells. This is better suited because the element has an additional node between the corner nodes. These nodes may be located out of the plane of the element corner nodes. The element has a total of 48 degrees of freedom. The computer costs of running an analysis with this element is not justified when an analysis with the STIF63 quadrilateral shell is sufficiently accurate.

In general, the flat element is simpler to formulate and is a more cost effective method of analysis due to the fewer number of nodes and input required. The flat element by itself is limited in its ability to model shells because membrane and bending actions are uncoupled within the single element, simply because it is flat. The necessary coupling for the entire shell comes about because a membrane force in one element exerts an element normal force component on its neighbor. Thus, apart from requiring many elements to obtain accuracy, flat elements may display bending moments where there should be none.

A comparison of results using an 8 node isoparametric shell element and the ANSYS STIF63 element can be found in the ANSYS Verification Manual. (Reference 2, pp. C3.1-C3.2. A copy is attached.) The 8 node isoparametric solution is from Reference 3, Cook, pages 284-287. Both results are from elements which extend over a ~~10~~ 5 degree arc. The stress results varied by only 0.6%. This is considered accurate enough to justify not using the much more costly isoparametric element for the System 80+ containment analysis.

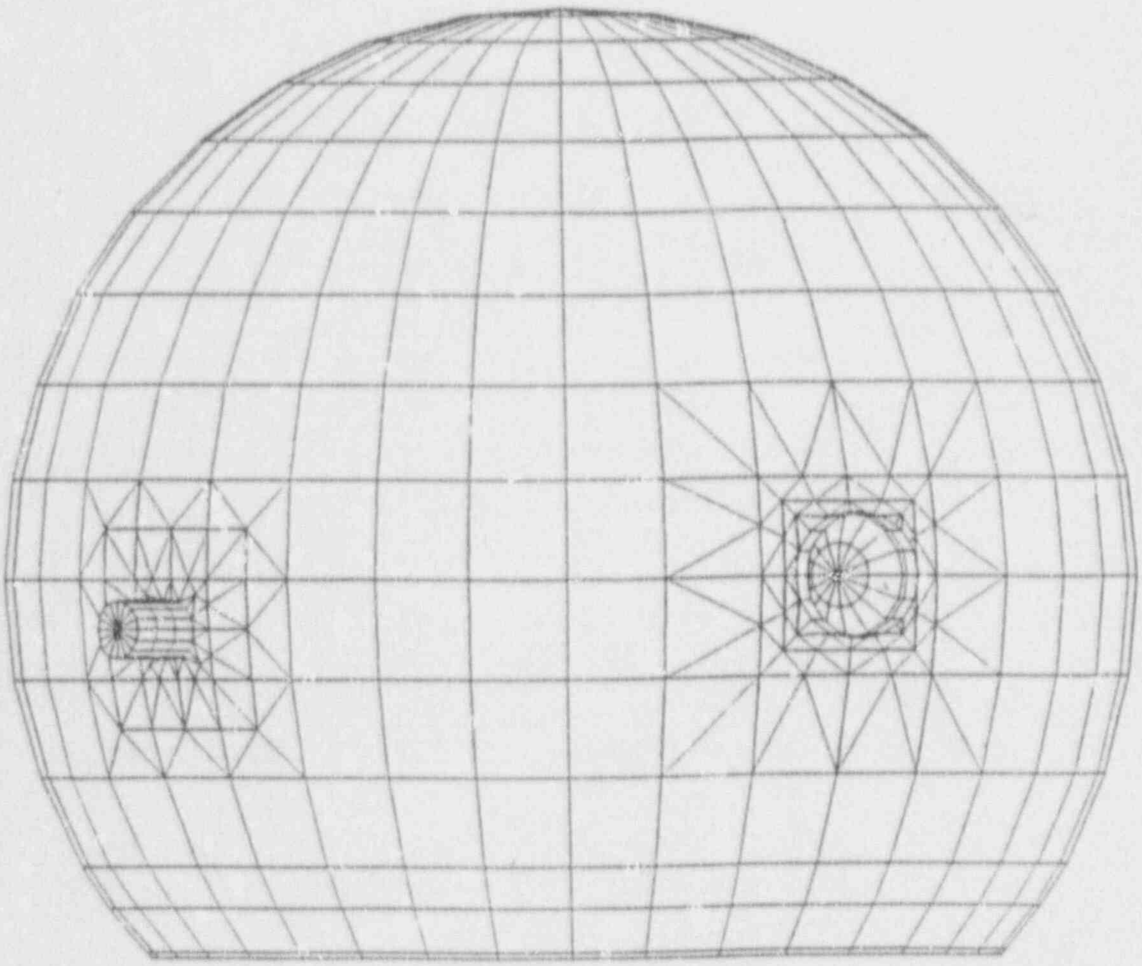
References

1. ANSYS Engineering System User's Manual, Swanson Analysis Systems, Inc., Houston, Pennsylvania, Revision 4.4, May, 1989.

2. ANSYS Engineering System Verification Manual, Swanson Analysis Systems, Inc., Houston, Pennsylvania, Revision 4.4, February, 1990.

3. Cook, R.D., "Concepts and Applications of Finite Element Analysis", Second Edition, John Wiley and Sons, Inc., New York, 1981.

ATTACHMENT TO
ALWR 416

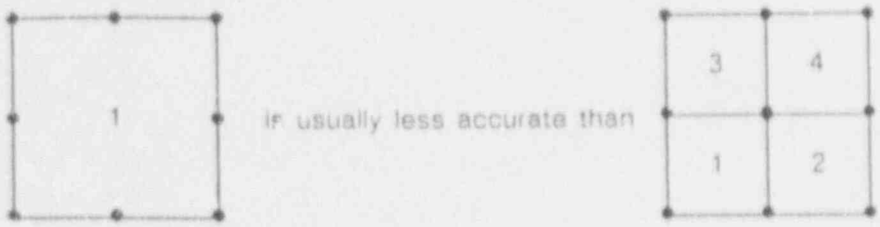


THREE DIMENSIONAL MODEL
OF
STEEL CONTAINMENT

SYSTEM 80+™

only in transition regions and not where simpler higher-order (Type b) elements will do. For example, the 4-node STIF42 element is recommended in place of an equivalent 8-node STIF82 element with all midside nodes removed. Nodes may also be removed after the element has been generated with the EMODIF command.

j) For a given mesh spacing, less accurate results are usually obtained with a 1:2 coarse model of quadratic elements over a nodal equivalent fine model of linear (Type b) elements. Note also that a quadratic element has no more integration points than a linear element.



Quadratic (Type c) Linear (Type b)

k) Simple meshes of higher-order elements used with the 2x2 integration point option (such as STIF82 and 93) may produce a singularity due to zero energy deformation (Ref. 29, Cocke).

l) Several features of the ANSYS program may not be available with the quadratic element types. For example:

1) Only corner nodes are used for section and hidden line displays.

2) Nodal stress data for printout and postprocessing are available only for the corner nodes.

3) Integration point stress data for printout and postprocessing are not available for all integration points.

Curved vs. Flat Elements - Another area subject to user preference is in the use of curved and flat elements. Again, each class of element has its advantages and disadvantages. For most practical cases, the majority of problems can be solved to a high degree of accuracy in a minimum amount of computer time with flat elements. Care must be taken, however, to insure that enough flat elements are used to model the curved surface adequately. Obviously, the smaller the element, the better the accuracy. It is recommended that the 3-D flat shell elements not extend over more than a 15° arc. Conical shell (axisymmetric line) elements should be limited to a 10° arc (or 5° if near the Y axis).

ATTACHMENT TO ALWR 416

4.63.2 Output Data

a) Printout - The printout associated with the shell element is summarized in Table 4.63.2. Several items are illustrated in Figure 4.63.2. A general description of element printout is given in Section 4.0.3. Printout includes the moments about the x face (MX), the moments about the y face (MY), and the twisting moment (MXY). The moments are calculated per unit length in the element coordinate system. The element stress directions are parallel to the element coordinate system.

b) Post Data - The post data associated with the shell element is shown below. The data are written on File12 if requested, as described in Section 4.0.4. TX, TY, TXY are the element in-plane forces per unit length (in element coordinates).

```
    1   TX
    2   TY
    3   TXY
  4-5   FOUND.PRESS.,SPARE
  6-8   MX,MY,MXY
1---------------------------
  9-12  SX,SY,SXY,SZ<TOP>
 13-20  9-12 @ <MID,BOT>

  21-24  SX,SY,SXY,SZ(I)<TOP>
  25-36  21-24 @ (J-L)<TOP>
  37-68  21-36 @ <MID,BOT>
2---------------------------
  69-71  SIG1,SIG2,SIG3(I)<TOP>
  72-73  S.I.,SIGE(I)<TOP>
  74-88  69-73 @ (J-L)<TOP>
 89-128  69-88 @ <MID,BOT>

129-131  SIG1,SIG2,SIG3<TOP>
132-133  S.I.,SIGE<TOP>
134-143  129-133 @ <MID,BOT>
144-146  XC,YC,ZC
147-149  AREA,TTOP,TBOT
150-155  PRESS(1-6)
3---------------------------
```

4.63.3 Theory

The membrane stiffness is the same as for the membrane shell element (STIF41), including the modified extra shapes. The bending stiffness is formed from the bending stiffness of four triangular shell elements (DKT formulation, Ref. 49 (Batoz, et al) and Ref. 59 (Razzaque)). Two triangles have one diagonal of the element as a common side and two triangles have the other diagonal of the element as a common side. The stiffness is obtained from the sum of the four stiffnesses divided by two.

4.63.4 Assumptions and Restrictions

Zero area elements are not allowed. This occurs most often whenever the elements are not numbered properly. Zero thickness elements or elements tapering down to a zero thickness at any corner are not allowed. The applied transverse thermal gradient is assumed to be linear through the thickness and uniform over the shell surface.

An assemblage of flat shell elements can produce a good approximation to a curved shell surface provided that each flat element does not extend over more than a 15° arc. If an elastic foundation stiffness is input, one-fourth of the total is applied at each node. Shear deflection is not included in this thin-shell element.

A triangular element may be formed by defining duplicate K and L node numbers as described in Section 4.0.9. The extra shapes are automatically deleted for triangular elements so that the membrane stiffness reduces to a constant strain formulation.

The four nodal points defining the element should lie in an exact flat plane; however, a small out-of-plane tolerance is permitted so that the element may

VMC3: Barrel Vault Roof Under Self Weight

Reference: Cook (Ref. 40) pp. 284-287

Analysis Type(s): Static analysis (KAN=0)

Element Type(s): Plastic quadrilateral shell elements (STIF43),
Elastic quadrilateral shell elements (STIF63),
8-node isoparametric shell elements (STIF93)

Test Case

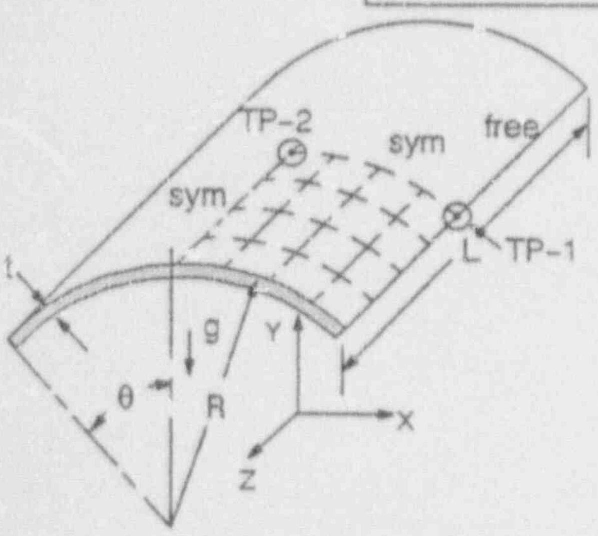
A cylindrical shell roof is subjected to gravity loading. The roof is supported by walls at each end and is free along the sides. Monitor the y displacement and bottom axial stress (σ_z) at target point 1, along with the bottom circumferential stress (σ_θ) at target point 2 for a series of test cases with increasing mesh refinement using quadrilateral and triangular element shapes. A companion problem that studies irregular element shapes is VMD2.

Material Properties

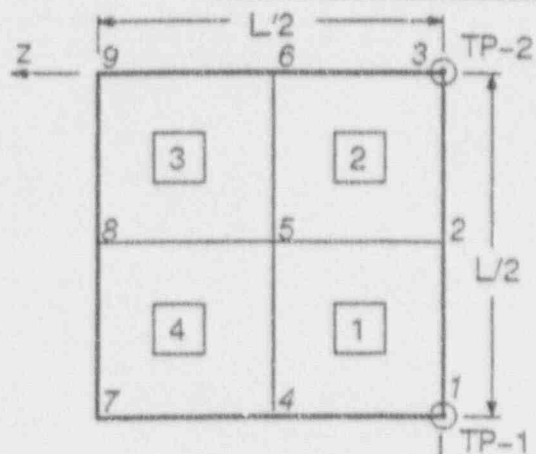
$E = 4.32 \times 10^8$ N/m^2
$\nu = 0.0$
$\rho = 36.7347$ kg/m^3

Geometric Properties

$L = 50$ m
$R = 25$ m
$t = 0.25$ m
$\theta = 40°$
$g = 9.8$ m/sec^2



Problem Sketch



Keypoint and Area Model

Parameter Definition

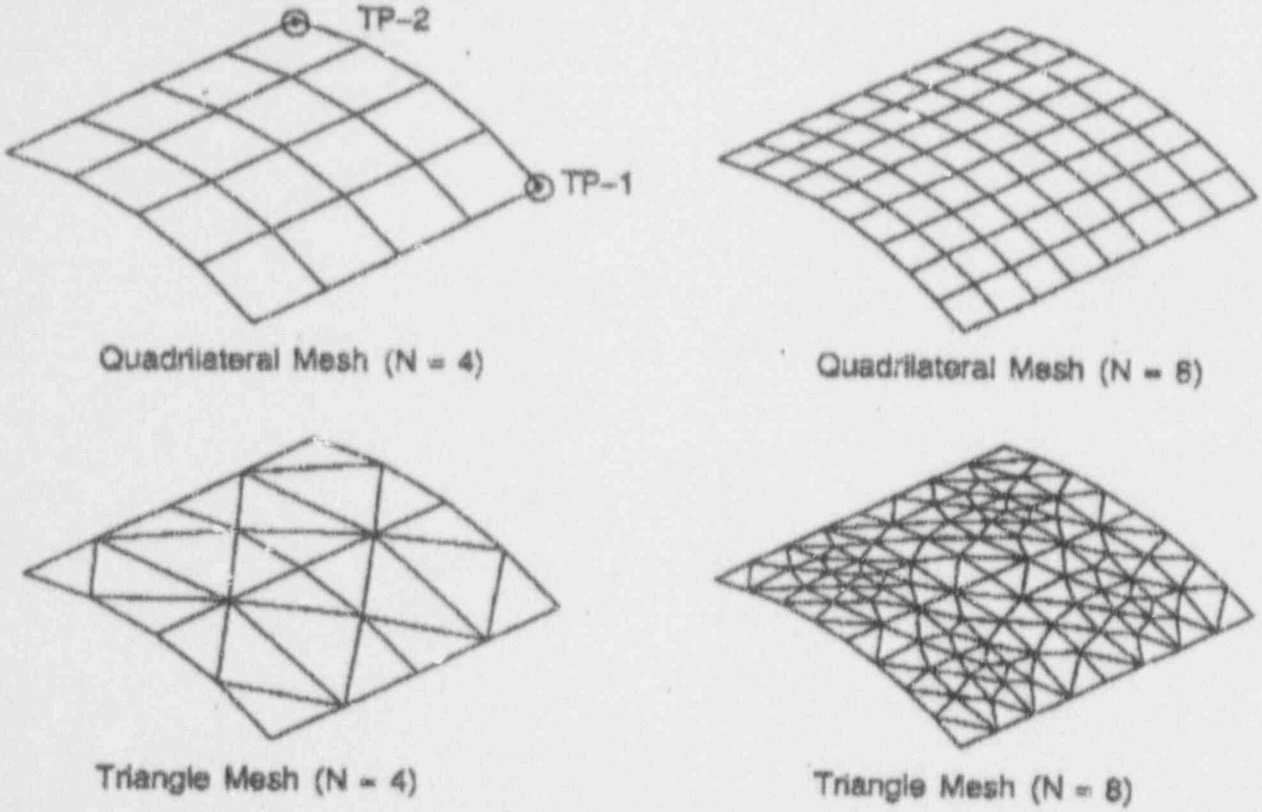
N = No. elements along each edge.

Loading and Boundary Conditions

At x = 0	Symmetric
At z = 0	Symmetric
At x = L/2	UX=UY=ROTZ=0

VMC3: Barrel Vault Roof Under Self Weight (continued)

Representative Mesh Options



Target Solution *

ETYP	N	DOF	UY(1), m	σ_z(1), Bottom, kPa	σ_θ (2), Bottom, kPa
Ref (40)	8	2310	.3016	358.42	-213.40

Results Comparison – Quadrilateral Elements

ETYP	N	DOF	Ratio		
			UY(1)	σ_z (1), Bottom	σ_θ (2), Bottom
43	4	150	1.048	.941	.984
43	8	486	1.012	1.001	.989
63	⇒ 10° 4	150	1.008	.928	1.017
63	⇒ 5° 8	486	.997	.994	.994
93	4	390	1.012	.955	1.030
93	8	1350	1.002	1.001	1.002

SYSTEM 80+ ANALYSIS USED MESHES AID COARSER THAN 10° ARCS.

ATTACHMENT 2

Section 2.3.4 of CESSAR-DC and the Chapter 15 safety analysis describe the dilution factors (X/Q) used in assessing radiological doses resulting from plant transients. At the Exclusion Area Boundary for the first two hours of the transient, the dilution factor used was 4.97x10-4 sec/m3 (see Table 2.3-1). In RAI 450.09, it was noted that such a dilution factor could preclude a large number of sites in the United States. In the response, ABB-CE agreed to revise the dilution factors and the corresponding doses, but did not provide specific values. The purpose of this transmittal is to confirm that the 0-2 hour dilution factor will be revised to a value of 1.0x10-3 sec/m3. This value is consistent with a forthcoming revision to the ALWR Utility Requirements Document and is large enough to envelope about 90% of the sites in the United States.

While the existing safety analysis in CESSAR-DC meets all dose criteria using the current methodology (TID-14844 and regulatory guidance), implementation of a revised source term would be aimed at consistency with forthcoming changes to NRC regulations and guidance. The revised doses may result in more stringent environmental qualification requirements for certain systems as well as a larger allowable containment leak rate and lower doses for the safety analysis. ABB-CE is evaluating whether to incorporate a revised source term in a revision to the safety analysis in CESSAR-DC.

ATTACHMENT 3

Table 3.2-1 lists the Safety, Seismic, and Quality classifications of major structures, systems and components. The Heated Junction Thermocouple Probe Assembly is listed on sheet 1 of that table. The pressure boundary portion of the probe is Safety Class 1 and the electrical portion is Safety Class 3 (Class 1E). The probe is also Seismic Category I and Quality Class 1 (10CFR50, Appendix B). The HJTC probe measures reactor vessel coolant level and meets the Regulatory Guide 1.97 (Revision 3) Category 1 guidance, as stated in Table 7.5-3 of CESSAR-DC. ABB-CE believes that Table 7.5-3 provides an adequate commitment to the design and qualification of the HJTC probe and that adding discussion of Regulatory Guide 1.97 (and TMI Item II.F.2) to Table 3.2-1 is inconsistent with the intent of Table 3.2-1 and other entries in that table. Table 7.5-3 was previously modified in ABB-CE letter LD-92-063 (dated April 30, 1992) to clarify compliance with Category 1 of Regulatory Guide 1.97. Included with this attachment is a revision to footnote 12 of Table 3.2-1 to reference Table 7.5-3 for additional information.

*For additional information on the Heated Junction Thermocouple probe, see Table 7.5-3 (footnote 8 and the corresponding entry for reactor vessel coolant level).

TABLE 3.2-1 (Cont'd)

(Sheet 16 of 17)

CLASSIFICATION OF STRUCTURES, SYSTEMS, AND COMPONENTS

NOTES: (Cont'd)

(7) Core support structures are designed to the criteria described in Section 3.9.5.4.

(8) CEA and fuel assemblies are designed to the criteria described in Section 4.2.

(9) Reactor coolant pump auxiliary components required for lubrication and cooling of pump seals and thrust bearings are Quality Class 2.

(10) Except Lifting Frame Assembly, which is NS.

(11) During normal plant operation only. D

(12) Safety Class 1 for pressure boundary; Safety Class 3 for electrical portion of system.*

(13) The piping, valves, and associated supports/restraints of the Main Feedwater System from (and including) the Main Feedwater Isolation Valves to the steam generator feed nozzles are Safety Class 2, Seismic Category I, Quality Class 1; the remainder is ANSI/ASME B31.1.

(14) Non-safety Cooling Headers are Safety Class NNS, Seismic Category II, and Quality Class 2.

(15) The Normal Chilled Water System serves no safety function. Portions of the system which are located in non-safety related areas are classed as non-seismic.

(16) Portions of the Fire Protection System piping and valves which are not in safety-related areas of the plant are designed as non-seismic. I

(17) Fuel Oil Recirculation System and storage tank fill line strainer are classed as non-nuclear safety.

(18) The Starting Air System is Safety Class NNS from the starting air compressor through the desiccant drying towers, and Safety Class 3 from the starting air receiver tank inlet check valve to the engine connections.

ATTACHMENT 4

LIST OF TABLES

CHAPTER 8

E

I

E

LIST OF FIGURES

CHAPTER 8

8.0 ELECTRIC POWER

8.1 INTRODUCTION

An offsite power system and an onsite power system are provided to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safety Feature Systems during abnormal and accident conditions. E

8.1.1 OFFSITE POWER SYSTEM

The typical offsite power transmission system grid may consist of interconnected hydro plants, fossil-fueled plants, combustion turbine units, and nuclear plants supplying energy to the service area at various voltages. I

The unit is connected to a switchyard and ~~thereby~~ to the transmission system via ~~two separate and independent~~ a transmission line~~s~~. The generator circuit breaker, along with the unit step-up transformers, allows ~~one of those~~ THIS line~~s~~ not only to supply power to the transmission system during normal operation, but also to serve as an immediately available source of preferred power. ~~The~~ Another separate transmission line is connected, TO THE PREFERRED SWITCHYARD INTERFACE II) via the switchyard and ~~a standby~~ TWO RESERVE auxiliary transformers, to provide an independent second immediate) source of offsite power to the onsite power distribution (system AVAILABLE for safety, NON SAFETY and permanent non-safety loads. E

A description of a representative offsite power system is provided in Section 8.2.

8.1.2 ONSITE POWER SYSTEMS

The onsite power system for the unit, as depicted on Figures 8.3.1-2 AND 8.3.1-1 ~~8.1-1~~, consists of the main generator, the generator circuit breaker, unit main transformers, the unit auxiliary transformers, ~~standby~~ RESERVE auxiliary transformers, the diesel generators, an alternate AC source, the batteries, and the auxiliary power system. Under normal operating conditions, the main generator supplies power through isolated phase bus and generator circuit breaker to the unit main step-up and unit auxiliary transformers. The unit auxiliary transformers are connected to the bus between the generator circuit breaker and the unit main transformers. During normal operation, station auxiliary power is supplied from the main generator through these unit auxiliary transformers. During startup and shutdown, the generator circuit breaker is open, and station auxiliary power is supplied from the transmission system through the unit main and unit auxiliary power transformers. I E

The Class 1E safety loads are divided into two redundant and independent load group Divisions I and II. Each Load Division is capable of being supplied power from the following sources, listed in decreasing order of priority:

A. Unit Main Turbine Generator

B. Unit Main Transformers (Offsite Preferred Bus-1)

C. RESERVE ~~Standby~~ Auxiliary Transformer (Offsite Preferred Bus-2)

D. Emergency Diesel Generators

E. Alternate AC Source

If both the offsite power sources and the standby emergency diesel generators are unavailable, either one of the Divisions may be powered independently from the Alternate AC (AAC) Source. The AAC is a Non-Class 1E gas turbine which provides an independent and diverse power source. The AAC source is furnished with a battery and charger to provide power to the associated DC loads.

A 125V DC Vital Instrumentation and Control Power System is available to provide power to the Class 1E DC loads and the diesel generators. Additionally, this system provides power to Class 1E 120V AC loads through inverters.

The unit also has a 125V DC Auxiliary Control Power System and a 250V DC Auxiliary Power System to supply essential Non-Class 1E DC loads. Additionally, this system also provides power to Non-Class 1E 208/120V AC loads through inverters.

The onsite power systems are described in detail in Section 8.3.

8.1.3 DESIGN BASES

The design bases for the offsite power system and the onsite power system are presented below.

A. Offsite Power System

1. Each of the two offsite power circuits has sufficient capacity, is normally energized, and is available to supply power to the plant safety-related systems within a few seconds following a loss-of-coolant accident (LOCA) to assure that core cooling, containment integrity, and other vital safety functions are maintained.

5. The two Reserve Auxiliary Transformers shall each be sized with power capability to supply the most conservative power requirements of its associated Class 1E buses, the most conservative power requirements of its associated permanent nonsafety bus, and the power requirements for at least one reactor coolant pump and its support loads.

2. The two offsite power circuits (to the switchyard) are designed to be independent and physically separate to assure their availability under normal and postulated accident conditions.

B. Onsite Power System

1. The Class 1E onsite power systems are located in Seismic Category I structures to provide protection from natural phenomena. E

2. The redundant Class 1E onsite power system equipments are located in separate rooms or fire zones with adequate independence to assure that the Plant Protection System safety functions can be performed assuming a single failure.

3. Voltage levels at the Class 1E safety-related buses are optimized for the full load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the power source by the adjustments of the voltage tap settings on the transformers.

4. The Class 1E onsite power systems have sufficient capacity to safely shut the unit down and to mitigate the effects of an accident assuming loss of offsite power (LOOP).

6 ~~5~~. The Class 1E onsite power systems are designed to permit appropriate surveillance, periodic inspections, and testing of important areas and features to assess the continuity of the systems and the condition of their components.

7 ~~6~~. The emergency diesel generators are designed to be automatically initiated in the event of an accident or a LOOP. I

8 ~~7~~. The vital batteries have adequate capacity, without chargers, to provide the necessary DC power to perform the required safety functions in the event of a postulated accident assuming a single failure. E

9 ~~8~~. Each vital battery charger has adequate capacity to supply its assigned steady-state loads while simultaneously recharging its associated battery.

10 ~~9~~. A non-Class 1E AAC source is provided to help mitigate the effects of LOOP and station blackout (SBO) scenarios.

10. The power distribution system is designed to maintain independence between the Main Control Room and Remote Shutdown Panel such that a fire in either location will not prevent transfer of control to the other location as described in Sections 7.4.1.1.10 and 7.7.1.3.

11. Non-Class 1E electrical equipment is designed or located to preclude adverse affects on Class 1E electrical equipment due to their failure during normal, accident or post-accident modes of plant operation. Where there is a risk of adverse impact, due to post-accident environment or seismic events, the Non-Class 1E electrical equipment is qualified for non-interference in accordance with the same qualification standards as is the Class 1E equipment.

8.1.4 DESIGN CRITERIA

The design criteria, including the General Design Criteria, NRC Regulatory Guides, and IEEE Standards that are considered in the design of the Class 1E AC and DC Power Systems, are presented and discussed below.

8.1.4.1 General Design Criteria

The General Design Criteria of 10 CFR 50, Appendix A are discussed in Chapter 3. Additionally, compliance with General Design Criteria 17 and 18 is discussed in Sections 8.2.1.4, 8.3.1.2, and 8.3.2.2.

8.1.4.2 NRC Regulatory Guides

A. Regulatory Guide 1.6

The design of the Class 1E onsite power systems, both AC and DC, meets the intent of Regulatory Guide 1.6 as discussed in Sections 8.3.1.2.3 and 8.3.2.2.

B. Regulatory Guide 1.9

The selection criteria for the diesel generators used as standby power sources meets the intent of Regulatory Guide 1.9 as discussed in Section 8.3.1.2.4.

C. Regulatory Guide 1.17

The following design features address the intent of Regulatory Guide 1.17 "Protection of Nuclear Power Plants Against Industrial Sabotage":

E

1. Separate Physical Locations for Equipment -

   Redundant divisions and channels of safety-related electrical sources and power distribution equipment are located in separate plant locations. E

2. Limited Ability to Change System Hardware Configurations -

   Systems are designed to limit the ability of operating and maintenance personnel to change basic system functions (e.g., Key lock administrative control with built-in alarms). I

3. On-Line Testing Philosophy -

   Test modes and methods are designed to minimize disturbing the power distribution system loads. The test methods and equipment are designed to preclude loss of independence between redundant electrical divisions and channels of equipment, such that tampering with one system will not disable the redundant system. Testing is assisted through an application program in the Data Processing System (DPS) which monitors pre- and post-test conditions and verifies that equipment is properly returned to service. E I

4. Power Distribution System Status Monitoring -

   The status of all safety related power distribution system equipment is monitored by the success path monitoring application program in the DPS for alarm and display in the main control room, such that unauthorized changes in systems can be detected.

The above features are designed to impede sabotage. See Section 7.1.2.16 and Chapter 13 (Appendix 13A) for a more comprehensive discussion on protection against sabotage.

D. Regulatory Guide 1.22

Periodic testing of the Class 1E power systems meets the intent of Regulatory Guide 1.22 as discussed in Sections 8.3.1.1.3.2 and 8.3.2.1.2.2.2. E

E. Regulatory Guide 1.26

The quality group classifications of the Class 1E portions of the Onsite Power systems major equipment are identified in Section 3.2.2.

F. Regulatory Guide 1.29

Class 1E power system equipment is classified as Seismic Category I in accordance with the intent of Regulatory Guide 1.29. Qualification of Seismic Category I electrical equipment is discussed in Section 3.10.

G. Regulatory Guide 1.30

The quality assurance requirements for the installation, inspection, and testing of Class 1E electrical equipment are addressed in the quality assurance program referenced in Chapter 17.

H. Regulatory Guide 1.32 E

The design of the Class 1E onsite power systems, both AC and DC, meets the intent of the recommendations of Regulatory Guide 1.32 as discussed in Sections 8.3.1.2.5 and 8.3.2.2.1.

I. Regulatory Guide 1.40

The qualification of continuous duty Class 1E motors installed inside the containment is discussed in Section 3.11.

J. Regulatory Guide 1.41

Preoperational testing to verify the assignment of loads for the Class 1E power systems complies with the intent of this regulatory guide and is included in the tests described in Chapter 14.

K. Regulatory Guide 1.47

Automatic indication of a bypass or deliberately induced inoperable status is provided for Class 1E power systems required for safety as discussed in Sections 7.2.1.1.5 and 7.3.1.1.3. I

L. Regulatory Guide 1.53

The Class 1E onsite power systems, both AC and DC, have sufficient independence and redundancy to perform their safety function assuming a single failure as discussed in Sections 8.3.1.1.2 and 8.3.2.1.2. E I

M. Regulatory Guide 1.62

Means for manual initiation of Class 1E power systems required for safety are provided in the control room that meet the intent of the recommendation of Regulatory Guide 1.62 as discussed in Section 8.3.1.1.4.1. E I

N. Regulatory Guide 1.63

The intent of the mechanical, electrical, and test requirements set forth in Regulatory Guide 1.63 for the design, construction, and installation of electric penetration assemblies in the containment structure are met.

For information regarding the environmental qualification of electrical penetrations, refer to Section 3.11. E

O. Regulatory Guide 1.68

Preoperational and startup testing meets the intent of this Regulatory Guide as described in Chapter 14.

P. Regulatory Guide 1.73

The qualification of Class 1E electric valve operators located inside containment is discussed in Section 3.11.

Q. Regulatory Guide 1.75

, TO SUCH SYSTEMS AS THE REACTOR PROTECTION SYSTEM,

The routing of 1E and associated electrical cabling and sensing lines from sensors meets the intent of Regulatory Guides 1.75 and 1.151. They are arranged to minimize the possibility of common mode failure. This requires that the cabling for the four safety channels be routed separately; however, the cables of different safety functions within one channel may be routed together. Low energy signal cables are routed separately from all power cables. Safety-related redundant sensors are separated. The separation of their safety-related cables requires that the cables be routed in separate cable trays. Associated circuit cabling from redundant channels is handled the same as 1E cabling.

Cabling associated with redundant channels of safety-related circuits is installed such that a single failure cannot cause multiple channel malfunctions or interactions between channels.

Non-Class 1E instrumentation circuits and cables (low level) which may be in proximity to Class 1E or associated circuits and cables, are treated as associated circuits unless analyses or tests demonstrate that credible features therein cannot adversely affect Class 1E circuits. Non-Class 1E channels X and Y instrumentation and control circuits and cabling are separated from each other.

The independence of redundant systems is further discussed in Section 8.3.1.4.

R. Regulatory Guide 1.81

The intent of this guide is met in that the Class 1E AC and DC power systems are not shared between units as discussed in Sections 8.3.1.1.2 and 3.3.2.1.2.

S. Regulatory Guide 1.89

Compliance with Regulatory Guide 1.89 is discussed in Section 3.11.

T. Regulatory Guide 1.93

The availability of electric power sources with respect to limiting conditions for operation is presented in Chapter 16, Technical Specifications.

U. Regulatory Guide 1.97

The design and installation of the accident monitoring instrumentation is in compliance with the intent of Regulatory Guide 1.97.

V. Regulatory Guide 1.100

The seismic qualification of Category I instrumentation and electrical equipment is discussed in Section 3.10.

W. Regulatory Guide 1.106

The application of thermal overload protection devices in Class 1E motor-operated valve circuits meets the intent of Regulatory Guide 1.106. The thermal overload protection devices are used to only provide alarm functions as described in Section 7.3.1.1.

X. Regulatory Guide 1.108

The periodic testing requirements for the safety-related diesel generators are presented in Chapter 16, Technical Specifications.

Y. Regulatory Guide 1.118

The periodic testing requirements of the electric power and protection system are presented in Chapter 16, Technical Specifications.

Z. Regulatory Guide 1.128

The installation design and installation of Class 1E batteries are in compliance with the intent of Regulatory Guide 1.128 as discussed in Section 8.3.2.1.2.1.

AA. Regulatory Guide 1.129

Maintenance, testing, and replacement of large lead batteries complies with the intent of Regulatory Guide 1.129. E

BB. Regulatory Guide 1.131

The qualification testing of electric cables, field splices, and connections complies with the intent of Regulatory Guide 1.131.

CC. Regulatory Guide 1.155

PERMANENT

The installation and design of the onsite AAC power source system is in compliance with the intent of Regulatory Guide 1.155 for a station blackout (SBO). The AAC power source is designed to be made available to power one safety load division and its corresponding ~~essential~~ non-safety load bus within 10 minutes of the onset of the SBO; such that the plant is capable of maintaining core cooling and containment integrity per Section 50.63 of 10 CFR Part 50.

The AAC source is not normally directly connected to the plant's main or standby offsite power sources or to the Class 1E Safety Division power distribution system. There is a minimum potential for common cause failure with the offsite power system or with the emergency diesel generators.

The AAC power source is further discussed in Section 8.3.1.1.5. I

DD. Regulatory Guide 1.158

The qualification testing of safety-related lead storage batteries complies with the intent of Regulatory Guide 1.158.

8.1.4.3 IEEE Standards

A. IEEE Standard 387-1984

The preoperational and periodic testing of the emergency diesel generators complies with the requirements of IEEE Standard 387-1984 as discussed in Section 8.3.1.1.4.11.

Add Insert A

~~B.~~ D IEEE Standard 741-1986

Protection for degraded voltage and loss of voltage conditions for safety and non-safety buses is provided, as described in Section 8.3.1.1.6.

~~C.~~ E IEEE Standard 765-1983

The offsite preferred power supply and its interface with the onsite power system comply with IEEE Standard 765-1983. The offsite supply consists of two independent transmission lines as discussed in Sections 8.2.1.3 and 8.2.1.4. These transmission lines are designed to minimize the probability of their simultaneous loss due to ~~a pylon~~ failure or a failure ~~of a~~ crossings transmission line. The switchyard design minimizes the probability of a single equipment failure causing the simultaneous loss of both preferred power supply circuits. E

TOWER

DUE TO OTHER

I

Add Insert B

Insert A:

Add the following to Section 8.1.4.3:

"B. IEEE Standard 484-1987

Recommended design practices and procedures for storage, location, mounting, ventilation, instrumentation, preassembly, assembly, and charging of large lead storage batteries is provided in Section 8.3.2.1.

C. IEEE Standard 535-1986

Qualification methods for Class 1E lead storage batteries and racks to be used in nuclear power generating stations is provided in Section 8.3.2.1."

Insert B:

Add the following as Section 8.1.4.4:

"8.1.4.4 <u>NRC Branch Technical Positions</u>

A. Branch Technical Position 4 (SRP 8.1) "Requirements on Motor-Operated Valves in the ECCS Accumulator Lines"

Branch Technical Position 4 of SRP 8.1 discusses Safety Injection Tank Motor-Operated Isolation Valves as "operating bypasses." Control logic is implemented to ensure that the valves open when Reactor Coolant System conditions necessitate the operability of the Safety Injection Tanks. Refer to Section 6.3.2.2.2.

B. Branch Technical Position 8 (SRP 8.1) "Use of Diesel-Generator Sets for Peaking"

System 80+™ design will not utilize the Emergency Diesel Generators for supplying power to the utility grid, except during periodic tests when placing loads on the Diesel Generator is required.

C. Branch Technical Position 11 (SRP 8.1) "Stability of Offsite Power Systems"

For transmission system reliability considerations, the sudden loss of generation of the largest operating unit on the electrical grid will be analyzed for to conform to the requirements of the owner's appropriate electric reliability council. Refer to Section 8.2.1.6.

D. Branch Technical Position 18 (SRP 8.1) "Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves

The System 80+™ design will incorporate, where appropriate, the guidelines and considerations of Branch Technical Position 18 (SRP 8.1).

E. Branch Technical Position 21 (SRP 8.1) "Guidance for Application of Regulatory Guide 1.47."

The provisions of Branch Technical Position 21 (SRP 8.1), in conjunction with Regulatory Guide 1.47, are discussed in Sections 7.2.1.1.5 and 7.3.1.1.3.

Insert B (continued)

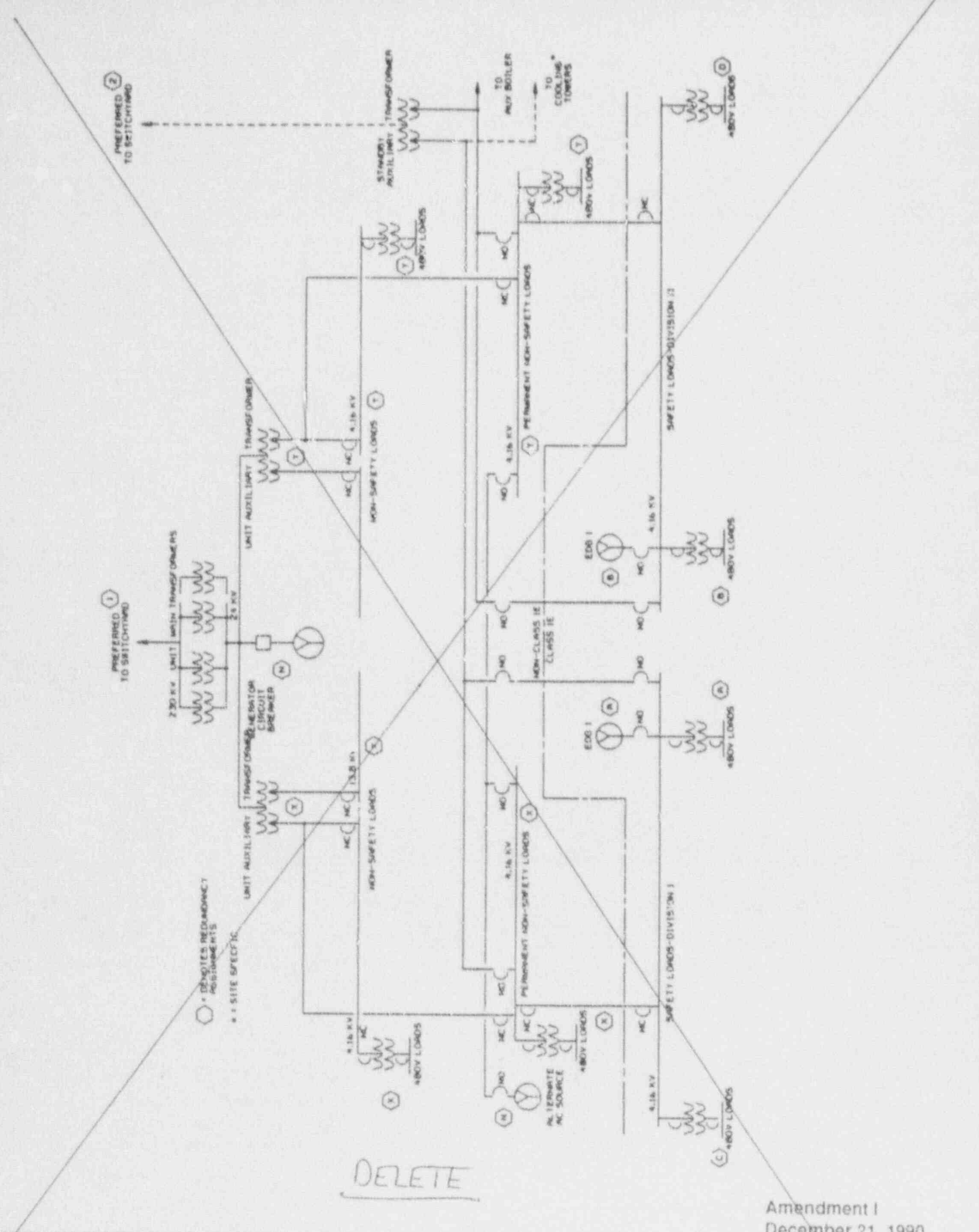
F. Branch Technical Position PSB-1 (SRP 8.1) "Adequacy of Station Electric Distribution System Voltages"

Protection for degraded voltage and loss of voltage conditions for safety and non-safety buses is provided, as described in Section 8.3.1.1.6.

G. Branch Technical Position PSB-2 (SRP 8.1) "Criteria for Alarms and Indications Associated with Diesel-Generator Unit Bypassed and Inoperable Status"

The provisions of Branch Technical Position PSB-2 (SRP 8.1), in conjunction with Regulatory Guide 1.47, regarding availability of the Emergency Diesel Generators, are described in Section 8.3.1.1.4.5."

CALMA FILE:



DELETE

Amendment I
December 21, 1990

SYSTEM 80+™	ONSITE POWER SYSTEM ONE-LINE	Figure 8.1-1

8.2 OFFSITE POWER SYSTEM E

8.2.1 SYSTEM DESCRIPTIONS

Insert A →

8.2.1.1 Utility Grid System

The utility grid system, which is not within the scope of the System 80+ Standard Design, may consist of interconnected hydro, fossil fueled and nuclear plants supplying energy to the service area at various voltages. The grid transmission system is also a source of reliable and stable power for the onsite power distribution system. The grid system design must include at least two preferred power circuits, each capable of supplying the plants' necessary safety loads and other equipment. I E

8.2.1.2 Utility Grid and Switchyard Interconnections

The switchyards ~~is~~ ARE connected to the primary transmission system by overhead transmission lines. Figure 8.2-1 - AND 8.2-2 depict~~s~~ ~~a~~ typical interconnection of the switchyards and onsite power.

8.2.1.3 Station Switchyard

A PREFERRED Transmission lines~~s~~ from the - INTERFACE I primary transmission system shall terminate in the switchyard with provisions for additional lines to be added in the future. ~~Additionally~~, the Unit and ~~Standby~~ RESERVE Auxiliary Transformers (TRANSFORMERS FED FROM PREFERRED SWITCHYARD INTERFACE I) are tied to the switchyards by separate and independent overhead lines. (FED FROM PREFERRED SWITCHYARD INTERFACE II)

~~The~~ entire switchyard, including the power circuit ~~breakers~~, cabling ~~system~~, AC and DC auxiliary power systems, ~~protective~~ relaying ~~system, and~~ control system shall be ~~divided~~ into two preferred power buses ~~designated~~ 1 and ~~2.~~ These designations shall be consistent with the ~~preferred~~ power feeder designations. Additionally, the incoming ~~transmission~~ lines shall be also assigned to power ~~buses~~ in such a way ~~as to~~ separate the associated ~~cabling~~, protective relaying, and ~~controls for~~ each ~~circuit transmission~~ line into two distinct sources of off~~site~~ ~~power~~.

The PREFERRED switchyard - INTERFACE I design shall provide ~~redundant~~ offsite power feed capability to the nuclear unit.

8.2.1.3.1 Switchyard 480V AC Auxiliary Power System

A 480V AC Auxiliary Power System shall be provided in the switchyard to supply a reliable source of continuous AC power for the power circuit breaker auxiliaries, battery chargers, relay house air conditioning, and switchyard lighting.

THE UNIT MAIN AND RESERVE TRANSFORMERS shall be ~~ARE~~ PHYSICALLY SEPARATED SUCH THAT NO FIRE NOR ENVIRONMENTAL EFFECT SHALL DISABLE BOTH THE OFFSITE SOURCES.

<u>Insert A</u>:

The ut'lity grid system and switchyard(s) are out of scope and site specific items which shall be provided by the license applicant. The following sections contain a description of a typical grid system and switchyard and interface requirements which must be met to ensure adequacy with the System 80+™ Standard Design. The word "shall" is used to distinguish interface requirements which are mandatory from the text that is purely descriptive.

The status of this system shall be monitored in the switchyard relay house with annunciators and in the control room via the Data Processing System (DPS) and Discrete Indication and Alarm System (DIAS) systems described in Chapters 7 and 18.

8.2.1.3.2 Switchyard 125V DC Auxiliary Power System

A 125V DC Auxiliary Power System shall be provided to supply a reliable source of continuous DC power for all relaying, control, and monitoring equipment in the switchyard. This system shall consist of two independent ~~trains~~ REDUNDANT DIVISIONS each supplying DC power to ~~its~~ THE ~~associated~~ preferred power bus equipment.

8.2.1.3.3 Switchyard Protective Relaying System

The Switchyard Protective Relaying System shall be provided to protect switchyard equipment and to contribute to power system stability by promptly and reliably removing a transmission line and/or switchyard bus from service under a fault or an abnormal condition. E

8.2.1.3.4 Switchyard Control System

The Switchyard Control System shall consist of all control circuits for operating switchyard power circuit breakers (PCBs) and motor-operated disconnect switches (MODs). Controls shall be provided, via the Process-CCs described in Section 7.7, in the main control room for the PCBs and MODs associated with the unit feeders.

In addition to the controls provided in the main control room, each PCB or MOD shall be able to be operated at the switchyard relay house or at the local control cabinet of the PCB or MOD.

8.2.1.4 Switchyard and Station Interconnections

Two separate and physically independent overhead transmission line circuits are provided to connect the switchyards to the ~~Unit~~ PLANT. These transmission lines shall be designed to withstand the heavy loading conditions defined in the National Electric Safety Code.

Compliance with General Design Criterion 17

The offsite power system is designed with sufficient independence, capacity, and capability to meet the requirements of GDC 17. The transmission network is connected to the onsite power system by two physically independent circuits.

The offsite power system shall be designed to minimize the probability of losing electric power from any supplies as a result of or coincident with the loss of the unit generator, the transmission network, or the onsite electric power supplies.

Compliance with General Design Criterion 18

The requirements of General Design Criterion 18 shall be implemented in the design of the offsite power system. The design shall permit periodic inspection and testing of important areas and features. The design shall include the capability to periodically test the operability and functional performance of the components of the systems as a whole and under conditions as close to design as practical.

8.2.1.5 Offsite Power System Operational Description

The nuclear generating unit shall be provided with one ~~two independent immediate access~~ circuit~~s~~ of offsite power. ~~Prior to and during startup of the nuclear unit, the Unit Auxiliary Power System shall receive power from the transmission system through the main unit main transformers and the unit auxiliary transformers. During this period, the generator circuit breaker and associated disconnect switches shall be open.~~ Insert A

After the unit generator has been brought to rated speed and its field applied, the unit generator shall be then connected to the system by closing the generator circuit breaker. Automatic and manual synchronization are provided and supervised by synchronizing relays. E

8.2.1.5.1 Offsite Power System Protective Relaying

The offsite power system protective relaying system shall be designed to remove from service with precision and accuracy any element of the offsite power system subjected to an abnormal condition that may prove detrimental to the effective operation or integrity of the unit.

8.2.1.6 Reliability Considerations

The transmission system shall be designed to conform to the reliability criteria established by the owners appropriate electric reliability council. Typically, transmission systems are designed to avoid system cascading upon the occurrence of any one of the following:

A. Loss of Generation

1. Sudden loss of entire generating capability ~~in any one plant.~~ of the largest operating unit on the electrical grid.

Insert A

"The redundant Class 1E Distribution Systems shall receive power from one circuit backfed from the transmission line through the Unit Auxiliary Transformers and the 4,160 V Permanent Non-safety Bus. The Class 1E Distribution System shall also be capable of being fed from two dedicated Reserve Auxiliary Transformers as a secondary means of receiving power. Prior to and during startup of the nuclear unit, the onsite non-safety distribution systems shall receive power from one circuit backfed from the grid through a Unit Main Transformer and Unit Auxiliary Transformers. These backfeeds are initiated by opening the generator circuit breaker and associated disconnect switch to isolate the main generator from the Unit Main and Unit Auxiliary Transformers. The generator circuit breaker is located on the isolated phase bus between the main generator and the connection point of the Unit Main and Unit Auxiliary Transformers.

The generator circuit breaker used to provide immediate access of the onsite power systems to offsite power systems will meet the guidelines of Appendix A to SRP Section 8.2. It will have the capability to interrupt the system's maximum fault current and function properly during steady-state operation, power system transients, and major fault conditions. Verification testing will include, as a minimum, all tests outlined in Appendix A, Subsection B.2, to SRP Section 8.2."

B. Loss of Load

1. Sudden loss of large load or major load center.

C. Loss of Transmission

1. The outage of the most critical transmission line caused by a three-phase fault during the outage of any other critical transmission line, or

2. Sudden loss of all lines on a common right-of-way, or

3. Sudden loss of a substation (limited to a single voltage level within the substation plus transformation from the voltage level), including any generating capacity connected thereto, or

4. Delayed clearing of a three-phase fault at any point on the system due to failure of a breaker to open.

In addition to the transmission system design, the switching arrangement in the switchyard and the redundant relaying that is provided minimizes the probability of losing offsite power.

8.2.2 ANALYSIS

8.2.2.1 Grid Stability and Availability Analysis

Grid stability and availability analyses involving interconnections with the primary transmission system shall be performed by the site operator. These analyses shall demonstrate that the 13,800V non-safety load buses do not subject the reactor coolant pumps to sustained frequency decays of greater than 3 Hz/sec, and there shall be at least three seconds delay between a turbine trip and subsequent LOOP event, in order to satisfy RCP flow conditions assumed in Chapter 15 Safety Analyses.

8.2.2.2 Offsite and Switchyard Power Systems Single Failure Analysis

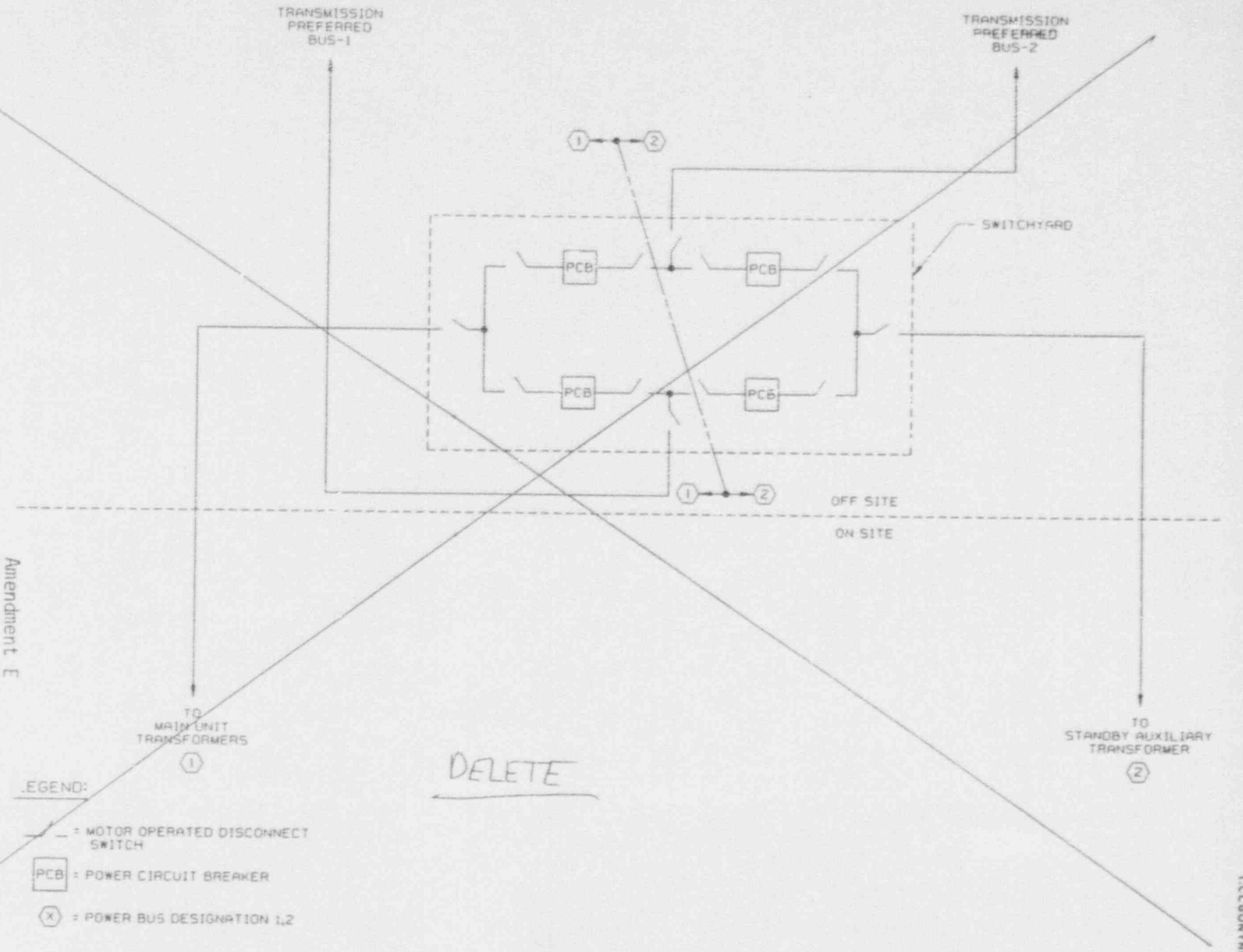
The design of the offsite power system shall be consistent with failure modes and effects analysis in Tables 8.2-1 and 8.2-2. I

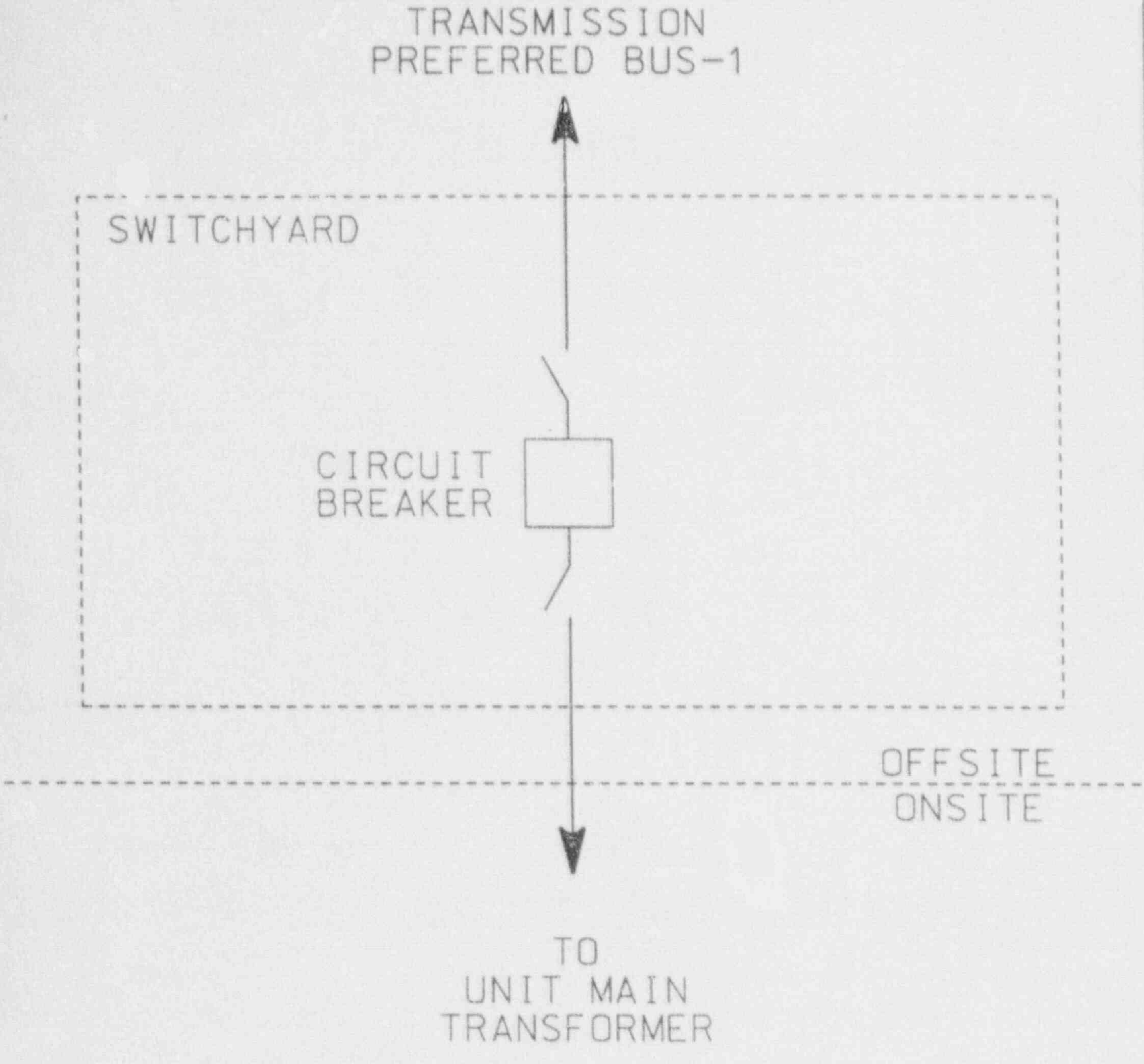
SYSTEM 80+™

ONSITE POWER SYSTEM INTERCONNECTION
WITH OFFSITE POWER

Figure
8.2-1

Amendment E
December 30, 1988

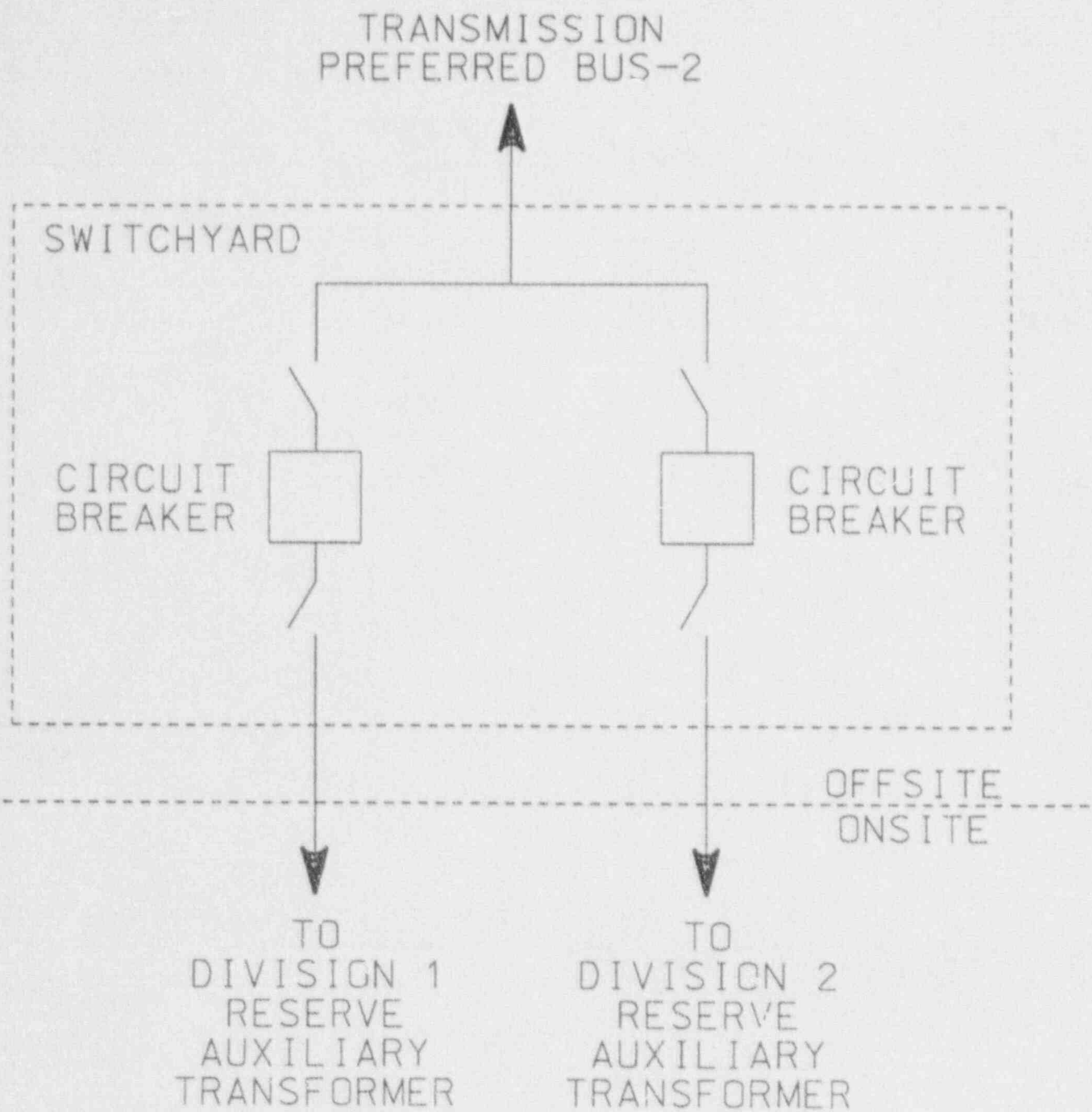




PREFERRED SWITCHYARD INTERFACE I

TYPICAL POWER SYSTEM INTER-CONNECTION
WITH OFFSITE POWER

FIGURE 8.2-1



PREFERRED SWITCHYARD INTERFACE II

TYPICAL POWER SYSTEM INTER-CONNECTION
WITH OFFSITE POWER

FIGURE 8.2-2

DELETE EXISTING
TABLE 8.2-1
AND REPLACE WITH
THE FOLLOWING

TABLE 8.2-1

(Sheet 1 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ~~ONSITE~~ OFFSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
1. Transmission System Preferred Switchyard Interface I	Loss of Power	(a) The switchyard PCB connecting the unit to the system (switchyard) trips automatically.
		(b) If main turbine generator is available, all unit and Class 1E auxiliaries continue to receive an uninterrupted flow of power from the main turbine generator through the main generator circuit breaker.
		(c) If the main turbine generator is not available, the 13.8KV Non-Safety bus may receive power from its alternate source. On the 4,160V Permanent Non-Safety bus, an automatic transfer takes place and the 4,160V Safety buses continue to receive an uninterrupted flow of power from the Preferred Switchyard Interface II.

TABLE 8.2-1

(Sheet 2 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ~~ONSITE~~ OFFSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
2. Preferred Switchyard Interface I power circuit breaker connecting the step-up transformers to the switchyard or Circuit from Preferred Switchyard Interface I to main unit transformer or Main Unit Transformer	Loss of one due to a fault or breaker failure	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent offsite circuit remains unaffected. (c) If on-line, the unit main turbine generator is automatically tripped. (d) If the unit main turbine generator is off line, the other offsite circuit from Preferred Switchyard Interface II is available for the 4,160V Permanent Non-Safety, 13.8KV Non-Safety and Class 1E Division auxiliaries via the Reserve Auxiliary Transformer

TABLE 8.2-1

(Sheet 3 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ~~ONSITE~~ OFFSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
3. Transmission System Preferred Switchyard Interface II	Loss of Power	(a) No consequence to unit. (b) The faulted equipment is isolated by protective relaying and protective equipment.
4. Preferred Switchyard Interface II Power Circuit Breakers Connecting to the Reserve Auxiliary Transformer switchyard. or Circuit from Preferred Switchyard Interface II to reserve Transformer or Reserve Auxiliary Transformer	Loss of one due to a breaker failure	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent offsite circuit remaining unaffected. (c) No consequence to unit.

NOTE: The Offsite Power System shall be protected such that it is unaffected by failures in the Onsite Power System.

TABLE 8.2-2

(Sheet 1 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE SWITCHYARD 125V DC SYSTEM

Component	Malfunction	Comments & Consequences
1. 480V AC power supply to charger	Loss of power	(a) No consequences - power from battery is available to supply power without interruption.
2. Battery charger	Loss of power from one	(a) The 125 volt DC bus continues to receive power from its respective battery without interruption except as in (b) below.
		(b) Severe internal faults may cause high short circuit currents to flow with the resulting voltage reduction on the 125 volt DC bus until the fault is cleared by the isolating circuit breakers. Complete loss of voltage on the 125 volt DC bus may result if the battery circuit breakers open. However, redundant protective relaying and panelboards are provided and are supplied from the other redundant 125 volt DC bus. E

TABLE 8.2-2 (Cont'd)

(Sheet 2 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE SWITCHYARD 125V DC SYSTEM

Component	Malfunction	Comments & Consequences
3. 125V DC battery	Loss of power from one	Only those 125 volt DC control panelboards supplied from the affected bus are lost. However, the redundant panelboards supplied from the other 125 volt DC bus are unaffected and continue to provide power for protection and control.
4. DC distribution center buses	Bus shorted	Same comment as 3.
5. 125V DC bus	Grounding a single bus	The 125 volt DC system is an ungrounded electrical system. Ground detector equipment monitors and alarms a ground anywhere on the 125 volt DC system. A single ground does not cause any malfunction or prevent operation of any safety feature.
6. 125V DC bus	Gradual decay of voltage on one bus	Each 125 volt bus is monitored to detect the voltage decay on the bus and initiate an alarm. Upon detection, power is restored by correcting the deficiency.

E

TABLE 8.2-2 (Cont'd)

(Sheet 3 of 3)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE SWITCHYARD 125V DC SYSTEM

Component	Malfunction	Comments & Consequences
7. DC distribution center load feeder cables	Cables shorted	Same comment as 3.
8. 125V DC primary or backup panelboards	Bus shorted in one	(a) Voltage on associated 125 volt DC bus decays until isolated by isolating circuit breakers. (b) Protective relaying connected to the affected panelboards are lost; however, redundant protective relaying supplied from the other 125 volt DC bus provide protection. E

with one installed spare transformer

8.3 ONSITE POWER SYSTEMS

8.3.1 AC POWER SYSTEMS

8.3.1.1 System Descriptions

8.3.1.1.1 Non-Class 1E AC Power Systems

with one installed spare transformer.

8.3.1.1.1.1 Unit Main Power System

The Unit Main Power System, as shown on Figure 8.3.1-1, consists of the unit main turbine generator, associated isolated phase bus, generator circuit breaker, ~~four~~ three unit main transformers and two 50% capacity unit auxiliary transformers~~.~~ The primary function of this system is to generate and transmit power to the transmission system while simultaneously supplying power to the unit auxiliaries. In the event that the main generator is not in service, this system is used to supply power from the transmission system to the unit auxiliaries. The design bases for the Unit Main Power System are discussed in Section 8.1.3. E

8.3.1.1.1.2 13,800 Volt Normal Auxiliary Power System

The 13,800V Normal Auxiliary Power System consists of ~~two~~ four non-safety switchgearS ~~groups. The first switchgear group designated "X" is normally connected through a main breaker to one of the dual voltage 13,800/4,160V Unit Auxiliary Transformers. A second switchgear group designated "Y" is normally connected to the other independent Unit Auxiliary Transformer~~. Insert A1

The 13,800 Volt Normal Auxiliary Power System furnishes power to large motors such as the reactor coolant pump motors and condensate water pump motors.

The protective relaying for the 13,800V switchgear feeders and buses can be classified as follows:

A. Protection of large motors.

B. Protection of buses and bus feeders.

The protective schemes are designed to isolate the faulted equipment from the rest of the system, to minimize the effect of the fault and to maximize availability of the remaining equipment. The scheme also limits the damage and the time out of service of the faulty equipment. Each scheme is designed to best achieve this for the specific equipment protected. The basic schemes consist of ground fault protection, instantaneous overcurrent and timed overcurrent protection. Other forms of

Insert A1

Two unit auxiliary transformers, each with dual low voltage 13,800/4160V windings, supplies the four 13.8KV switchgears. With this arrangement, one low voltage winding of each transformer normally supplies two of the 13.8KV switchgears through their normal source breakers.

protection are provided where applicable and consist of current or undervoltage differential and reverse power flow protection. Each breaker in this auxiliary power system is provided with timed overcurrent protection and an anti-pump device.

Each switchgear assembly has a short circuit capability which is verified by manufacturers prototype tests and exceeds the short circuit requirements of the 13,800V Normal Auxiliary Power System.

8.3.1.1.1.3 4,160 Volt Normal Auxiliary Power System

The 4,160V Normal Auxiliary Power System consists of four switchgear groups and a non-Class 1E Alternate AC source. The first switchgear group designated "X" is connected to the X-Unit Auxiliary ~~"X"~~ Transformer to power large non-safety loads such as Containment Purge Fans ~~main circulating water pumps~~, turbine building ~~CCW~~ cooling water pumps, etc. The second switchgear group "Y" is connected to the other Y-Unit Auxiliary ~~"Y"~~ Transformer to power the ~~remaining large~~ similar non-safety loads.

The third switchgear group designated X-Permanent Non-safety ~~"X"~~ provides power to auxiliary and service loads which must typically remain operational independent of the plant operating conditions or during plant outages (such as CVCS charging pump and building supply fans). Its normal source is preferred power from the X-4,160V Unit Auxiliary Transformer ~~"X"~~. In the event that its normal source is lost, this switchgear may be connected either to the Reserve ~~Standby~~ Auxiliary Transformer ~~(preferred bus 2)~~ "X" or to the Alternate AC source. An interlock is provided between the normal (preferred-1) and ~~standby~~ (preferred-2) power source breakers to preclude them alternate from both being closed simultaneously.

In case of failure of the normal power source, (i.e., the Unit Auxiliary Transformers) without loss of offsite power; the Permanent Non-safety buses are automatically transferred to the 2nd preferred source of offsite power, i.e., the ~~Standby~~ Reserve Auxiliary Transformer.

The ~~Standby~~ Reserve Auxiliary Transformer also provides power to the stations Auxiliary Boiler and, ~~if required~~, Cooling Tower forced cooling motors, if these components are site-specific required.

The fourth switchgear group designated Y-Permanent Non-safety ~~"Y"~~ is normally connected to the Y-4,160V Unit Auxiliary Transformer ~~"Y"~~. It also has the same ability to be connected to either the Reserve ~~Standby~~ Auxiliary Transformer ~~"Y"~~ "Y" or Alternate AC source as previously described for the third switchgear.

If the residual voltage of the 4,160V motors is in synchronism with the alternate source, a fast transfer will result. If not in synchronism, the transfer will be delayed until the residual voltage is 25% or less.

Diagrams 8.3.1-1 and 8.3.1-2 illustrate the safety buses being powered normally from Preferred Switchyard Interface I. However, Preferred Switchyard Interface II may provide normal power to the safety buses, based on site-specific reliability analysis.

The Permanent Non-safety "X" and "Y" switchgears also are the normal supply of preferred power to their respective 4,160 volt Class 1E Auxiliary Power System Safety Load Divisions I and II as described in Section 8.3.1.1.2.5

These four non-Class 1E switchgear groups, with the four sources of power (preferred-1, preferred-2, main generator and AAC) and their ability to energize the Division I or II safety loads reduce the likelihood of Station Blackout.

The protective relaying for the 4,160 volt switchgear feeders and buses can be classified into four separate protection configurations. The type, size, and function of the protected equipment determines which of the schemes below will be employed.

A. Protection of large (5MVA or above) motors and (or special) transformers.

B. Protection of small motors and small transformers.

C. Protection of AC sources.

D. Protection of buses and bus feeders.

The protective schemes are designed to isolate the faulted equipment from the rest of the system, to minimize the effect of the fault, and to maximize availability of the remaining equipment. The scheme also limits the damages and the time out of service of the faulty equipment. Each scheme is designed to best achieve this for the specific equipment protected. The basic schemes consist of ground fault protection, instantaneous overcurrent and timed overcurrent protection. Other forms of protection, such as undervoltage, and reverse power flow, are provided where applicable. Each breaker in this auxiliary power system is provided with timed overcurrent protection and an anti-pump device. E

8.3.1.1.1.4 480 Volt Normal Auxiliary Power System

The 480 Volt Normal Auxiliary Power system is energized by the 4160V Normal Auxiliary Power System switchgear through 4160V to 480V transformers.

The secondary of a typical transformer is connected to a 480 volt load center bus through a 480V load center circuit breaker. Connected to the load centers are large motors, large heaters and 480 volt motor control centers located throughout the plant in areas of concentrated 480V loads.

In the application of the 480V load centers, a selective system is used whereby both the main and feeder circuit breakers have interrupting capacity greater than their required duty.

The main breakers are equipped with overcurrent trip devices having long-time and short-time delay functions, and the feeder breakers are equipped with overcurrent trip devices having long-time and instantaneous functions. Each breaker in the auxiliary power system is provided with an anti-pump device.

8.3.1.1.2 Class 1E AC Power Systems

8.3.1.1.2.1 4,160 Volt Class 1E Auxiliary Power System

Each unit has two redundant and independent 4,160V Class 1E Auxiliary Power Systems, identified as Safety Divisions I and II, which normally receive power from the 4,160V Normal Auxiliary Power System. The incoming source breakers trip upon loss of normal power, and emergency power is provided to each of the redundant 4,160V Class 1E Auxiliary Power System Divisions by two (one per division) separate and completely independent emergency diesel generators (EDGs). In the event of a diesel generator out of service or failure condition, the Alternate AC source can be aligned to provide emergency power to either Class 1E Safety Load Division.

Each of the redundant 4,160V safety ~~buses~~ power systems is provided with undervoltage protection to monitor bus voltage.

The under-voltage setpoint is selected such that relay operation will not be initiated during normal motor starting; however, these relays will detect loss of voltage and initiate action in a time frame consistent with the accident analysis.

All safety-related equipment in the plant requiring electrical power during a Loss of Offsite Power, Loss of Coolant Accident, or major secondary system break condition is fed from the 4,160V Class 1E Auxiliary Power System, either directly if at 4,160V or through transformers if at a lower voltage. All Engineered Safety System loads are assigned to the two 4,160V Class 1E Auxiliary Power Systems with capacities and quantities such that the failure of any component in one of the two Class 1E Auxiliary Power Systems does not affect the other system. Refer to Table 8.3.1-2 for listing of typical Class 1E equipment, loads and design ratings.

With such an arrangement of emergency diesel generators, electrical distribution system and loads, complete redundancy of the entire Class 1E Auxiliary Power System is provided.

In addition, the non-Class 1E onsite Alternate AC is also provided to help cope with effects of Loss of Offsite Power and Station Blackout scenarios.

8.3.1.1.2.2 480 Volt Class 1E Auxiliary Power System

Each of the redundant 4,160V Class 1E Auxiliary Power Systems, Divisions I and II, includes two load centers (one per DVS ~~channel~~), each normally fed from a separate 4,160/480V load center transformer connected to the 4,160V Class 1E Auxiliary Power System buses. Circuit breakers are provided on both the primary and secondary sides of the transformer. As shown on Figure 8.3.1-1, this results in four redundant load centers designated A, C for Division I and B, D for Division II.

The load centers furnish power to large heater loads, large 480 volt motors, and 480V motor control centers which are located in concentrated load areas in the station. Connected to the motor control centers are all of the 480 volt loads which require power during LOOP or accident conditions. A list of Class 1E equipment, loads and design ratings are provided in Tables 8.3.1-2 and 8.3.1-3. Redundancy is provided in order to assure proper operation of Engineered Safety Feature Systems in the event of the failure of any single component in the 480V AC Class 1E Auxiliary Power Systems.

In the application of the 480V Class 1E Auxiliary Power System load centers, a selective system is used whereby both the main and feeder circuit breakers have interrupting capacity greater than their required duty.

The main source breakers are equipped with overcurrent trip devices having long time and short time delay functions, and the feeder breakers are equipped with overcurrent trip devices having long time and instantaneous functions.

All Class 1E motor-operated valve starters are equipped with thermal overload devices which are connected to alarm only.

8.3.1.1.3 Tests

8.3.1.1.3.1 Preoperational Tests

Preoperational tests are performed on the Onsite AC Power System equipment to assure proper installation and operation as described in Chapter 14 and in accordance with IEEE 415-1986.

8.3.1.1.3.2 Periodic Tests

Inspection, maintenance and testing is performed in accordance with a periodic testing program. The periodic testing program is conducted so as not to interfere with unit operation. Where tests do not interfere with unit operation, system and equipment tests are scheduled with the nuclear unit in operation. The means to accomplish this testing is described below.

The 13,800V and 4,160V circuit breakers and associated equipment can be tested in service where testing does not interfere with the operation of the Unit. These circuit breakers can be "racked out" to a test position and operated without energizing the circuits. A separate feed (whose breakers are normally open) RESERVE from the ~~Standby~~ Auxiliary Transformer to each Class 1E Safety Load Division is provided to facilitate maintenance and testing of the normal source breakers feeding each Division.

The 480V circuit breakers, motor contactors and associated equipment can be tested in service by opening and closing the circuit breakers or contactors. Transfers to the various E emergency power sources can be tested on a routine basis to prove the operational ability of these systems.

In compliance with General Design Criterion 18 and the intent of Regulatory Guide 1.22, the Class 1E Auxiliary Power System design is such that inspection, maintenance and periodic testing can be carried out with a minimum of interference with operation of the nuclear unit. Unit design includes two completely redundant (SAFETY DIVISIONS, ~~4,160V, four redundant 480V, and four redundant 120 Volt Class 1E Auxiliary Power busses~~. Testing during reactor operation can be accomplished by allowing one a SAFETY DIVISION system to be taken out of service for testing. Breakers can be racked out to the test position while the system is undergoing test. Continuous indication of unavailable systems is provided in the control room.

The generator power circuit breaker (PCB) periodic test program includes ~~load~~ OPEN/close measurements, and dielectric tests.

Testing of protective relays is performed on a periodic basis. Testing facilities are provided to meet the capability for testing in compliance with General Design Criterion 18 and the intent of Regulatory Guide 1.22. Relay sensors such as current transformers are tested before initial installation and unit operation and periodically thereafter. These protective devices are in service during normal operation. The preoperational tests for the protective relaying system verify the continuity of the system and the condition of all the components. The methods used to accomplish this are as follows:

A 10 percent capacity margin based on the continuous rating of the EDG will be applied in the initial EDG procurement specification.

A. All relays and other momentary duty type operating devices associated with the protective relaying of the onsite power system are tested to determine individual performance characteristics, and assure repeatability of design settings, under various simulated conditions. This ensures device integrity.

B. All relay sensors such as current and potential transformers are tested for correct and reliable outputs.

C. All interconnecting wiring and cabling is inspected for proper installation and connections.

D. All protective relaying systems are tested under necessary simulated conditions to verify correct operation in preferred, alternate and abnormal modes. E

The 120V AC Vital Power System is normally powered from inverters which are in use during normal operation. The continuous operation of the inverters is indicative of their operability and functional performance since accident conditions will not substantially change their load.

8.3.1.1.4 Class 1E Emergency Diesel Generators I

Each Division of the 4,160V AC Class 1E Auxiliary Power System is supplied with emergency standby power from an independent emergency diesel generator. The emergency diesel generator is designed and sized with sufficient capacity to operate all the needed engineered safety feature and emergency shutdown loads powered from its respective Class 1E Safety Division buses. E I E

Each emergency diesel generator is designed to attain rated voltage and frequency within 20 seconds and to begin accepting sequenced loads after receipt of a start signal to meet the response times assumed in Chapter 15 analyses. Refer to Table 8.3.1-2 for loading sequence and bases. The characteristics of the generator exciter and voltage regulator provide satisfactory starting and acceleration of sequenced loads and ensures rapid voltage recovery when starting large motors. The generator voltage and frequency excursions between sequencing steps are in compliance with the intent of Regulatory Guide 1.9. I E

Each emergency diesel generator and its associated auxiliaries are installed in separate rooms and are protected against tornadoes, external missiles, and seismic phenomena. The diesel rooms are protected with firewalls which are designed to prevent the spread of fire. ~~from one diesel room to the redundant diesel room.~~ Refer to Section 9.5.9 for a description of the diesel room sump pump. I

Each emergency diesel generator room is provided with its own independent ventilation system which is designed to automatically maintain a suitable environment in each diesel room for equipment operation and personnel access. I E

The emergency diesel generator controls and monitoring instrumentation, with the exception of the sensors and other equipment that must necessarily be mounted on the diesel generator or its associated piping, are installed in free standing floor mounted panels. These panels are designed for their normal vibration environment and qualified to Seismic Category I requirements. I E

The emergency diesel generator engine-mounted components and piping are Seismic Category I, seismically qualified in accordance with IEEE Standard 344-1987. I

8.3.1.1.4.1 Starting Circuits E

Each emergency diesel generator is automatically started and loaded by the ESF-Component Control System emergency diesel loading sequencer as discussed in Section 7.3.1.1.2.3. I

In addition to the above automatic start, each diesel generator can also be manually started for test and maintenance purposes from the control room or from the local diesel control panel. E

8.3.1.1.4.2 Starting System

Each emergency diesel generator has an independent air starting system with storage to provide at least five fast starts. The diesel generator starting air system is further described in Section 9.5.6. I E

8.3.1.1.4.3 Combustion Air System

Refer to Section 9.5.8 for a description of the diesel air intake and exhaust system.

8.3.1.1.4.4 Emergency Diesel Generator Protection Systems

The emergency diesel generator protection systems initiate automatic and immediate protective actions to prevent or limit damage to the emergency diesel generator. The following protective trips are provided to protect each diesel generator at all times and are not bypassed when the emergency diesel generator is started as a result of an ESF-CCS automatic or manual start signal. These are the only trips that will lock out the diesel generator breaker. I

A. Engine Overspeed.

B. Generator Differential Protection.

C. Low-low Lube Oil Pressure.

D. Generator Voltage-Controlled Overcurrent (Protection From External Faults). E

The implementation of these protective trips is in accordance with Branch Technical Position EICSB-17. Overspeed protection is provided by an overspeed trip, the set-point is above the maximum engine speed on a full-load rejection. Therefore, in accordance with Regulatory Guide 1.9, the engine speed resulting from a step increase or decrease in load will not exceed nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint.

The following mechanical trips are provided to protect the diesel generators during test periods and while running with offsite power available:

A. Low Pressure Turbo Oil.

B. Low Pressure Lube Oil.

C. High Pressure Crankcase.

D. High Temperature Bearings.

E. High Temperature Lube Oil Out.

F. High Temperature Jacket Water.

G. High Vibration.

These mechanical trips are bypassed in the event of an ESF actuation condition, concurrent with a Loss of Offsite Power. The Design of the bypass circuitry meets the intent of IEEE Standard 279-1971 and RG 1.9. In addition, the following electrical trips are provided to protect the emergency diesel generators during testing periods: I

A. Generator Instantaneous Overcurrent Protection.

B. Generator Loss of Field Protection.

C. Generator Reverse Power Protection. E

D. Generator Ground Protection.

The bypass circuitry meets the intent of IEEE Standard 279-1971 and RG 1.9.

These electrical trips are bypassed in the event of an ESF actuation condition, concurrent with a Loss of Offsite Power. | E

8.3.1.1.4.5 Control Room Indication of Emergency Diesel Generator Operational Status | I

Various monitoring devices are provided in the diesel room and the control room to give the operator the complete status of operability for the diesels. The following is a listing of the typical parameters monitored:

A. Lube Oil Temperature and Pressures.

B. Bearing Temperatures.

C. Cooling Water Temperatures and Pressures.

D. Generator Parameters.

E. Speed.

F. Starting Air Pressure.

"and Branch Technical Position PSB-2"

In order to meet the intent of Regulatory Guide 1.47, the following conditions are monitored to determine the operable status of the emergency diesel generator: | E | I

A. Cooling water not available.

B. Diesel generator breaker racked out.

C. Diesel generator overspeed.

D. Loss of control power.

E. Generator fault.

F. Low air and oil pressure.

Add Insert A

G. Maintenance mode.

Add Insert C

8.3.1.1.4.6 Load Shedding and Sequencing

All Class 1E switchgear and load center breakers that are required to automatically close following an accident, LOOP and/or station blackout condition are controlled by the ESF-CCS load sequencer associated with each emergency diesel generator. | E | I

Insert A

"All conditions that render the emergency diesel generators incapable of responding to an ESF-CCS automatic start signal will activate an alarm window in the control room. These alarms cannot be activated by any other alarm signals."

Insert C:

"Diesel Generator unit bypass or inoperability status is automatically indicated and alarmed in the Control Room. Such indications and alarms are of sufficiently precise a nature so as to prevent misinterpretation. To enhance HED distinction between the classes of inoperable status indications/alarms and the normal diesel generator indications/alarms in the Control Room, these two classes of indications/alarms are segregated from each other."

A time delay will be provided between load shedding and sequencing to allow motor residual voltages to decay to less than 25 % of rated voltage.

Load shedding of all loads at the 4,160V level (except the 4,160/480V load center transformers) occurs whenever a sustained bus under voltage condition is detected by the ESF-CCS logic.

Following the load shedding operation, the emergency diesel generator load sequencer automatically sequences the required loads per Table 8.3.1-2, as described in Section 7.3.1.1.,

8.3.1.1.4.7 Lube Oil System

Reference Section 9.5.7 for a description of the diesel lube oil system.

8.3.1.1.4.8 Fuel Oil Storage System

Reference Section 9.5.4 for a description of the diesel fuel oil storage system.

8.3.1.1.4.9 Cooling System

Reference Section 9.5.5 for a description of the diesel cooling system.

8.3.1.1.4.10 Emergency Diesel Generator Proven Technology

The emergency diesel generators are of proven technology that has been applied successfully for several years in existing LWRs.

8.3.1.1.4.11 Preoperational and Periodic Testing

In addition to the factory tests, the following preoperational onsite acceptance tests and periodic tests are conducted on each diesel generator and their associated auxiliary systems.

A. Preoperational Testing

Preoperational acceptance tests meet the intent of the following:

1. IEEE Standard 387-1984, Sections 6.4 and 6.5.
2. Regulatory Guide 1.9, Section C.3 and C.4.
3. Regulatory Guide 1.41, Section C.
4. Regulatory Guide 1.68, Appendix A, Section 1.g.3.
5. Regulatory Guide 1.108, Sections C.2.a and C.2.b.

Testing is performed by manually synchronizing the diesel generators with the offsite power system. This synchronization is supervised by a synchronism check relay.

6. Regulatory Guide 1.137, Section C.1.c.

7. ANSI N195, 1976, Section 6.1.

These preoperational tests conform with the provisions of Regulatory Guide 1.108, C.2.a and C.2.b regarding tests to be performed on emergency diesel generators. I

B. Periodic Testing E

Periodic testing of the emergency diesel generator meets the intent of Regulatory Guide 1.108 and NRC Generic Letter 84-15. I E

The emergency diesel generator (EDG) is removed Insert A from service in accordance with approved procedures. Any maintenance work on the diesels is performed and inspected by qualified personnel in accordance with approved procedures. Upon completion of maintenance work, appropriate tests are completed to assure operability of the diesel generator. Upon completion of testing, appropriate operating procedures restore the diesels to standby readiness. Insert B I E

8.3.1.1.4.12 125V DC Emergency Diesel Control Power I

125V DC control power for each emergency diesel generator is provided by the Class 1E 125V DC ~~power~~ P ~~system~~ S batteries as described in Section 8.3.2.1.2. E

8.3.1.1.5 Non-Class 1E Alternate AC Source Standby Power Supply

The Alternate AC Source (AAC) is a non-safety gas turbine power source provided to cope with Loss of Offsite Power (LOOP) and Station Blackout (SBO) scenarios. This standby unit is independent and diverse from the Class 1E standby emergency diesel generators. I E

The AAC is sized with sufficient capacity to accommodate either of the following load configurations:

A. Both sets of X and Y Permanent Non-safety loads for a worst case unit shutdown to cold shutdown; or

B. One set of Permanent Non-Safety loads and one set of a Safety Division's loads ~~as indicated below:~~ for a worst case unit shutdown to cold shutdown and/or Design Basis Accident as indicated below:

1. Permanent Non-Safety X with Division I only, or,

2. Permanent Non-Safety Y with Division II only.

Insert A:

"Additionally, a root-cause analysis maintenance program shall be implemented to track and to resolve repetitive failures of EDG components, including replacement of components with acceptable substitutes, if warranted."

Insert B:

"After periods of operating the EDG in unloaded condition, the EDG will be run loaded per manufacturer's recommendation to clean any deposits from cylinders, etc."

The AAC is not normally nor automatically directly connected to any Class 1E Safety Load Division. However, it can be manually aligned to power one Safety Load Division via one Permanent Non-Safety Bus, to accommodate a emergency diesel generator failure or out-of-service condition. The AAC is provided with a ~~sufficient~~ continuous rating capacity margin of at least 10 percent to compensate for load growth.

8.3.1.1.5.1 AAC Starting and Loading

The AAC is designed to start automatically within ten minutes from the onset of a LOOP event. It is then available for loading if either of the 4,160V Permanent Non-Safety Load Bus~~s~~es X and Y become de-energized. Automatic connection and sequential loading of the X and/or Y PERMANENT non-safety loads will occur utilizing a sequencer design similar to that described in 7.3.1.1.2.3.

8.3.1.1.5.2 AAC Instrumentation and Controls

The instrumentation and controls necessary to start and run the AAC are powered from a dedicated local 125V DC battery.

Various monitoring and control devices are provided locally and in the control room to give the operator control and operational status information. The following typical parameters are monitored and/or alarmed:

A. Lube oil temperatures and pressures

B. Bearing temperatures

C. Cooling temperatures and pressures

D. Generator parameters and status

E. Speed

F. Starting air pressure

G. Control mode status (standby, starting, running, local).

8.3.1.1.5.3 AAC Auxiliary Support Systems

A. Fuel System and Supply

The AAC is equipped with redundant fuel systems. Sufficient fuel is stored on site to support 24 hour operation at rated load.

B. Starting System

The AAC is equipped with redundant starting systems and controls. The system is designed with sufficient capacity for five starts.

C. Cooling System

The AAC is equipped with a self-contained cooling system.

D. Lubrication System

The AAC design includes a pre/post lubrication system that utilizes redundant components.

8.3.1.1.5.4 AAC Periodic Testing

The AAC is designed to be routinely inspected and maintained while the plant is at power. E

Instrumentation and controls are provided to permit its synchronization and loading during refueling periods to periodically demonstrate its operability.

8.3.1.1.5.5 AAC Quality Assurance

The intent of the quality assurance guidelines to incorporate a lesser degree of stringency as identified in Regulatory Guide 1.155 Section 3.5 will be implemented. The Q/A program as described in Chapter 17 contains all the necessary elements to address the guidance given in Regulatory Guide 1.155 Appendix A. Selected features of this program will be used to address all applicable AAC Q/A requirements.

8.3.1.1.6 Protective Relaying System

The basic criterion for the Protective Relaying System is that it shall, with precision and reliability, promptly initiate the operation of isolation devices that serve to remove from service any element of the Onsite Power System when that element is subjected to an abnormal condition that may prove detrimental to the effective operation or integrity of the unit.

The basic protective relaying has zone-over-lapping differential relaying with redundant circuits. Each circuit has independent current sources, separate DC sources, independent lockout relays and independent trip coils. Each redundant circuit is composed of independent channels of relaying. Each channel is also

"Capability for test and calibration during power operation shall be provided, as well as annunciation in the Control Room for any bypasses incorporated into the design."

comprised of diverse relaying. Tripping of the independent lockout relays is achieved through a coincidence of like trip signals.

This requirement prevents a false trip of the lockout relays due to a malfunction of one relay. The scheme also allows for testing and maintenance of each channel without causing a false trip and without removing the protection from the system. The inherent quality of this scheme is that each primary channel provides the redundancy needed for proper operation in case one relay fails and assurance of not tripping due to false operation of one relay.

~~Non-safety buses feeding loads required for unit operation only are provided with an undervoltage protection scheme design to protect the loads against damage due to sustained operation under degraded voltage conditions and shed all major loads under loss-of-voltage conditions.~~

Class 1E Division buses and PERMANENT non-safety buses ~~feeding permanent non-safety loads~~ are provided with separate bus voltage monitoring and protection schemes for degraded voltage and loss of voltage conditions, respectively. These schemes are designed according to the recommendations of IEEE Standard 741* "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Systems,"# Two separate time delays are selected for degraded voltage protection as recommended in IEEE Standard 741,* Appendix A. Based on the automatic bus transfer sequences adopted, a time delay is provided for loss of voltage relay actuation to preclude unnecessary starting of the onsite standby power sources during the transfer sequences. The undervoltage protection schemes use coincidental logic (e.g., two out of three phases) to avoid spurious trips of the offsite power sources. E

The relay zones in the Onsite Protection System overlap to maintain protection throughout the system. Any fault condition in a particular tripping zone trips the circuit breakers in that zone by its associated protective relays.

8.3.1.1.7 Monitoring Instrumentation and Controls for Onsite Power System

The monitoring instrumentation associated with the Onsite Power System provides a reliable source of information in the control room and protective functions for major components. The instrumentation provides quantitative values and status conditions for the operator in the control room. This instrumentation provides the operator with the information necessary for efficient operation of the unit. The

* - 1986

\# and NRC Branch Technical Position PSB-1, "Adequacy of Station Electric Distribution System Voltages."

instrumentation also provides pertinent quantitative values and status conditions for alarming and tripping action. All control room instrumentation and controls are designed in accordance with the Human Factors Engineering design criteria and implementation methods, as described in Chapter 18.

Manual and automatic controls are provided in the main control room and locally to permit the following operations:

A. Selection of the most suitable power source for the various onsite distribution systems.

B. Disconnection of appropriate loads when normal and emergency power are not available.

In addition to the controls provided in the main control room and in the remote shutdown control room, local (near equipment) controls are also provided for:

A. Switchgear operation, in particular, for the circuit breakers that transfer Class 1E buses and Class 1E loads from preferred to standby sources.

B. Operation of auxiliary supporting systems, e.g, transformer fans, heaters, etc..

C. Startup of standby power sources. E

Class 1E local controls are located behind doors or otherwise protected against operation by inadvertent contact, e.g. protected with keys or interlocks.

All Class 1E 4,160V Safety Division switching devices are equipped with redundant trip coils. Each Class 1E medium voltage switchgear assembly is provided with two separate sources of control power, one per redundant tripping circuit. One of the power sources is the Class 1E 125VDC Vital Instrumentation battery of the switchgear's safety division; the other power source is the Class 1E Divisions battery used to power of the Standby Emergency Diesel Generator of the same division.

The 4,160V switchgear used to connect the onsite standby non-safety AAC source to the plant Permanent Non-safety loads is provided with two separate sources of control power, one of which is the dedicated starting battery of the standby AAC source.

Provisions are included to permit opening and closing all 13,800V and 4,160V switching devices manually in the absence of any DC or AC power supply.

8.3.1.1.8 Design Bases for Class 1E Motors

As a minimum, Class 1E motors, except motor operated valve (MOV) motors, are capable of accelerating their loads within the required time with a starting voltage as low as 75% of rated motor voltage. MOV motors shall be capable of accelerating as required with a starting voltage as low as 80 percent. E

When operated under nominal conditions, the plant motors have a continuous power rating greater than the maximum power rating of the driven equipment for the worst case operating demand. Service factor requirements are in accordance with NEMA Standard MG 1 "Motors and Generators" - Section MG 1-12.47. I

Except where specified otherwise, medium voltage motors which are required to operate continuously during normal plant operation, are designed for Class B temperature rises and provided with Class F insulation systems.

Medium voltage motors which are required to operate continuously during normal plant operation are provided with thermocouples or resistance temperature devices to measure winding and bearing temperatures. E

Insert A

8.3.1.2 Analysis

The 4,160V AC and 480V AC Safety Auxiliary Power Systems (Divisions I and II) are Class 1E systems, and as such are designed to meet the requirements of General Design Criteria 17 and 18, and the intent of NRC Regulatory Guides 1.6, 1.9, 1.32, 1.63, 1.81, and 1.106 as discussed below. A failure modes and effects analysis for the onsite power system is presented in Table 8.3.1-1.

8.3.1.2.1 Compliance with General Design Criterion 17 and Regulatory Guide 1.32

Two separate circuits from the transmission network are normally available to the Class 1E Auxiliary Power Systems.

The separation of the two independent circuits at the offsite voltage level is maintained by the LOCATION OF THE switchyards ~~power circuit breakers~~. Each circuit is separately connected through transformers and breakers to the redundant 4,160V Permanent Non-safety switchgear. ~~which in turn are~~ THE 4160V PERMANENT NON-SAFETY SWITCHGEAR CAN ALTERNATELY BE connected through double isolation feeder breakers to the redundant Division I or II 4160V Class 1E Safety Division switchgear OR THE 4160V SAFETY BUS SWITCHGEAR. ~~Since each of the supplies is normally available within seconds following the tripping of the reactor and the opening of the generator breakers, the~~ THE requirements of GDC 17 and the intent of guidance in Regulatory Guide 1.32 are fully met.

Insert A:

"Actuation circuitry for Class 1E motors/pumps will not include pressure switch or device permissives (lube oil, cooling water, etc.) which would have to be satisfied prior to automatic or manual motor/pump starts."

THROUGH THE PERMANENT NON-SAFETY SWITCHGEAR

RESERVE

In the event that one of the two 50% capacity Unit Auxiliary transformers is out of service, the 4,160V Class 1E Safety Division System switchgear supplied from that transformer will be supplied from the ~~Standby~~ Auxiliary transformer, thereby maintaining two independent circuits to the Class 1E Divisions I and II during this period. In the event that the unit main transformers are out of service, both of the 4,160V Class 1E Divisions can be supplied from the remaining ~~single~~ independent ~~Standby Auxiliary Transformer~~ circuits. THROUGH THE RESERVE AUXILIARY TRANSFORMERS.

The Onsite Power System is designed to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of the unit generator, the transmission network, or the onsite electric power supplies.

8.3.1.2.2 Compliance with General Design Criterion 18

Provisions are made for periodic testing of all important components of the Class 1E AC power systems. Further provision is made for periodic testing of the emergency diesel generators to assure their capability to start and to accept loads within design limits. Electric power systems important to safety are designed to allow periodic testing to the extent practical. Included in the system design is the capability to periodically test the operability and functional performance of these systems as a whole and under conditions as close to design as practical. Staggered tests may be employed to avoid the testing of redundant equipment at the same time. E

The 4,160V circuit breakers and associated equipment are tested in-service by opening and closing the breakers so as not to interfere with the operation of the unit. The 480V breakers, motor starters, and associated equipment are also tested in-service by opening and closing the breakers and contactors so as not to interfere with unit operation. Additionally, the protective relaying associated with the 4,160V and 480V Safety Auxiliary Power System Divisions are inspected, tested, and maintained on a routine basis.

8.3.1.2.3 Compliance with Regulatory Guide 1.6

The design of the Class 1E AC power systems complies with the intent of independence requirement of Regulatory Guide 1.6.

The electrically powered Class 1E AC loads are separated into two redundant and completely independent divisions for the unit. There are no direct automatic or manual ties between redundant divisions.

No single failure can prevent operation of the minimum number of required safety loads, and loss of any one division will not prevent the minimum safety functions from being performed. Each Class 1E 4,160V switchgear has access to an offsite power source, the Alternate AC and an emergency diesel generator power source. E I

Two emergency diesel generators are provided. Each emergency diesel generator is connected exclusively to its associated Class 1E 4,160V safety switchgear division which ensures independence of the onsite Class 1E standby power sources. E

8.3.1.2.4 Compliance with Regulatory Guide 1.9

The design of the emergency diesel generators used as standby power sources complies with the intent of Regulatory Guide 1.9. I E

Each emergency diesel generator set is capable of starting and accelerating to rated speed, in the proper sequence, all of the required engineered safety feature and emergency shutdown loads. I

8.3.1.2.5 Compliance with IEEE Standards 308-1980, 387-1984 and Regulatory Guide 1.32

The Onsite 1E AC Electric Power System distribution design and configuration as described herein, is capable of transmitting sufficient energy to start and operate all required loads. The systems redundant division equipment is physically and electrically independent from each other in accordance with IEEE Standard 308-1980. Instrumentation and controls are provided to perform maintenance and periodic surveillance tests. The design complies with the intent of Regulatory Guide 1.32. E

The requirements of IEEE Standard 387-1984 are implemented in the design of the standby power system. Emergency diesel generators are tested on a periodic basis, as identified in Chapter 16 Technical Specifications. I

8.3.1.2.6 Compliance with IEEE Standard 384-1981 and Regulatory Guide 1.75

The physical layout and separation of the Class 1E AC electrical system equipment circuits is designed to minimize the vulnerability of the Reactor Protection Systems, Engineered Safety Feature Systems and Class 1E Power Systems to physical damage. E

A further description of the methods used to comply with the intent of this standard and Regulatory Guide regarding physical identification and independence of redundant power sources, switchgear, inverters, motor control centers and related cabling are contained in Sections 8.3.1.3 and 8.3.1.4. E

8.3.1.2.7 Compliance with IEEE Standard 379-1977

The single failure criterion as set forth in 4.2 of IEEE Standard 279-1971 and interpreted in IEEE Standard 379-1977 is applied to the design and analysis of the Class 1E AC Power System.

Any single failure within the Class 1E Auxiliary Power System will not prevent proper Class 1E AC Power System action when required.

8.3.1.2.8 Compliance with Regulatory Guide 1.63

The mechanical, electrical, and test guidance as set forth in Regulatory Guide 1.63 for the design, construction, and installation of electric penetration assemblies in the containment structure are followed.

Insert A →

8.3.1.2.9 Compliance with Regulatory Guide 1.106

The intent of Regulatory Guide 1.106 is met by not using thermal overload protective devices in safety-related motor-operated valve control circuits. The thermal overload signals are used only for status annunciation. The ESF-CCS, as described in Section 7.3, has the capability to provide Motor Operated Valve (MOV) thermal overload status information to the operator via the Data Processing System (DPS) displays described in Section 7.7.1.7.

8.3.1.3 Physical Identification of Safety-Related Equipment

All Class 1E equipment, cables, and raceways are identified according to the particular safety division ~~train~~ or channel with which they are associated.

All major Class 1E equipment is identified with a nameplate which categorizes the particular equipment.

All Class 1E cables and raceways are identified by a color coding method. The color coding method is implemented with four basic colors: red, green, yellow, and blue. These colors correspond to the following safety Divisions and channels:

Insert A

"All electical circuits which go through containment penetration assemblies will be provided with redundant protective devices unless the maximum current available in the circuit is less than the continuous rating of the penetration assembly (RTD, thermocouple, transducer, and annunciator circuits).

Redundant protective devices for circuits passing through containment penetration assemblies will conform all the requirements of IEEE Standard 741-1990. The primary and backup protective devices will be set with corresponding breaker trip times taken into account to ensure circuit interruption prior to reaching penetration assembly maximum time-current capabilities. This protection will be designed to undergo periodic testing to verify equipment operational status as outlined in Section 7.3 of IEEE Standard 741-1990.

The primary and secondary overcurrent protection provided for each cable type which penetrates containment will meet the requirements of independence and testing capabilities of IEEE Standard 603-1980, Sections 5.6 and 5.7. Redundant protection channels will be designed for independence to ensure proper operation in any event (including a random nonsafety equipment failure) which requires the protection circuit to be activated. Protection systems will be designed to allow circuits and devices to be tested while maintaining their capability to perform protective functions unless this will adversely affect safety or operability of the unit."

Protective Channels	Electrical Divisions	Associated Channels
Channel A: Red	I: Red	Channel J: White/Red Stripe
Channel B: Green	II: Green	Channel K: White/Green Stripe
Channel C: Yellow		Channel L: White/Yellow Stripe
Channel D: Blue		Channel M: White/Blue Stripe

All non-panel mounted Class 1E system instrumentation and equipment is identified with a name tag which provides the channel number and the suffix A, B, C, or D to specifically identify the protection channel with which the component is identified.

Non-Class 1E cables channels "X" or "Y" do not use the above color coding scheme.

Class 1E cables are marked prior to or during installation with the appropriate color code at intervals not to exceed five feet and are also identified by tags affixed at both ends bearing the appropriate cable number. Color-coded tags are also used to identify Class 1E cable tray and major pieces of equipment. E

Cable routing documentation is prepared to establish a permanent record of the cable numbers (Class 1E cables have a unique identifier in the number), cable types, origin, terminations, routing, restriction code, and color code. Add Insert A

All cable trays, conduits, and wireways containing Class 1E cables are also color coded for ease of identification and to assure that separation is maintained. These raceways are marked at each end, at all entrances and exits to rooms, and at intervals not to exceed 15 feet. Raceways are marked prior to the installation of their cables.

Add Insert B

8.3.1.4 Independence of Redundant Systems

The physical layout of Class 1E systems is designed to minimize the vulnerability of redundant equipment and cabling to damage. Special consideration is given to potential hazards in the various areas of the plant where Class 1E systems are located. In particular, these areas are analyzed for potential pipe whips, missiles, and other hazards. Separation and/or barriers are provided such that damage from potential hazards does not preclude the performance of a required safety function.

Insert A:

"Component wires of a color coded cable are not themselves color coded following entry into a safety-related cabinet and/or panel. However, all such wires are appropriately labeled, and permanent documentation is maintained."

Insert B:

"A program for maintaining markings and labeling of safety-related components and cabling will be provided by the owner/operator."

The criteria established to assure the preservation of the independence of Class 1E systems is discussed below: E

8.3.1.4.1 Emergency Diesel Generators I

Two mutually redundant emergency diesel generators are provided and are physically separated in individual Category 1 structure to preserve their independence and integrity and to assure their maximum availability. No common failure mode exists which may jeopardize independence for any design basis event.

8.3.1.4.2 Switchgear and Load Centers E

Redundant ~~trains~~ DIVISIONS of Class 1E switchgear and associated load centers are provided and are located in separate rooms within Category 1 structures, thereby establishing maximum availability through their separation and independence. No common failure mode exists which may jeopardize independence between the redundant groups for any design basis event.

8.3.1.4.3 Motor Control Centers

Redundant groups of Class 1E motor control centers are provided. Physical separation is employed to provide the required independence of the groups. No common failure mode exists which may jeopardize independence between the redundant groups for any design basis event.

8.3.1.4.4 Batteries, Chargers, Inverters and Panelboards

Each of the four channels of the 125V DC and 120V AC Vital Instrumentation and Control Power System is located in a separate compartment in a Category 1 structure to preserve its independence. No common failure mode exists which may jeopardize independence between the redundant groups.

8.3.1.4.5 Cable Installation and Separation

Cables of redundant systems are routed separately to preserve their independence. Separation criteria are established based on location of the cables within the station to preclude any single credible event from preventing the safe shutdown of the unit.

8.3.1.4.5.1 Cable and Conduit Installation and Support

Cables are installed in open ventilated ladder type trays, open ventilated electray channels, conduit, or wireways. A seismically qualified cable support system is provided for all raceways containing Class 1E cables. Additionally, all raceways are of non-combustible construction.

Add Insert A1

Cables are routed in separate raceway systems according to voltage level and function. Where practical, a vertical stack of trays is arranged such that the highest voltage level is on top with the lower trays in descending order of voltage levels and finally control and instrumentation trays at the lowest level. The 125V DC and 120V AC vital instrument buses and cabling are designed and installed such that their maximum voltage fault will not exceed 480V AC +10% or 125V DC + 10% values assumed for the qualification of Class 1E isolation devices used in various instrumentation and control systems. Insert 1 Cable splicing is not allowed in raceways.

Insert B →

Cable tray and conduit are located a safe distance from the high temperature piping system to preclude the necessity of reducing the cable ampacity as a result of increased ambient temperature.

Insert 4 →

Multi-level cable tray systems provide, as a minimum, one-foot, four-inch vertical spaces between the bottom of the upper tray and the top of the lower tray, and two feet of horizontal space between adjacent trays. Any reduction of these distances will require a barrier.

Drip loops are provided in conduit runs at the inlet to electrical devices where conduit enters from the top and when required to maintain device qualification as an alternative to device-sealing type hardware. E

Insert A2 →

Light weight conduit, fittings, and cable tray materials are utilized in lieu of rigid steel. Installation of intermediate metal conduit or aluminum rigid conduit is utilized where technically acceptable (e.g., outside containment). I

In cable tunnels, in lieu of ceiling supports, large seismic cable tray support structures are mounted on floors.

Precast concrete trenches, ductbanks, and manholes are used whenever technically acceptable.

Planning of cable pulls are included in the design of equipment locations, cable tray routings, and conduit routings to maximize group pulling of cables. E

Color-coded jacketing for multi-paired conductors are specified where possible.

Exothermic cadwelded connections are used in the installation of ground grid system in lieu of wedge pressure cable connectors where possible.

INSERT 1

"The separation of the wiring at the input and output terminals of the isolation device may be less than 6 in. provided it is not less than the distance between input and output terminals.

Minimum separation requirements do not apply for wiring and components within the isolation device; however, separation shall be provided wherever practicable.

The capability of the device to perform its isolation function shall be demonstrated by qualification test. The qualification shall consider the levels and duration of the fault current on the non-Class 1E side.

The following devices may be used as acceptable isolation devices for instrumentation and control circuits:

(1) Amplifiers
(2) Control switches
(3) Current transformers
(4) Fiber optic couplers
(5) Photo-optical couplers
(6) Relays
(7) Transducers
(8) Power packs
(9) Circuit breakers"

INSERT 4

"Power cables shall be routed away from control and instrumentation cables to prevent faulty operation which is caused by the electromagnetic interference by the power cables."

Insert A:

"The voltage levels in descending order are as follows:

- 15 KV power cables;
- 8 or 5 KV power cables;
- Low voltage power ac and dc cables;
- High level signal and control cables (120 VAC, 125 VDC);
- Cables for low level analog and digital signal."

Insert B:

"A raceway designated for a single class of cables shall contain only cables of the same class."

Insert A7

"Watertight sealing of all electrical conduit-to-junction boxes and conduit-to-terminal box connection points for safety-related equipment located in areas of the reactor building and areas that are potentially subject to high temperature steam or water impingement shall be provided. Box drain holes and equipment interfaces shall be in conformance with test setup established during the equipment qualification testing and with the vendor's recommendations."

8.3.1.4.5.2 Cable Separation

The minimum separation between Class 1E cables and between Class 1E and Non-Class 1E cables meets the intent of Regulatory Guide 1.75. Insert 5

Insert 2

Insert 3

8.3.1.5 Cable Derating and Cable Tray Fill

8.3.1.5.1 Cable Derating

The cable ampacities for both AC and DC power cables are derated per IEEE Standard S-135 and IPCEA P-46-426 to assure minimum degradation of cable insulation caused by high temperatures should the cables be loaded to their maximum ampacity rating.

The maximum ampacities for all power cables are determined by multiplying the appropriate cable manufacturer's IPCEA cable ampacity rating by 0.7. This provides a 30% margin between each power cable's rated full load capacity and its actual full load application.

8.3.1.5.2 Cable Tray Fill Criteria

The cable tray fill criterion for those trays containing power cables allows only one single layer of power cables to be routed in any tray, and, in general, separation of one-quarter the diameter of the larger cable is maintained between adjacent power cables within a tray.

The cable tray fill criterion for those trays containing instrumentation and control cables is that the cross-sectional area of these cables will not exceed the usable cross-sectional area of the tray.

Insert C

8.3.1.6 Fire Protection and Detection

The fire protection system provided in the unit is discussed in Section 9.5.1.

All openings for cable and cable tray runs in fire rated walls and floors are protected consistent with the rating of the wall or floor. The barrier openings are protected with approved devices such as fire dampers and fire stopping material of Class C (3/4 hour) for openings in one hour fire barriers and Class B (1-1/2 hours) for openings in two hour fire barriers and Class A (3 hours) for openings in three hour fire barriers.

E

The cable spacing may vary between tiedown points due to cable snaking or cable entering/exiting a tray; however, if cables touch, the contact is limited to approximately two feet.

INSERT 2

"Where the control switchboard materials are flame retardant and analysis is not performed, the minimum separation distance shall be 6 in. In the event the above separation distances are not maintained, barriers shall be installed between redundant Class 1E equipment and wiring."

INSERT 3

"The minimum separation distance between conduit and non-enclosed raceway shall be 1 foot horizontally and 3 foot vertically in nonhazardous areas and 3 foot horizontally and 5 foot vertically in hazardous areas. Where the plant arrangements preclude maintaining the minimum separation distance, the circuits requiring separation shall be run in enclosed raceways, or barriers shall be provided between circuits. The minimum distance between these enclosed raceways shall be 1 inch."

INSERT 5

"8.3.1.4.6 Electrical Penetration

Redundant Class 1E containment electrical penetrations are physically separated and electrically isolated to maintain the independence of Class 1E circuits and equipment so that safety functions required during and following any design basis event can be accomplished. The redundant penetrations are located in four quadrants of the containment each enclosed in a penetration room. The minimum separation between electrical penetrations containing non-Class 1E circuits and penetrations containing Class 1E or associated cables is 3 foot horizontally and 5 foot vertically."

Insert C:

"8.3.1.5.3 Insulation

Cable insulations are applied very conservatively. The following guidelines are to be used in applying cable insulation ratings to various station applications.

Cable Insulation Rating	Application Rating
15,000 Volt	13,800 volt power cable
8,000 Volt	4,160 volt power cable
2,000 Volt	600 volt power cable
1,000 Volt	Low volt power and control cable
600 Volt	208/120 volt lighting cable
300 Volt	120 volt ac and 125 volt dc instrumentation cable"

The type of fire stop and seal used at each fire barrier opening for cable or cable tray depends on the cable or cable tray configuration penetrating the barrier. The primary types used are multiple cable transit assemblies (a metal frame with fire-proof elastomer building blocks which form a compression fit around each cable), mineral wool fiber packing (voids around cable and cable tray filled with mineral wool fiber and then sprayed with a fire retardant spray), and foam (two fire retardant plates placed on each side of the barrier and any void filled with fire retardant foam).

Specifications for fire stops and seals require the manufacturer to supply material and/or components that will remain functional throughout the life of the plant.

Proper installation of the fire stops and seals is assured by following approved manufacturer's installation procedures and techniques. Each installation is visually inspected periodically to verify that its integrity is maintained. When it becomes necessary to breach a completed fire stop or seal to add or remove cables, a documented inspection is performed to ensure that the fire stop or seal is reinstalled to the specifications of the original installation.

There are no cable fire stops installed at locations other than fire barrier penetrations on vertical or horizontal cable tray runs. Fire retardant cables are used throughout the unit. ~~All cables, except a few Non-Class 1E instrumentation and control cables, are of the interlocked armor type, with a fire retardant jacket and will not propagate fire to another area, or add to the severity of the fire.~~ These cables have passed the flame test of IEEE Standard 383-1974. E

Fire detectors and water sprinkler systems are provided in the areas identified in the hazard analysis.

The fire protection system cannot prevent a fire from damaging equipment and materials necessary to nuclear safety, but it is intended to aid in preventing a fire from damaging redundant safety equipment as well as preventing the spread of fire or flammable materials due to fire.

Mutually redundant Class 1E cables are separated in accordance with the intent of Regulatory Guide 1.75. The separation criteria utilized is based on the location of the cables within the station so as to preclude any single credible event applicable to that location from rendering inoperative a sufficient number of mutually redundant cables to prevent the fulfillment of the required safety function.

THIS PAGE INTENTIONALLY BLANK

DELETE EXISTING
TABLE 8.3.1-1
AND REPLACE WITH
THE FOLLOWING

TABLE 8.3.1-1

(Sheet 1 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
1. Isolated phase bus from unit main transformer to the generator breaker or to the unit auxiliary transformer. or Unit Auxiliary Transformer.	Loss due to a fault.	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent preferred offsite circuit remains unaffected. (c) Automatic reactor trip occurs. (d) The unit generator automatically trips and its breaker opens. (e) The Permanent Non-Safety Auxiliary System switchgear supplied from the faulted circuit is connected in a automatic rapid bus transfer to the Reserve Auxiliary Transformer in the second independent circuit and Class 1E auxiliaries continue to receive uninterrupted offsite power.

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
2. Reserve Auxiliary Transformer	Loss due to a fault	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent preferred offsite circuit remains unaffected. (c) No effect on unit power generation or Essential Safety buses, since not normally connected to onsite system.
3. Isolated phase bus connecting the generator circuit breaker and the unit generator or Unit generator	Loss due to a fault	(a) Generator breaker trip. (b) The unit turbine generator is tripped automatically. (c) All unit and Class 1E auxiliaries continue to receive uninterrupted offsite power from the Unit Auxiliary transformers.

TABLE 8.3.1-1

(Sheet 3 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
4. Generator circuit breaker	Breaker fault, failure, or pole disagreement	(a) The other two poles of the breaker trip. (b) The faulted equipment is isolated by protective relaying and protective equipment. (c) The other independent preferred offsite circuit remains unaffected. (d) Automatic reactor trip occurs. (e) The Permanent Non-Safety Auxiliary System switchgear supplied from the faulted circuit is connected in a automatic rapid bus transfer to the Reserve Auxiliary Transformer in the second independent circuit and Class 1E auxiliaries continue to receive uninterrupted offsite power.

TABLE 8.3.1-1

(Sheet 4 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
5. Isolated Phase Bus Cooling System	Loss of bus cooling	(a) No immediate consequence. The unit and Class 1E auxiliaries continue to receive an uninterrupted flow of power from the Unit Auxiliary Transformers. However, continued unit operation is dependent upon bus design capacities with and without forced cooling.
6. Unit Auxiliary Transformers Cooling System	Loss of one of the cooler banks	(a) No immediate consequence. The unit and the Class 1E auxiliaries continue to receive an uninterrupted flow of power from this source. However, continued transformer and unit operation is dependent upon its rated design capacities with and without cooling.
7. Unit Main Transformer Cooling System	Loss of one of the cooler banks	(a) No immediate consequence with step-up transformer at full load. The operator must

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		reduce load to the transformer immediately, trip the unit generator, and completely isolate the transformer within approximately 15 minutes. (The exact time will be dependent upon manufacturer recommendations.)
8. 13,800V Non-Safety Auxiliary System switchgear source breaker	Breaker fault or failure	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent preferred offsite circuit remains unaffected. (c) Automatic reactor trip occurs. (d) The unit generator automatically trips and its breaker opens. (e) The Permanent Non-Safety Auxiliary System switchgear supplied from the faulted circuit is

TABLE 8.3.1-1

(Sheet 6 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

	Component	Malfunction		Resulting Consequences
				connected in a automatic rapid bus transfer to the Reserve Auxiliary Transformer in the second independent circuit and Class 1E auxiliaries continue to receive uninterrupted offsite power.
9.	13,800V Non-Safety Auxiliary System switchgear bus or switchgear	Bus shorted or breaker fault	(a)	The switchgear source breaker trips.
			(b)	The plant will experience a reactor trip due to the loss of reactor coolant pumps.
			(c)	No effect on 4160V Non-Safety, 4160V Permanent Non-Safety or Class 1E Safety Division loads.
10.	4,160 Non-Safety Auxiliary Power System Switchgear source breaker	Breaker fault or failure	(a)	The faulted equipment is isolated by protective relaying and protective equipment.

TABLE 8.3.1-1

(Sheet 7 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		(b) The other independent preferred offsite circuit remains unaffected.
		(c) Automatic reactor trip occurs.
		(d) The unit generator automatically trips and its breaker opens.
		(e) The Permanent Non-Safety Auxiliary System switchgear supplied from the faulted circuit is connected in a automatic rapid bus transfer to the Reserve Auxiliary Transformer in the second independent circuit, Class 1E auxiliaries continue to receive uninterrupted offsite power.
11. 4160V Non-Safety System Switchgear	Bus shorted or feeder breaker fault	(a) The switchgear source breaker trips.
		(b) Loss of normal source to 4,160V Non-Safety Bus. Required unit

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		power reduction to the capacity supported by remaining non-safety auxiliaries. May cause Reactor Power Cutback or unit to trip.
		(c) No effect on Permanent Non-Safety or Class 1E safety division loads.
12. 4160V Non-Safety System Switchgear feeder 4160V load cables	Fault on one	(a) The associated 4160V feeder breaker trips and isolates the fault from the system. Remaining loads should not be affected.
		(b) Loss of source to 4160V Non-Safety load may require further power reduction to the capacity supported by remaining non-safety auxiliaries. May cause Reactor Power Cutback or unit to trip.

TABLE 8.3.1-1

(Sheet 9 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
13. 4160/480 Volt Non-Safety Load Center Transformer or its Feeder Cables or 480V Non-Safety load center source breaker	Fault on one	(a) The associated 4160V feeder breaker trips and isolates the fault from the system. (b) The load center is deenergized. (c) The 480V Non-Safety motor control centers dead bus transfer to their alternate source.
14. 480 Volt Non-Safety Load Center bus or 480 Volt Non-Safety Load Center Feeder Breaker	Fault	(a) The load center source circuit breaker trips. (b) The associated 480V loads are deenergized. (c) The associated 480V Non-Safety motor control centers dead bus transfer to their alternate source.

TABLE 8.3.1-1

(Sheet 10 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
15. 480 Volt Non-Safety Load Center Feeder Cable or 480 Volt Non-Safety Motor Control Center Source Breaker	Fault	(a) The load center feeder breaker trips. (b) The load or motor control center remains deenergized.
16. 480 Volt Non-Safety Motor Control Center Bus or 480 Volt Non-Safety Motor Control Center Source Feeder Breaker	Fault	(a) The motor control center source breaker trips.
17. 480 Volt Non-Safety Motor Control Center Feeder Cable	Fault	(a) The motor control center feeder breaker trips.

TABLE 8.3.1-1

(Sheet 11 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
18. 4160V Permanent Non-Safety Auxiliary Power System Switchgear Normal or Gas Turbine Source Breaker	Breaker Fault or Failure	(a) The faulted equipment is isolated by protective relaying and protective equipment. (b) The other independent preferred offsite circuit remains unaffected. (c) Automatic reactor trip occurs. (d) The unit generator automatically trips and its breaker opens. (e) The 4.16KV Permanent Non-Safety switchgear (other than the one with the breaker fault or failure) fast transfer to the alternate source. The 13.8KV Non-Safety switchgear deenergizes and has the capability of being powered from an alternate source. (f) 4160V Non-Safety Bus goes dead.

TABLE 8.3.1-1

(Sheet 12 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
19. 4160V Permanent Non-Safety System Switchgear	Bus shorted or feeder breaker fault	(a) The switchgear source breaker trips. (b) Sufficient redundant auxiliaries remain operable from the redundant Permanent Non-Safety System switchgear. (c) Affected 4,160V Class 1E switchgear will be deenergized and the diesel will start. Associated 480V buses will also deenergize.
20. 4160V Permanent Non-Safety System Switchgear 4160V load feeder cables	Fault on one	(a) The associated 4160V feeder breaker trips and isolates the fault from the system. Remaining loads should not be affected. Sufficient redundant auxiliaries remain operable from the redundant Permanent Non-Safety System.

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
21. 4160/480 Volt Permanent Non-Safety Load Center Transformer or its Feeder Cables or 480V Permanent Non-Safety load center source breaker.	Fault on one	(a) The associated 4160V feeder breaker trips and isolates the fault from the system. (b) The load center is deenergized. (c) The 480V Permanent Non-Safety motor control centers dead bus transfer to their alternate source. (d) Should any load center loads be lost, sufficient redundant auxiliaries remain operable from the redundant Permanent Non-Safety System.
22. 480 Volt Permanent Non-Safety Load Center bus or 480 Volt Permanent Non-Safety Load Center Feeder Breaker	Fault	(a) The load center source circuit breaker trips. (b) The associated 480V loads are deenergized. (c) The associated 480V Permanent Non-Safety Motor Control Centers automatically transfer to their alternate source.

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
23. 480 Volt Permanent Non-Safety load Center feeder cable or 480 Volt Permanent Non-Safety Motor Control Center Source Breaker	Fault	(a) The load center feeder breaker trips. (b) The load or motor control center remains deenergized.
24. 480 Volt Permanent Non-Safety Motor Control Center Bus or 480 Volt Permanent Non-Safety Motor Control Center Feeder Breaker	Fault	(a) The motor control center source breaker trips.
25. 480 Volt Permanent Non-Safety Motor Control Center Feeder Cable	Fault	(a) The motor control center feeder breaker trips. Sufficient redundant auxiliaries remain operable from the

TABLE 8.3.1-1

(Sheet 15 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		redundant Permanent Non-Safety System.
26. 4160V AAC Source feeder cable or Gas Turbine Output breaker	Fault	(a) If the ACC Source is connected, the 4160V Permanent Non-Safety switchgears are deenergized.
		(b) At the operators discretion, critical Permanent Non-Safety loads may be backfed from the diesel generator provided sufficient load shedding has taken place.
		(c) The faulted equipment is isolated by protective relaying and protective equipment.
		(d) The circuit from the Permanent Non-Safety bus is automatically transformed to the Reserve Auxiliary

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		Transformer and Class 1E auxiliaries continue to receive uninterrupted offsite power.
27. 4160V Class 1E Safety Auxiliary Power System Division Switchgear Source Breaker	Breaker Fault or Failure	(a) The faulted equipment is isolated by protective relaying and protective equipment.
		(b) Affected 4160V Class 1E switchgear is deenergized. Associated 480V buses are also deenergized.
		(c) The associated diesel generator starts and loads on unfaulted 4160V class 1E switchgear are sequenced on.
		(d) Sufficient redundant auxiliaries remain operable from the redundant class 1E Safety Power System Division for safe shutdown of the reactor.

TABLE 8.3.1-1

(Sheet 17 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
28. 4160V Class 1E Safety Auxiliary Power System Division switchgear or feeder breakers	Fault	(a) Source breakers trip and the affected 4160V Class 1E Division switchgear is deenergized. Loss of redundant 1E 480V buses (Channels A,C or B, D) associated with division. Sufficient redundant auxiliaries remain operable from the redundant Class 1E Safety Auxiliary Power System Division for the safe shutdown of the reactor.
29. 4160V Safety Division Emergency Diesel Generator	Fault	(a) If the EDG source is supplying power under blackout conditions, the affected 4160V Safety Division is deenergized until the fault is cleared and the AAC source can be manually aligned to re-energize the division.

TABLE 8.3.1-1

(Sheet 18 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		(b) Sufficient redundant auxiliaries rema n operable from t e redundant Clas 1E Safety Power System Division.
30. 4160V Class 1E Safety Auxiliary Power System Division switchgear feeder cables or 4160/480 Volt 1E load center transformer or 480 V Class 1E load center source breaker	Fault on one	(a) The associated load feeder breaker trips and isolates the fault from the system. Remaining Division loads should not be affected. Sufficient redundant auxiliaries remain operable from the redundant Class 1E Safety Power System Division for safe shutdown of the reactor.
31. 480 Volt Class 1E loa cer r bus or 480 Volt Class 1E load center feeder breaker	Fault	(a) The load center source circuit breaker trips. Sufficient redundant auxiliaries remain operable from the

TABLE 8.3.1-1

(Sheet 19 of 19)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE ONSITE POWER SYSTEMS

Component	Malfunction	Resulting Consequences
		redundant Class 1E Safety Power System Division for the safe shutdown of the reactor.
32. 480 Volt Class 1E load center feeder cable or 480 Volt Class 1E motor control center bus	Fault	(a) The load center feeder breaker trips. Sufficient redundant auxiliaries remain operable from the redundant Class 1E Safety Power System Division for the safe operation of the reactor.
33. 480 Volt Class 1E motor control center feeder cable	Fault	(a) The motor control center feeder breaker trips. Sufficient redundant auxiliaries remain operable from he redundant Class 1E Safety Power System Division for the safe operation of the reactor.

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group A (NOTE B)										
Division I Diesel Generator Building Sump Pump 1A	1	480	5 HP	0.9	0.9	4	4	0	4	0
Division I Diesel Generator 480/208/120 Power Panelboard	1	480	15 KVA	0.9	-	13.5	13.5	0	13.5	0
Division I Diesel Generator Building Ventilation Fan 1A	1	480	100 HP	0.9	0.9	75	75	0	75	0
Division I Diesel Generator Crankcase Blower	1	480	0.25 HP	0.9	0.9	0.2	0.2	0	0.2	0
Division I Diesel Generator Prelube Pump	1 NOTE C	480	7.5 HP	0.9	0.9	5.6	0	0	0	0
Division I Diesel Generator Engine Jacket Water Keep Warm Pump	1 NOTE C	480	2 HP	0.9	0.9	1.5	0	0	0	0
Division I Diesel Generator Jacket Water Heater	1 NOTE C	480	75 KW	1.0	-	75	0	0	0	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Division I Diesel Generator Barring Gear Motor	1 NOTE C	480	[illegible] HP	0.9	0.9	2.3	0	0	0	0
Division I Diesel Generator Lube Oil Heater	1 NOTE C	480	7.5 KW	1.0	-	7.5	0	0	0	0
Division I Diesel Generator Space Heater	1 NOTE C	480	4.6 KW	1.0	-	4.6	0	0	0	0
Channel A 125 V Vital Battery Chargers for I & C	1	480	43.9 KVA	0.9	-	39.5	4.5	0	39.5	0
Control Room and Remote Shutdown Panel Division I Lighting	1	480	12.5 KW	1.0	-	12.5	12.5	0	12.5	0
Division I Class 1E Motor Operated Valves Powered from Safety Bus A	-	480	42.5 HP	0.9	0.9	32	32	0	32	0
Quadrant A Reactor Building Subsphere Floor Drain Sump Pumps 1 and 2	2	480	15 HP	0.9	0.9	22.4	22.4	0	22.4	0
Auxiliary Building Groundwater Drainage Sump Pump 1A	1 NOTE L	480	20 HP	0.9	0.9	15	15	0	15	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Division I Control Room Air Handling Unit	1	480	8 BHP	0.9	0.9	6.7	6.7	0	6.7	0
Division I Control Room Mechanical Equipment Room Air Handling Unit	1	480	1.0 BHP	0.9	0.9	0.9	0.9	0	0.9	0
Essential Chiller Pump 1	1	480	13 BHP	0.9	0.9	10.8	10.8	0	10.8	0
CCW Pump 1A Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
50' Elev. Vital Inst. & Equip. Room Channel A AHU's	2 NOTE O	480	10 BHP	0.9	0.9	8.3	8.3	0	8.3	0
70' Elev. Division Channel Equipment Room Air Handling Unit	2 NOTE O	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
Penetration Room A Air Handling Unit	2 NOTE O	480	1 BHP	0.9	0.9	0.9	0.9	0	0.9	0
50' Elev. 125 VDC Vital Battery Room Exhaust Fan Channel A	1	480	1 BHP	0.9	0.9	0.9	0.9	0	0.9	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
70' Elev. Division I Channel Equipment 125 VDC Battery Room Exhaust Fan	1	480	1 BHP	0.9	0.8	0.9	0.9	0	0.9	0
SSW Pump Strainer Backwash Drive Motor 1A	1 NOTE O	480	0.75 BHP	0.9	0.9	0.7	0.7	0	0.7	0
Shutdown Cooling Pump 1 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
Shutdown Cooling Heat Exchanger Room 1 Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	0	0
Division I 125 VDC Vital Battery Chargers	1	480	20.3 KVA	0.9	-	18.3	18.3	0	18.3	0
Safety Injection Pump 1 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	0	2.5	0
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP A:						273	0	273	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 1 (NOTE D)										
Safety Injection Pump 1	1	4160	910 BHP	0.9	0.9	755	0	0	755	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 1:							^	0	755	0
Load Sequence Group C (NOTE E)										
Division I Subsphere Ventilation Exhaust Fan	1	480	20 BHP	0.9	0.9	15	0	15	0	15
Division I Subsphere Exhaust Filter Train Heating Element	1	480	23 KW	1.0	-	23	0	23	0	23
Division I Annulus Ventilation Exhaust Fan	1	480	63 BHP	0.9	0.9	52.3	0	0	0	52.3
Division I Annulus Exhaust Filter Train Heating Element	1	480	83 KW	1.0	-	83	0	0	0	83

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Division I Fuel Po[illegible] Exhaust Fan	1	480	75 BHP	0.9	0.9	62.2	0	62.2	0	0
Division I Fuel Pool Exhaust Filter Train Heating Element	1	480	116 KW	1.0	-	116	0	116	0	0
Division I Fuel Pool Cooling Hx/Pumproom Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	2.5	0	0
CCW Pump 1B Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	2.5	0	2.5
50' Elev. Vital Inst. & Equip. Room Channel C AHU	2 NOTE O	480	10 BHP	0.9	0.9	8.3	0	[illegible]	0	8.3
70' Elev. Division I Channel Equipment Room Air Handling Unit	2 NOTE O	480	3 BHP	0.9	0.9	2.5	0	2.5	0	2.5
Penetration Room C Air Handling Unit	2 NOTE O	480	1 BHP	0.9	0.9	0.9	0	0.9	0	0.9
50' Elev. 125 VDC Vital Battery Room Exhaust Fan Channel C	1	480	1 BHP	0.9	0.9	0.9	0	0.9	0	0.[illegible]

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
SSW Pump Strainer Backwash Drive Motor 1B	1 NOTE O	480	0.75 BHP	0.9	0.9	0.7	0	0	0	0
Containment Spray Pump 1 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	[illegible]	0	0	2.5
Containment Spray Heat Exchanger Room 1 Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	0	0	2.5
Service Water Pump House House Division I Ventilation Fan	1	480	7.5 BHP	0.9	0.9	6.3	0	6.3	0	6.3
Division I Emergency Feedwater Pump Rooms' Air Handling Units	2	480	3 BHP	0.9	0.9	5.0		5	0	5
Safety Injection Pump 3 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	5.0		0	0	2.5
Channel C 125 VDC Vital Battery Chargers for I & C	1	480	32.2 KVA	0.9	-	29	[illegible]	29	0	29

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Division I Diesel Generator Building Sump Pump 1B	1	480	5 HP	0.9	0.9	4	0	4	0	4
Division I Diesel Generator Building Ventilation Fan 1B	1	480	100 HP	0.9	0.9	75	0	75	0	75
Control Room and Remote Shutdown Panel Division I Lighting	1	480	12.5 KW	1.0	-	12.5	0	12.5	0	12.5
Division I Class 1E Motor Operated Valves Powered from Safety Bus C	-	480	42.5 HP	0.9	0.9	32	0	32	0	32
Auxiliary Building Groundwater Drainage Sump Pump 1B	1 NOTE L	480	20 HP	0.9	0.9	15	0	15	0	15
Quadrant C Reactor Building Subsphere Floor Drain Sump Pumps 1 and 2	2	480	15 HP	0.9	0.9	22.4	0	22.4	0	22.4
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP C:							0	435	0	398

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 2 (NOTE D)										
Safety Injection Pump 3	1	4160	910 BHP	0.9	0.9	755	0	0	0	755
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 2:						0	0	0	755
Load Sequence Group 3 (NOTE F)										
Motor Driven Emergency Feedwater Pump 1	1	4160	850 HP	0.9	0.9	635	0	635	0	635
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 3:						0	635	0	635

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 4 (NOTE G)										
Containment Spray Pump 1	1	4160	600 HP	0.9	0.9	448	0	0	0	448
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 4:							0	0	0	448
Load Sequence Group 5 (NOTE H)										
Component Cooling Water Pump 1A	1	4160	1250 BHP	0.9	0.9	1037	1037	0	1037	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 5:							1037	0	1037	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 6 (NOTE I)										
Station Service Water Pump 1A	1	4160	700 BHP	0.9	0.9	581	581	0	581	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 6:							581	0	581	0
Load Sequence Group 7										
Essential Chiller 1	1	4160	260 BHP	0.9	0.9	216	216	0	216	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 7:							216	0	216	0

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 8 (NOTE H)										
Component Cooling Water Pump 1B	1	4160	1250 BHP	0.9	0.9	1037	0	1037	0	1037
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 8:						0	1037	0	1037
Load Sequence Group 9 (NOTE I)										
Station Service Water Pump 1B	1	41o0	700 BHP	0.9	0.9	581	0	581	0	581
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 9:						0	581	0	581

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C
Load Sequence Group 10 (NOTE G)										
Shutdown Cooling Pump 1	1	4160	600 HP	0.9	0.9	448	448	0	448	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 10:							448	0	448	0
Manual Load Group (NOTE J)										
Containment Hydrogen Recombiner 1	1	480	20 KW	1.0	-	20	0	0	20	0
Spent Fuel Pool Cooling Pump 1	1	480	75 HP	0.9	0.9	56	0	56	0	56
Essential AC Lighting	-	120	225 KW	1.0	-	225	110	115	110	115
Division I Control Room Pressurized Filter Train Fan	1 NOTE K	480	7 BHP	0.9	0.9	5.8	0	0	0	5.8

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	COMPONENT VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS A	LOSS OF OFFSITE POWER LOAD SAFETY BUS C	DBA/LOOP LOAD SAFETY BUS A	DBA/LOOP LOAD SAFETY BUS C	REF
Division I Control Room Pressurized Fil[illegible]r Train Heating Element	1 NOTE K	480	10 KW	1.0	-	10	0	0	0	10	4
Backup Pressuriz[illegible] eaters	1	480	200 KW	1.0	-	200	0	200	0	0	
SUBTOTAL LOADINGS FOR MANUAL LOAD SEQUENCE GRP:							110	~~171~~ 371	130	187	

Total Load Per Diesel on LOOP Including Manual Load - (NOTE N)	~~3458~~ 3658	
Total Load Per Diesel on LOOP Excluding Manual Load - (NOTE N)	3177	
Total Load Per Diesel on DBA/LOOP Including Manual Load - (NOTE N)		5415
Total Load Per Diesel on DBA/LOOP Excluding Manual Load - (NOTE N)		5058

TABLE 8.3.1-2 DIVISION I TYPICAL CLASS 1E LOADS
DIESEL GENERATOR LOAD SEQUENCER
ASSUMPTIONS AND INFORMATION

NOTE A

The loads given for the listed components are typical. Actual loads are site dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments and evaluations as necessary.

NOTE B

For Station Loss-of-Offsite-Power or DBA/LOOP event, Load Sequence Group A is energized immediately upon closure of the Diesel Generator Breaker for Safety Bus A.

NOTE C

Although these loads are connected to the Emergency Buses, they are not required once the Diesel Generator is operating, therefore, they are considered to be zero for purposes of Diesel Generator sizing.

NOTE D

Load Sequence Groups 1 and 2, Safety Injection Pumps 1 and 3, will normally be activated by the sequencer to provide Direct Vessel Safety Injection. The Safety Injection System (SIS) interface requirements specify flow to the vessel within 40 seconds after an Safety Injection Actuation Signal (SIAS). This assumes a 20 second Diesel Generator start time, a 2.5 second Safety Injection Pump 1 sequence load time (6.5 seconds for Safety Injection Pump 3) and a 10 second interval to provide actual SIS flow to the Direct Vessel Injection nozzles.

NOTE E

Load Sequence Group C consists of 480V loads powered on Safety Bus C.

NOTE F

Load Sequence Group 3, Motor Driven Emergency Feedwater Pump 1, is loaded onto the Emergency Bus by the sequencer when it receives a Low-Low Steam Generator EFAS (Emergency Feedwater Actuation Signal) signal from the Plant Protection System. This Load Group is designed such that the associated steam generator will receive Emergency Feedwater within 60 seconds after a Low-Low Steam Generator condition exists. The time breakdown for a station loss of offsite power (condition which could result in low steam generator level as a result of main feedwater pumps tripping) is as follows: 1 second for low-low steam generator condition to be detected and EFAS signal generated, 20 seconds for the Diesel Generator to start and attain rated speed and voltage, 15 seconds for the Sequencer to load Load Sequence Group 5 onto the Emergency Bus, and 24 seconds for the Motor-Driven Emergency Feedwater Pump to start and provide Emergency Feedwater flow to its associated Steam Generator. This assumes time to purge the hot water from the EFW lines adjacent to the steam generator.

NOTE G

Load Sequence Group 4, Containment Spray Pump 1, starts the divisional Containment Spray Pump as a result of a Safety Injection Actuation Signal (SIAS) activating the sequencer. The Containment Spray Pump will then operate in recirculation mode until a Containment Spray Actuation Signal (CSAS) is generated, which will cause the Containment Spray Header valves to open and supply containment spray to the spray rings. The interface requirements mandate that Containment Spray flow to the containment atmosphere result within 68 seconds of a CSAS. To accomplish this, Load Sequence Group 4 will be loaded onto the Emergency Bus 20 seconds after the sequencer begins Accident loading (40 seconds after receipt of the initiating SIAS signal). The Containment Spray pump will then operate in miniflow condition until a CSAS opens the spray header valves.

Load Sequence Group 4 and Load Sequence Group 10, Shutdown Cooling Pump 1, are interlocked such that either the Containment Spray Pump or Shutdown Cooling Pump may provide Containment Spray. If a division's Containment Spray Pump is out-of-service, the Shutdown Cooling Pump discharge valves may be manually aligned to supply water from the IRWST (In-Containment Refueling Water Storage Tank) to the Containment Spray Header. At the same time, the sequencer interlock controls are switched to bypass the defunct Containment Spray Pump 1 and to start the Shutdown Cooling Pump in its place. The normal, preferred alignment, however, is to have the Containment Spray Pump aligned for standby readiness and to use the Shutdown Cooling Pump as a backup. In this normal alignment, the sequencer will not load Load Sequence Group 12, unless manually aligned and actuated.

The Shutdown Cooling Pump is listed as a Loss-of-Offsite-Power load, since restart of this pump is required during refueling and Reactor Coolant System drained-down conditions. However, its load value is not part of the total Diesel Generator load for the LOOP event, because the Motor Driven EFW Pump (mutually exclusive to the Shutdown Cooling Pump) in a plant operating LOOP scenario is a larger, and hence more conservative load to be applied to the LOOP total.

The Shutdown Cooling Pump is also listed as a DBA/LOOP load. Its use for such an event would occur if the Shutdown Cooling Pump were functioning as the Containment Spray Pump. For load summation purposes, the Shutdown Cooling Pump is not added to the DBA/LOOP total, since the Containment Spray Pump has already been added.

NOTE H

For a Design Basis Accident with no concurrent loss of offsite power, the Component Cooling Pump in each division will remain operating. However, if Station Loss-Of-Offsite-Power occurs concurrently with a Design Basis Accident, the Diesel Generator Sequencer will function to load the divisional Component Cooling Pump which was operating just prior to the event onto the Emergency Bus within 10 seconds after the sequencer completes the Accident Loading Sequence. For a Station Loss-Of-Offsite-Power during which no DBA occurs, the sequencer will load the Component Cooling Pump which was operating just prior to the event onto the Emergency Bus within 5 seconds after receiving a Diesel Generator running signal. If this pump fails to operate, the sequencer will attempt to load the other divisional Component Cooling Water Pump onto the Emergency bus immediately.

After initial loading by the sequencer, the Component Cooling Water Pump which remains on standby may still be manually activated, or automatically activated by the sequencer immediately should the running CCW pump trip.

NOTE I

The Station Service Water Pumps will be loaded onto the Emergency Bus dependent upon the following factors and requirements.

1) The sequencer will attempt to load onto the Emergency Bus the Station Service Water Pump which was operating just prior to a Station Loss-Of-Offsite-Power. This also applies to Design Basis Accident coincident with a Station Loss-Of-Offsite-Power. The SSW Pump not loaded by the sequencer will remain on standby, capable only of being started manually when Operations determines that the corresponding increase in the Diesel Generator loading is warranted (2 pumps/division operation) or when pump cycling is desired. Sequencer logic will prohibit automatic loading of both a division's SSW Pumps.

2) If a LOCA occurs and offsite power remains uninterrupted, the running SSW pump will remain operational, still connected to normal incoming bus.

3) If the SSW Pump chosen to start by the sequencer fails to start, the sequencer will attempt to start the other SSW pump immediately.

4) The Sequencer will load the SSW Pump 10 seconds after either the completion of all Accident loadings or the sequencer's receipt of a Diesel Generator running signal (Normal Loss-Of-Offsite-Power sequence).

NOTE J

Manual Loads may be added to the emergency bus by Operations whenever plant conditions require their usage.

NOTE K

The Control Room Pressurized Filter Train and associated Heating Element will only be manually employed when high radiation levels are detected in the outside air intakes. The Control Room Ventilation System has been designed to keep the Control Room at a positive pressure relative to its surrounding environment during normal operation. Therefore, the normal divisional Control Room ventilation unit will activate on a LOCA (normal Control Room Ventilation Unit operating prior to the event will remain loaded unless load shed by a Station Loss-Of-Offsite-Power), but the Control Room Pressurized Filter Train and its associated Heating Element may or may not be activated, subject to outside environment radiation levels.

NOTE L

Number of Auxiliary Building Sump pumps is dependent on site characteristics. Two pumps per division are shown as an example here.

NOTE M

Rated Horsepower was assumed to account for pump, fan, or other mechanical efficiencies as well as for motor efficiency. Conversion into equivalent Kilowatts for Rated Horsepower involved multiplying rated horsepower by the conversion factor 0.746 KW/HP. When unit of Brake Horsepower (BHP) was assumed, a motor efficiency of 0.9 was used in addition to this conversion factor to calculate Equivalent [illegible] Unless designated by "BHP," all horsepowers are "Rated."

NOTE N

This note provides an explanation of the assumptions used for calculating the total diesel loads at the conclusion of the table. The following subtotal loads are assumed to be supplied and are summed to obtain the resultant total:

Total Load Per Diesel on LOOP Excluding Manual Load:

Load Sequence Group A
Load Sequence Group C
CCW Pump in operation prior to event
SSW Pump in operation prior to event
Essential Chiller
Motor Driven EFW Pump

Total Load Per Diesel on LOOP Including Manual Load consists of the above total plus the appropriate manual load.

Total Load Per Diesel on DBA/LOOP Excluding Manual Load:

Load Sequence Group A
SI Pump 1
Load Sequence Group C
SI Pump 3
Motor Driven EFW Pump
Containment Spray Pump or Shutdown Cooling Pump (Interlocked such that both cannot operate from sequencer simultaneously during accident)
CCW Pump in operation prior to event
SSW Pump in operation prior to event
Essential Chiller

Total Load Per Diesel on DBA/LOOP Including Manual Load consists of the above total plus the appropriate manual load.

<u>Notes on Accident and Normal Loading Sequences</u>

The following components and times apply to Accident Scenarios coincident with a Station Loss-Of-Offsite-Power:

Load Sequence Group A	0.5 seconds
Safety Injection Pump 1	2.5 seconds
Load Sequence Group C	4.5 seconds
Safety Injection Pump 3	6.5 seconds
Motor Driven EFW Pump	15.0 seconds (if req'd)
Containment Spray Pump	20.0 seconds
Component Cooling Water Pump	30.0 seconds
Station Service Water Pump	35.0 seconds
Essential Chiller	40.0 seconds

The following components and times apply to Normal Loss-Of-Offsite-Power scenarios:

Load Sequence Group A	0.5 seconds
Load Sequence Group C	2.5 seconds
Component Cooling Water Pump	5.0 seconds
Station Service Water Pump	10.0 seconds
Essential Chiller	15.0 seconds
Motor Driven EFW Pump	After 20.0 seconds (if req'd)

NOTE O

Each ventilated area listed with NOTE O has redundant 100% ventilation units. Only one of these ventilation units is allocated in the calculation for diesel generator sizing.

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	SAFETY BUS D
Load Sequence Group B (NOTE B)										
Division II Diesel Generator Building Sump Pump 2A	1	480	5 HP	0.9	0.9	4	4	0	4	0
Division II Diesel Generator 480/208/120 Power Panelboard	1	480	15 KVA	0.9	-	13.5	13.5	0	13.5	0
Division II Diesel Generator Building Ventilation Fan 2A	1	480	100 HP	0.9	0.9	75	75	0	75	0
Division II Diesel Generator Crankcase Blower	1	480	0.25 HP	0.9	0.9	0.2	0.2	0	0.2	0
Division II Diesel Generator Prelube Pump	1 NOTE C	480	7.5 HP	0.9	0.9	5.6	0	0	0	0
Division II Diesel Generator Engine Jacket Water Keep Warm Pump	1 NOTE C	480	2 HP	0.9	0.9	1.5	0	0	0	0
Division II Diesel Generator Jacket Water Heater	1 NOTE C	480	75 KW	1.0	-	75	0	0	0	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Division II Diesel Generator Barring Gear Motor	1 NOTE C	480	3 HP	0.9	0.9	2.3	0	0	0	0
Division II Diesel Generator Lube Oil Heater	1 NOTE C	480	7.5 KW	1.0	-	7.5	0	0	0	0
Division II Diesel Generator Space Heater	1 NOTE C	480	4.6 KW	1.0	-	4.6	0	0	0	0
Channel B 125 V Vital Battery Chargers for I & C	1	480	43.9 KVA	0.9	-	39.5	39.5	0	39.5	0
Control Room and Remote Shutdown Panel Division II Lighting	1	480	12.5 KW	1.0	-	12.5	12.5	0	12.5	0
Division II Class 1E Motor Operated Valves Powered from Safety Bus B	-	480	42.5 HP	0.9	0.9	32	32	0	32	0
Quadrant B Reactor Building Subsphere Floor Drain Sump Pumps 1 and 2	2	480	15 HP	0.9	0.9	22.4	22.4	0	22.4	0
Auxiliary Building Groundwater Drainage Sump Pump 2A	1 NOTE L	480	20 HP	0.9	0.9	15	15	0	15	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Division II Control Room Air Handling Unit	1	480	8 BHP	0.9	0.9	6.7	6.7	0	6.7	0
Division II Control Room Mechanical Equipment Room Air Handling Unit	1	480	1.0 BHP	0.9	0.9	0.9	0.9	0	0.9	0
Essential Chiller Pump 2	1	480	13 BHP	0.9	0.9	10.8	10.8	0	10.8	0
CCW Pump 2A Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
50' Elev. Vital Inst. & Equip. Room Channel B AHU's	2 NOTE O	480	10 BHP	0.9	0.9	8.3	8.3	0	8.3	0
70' Elev. Division II Channel Equipment Room Air Handling Unit	2 NOTE O	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
Penetration Room B Air Handling Unit	2 NOTE O	480	1 BHP	0.9	0.9	0.9	0.9	0	0.9	0
50' Elev. 125 VDC Vital Battery Room Exhaust Fan Channel B	1	480	1 BHP	0.9	0.9	0.9	0.9	0	0.9	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
70' Elev. Division II Channel Equipment 125 VDC Battery Room Exhaust Fan	1	480	1 BHP	0.9	0.9	0.9	0.9	0	0.9	0
SSW Pump Strainer Backwash Drive Motor 2A	1 NOTE O	480	0.75 BHP	0.9	0.9	0.7	0.7	0	0.7	0
Shutdown Cooling Pump 2 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	2.5	0
Shutdown Cooling Heat Exchanger Room 2 Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	2.5	0	0	0
Division II 125 VDC Vital Battery Chargers	1	480	18.4 KVA	0.9	-	16.6	16.6	0	16.6	0
Safety Injection Pump 2 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	0	2.5	0
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP B:						271	0	271	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT ø PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 1 (NOTE D)										
Safety Injection Pump 2	1	[illegible]	910 BHP	0.9	0.9	755	0	0	755	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 1:							0	0	755	0
Load Sequence Group D (NOTE E)										
Division II Subsphere Ventilation Exhaust Fan	1	480	20 BHP	0.9	0.9	15	0	15	0	15
Division II Subsphere Exhaust Filter Train Heating Element	1	480	23 KW	1.0	-	23	0	23	0	23
Division II Annulus Ventilation Exhaust Fan	1	480	63 BHP	0.9	0.9	52.3	0	0	0	52.3
Division II Annulus Exhaust Filter Train Heating Element	1	480	83 KW	1.0	-	83	0	0	0	83

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Division II Fuel Pool Exhaust Fan	1	480	75 BHP	0.9	0.9	62.2	0	62.2	0	0
Division II Fuel Pool Exhaust Filter Train Heating Element	1	480	116 KW	1.0	-	116	0	115	0	0
Division II Fuel Pool Cooling Hx/Pumproom Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	2.5	0	0
CCW Pump 2B Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	2.5	0	2.5
50' Elev. Vital Inst. & Equip. Room Channel D AHU	2 NOTE O	480	10 BHP	0.9	0.9	8.3	0	8.3	0	8.3
70' Elev. Division II Channel Equipment Room Air Handling Unit	2 NOTE O	480	3 BHP	0.9	0.9	2.5	0	2.5	0	2.5
Penetration Room D Air Handling Unit	2 NOTE O	480	1 BHP	0.9	0.9	0.9	0	0.9	0	0.9
50' Elev. 125 VDC Vital Battery Room Exhaust Fan Channel D	1	480	1 BHP	0.9	0.9	0.9	0	0.9	0	0.9

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
SSW Pump Strainer Backwash Drive Motor 2B	1 NOTE O	480	0.75 BHP	0.9	0.9	0.7	0	0	0	0
Remote Shutdown Panel Room Air Handling Unit	1 NOTE P	480	1 BHP	0.9	0.9	0.9	0	0.9	0	0.9
Containment Spray Pump 2 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	0	0	2.5
Containment Spray Heat Exchanger Room 2 Air Handling Unit	1	480	3 BHP	0.9	0.9	2.5	0	0	0	2.5
Service Water Pump House House Division II Ventilation Fan	1	480	7.5 BHP	0.9	0.9	6.3	0	6.3	0	6.3
Division II Emergency Feedwater Pump Rooms' Air Handling Units	2	480	3 BHP	0.9	0.9	5.0	0	5	0	5
Safety Injection Pump 4 Room Air Handling Unit	1	480	3 BHP	0.9	0.9	5.0	0	0	0	2.5
Channel D 125 VDC Vital Battery Chargers for I & C	1	480	32.2 KVA	0.9	-	29	0	29	0	29

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Division II Diesel Generator Building Sump Pump 2B	1	480	5 HP	0.9	0.9	4	0	4	0	4
Division II Diesel Generator Building Ventilation Fan 2B	1	480	100 HP	0.9	0.9	75	0	75	0	75
Control Room and Remote Shutdown Panel Division II Lighting	1	480	12.5 KW	1.0	-	12.5	0	12.5	0	12.5
Division II Class 1E Motor Operated Valves Powered from Safety Bus D	-	480	42.5 HP	0.9	0.9	32	0	32	0	32
Auxiliary Building Groundwater Drainage Sump Pump 2B	1 NOTE L	480	20 HP	0.9	0.9	15	0	15	0	15
Quadrant D Reactor Building Subsphere Floor Drain Sump Pumps 1 and 2	2	480	15 HP	0.9	0.9	22.4	0	22.4	0	22.4
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP D:							0	436	0	398

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 2 (NOTE D)										
Safety Injection Pump 4	1	4160	910 BHP	0.9	0.9	755	0	0	0	755
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 2:						0	0	0	755
Load Sequence Group 3 (NOTE F)										
Motor Driven Emergency Feedwater Pump 2	1	4160	850 HP	0.9	0.9	635	0	635	0	635
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 3:						0	635	0	635

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 4 (NOTE G)										
Containment Spray Pump 2	1	4160	600 HP	0.9	0.9	448	0	0	0	448
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 4:							0	0	0	448
Load Sequence Group 5 (NOTE H)										
Component Cooling Water Pump 2A	1	4160	1250 BHP	0.9	0.9	1037	1037	0	1037	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 5:							1037	0	1037	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 6 (NOTE I)										
Station Service Water Pump 2A	1	4160	700 BHP	0.9	0.9	581	581	0	581	0
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 6:						581	0	581	0
Load Sequence Group 7										
Essential Chiller 2	1	4160	260 BHP	0.9	0.9	216	216	0	216	0
	SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 7:						216	0	216	0

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 8 (NOTE H)										
Component Cooling Water Pump 2B	1	4160	1250 BHP	0.9	0.9	1037	0	1037	0	1037
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 8:							0	1037	0	1037
Load Sequence Group 9 (NOTE I)										
Station Service Water Pump 2B	1	4160	700 BHP	0.9	0.9	581	0	581	0	581
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 9:							0	581	0	581

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D
Load Sequence Group 10 (NOTE G)										
Shutdown Cooling Pump 2	1	4160	600 HP	0.9	0.9	448	448	0	448	0
SUBTOTAL LOADINGS FOR LOAD SEQUENCE GRP 10:							448	0	448	0
Manual Load Group (NOTE J)										
Containment Hydrogen Recombiner 2	1	480	20 KW	1.0	-	20	0	0	20	0
Spent Fuel Pool Cooling Pump 2	1	480	75 HP	0.9	0.9	56	0	56	0	56
Essential AC Lighting	-	120	225 KW	1.0	-	225	110	115	110	115
Division II Control Room Pressurized Filter Train Fan	1 NOTE K	480	7 BHP	0.9	0.9	5.8	0	0	0	5.8

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS

EQUIPMENT (NOTE A)	COMPONENT # PER BUS	VOLTS	COMPONENT ESTIMATED HP (NOTE M)	pf	MOTOR EFFICIENCY	EQUIV. LOAD KW	LOSS OF OFFSITE POWER LOAD SAFETY BUS B	LOSS OF OFFSITE POWER LOAD SAFETY BUS D	DBA/LOOP LOAD SAFETY BUS B	DBA/LOOP LOAD SAFETY BUS D	REF
Division II Control Room Pressurized Filter Train Heating Element	1 NOTE K	480	10 KW	1.0	-	10.0	0	0	0	10	4
Backup Pressurizer Heaters	1	480	200 KW	1.0	-	200	0	200	0	0	
SUBTOTAL LOADINGS FOR MANUAL LOAD SEQUENCE GRP:							110	~~171~~ 371	130	187	
Total Load Per Diesel on LOOP Including Manual Load - (NOTE N)								~~3457~~ 3657			
Total Load Per Diesel on LOOP Excluding Manual Load - (NOTE N)								3176			
Total Load Per Diesel on DBA/LOOP Including Manual Load - (NOTE N)										5413	
Total Load Per Diesel on DBA/LOOP Excluding Manual Load - (NOTE N)										5096	

Rev. 1

TABLE 8.3.1-3 DIVISION II TYPICAL CLASS 1E LOADS
DIESEL GENERATOR LOAD SEQUENCER
ASSUMPTIONS AND INFORMATION

NOTE A

The loads given for the listed components are typical. Actual loads are site dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments and evaluations as necessary.

NOTE B

For Station Loss-of-Offsite-Power or DBA/LOOP event, Load Sequence Group B is energized immediately upon closure of the Diesel Generator Breaker for Safety Bus B.

NOTE C

Although these loads are connected to the Emergency Buses, they are not required once the Diesel Generator is operating, therefore, they are considered to be zero for purposes of Diesel Generator sizing.

NOTE D

Load Sequence Groups 1 and 2, Safety Injection Pumps 2 and 4, will normally be activated by the sequencer to provide Direct Vessel Safety Injection. The Safety Injection System (SIS) interface requirements specify f'. v to the vessel within 40 seconds after an Safety Injection Actuation Signal (SIAS). This assumes a 20 second Diesel Generator start time, a 2.5 second Safety Injection Pump 2 sequence load time (6.5 seconds for Safety Injection Pump 4) and a 10 second interval to provide actual SIS flow to the Direct Vessel Injection nozzles.

NOTE E

Load Sequence Group D consists of 480V loads powered on Safety Bus D.

NOTE F

Load Sequence Group 3, Motor Driven Emergency Feedwater Pump 2, is loaded onto the Emergency Bus by the sequencer when it receives a Low-Low Steam Generator EFAS (Emergency Feedwater Actuation Signal) signal from the Plant Protection System. This Load Group is designed such that the associated steam generator will receive Emergency Feedwater within 60 seconds after a Low-Low Steam Generator condition exists. The time breakdown for a station loss of offsite power (condition which could result in low steam generator level as a result of main feedwater pumps tripping) is as follows: 1 second for low-low steam generator condition to be detected and EFAS signal generated, 20 seconds for the Diesel Generator to start and attain rated speed and voltage, 15 seconds for the Sequencer to load Load Sequence Group 5 onto the Emergency Bus, and 24 seconds for the Motor-Driven Emergency Feedwater Pump to start and provide Emergency Feedwater flow to its associated Steam Generator. This assumes time to purge the hot water from the EFW lines adjacent to the steam generator.

NOTE G

Load Sequence Group 4, Containment Spray Pump 2, starts the divisional Containment Spray Pump as a result of a Safety Injection Actuation Signal (SIAS) activating the sequencer. The Containment Spray Pump will then operate in recirculation mode until a Containment Spray Actuation Signal (CSAS) is generated, which will cause the Containment Spray Header valves to open and supply containment spray to the spray rings. The interface requirements mandate that Containment Spray flow to the containment atmosphere result within 68 seconds of a CSAS. To accomplish this, Load Sequence Group 4 will be loaded onto the Emergency Bus 20 seconds after the sequencer begins Accident loading (40 seconds after receipt of the initiating SIAS signal). The Containment Spray Pump will then operate in miniflow condition until a CSAS opens the spray header valves.

Load Sequence Group 4 and Load Sequence Group 10, Shutdown Cooling Pump 2, are interlocked such that either the Containment Spray Pump or Shutdown Cooling Pump may provide Containment Spray. If a division's Containment Spray Pump is out-of-service, the Shutdown Cooling Pump discharge valves may be manually aligned to supply water from the IRWST (In-Containment Refueling Water Storage Tank) to the Containment Spray Header. At the same time, the sequencer interlock controls are switched to bypass the defunct Containment Spray Pump 2 and to start the Shutdown Cooling Pump in its place. The normal, preferred alignment, however, is to have the Containment Spray Pump aligned for standby readiness and to use the Shutdown Cooling Pump as a backup. In this normal alignment, the sequencer will not load Load Sequence Group 12, unless manually aligned and actuated.

The Shutdown Cooling Pump is listed as a Loss-of-Offsite-Power load, since restart of this pump is required during refueling and Reactor Coolant System drained-down conditions. However, its load value is not part of the total Diesel Generator load for the LOOP event, because the Motor Driven EFW Pump (mutually exclusive to the Shutdown Cooling Pump) in a plant operating LOOP scenario is a larger, and hence more conservative load to be applied to the LOOP total.

The Shutdown Cooling Pump is also listed as a DBA/LOOP load. Its use for such an event would occur if the Shutdown Cooling Pump were functioning as the Containment Spray Pump. For load summation purposes, the Shutdown Cooling Pump is not added to the DBA/LOOP total, since the Containment Spray Pump has already been added.

NOTE H

For a Design Basis Accident with no concurrent loss of offsite power, the Component Cooling Pump in each division will remain operating. However, if Station Loss-Of-Offsite-Power occurs concurrently with a Design Basis Accident, the Diesel Generator Sequencer will function to load the divisional Component Cooling Pump which was operating just prior to the event onto the Emergency Bus within 10 seconds after the sequencer completes the Accident Loading Sequence. For a Station Loss-Of-Offsite-Power during which no DBA occurs, the sequencer will load the Component Cooling Pump which was operating just prior to the event onto the Emergency Bus within 5 seconds after receiving a Diesel Generator running signal. If this pump fails to operate, the sequencer will attempt to load the other divisional Component Cooling Water Pump onto the Emergency bus immediately.

After initial loading by the sequencer, the Component Cooling Water Pump which remains on standby may still be manually activated, or automatically activated by the sequencer immediately should the running CCW pump trip.

NOTE I

The Station Service Water Pumps will be loaded onto the Emergency Bus dependent upon the following factors and requirements.

1) The sequencer will attempt to load onto the Emergency Bus the Station Service Water Pump which was operating just prior to a Station Loss-Of-Offsite-Power. This also applies to Design Basis Accident coincident with a Station Loss-Of-Offsite-Power. The SSW Pump not loaded by the sequencer will remain on standby, capable only of being started manually when Operations determines that the corresponding increase in the Diesel Generator loading is warranted (2 pumps/division operation) or when pump cycling is desired. Sequencer logic will prohibit automatic loading of both a division's SSW Pumps.

2) If a LOCA occurs and offsite power remains uninterrupted, the running SSW pump will remain operational, still connected to normal incoming bus.

3) If the SSW Pump chosen to start by the sequencer fails to start, the sequencer will attempt to start the other SSW pump immediately.

4) The Sequencer will load the SSW Pump 10 seconds after either the completion of all Accident loadings or the sequencer's receipt of a Diesel Generator running signal (Normal Loss-Of-Offsite-Power sequence).

NOTE J

Manual Loads may be added to the emergency bus by Operations whenever plant conditions require their usage.

NOTE K

The Control Room Pressurized Filter Train and associated Heating Element will only be manually employed when high radiation levels are detected in the outside air intakes. The Control Room Ventilation System has been designed to keep the Control Room at a positive pressure relative to its surrounding environment during normal operation. Therefore, the normal divisional Control Room ventilation unit will activate on a LOCA (normal Control Room Ventilation Unit operating prior to the event will remain loaded unless load shed by a Station Loss-Of-Offsite-Power), but the Control Room Pressurized Filter Train and its associated Heating Element may or may not be activated, subject to outside environment radiation levels.

NOTE L

Number of Auxiliary Building Sump pumps is dependent on site characteristics. Two pumps per division are shown as an example here.

NOTE M

Rated Horsepower was assumed to account for pump, fan, or other mechanical efficiencies as well as for motor efficiency. Conversion into equivalent Kilowatts for Rated Horsepower involved multiplying rated horsepower by the conversion factor 0.746 KW/HP. When unit of Brake Horsepower (BHP) was assumed, a motor efficiency of 0.9 was used in addition to this conversion factor to calculate Equivalent Load. Unless designated by "BHP," all horsepowers are "Rated."

NOTE N

This note provides an explanation of the assumptions used for calculating the total diesel loads at the conclusion of the table. The following subtotal loads are assumed to be supplied and are summed to obtain the resultant total:

Total Load Per Diesel on LOOP Excluding Manual Load:

Load Sequence Group B
Load Sequence Group D
CCW Pump in operation prior to event
SSW Pump in operation prior to event
Essential Chiller
Motor Driven EFW Pump

Total Load Per Diesel on LOOP Including Manual Load consists of the above total plus the appropriate manual load.

Total Load Per Diesel on DBA/LOOP Excluding Manual Load:

Load Sequence Group B
SI Pump 2
Load Sequence Group D
SI Pump 4
Motor Driven EFW Pump
Containment Spray Pump or Shutdown Cooling Pump (Interlocked such that both cannot operate from sequencer simultaneously during accident)
CCW Pump in operation prior to event
SSW Pump in operation prior to event
Essential Chiller

Total Load Per Diesel on DBA/LOOP Including Manual Load consists of the above total plus the appropriate manual load.

Notes on Accident and Normal Loading Sequences

The following components and times apply to Accident Scenarios coincident with a Station Loss-Of-Offsite-Power:

Load Sequence Group B	0.5 seconds
Safety Injection Pump 2	2.5 seconds
Load Sequence Group D	4.5 seconds
Safety Injection Pump 4	6.5 seconds
Motor Driven EFW Pump	15.0 seconds (if req'd)
Containment Spray Pump	20.0 seconds
Component Cooling Water Pump	30.0 seconds
Station Service Water Pump	35.0 seconds
Essential Chiller	40.0 seconds

The following components and times apply to Normal Loss-Of-Offsite-Power scenarios:

Load Sequence Group B	0.5 seconds
Load Sequence Group D	2.5 seconds
Component Cooling Water Pump	5.0 seconds
Station Service Water Pump	10.0 seconds
Essential Chiller	15.0 seconds
Motor Driven EFW Pump	After 20 seconds (if req'd)

NOTE O

Each ventilated area listed with NOTE O has redundant 100% ventilation units. Only one of these ventilation units is allocated in the calculation for diesel generator sizing.

NOTE P

Remote Shutdown Panel Room is located in the Division I area. Normally this room is cooled by the 50' Elevation Channel A Vital Inst. & Equip. Room Air Handling Unit. For redundancy purposes, the Remote Shutdown Panel Room is also cooled by a Division II-powered air handling unit.

TABLE 8.3.1-4
TYPICAL ELECTRICAL BUS LOADS

Component	Load (KW)
4.16 KV Safety Bus A:	
Safety Injection Pump	755
Station Service Water Pump	581
Component Cooling Water Pump	1037
Shutdown Cooling Pump	448
Essential Chiller	216
Balance of Other Loads	502
Safety Bus A Total = 3539 KW	
4.16 KV Safety Bus C:	
Safety Injection Pump	755
Station Service Water Pump	581
Component Cooling Water Pump	1037
Containment Spray Pump	448
Motor Driven EFW Pump	635
Balance of Other Loads	766
Safety Bus C Total = 4222 KW	

TABLE 8.3.1-4
TYPICAL ELECTRICAL BUS LOADS

Component	Load (KW)
4.16 KV Safety Bus B:	
Safety Injection Pump	755
Station Service Water Pump	581
Component Cooling Water Pump	1037
Shutdown Cooling Pump	448
Essential Chiller	216
Balance of Other Loads	500
	Safety Bus B Total = 3537 KW
4.16 KV Safety Bus D:	
Safety Injection Pump	755
Station Service Water Pump	581
Component Cooling Water Pump	1037
Containment Spray Pump	448
Motor Driven EFW Pump	635
Balance of Other Loads	769
	Safety Bus D Total = 4225 KW

TABLE 8.3.1-4
~~TYPICAL~~ ELECTRICAL BUS LOADS #

Component	Load (KW)
X - 4.16 KV Permanent Non-Safety Bus:	
CVCS Pump	448
CEDM Cooling Fan	75
Containment Ventilation Fan	75
Containment Ventilation Fan	75
Non-Essential Chiller	719
Non-Essential Chiller	719
IA Compressor	262
IA Compressor	262
Non-Essential Lighting	270
*Startup Feedwater Pump	635
*Motor-Driven Fire Pump	232
~~Backup Pressurizer Heater~~	~~200~~
DG Starting Air Compressor	45
DG Starting Air Compressor	45
*Fuel Pool Supply Fan	21
Miscellaneous Loads	~~204~~ 200

X - Permanent Non-Safety Bus Total = ~~4287~~ 4083 KW

* Single component capable of being powered by either X or Y.

The loads given in this table are typical. Actual loads are site-dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments and evaluations as necessary.

TABLE 8.3.1-4
~~TYPICAL~~ ELECTRICAL BUS LOADS #

Component	Load (KW)
Y - 4.16 KV Permanent Non-Safety Bus:	
CVCS Pump	448
CEDM Cooling Fan	75
Containment Ventilation Fan	75
Containment Ventilation Fan	75
Non-Essential Chiller	719
Non-Essential Chiller	719
IA Compressor	262
IA Compressor	262
Non-Essential Lighting	270
*Startup Feedwater Pump	635
*Motor-Driven Fire Pump	232
~~Backup Pressurizer Heater~~	~~200~~
DG Starting Air Compressor	45
DG Starting Air Compressor	45
*Fuel Pool Supply Fan	21
Miscellaneous Loads	~~204~~ 200

Y - Permanent Non-Safety Bus Total = ~~4287~~ 4083 KW

* Single Component capable of being powered by either X or Y.

\# The loads given in this table are typical. Actual loads are site-dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments and evaluations as necessary.

TABLE 8.3.1-4
TYPICAL ELECTRICAL BUS LOADS

Component	Load (KW)
X - 4.16 KV Non-Safety Bus:	
TBSWS Pump	224
TBCWS Pump	75
*Containment High Purge Exhaust Unit	195
Containment High Purge Supply Fan	75
Nuclear Annex Exhaust Unit	115
Nuclear Annex Supply Fan	45
Main Pressurizer Heaters	2400
Miscellaneous Loads	300
X - Non-Safety Bus Total = 3429 KW	
Y - 4.16 KV Non-Safety Bus:	
TBSWS Pump	224
TBCWS Pump	75
*Containment High Purge Exhaust Unit	195
Containment High Purge Supply Fan	75
Nuclear Annex Exhaust Units (2)	170
Nuclear Annex Supply Fan	157
Main Pressurizer Heaters	2400
Miscellaneous Loads	300
Y - Non-Safety Bus Total = 3596 KW	

* Single Component capable of being powered by either X or Y.

TABLE 8.3.1-4
TYPICAL ELECTRICAL BUS LOADS

Component	Load (KW)
13.8 KV Non-Safety Bus X-1:	
RCP Switchgear	9574
FW Booster/FW Pump	17771
Condensate Pump	1878
Circulating Water Pump	2940
13.8 KV Non-Safety Bus X-1 Total = 32,163 KW	
13.8 KV Non-Safety Bus X-2:	
RCP Switchgear	9574
FW Booster/FW Pump	17771
Condensate Pump	1878
Circulating Water Pump	2940
13.8 KV Non-Safety Bus X-2 Total = 32,163 KW	

TABLE 8.3.1-4
TYPICAL ELECTRICAL BUS LOADS

Component	Load (KW)
13.8 KV Non-Safety Bus Y-1:	
RCP Switchgear	9574
Circulating Water Pump	2940
Circulating Water Pump	2940
Circulating Water Pump	2940
13.8 KV Non-Safety Bus Y-1 Total = 18,394 KW	
13.8 KV Non-Safety Bus Y-2:	
RCP Switchgear	9574
FW Booster/FW Pump	17771
Condensate Pump	1878
Circulating Water Pump	2940
13.8 KV Non-Safety Bus Y-2 Total = 32,163 KW	

8.3.2 DC POWER SYSTEMS

8.3.2.1 System Descriptions

8.3.2.1.1 Non-Class 1E DC Power Systems

8.3.2.1.1.1 125V DC Auxiliary Control Power System

The 125V DC Control Power System consists of two 125 volt batteries, two battery chargers, and two 125 volt DC distribution centers. The system is divided into two channels which supply DC power to the Non-Class 1E instrumentation, controls, Data Processing System (DPS) and the 125V DC - 120V AC auxiliary control power inverters. The 125V DC Control Power System is shown on Figure 8.3.2-1. Battery installations are designed to meet the intent of IEEE Standard 484-1987. E

8.3.2.1.1.2 208/120V AC Control Power System

The 208/120V AC Control Power System consists of 125V DC - 208/120V AC inverters, static and manual bypass transfer switches, distribution centers, and panelboards as indicated in Figure 8.3.2-1.

The system is divided into two trains, each supplying non-interruptible 120 volt AC power to Non-Class 1E instrumentation and controls; 208/120 volt AC power to the DPS and security lighting systems.

Two 125V DC - 120V AC inverters supply power from the 125V DC Control Power System to separate non-interruptible 208/120 volt AC panelboards. Backup power is available for each inverter from an associated Permanent Non-Safety 480/208 volt AC regulated power transformer.

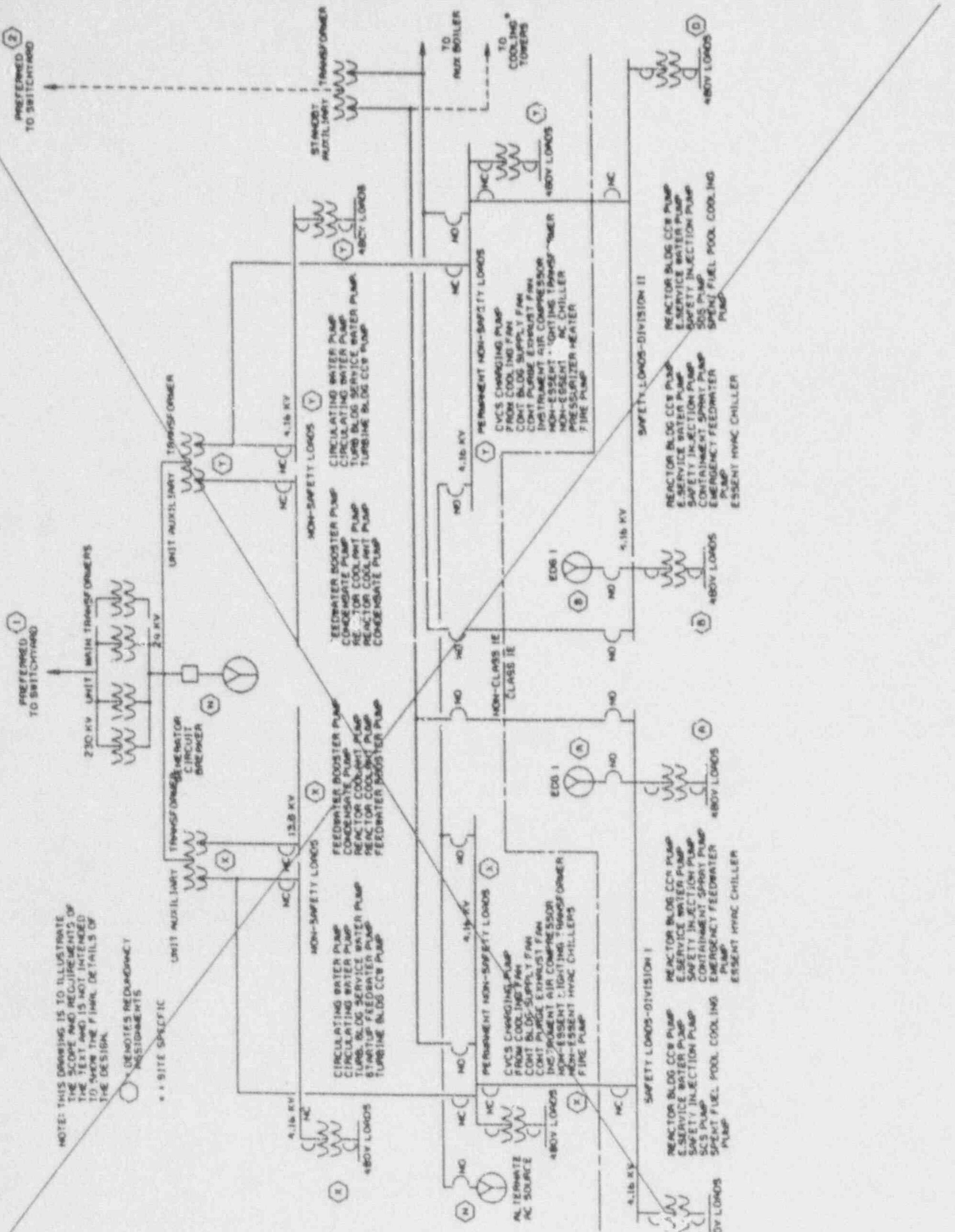
Two 120V AC power feeds are provided to each Process-Component Control System to enhance their availability. One feed is from the Non-Class 1E inverter distribution panel as shown on Figure 8.3.2-1. The other feed is from the same channel permanent non-safety 480V/120V AC regulated transformer. I

8.3.2.1.1.3 250V DC Auxiliary Power System

The 250V DC Power System consists of two 250 volt batteries, two battery chargers and two distribution centers. This system is shown on Figure 8.3.2-1.

The 250V DC Power System supplies power to high inrush DC loads that generally serve as backups to AC loads. The current limiting battery chargers are normally connected to their E

CALMA FILE:
LCLKOHL:FIG83RA



REPLACED

Amendment I
December 21, 1990

SYSTEM 80+™	UNIT MAIN POWER SYSTEM	Figure 8.3.1-1

respective 250 volt DC distribution centers to maintain the charge on the batteries. The chargers are sized to recharge the battery or to carry the largest single DC load for testing purposes. Power to the battery chargers is from their respective permanent non-safety buses. Battery installations are designed to meet the intent of IEEE Standard 484-1987. E I

8.3.2.1.1.4 Alternate AC Source 125V DC Power System

The 125V power system for the onsite AAC consists of a local 125V battery, battery charger and distribution panel as shown on Figure 8.3.2-1. This system is designed to supply the DC power necessary to start and operate the AAC. The battery charger is powered from a non-safety 480V AC MCC. The battery installation is designed to meet the intent of IEEE Standard 484-1987. E

8.3.2.1.2 Class 1E DC Power Systems

8.3.2.1.2.1 125V DC and 120V AC Vital Instrumentation and Control Power System

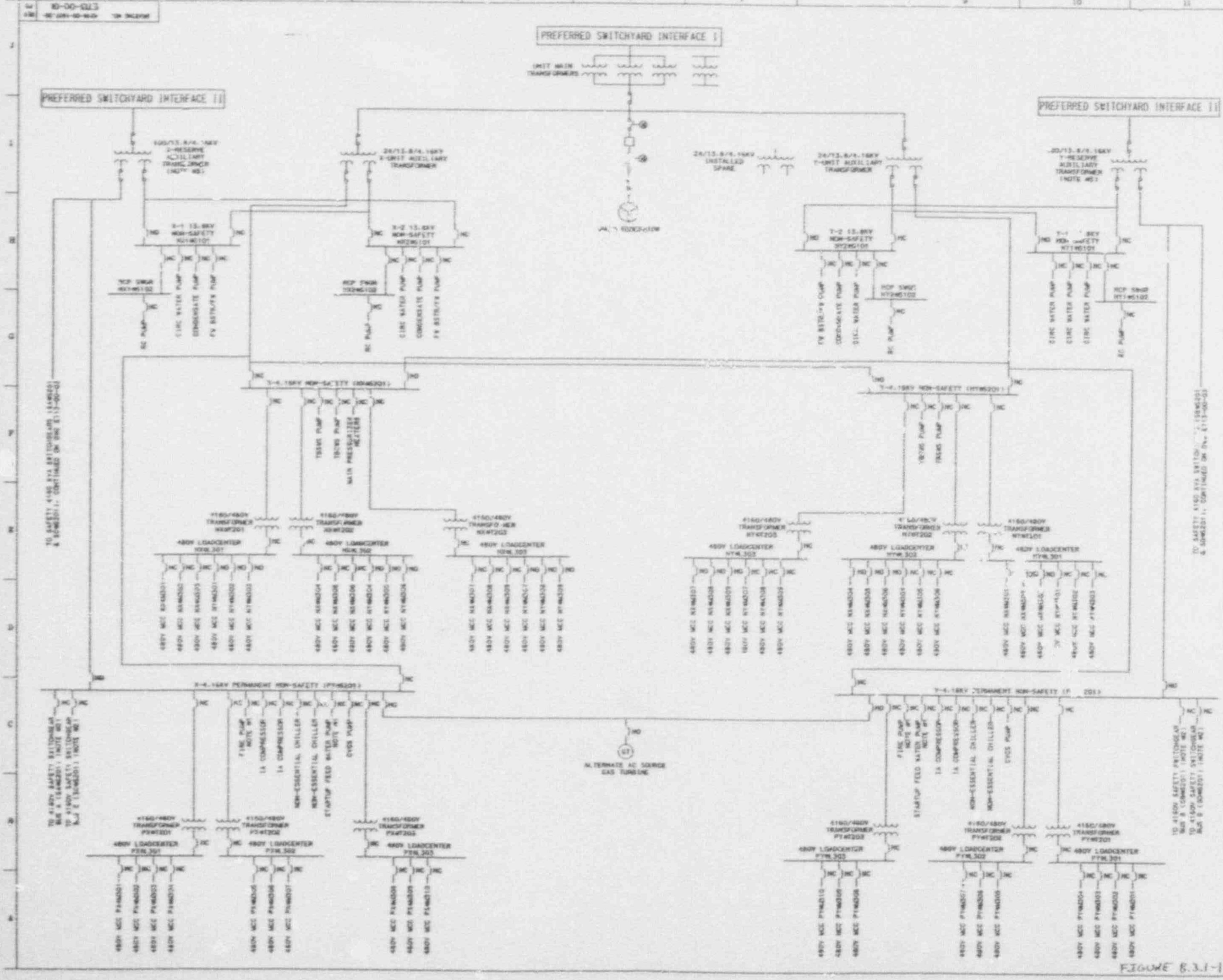
The 125V DC and 120V AC Vital Instrumentation and Control Power System provides a reliable, continuous source of power to Class 1E instrumentation and controls. The system consists of four independent and physically separated load groups that supply instrumentation and control channels A, B, C, and D. Each load group includes a battery, a battery charger, a DC distribution center and associated DC panelboard, an inverter, and an AC panelboard. Each instrumentation bus is powered from a separate battery to provide stable and noise free power to its respective control channel. This system is shown on Figure 8.3.2-2.

The Divisions I and II each also include an additional battery, battery charger, DC distribution center, and associated DC panelboard, inverter and AC panel board for their respective Divisions and switchgear controls and indication.

The 125V DC and 120V AC Vital Instrumentation and Control Power System is a seismic Category 1 system and is located in the Control Building. The 125 volt batteries are located in their separate respective channelized rooms within the Control Building. The vital instrumentation and control power system is an ungrounded system. Refer to Tables 8.3.2-3 and 8.3.2-4 for typical AC and DC vital buses loads.

8.3.2.1.2.1.1 125V DC Vital Instrumentation and Control Power Battery Chargers

Each load group of the 125V DC Vital Instrumentation and Control Power System is provided with a separate and independent 125 volt battery charger. The battery chargers of



NOTES:

1. SINGLE COMPONENT CAPABLE OF BEING POWERED BY EITHER X OR Y.
2. DIAGRAM ILLUSTRATES SAFETY BUSES POWERED NORMALLY FROM PREFERRED SWITCHYARD INTERFACE I. PREFERRED SWITCHYARD II MAY PROVIDE NORMAL POWER TO SAFETY BUSES, BASED ON SITE SPECIFIC RELIABILITY ANALYSIS.
3. TRANSMISSION LINE VOLTAGE SITE SPECIFIC.

ABB COMBUSTION ENG. NUCLEAR POWER

SYSTEM 80+™ DESIGN CERTIFICATION

DRAWING TITLE

NON-CLASS E AUXILIARY POWER SYSTEM MAIN ONE-LINE DIAGRAM

DRAWING NO. E113-00-01

FIGURE 8.3.1-1

NOTES:

DIAGRAM ILLUSTRATES SAFETY BUSES POWERED NORMALLY FROM PREFERRED SWITCHYARD INTERFACE I. PREFERRED SWITCHYARD II MAY PROVIDE NORMAL POWER TO SAFETY BUSES, BASED ON SITE SPECIFIC RELIABILITY ANALYSIS.

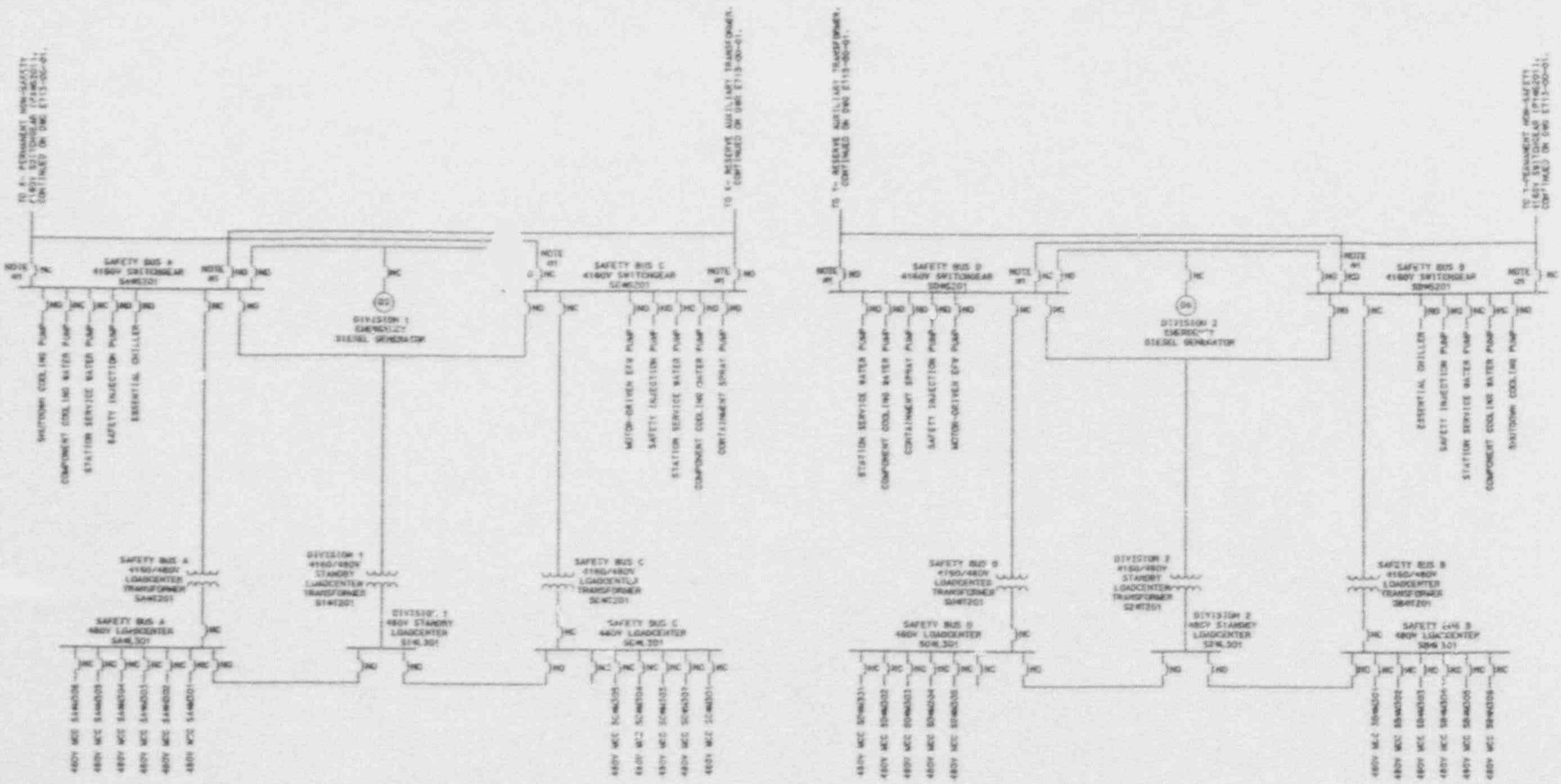


ABB COMBUSTION ENG.
NUCLEAR POWER

SYSTEM 80+™
DESIGN CERTIFICATION

DRAWING TITLE

CLASS 1E
AUXILIARY POWER SYSTEM
MAIN ONE-LINE DIAGRAM

DRAWING NO. E113-00-03 REV 00

SCALE: NONE

FIGURE 8.3.1-2

Insert A

load group channels A and C are powered from Division I of the Class 1E Safety Auxiliary Power System. The chargers of load group channels B and D are powered from Division II. ~~Each charger is capable of supplying the steady-state loads of its own load group while recharging its associated battery.~~

Each battery charger normally supplies the loads of its associated distribution center while maintaining a float charge on its associated battery. The battery chargers are designed to prevent a battery from discharging back into any internal charger load in the event of a charger malfunction or AC power supply failure.

Should a battery be removed from service, either the normal charger associated with the isolated battery or a bus tie to one of the other DC buses in the same Division can be closed such that the two inter-tied channels would have one battery and two chargers in operation. E

Each charger can recharge its associated battery, assuming the battery was discharged for one hour, in approximately 8 hours while also supplying worst case steady-state loads.

Each battery charger is provided with an overvoltage sensing circuit.

The Class 1E DC loads have an operating voltage range of 105 to 140 volts. The minimum battery discharge voltage is 105V DC.

8.3.2.1.2.1.2 125V DC Vital Instrumentation and Control Power Batteries

Each of the independent load group channels and divisions of 125 Volt DC Vital Instrumentation and Control Power is provided with a separate and independent 125 volt battery.

Each battery is sized to supply the continuous emergency load of its own load group one division battery's loads and one channel of loads for a period of ~~1~~ 2 hours. In addition, the batteries provide a SBO coping capability which, assuming manual load shedding or the use of load management programs, exceeds 2~~8~~ hours and, as a minimum, permits operating the instrumentation and control loads associated with the turbine-driven emergency feedwater pumps for 8 hours.*

* Battery installations are designed to meet the intent of IEEE Standard 484-1987 and are qualified using methodologies described in IEEE Standard 535-1986.

8.3.2.1.2.1.3 125V DC Vital Instrumentation and Control Power Distribution Centers and Panelboards

A 125 volt DC distribution center is provided for each of the 125V DC Vital Instrumentation and Control Power System load groups. Each distribution center supplies an independent

Insert A:

"Each battery charger is capable of supplying the largest combined demand of the various steady-state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the plant during which these demands occur."

channel of vital instrumentation and control, and is powered directly from an independent 125 volt battery and battery charger. Each of the distribution centers supplies one DC panelboard and one 125V DC - 120V AC static inverter. Each Division I and II distribution center also powers its respective emergency diesel generator.

8.3.2.1.2.1.4 120V AC Vital Instrumentation and Control Power System

E

The 120V AC Vital Instrumentation and Control Power System consists of four separate and independent 120 volt AC power panelboards, each powered from a 125 volt DC load group distribution center via a 125V DC - 120V AC static inverter. This power supply system is designed to provide an output frequency of 60 $\pm$0.5 Hz and voltage regulation to within $\pm$2% at full rated load for a load power factor greater than 0.8 (towards unity). Each 120 volt AC power panelboard supplies one channel of AC vital instrumentation and controls. A manual make-before-break bypass switch is provided to bypass the inverter for maintenance. The 120V AC Vital Instrumentation and Control Power System is shown in Figure 8.3.2-2. I

E

The channelized portion of the AC vital instrumentation and control power system is an ungrounded system.

The 120V AC power feeds are provided to each redundant ESF-Component Control System to enhance their availability. One feed is from the Class 1E inverter via the vital I&C channel power panel as shown on Figure 8.3.2-2. The other feed is from the same Class 1E channel 480/120V AC regulated transformer. I

8.3.2.1.2.1.5 125V DC and 120V AC Vital Instrumentation and Control Power System Status Information

E

The following parameters or status points are monitored in the control room for the 125 volt DC and 120 volt AC Vital I&C power systems:

A. Battery charger output voltage low.

B. Battery charger output voltage high.

C. Loss of AC input to battery charger.

D. Battery charger output circuit breaker open, indication and alarm.

E. Distribution center main circuit breaker open.

F. Battery circuit breaker open, indication and alarm

G. Vital distribution center tie breaker closed.

H. Vital 125 volt DC panelboard undervoltage.

I. Battery positive or negative leg ground.

J. Battery undervoltage.

K. Inverter 125 volt DC input failure.

L. Inverter AC output voltage low.

M. Inverter manual bypass switch in alternate source position.

N. Inverter alternate source abnormal (voltage or frequency). E

O. 120 volt AC inverter panelboard undervoltage.

P. Static inverter manual bypass switch position.

Q. 120 volt AC regulated distribution center breaker status.

R. Battery Discharge Alarm

8.3.2.1.2.2 Testing

8.3.2.1.2.2.1 Preoperational Tests

Preoperational testing of the Class 1E DC systems is performed in accordance with the recommendations of Regulatory Guide 1.41 to verify proper design, installation and operation.* Testing of panelboard circuit breakers and all circuit breakers associated with the 120 volt regulated AC power system consists of operating the breakers to assure proper functioning. System voltage levels are verified and, in the 120 volt AC system, the capability to perform manual transfers from the inverters and regulated power supply is demonstrated.

* Battery installations are designed to meet the intent of IEEE standard 484-1987 and are qualified using methodologies described in IEEE Standard 535-1986.

Add Insert A

DC loads are verified to be in accordance with battery sizing assumptions. The battery capacity is verified by a discharge performance test in accordance with IEEE Standard 450-1980. Operability of vital loads is verified at reduced system voltage.

Proper installation and operability of the Class 1E DC systems is demonstrated by verifying proper breaker operation, voltage levels and transfer schemes to alternate sources.

Insert A:

"Ammeters employed to monitor battery current have the capability to monitor both charge an discharge currents.

Ground fault detectors and their corresponding ground monitoring alarms have sufficient sensitivity and high source impedance such that they can detect relatively high resistance grounds on the DC system without themselves creating grounds on the system."

8.3.2.1.2.2.2 **Periodic Tests**

Inspection, maintenance, and testing of Class 1E DC systems are performed on a periodic testing program in accordance with the recommendations of Regulatory Guide 1.22. The periodic testing program is scheduled so as not to interfere with unit operation. Where tests do not interfere with unit operation, system and equipment tests may be scheduled with the nuclear unit in operation.

The continuous operation of the vital instrumentation and control system inverters is indicative of their operability and functional performance since accident conditions do not substantially change their load. The means for manual transfer to the various power sources available to the 120 volt AC vital power system can be tested on a routine basis to assure their operation.

8.3.2.2 Analysis

The 125V DC and 120V AC Vital Instrumentation and Control Power System are Class 1E systems, and as such, are designed to meet the requirements of General Design Criteria 17 and 18, and the intent of Regulatory Guides 1.6 and 1.32. For a discussion of additional Regulatory Guides and Industry Standards applied in the design of the Onsite DC Power System, refer to Section 8.1.4. Refer to Tables 8.3.2-1 and 8.3.2-2 for a single failure analysis of these systems. E

8.3.2.2.1 Compliance with Regulatory Guide 1.32, IEEE Standards 308-1980 and 450-1980

The design of Class 1E DC power systems complies with the intent of IEEE Standard 308-1980 as augmented by Regulatory Guide 1.32. The Class 1E batteries are given a service test at an interval not to exceed 18 months. ~~Additionally, the Class 1E battery performance and acceptance tests comply with the~~ Insert → ~~intent of IEEE Standard 450-1980.~~

8.3.2.2.2 Class 1E Equipment Qualification Requirements

The seismic and environmental qualifications of Class 1E DC power system equipment are discussed in Sections 3.10 and 3.11, respectively.

8.3.2.3 Physical Identification of Class 1E Equipment

The physical identification of the Class 1E DC systems equipment is discussed in Section 8.3.1.3.

Revise Section 8.3.2.2.1 to include the following text at "INSERT" mark:

> "The maintenance, testing, and replacement of the Class 1E batteries comply with the intent of IEEE Standard 450-1987. This includes safety precautions; monthly, quarterly and annual inspections and appropriate corrective actions resulting from the same; acceptance and performance testing; battery replacement criteria; and, proper record keeping."

8.3.2.4 Independence of Redundant Systems

The independence of redundant Class 1E DC systems is discussed in Section 8.3.1.4. E

THIS PAGE INTENTIONALLY BLANK

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

Refer to Section 8.3.1.6 for fire protection details. I

TABLE 8.3.2-1

(Sheet 1 of 2)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE 125V DC CLASS 1E VITAL INSTRUMENTATION AND CONTROL POWER SYSTEM

Component	Malfunction	Comments & Consequences
1. 480V AC power supply to chargers	Loss of power to one	No consequences - power from battery is available to supply power without interruption.
2. Battery chargers	Loss of power from one	The 125 volt DC bus continues to receive power from its respective battery without interruption. Severe internal faults may cause high short circuit currents to flow with the resulting voltage reduction on the 125 volt DC bus until the fault is cleared by the isolating circuit breakers. Complete loss of voltage on one 125 volt DC bus may result if the battery circuit breakers open.
3. 125V DC batteries	Loss of power from one Division or Channel battery	Isolating circuit breaker manually opened to clear the battery from the bus on a fault condition thereby allowing the battery charger to continue supplying power to the connected loads. No safety significance - an independent division of 125V DC is provided for the redundant diesel generator. An alarm in the control room alerts the operator of the malfunction.
4. 125V DC distribution centers	P and N buses shorted on one	Power is lost to the instrumentation and control Channel or Division serviced by the shorted distribution center. Remaining redundant division channels are available for the safe operation of the Unit.

E

TABLE 8.3.2-1 (Cont'd)

(Sheet 2 of 2)

FAILURE MODES AND EFFECTS ANALYSIS FOR THE 125V DC CLASS 1E VITAL INSTRUMENTATION AND CONTROL POWER SYSTEM

Component	Malfunction	Comments & Consequences
5. 125V DC distribution centers	Grounding of a single bus	The 125 volt DC system is an ungrounded electrical system. Ground detector equipment monitors and alarms a ground anywhere on the 125 volt DC system. A single ground does not cause any malfunction or prevent operation of any safety feature.
6. 125V DC distribution centers	Gradual decay of voltage on one	The 125 volt bus is monitored to detect the voltage decay on the bus and initiate an alarm at a voltage setting where the battery can still deliver power for safe and orderly shutdown of the unit. Upon detection power can be restored either by correcting the deficiency, by switching to a redundant source.
7. DC distribution centers incoming feeder cables	Cables shorted on one	Same comment as 4. Also, all incoming feeder cables are provided with isolating circuit breakers that isolate the "shorted" cable on a sustained fault condition.
8. 125V DC instrumentation and control power panelboards	Bus shorted	Voltage on the shorted 125 volt DC bus system of the affected unit decays until isolated by the isolating circuit breakers. Remaining redundant division channels are available for the safe operation of the Unit.

E

TABLE 8.3.2-2

FAILURE MODES AND EFFECTS ANALYSIS FOR THE 120V AC CLASS 1E VITAL INSTRUMENTATION AND CONTROL POWER SYSTEM

Component	Malfunction	Comments & Consequences
1. 125V DC distribution centers	P and N buses shorted or one	One static inverter is lost. The loss of one vital instrument bus results in the temporary loss of one channel of reactor protection and engineered safety instrumentation systems. Other remaining channels receive vital instrument control power from the other panelboards thus maintaining safe operation of the Unit.
2. Static inverter	Failure	Same as 1.
3. Static inverter alternate regulated 480/120V AC source	Failure	If alternate source in use, similar to 1.
4. Vital instrumentation and control power panelboards	Failure on one	For any one bus failure, only one Division or Channel of any system associated with reactor protective system or engineered safety features actuation system is lost. Sufficient redundant Channels or Divisions supplied from other vital instrument buses provide adequate protection. E

TABLE 8.3.2-3

(Sheet 1 of 2)

CLASS 1E 120V AC VITAL I&C POWER SYSTEMS*

Description	Load (KVA)
Division 1	
Containment Atmosphere Radiation Monitor	1.7
Hydrogen Igniters	11
Containment Hydrogen Analyzer Control Panel	1
Control Room Air Intake Radiation Monitor	2
Primary Coolant Loop Area Radiation Monitor	1.7
High Range Containment Area Radiation Monitor	1.7
Bus Total:	~~17.4~~ 19.1
Channel A	
DIAS-P	2
PPS	8
APC (Safety)	1
ESF-CCS	14
Control Panel Lamps	2
Bus Total:	27
Channel C	
PPS	8
APC (Safety)	1
ESF-CCS	5
Control Panel Lamps	0.5
Bus Total:	14.5

I

* The loads given are typical. Actual loads are site dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments as necessary.

TABLE 8.3.2-4

(Sheet 1 of 3)

CLASS 1E DC VITAL POWER SYSTEM LOADS*

Description	DBA (a)	SBO (b)	Severe Accident (c)
	Load on BUS (amperes)		
Division 1			
Class 1E Switchgear Breaker Tripping	80.4 (k)	—	—
Inverter	53.3	--	100.0 (i)
Diesel Generator Control & Field Flash	69.0 (d)	--	--
Reactor Cavity Flood Valve	--	--	3.6 (j)
Bus Peak Total:	~~122.3~~ 147.9	--	103.6
Channel A			
Class 1E Switchgear Breaker Tripping	40.2 (k)	—	—
Inverter	225.0	116.7 (f)	--
Reactor Trip Switchgear	2.5 (d)	--	--
Class 1E Switchgear & Load Center Control	14.7	--	--
Atmospheric Dump Valve	47.~~1~~8 (d)	47.~~1~~8 (g)	--
Holdup Volume Flood Valve	--	--	3.6 (j)
EFW Valve EF-105	9.9 (e)	9.9	--
SDS Valve SD-1	19.2 (d)	--	19.2 (j)
Bus Peak Total:	319.~~0~~1	174.~~1~~4	22.8
Channel C			
Class 1E Switchgear Breaker Tripping	40.2 (k)	—	—
Inverter	120.8	41.7 (f)	--
Reactor Trip Switchgear	2.5 (d)	--	--
Class 1E Switchgear & Load Center Control	14.7	--	--
Atmospheric Dump Valve	47.~~1~~8 (d)	47.~~1~~8 (g)	--
Holdup Volume Flood Valve	--	--	3.6 (j)
EFW Valve EF-101	6.6 (e)	6.6 (h)	--
EFW Trip & Throttle Valve #2	2.2 (d)	--	--
EFW Steam-driven Pump Turbine Governor Control	1.0	1.0	--
SDS Valve SD-2	38.5 (d)	--	38.5 (j)
Bus Peak Total:	234.~~0~~1	97.~~0~~1	42.1

* The loads given are typical. Actual loads are site dependent based on the equipment procured. Therefore, the site-specific SAR shall make appropriate adjustments as necessary.

TABLE 8.3.2-4 (Cont'd)

(Sheet 2 of 3)

CLASS 1E DC VITAL POWER SYSTEM LOADS*

Description	Load on BUS (amperes) DBA (a)	SBO (b)	Severe Accident (c)
Division 2			
Class 1E Switchgear Breaker Tripping	80.4 (k)	—	—
Inverter	53.3	--	100.0 (i)
Diesel Generator Control & Field Flash	69.0 (d)	--	--
Reactor Cavity Flood Valve	--	--	3.6 (j)
Bus Total:	~~122.3~~	--	103.6
Peak	133.7		
Channel B			
Class 1E Switchgear Breaker Tripping	40.2 (k)	—	—
Inverter	225.00	116.7 (f)	--
Reactor Trip Switchgear	2.5 (d)	--	--
Class 1E Switchgear & Load Center Control	14.7	--	--
Atmospheric Dump Valve	47.~~7~~8 (d)	47.~~1~~8 (g)	--
Holdup Volume Flood Valve	--	--	3.6 (j)
EFW Valve EF-100	6.6 (e)	6.6 (h)	--
EFW Trip & Throttle Valve #1	2.2 (d)	--	--
EFW Steam-Driven Pump Turbine Governor Control	1.0	1	--
SDS Valve SD-3	19.2 (d)	--	19.2 (j)
Bus Total:	~~318.9~~	172.~~0~~1	22.8
Peak	319.0		
Channel D			
Class 1E Switchgear Breaker Tripping	40.2 (k)	—	—
Inverter	120.8	41.7 (f)	--
Reactor Trip Switchgear		2.5 (d)	--
Class 1E Switchgear & Load Center	14.7	--	--
~~Class 1E Switchgear & Load Center Control~~	~~14.7~~	~~--~~	~~--~~
Atmospheric Dump Valve	47.~~1~~8 (d)	47.~~1~~8 (g)	--
Holdup Volume Flood Valve	--	--	3.6 (j)
EFW Valve EF-104	9.9 (e)	9.9 (h)	--
SDS Valve SD-4	38.5 (d)	--	38.5 (j)
Bus Total:	234.~~7~~2	99.~~2~~4	42.1
Peak			

TABLE 8.3.2-4 (Cont'd)

(Sheet 3 of 3)

CLASS 1E DC VITAL POWER SYSTEM LOADS

NOTES:

a. Loads for Design Base Accident (DBA) to which the batteries are sized to maintain power supply for at least two hours.

b. Loads for Station Blackout (SBO) conditions considering manual load shedding or use of load management programs to achieve 8 hours of turbine-driven emergency feedwater pumps.

c. Load for Severe Accident Conditions considering manual load shedding or use of load management programs to achieve extended battery life.

d. Random load assumed to occur at 119-120 minutes.

e. Intermittent load, 4 actuation-reset cycles assumed to occur during the two hour period.

f. Power to ESF-CCS for controlling EFW steam-driven pump turbine speed for steam generator water level control. Other inverter loads are load shed. Steam generator level and other plant conditions are monitored through the DPS, which is powered from the non-safety batteries (X & Y). I

g. Atmospheric dump valve positioned once during the 8 hour period to maintain the plant at hot standby.

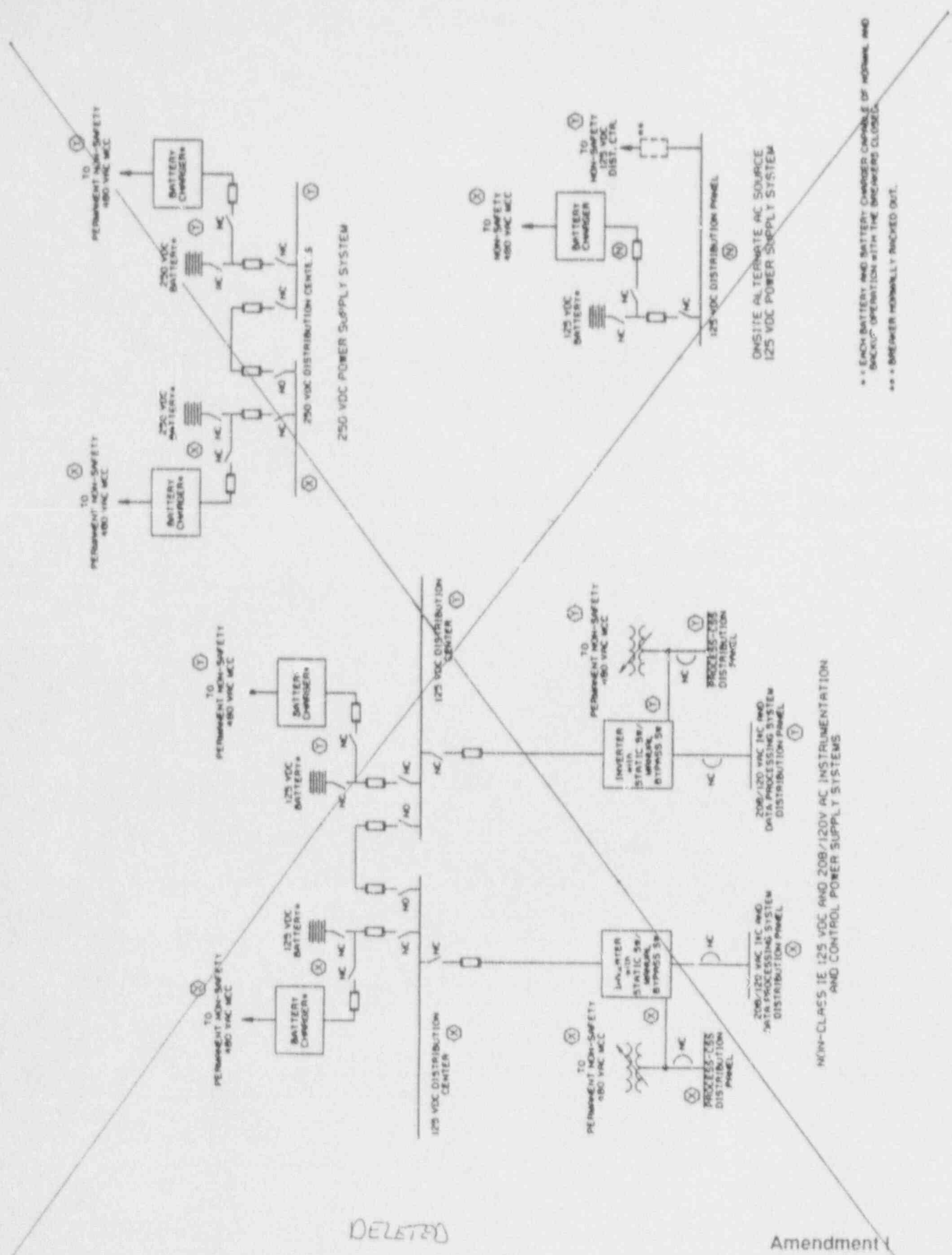
h. EFW valve opened once to the full open position during the 8 hour period. Steam generator level control is accomplished through adjusting the steam-driven EFW pump speed turbine.

i. Power to hydrogen igniters and analyzers.

j. Reactor Cavity Flood Valves, Holdup Volume Flood Valves, and SDS valves opened one time.

k. Load occurs at 0-1 minute.

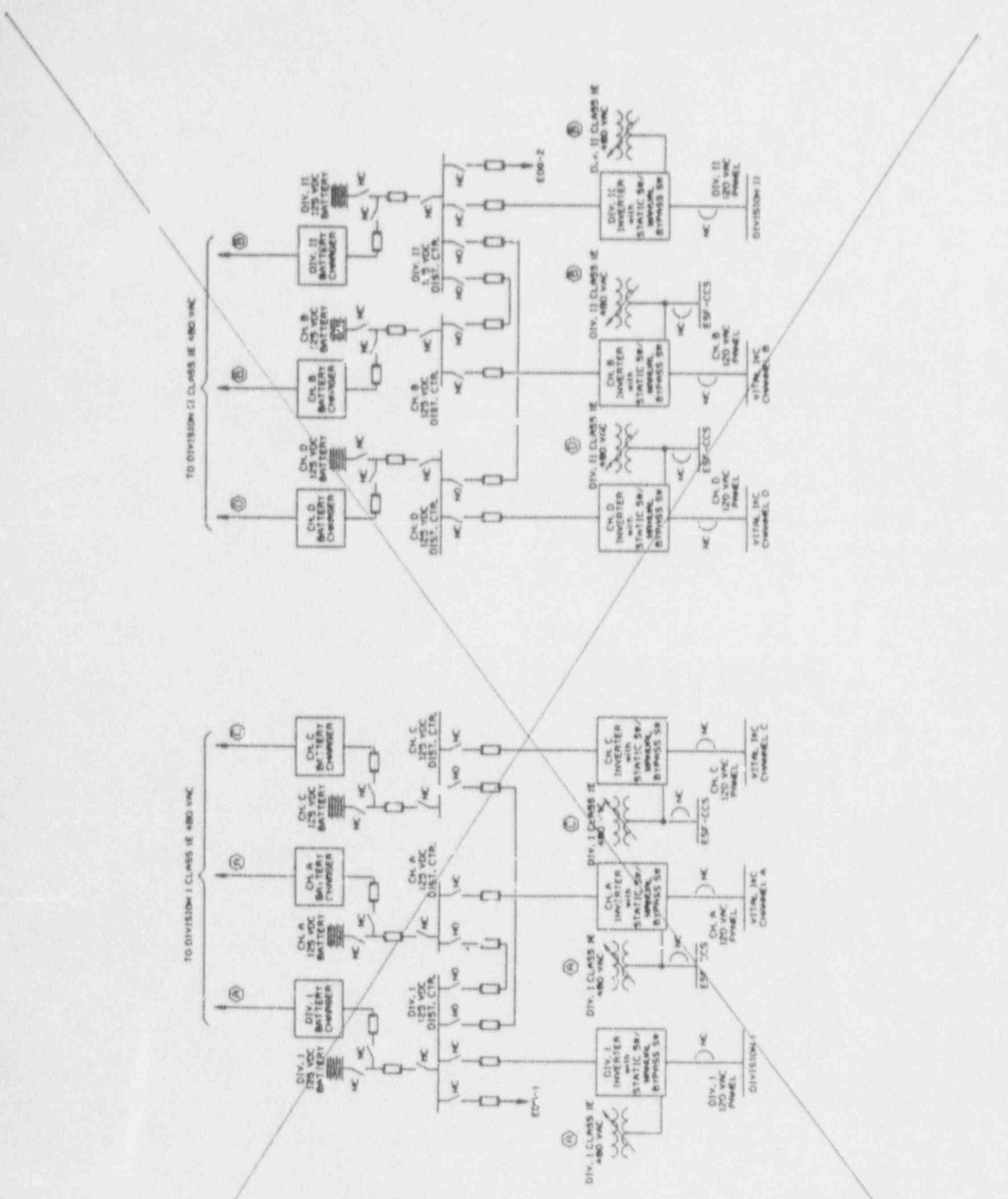
CALMA FILE: I.SYS80IFIG832I



DELETED

Amendment I
December 21, 1990

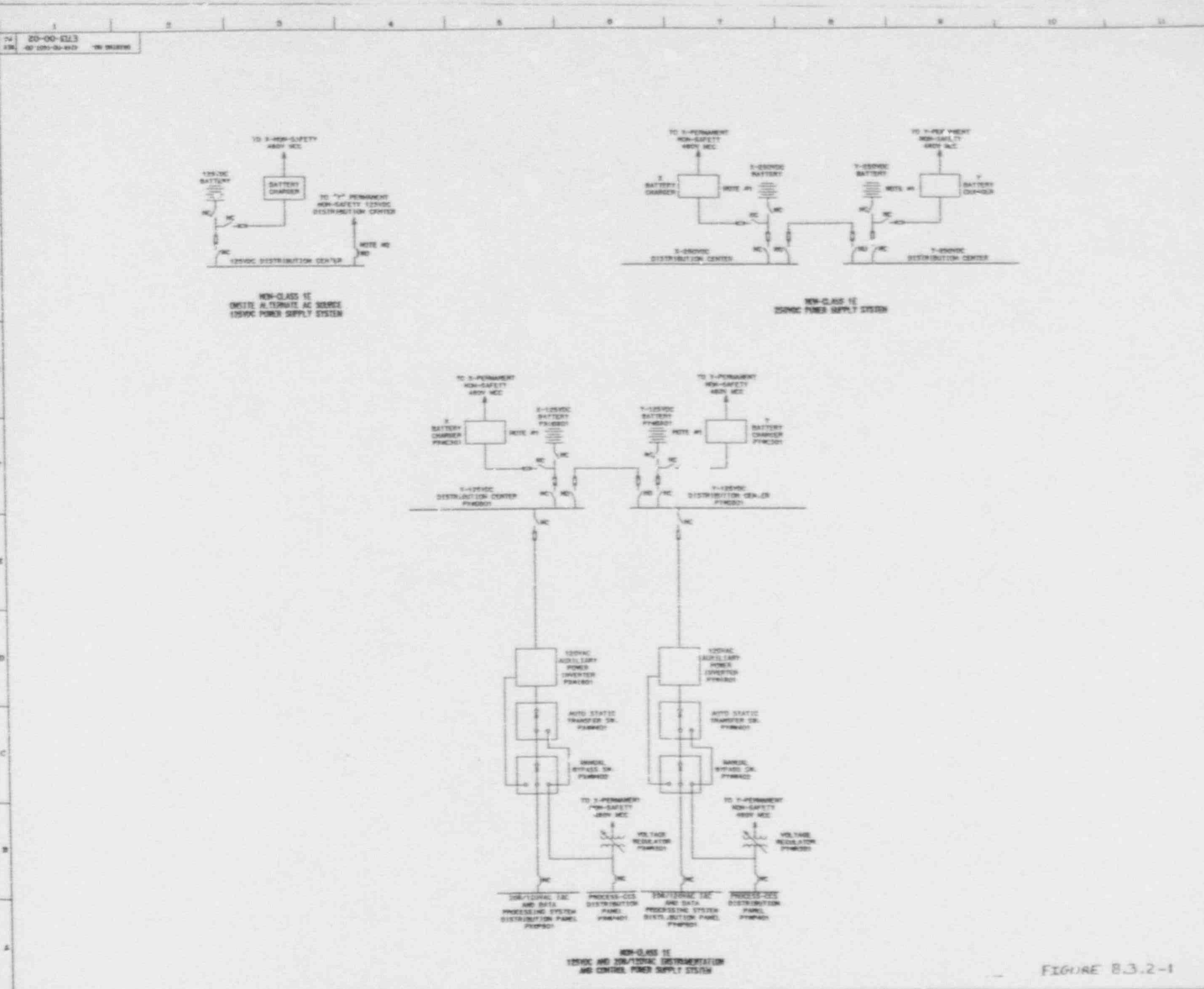
SYSTEM 80+™	NON-CLASS 1E DC AND VITAL AC INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEMS	Figure 8.3.2-1



DELETED

Amendment I
December 21, 199

SYSTEM 80+™	CLASS 1E DC AND VITAL AC INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEMS	Figure 8.3.2-2



NOTES:

1. EACH BATTERY AND BATTERY CHARGER CAPABLE OF NORMAL AND BACKUP OPERATION WITH THE BUS TIE DISCONNECTS CLOSED.
2. BREAKER NORMALLY RACKED OUT.

ABB COMBUSTION ENG.
NUCLEAR POWER

SYSTEM 80+™
DESIGN CERTIFICATION

DRAWING TITLE
NON-CLASS 1E
125VDC AND 208/120VAC
INSTRUMENTATION AND CONTROL
AND 125V ONSITE ALTERNATE
AC SOURCE AND 250VDC
POWER SUPPLY SYSTEMS

FIGURE 8.3.2-1

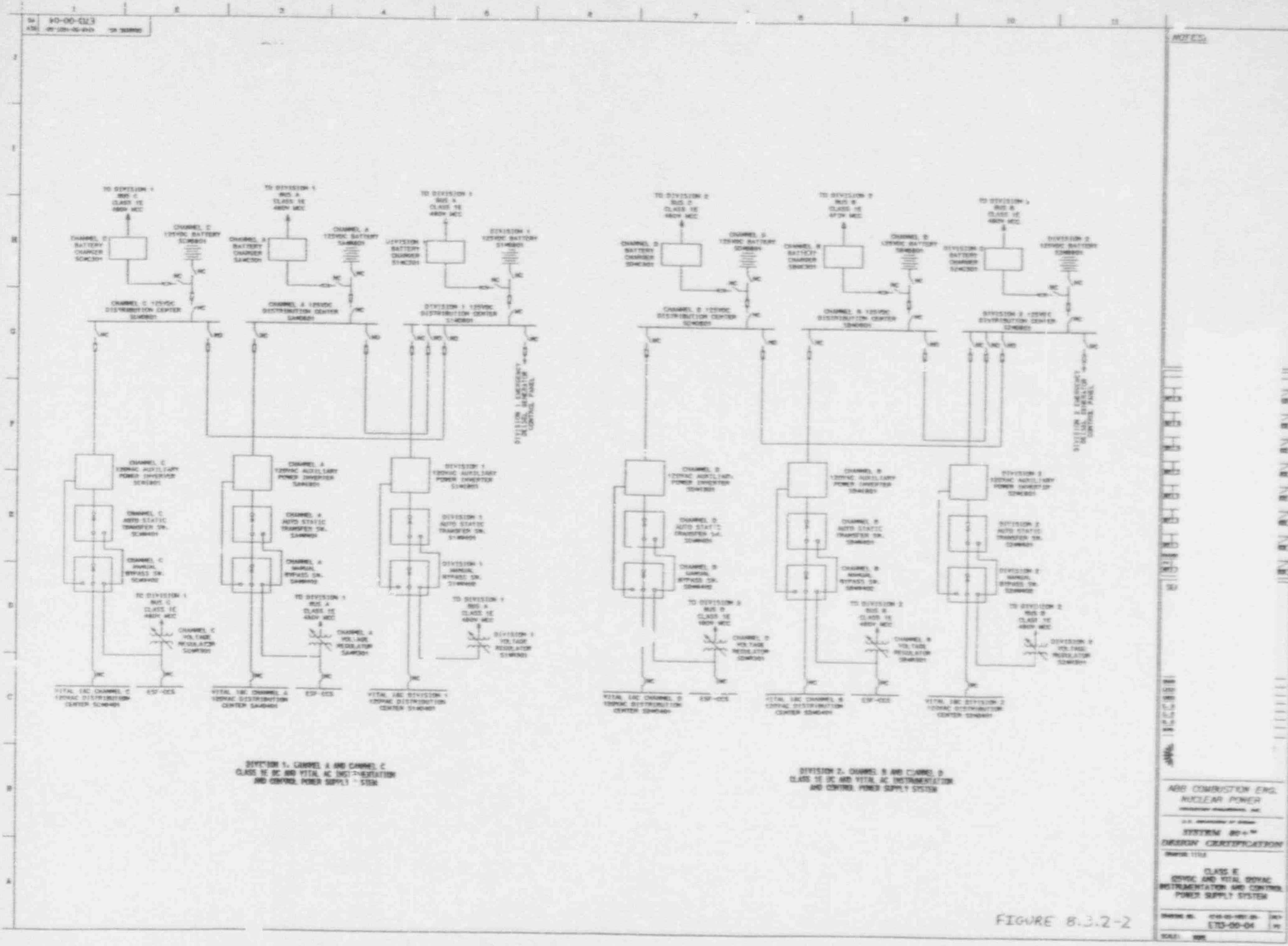

DIVISION 1, CHANNEL A AND CHANNEL C
CLASS 1E DC AND VITAL AC INSTRUMENTATION
AND CONTROL POWER SUPPLY SYSTEM
DIVISION 2, CHANNEL B AND CHANNEL D
CLASS 1E DC AND VITAL AC INSTRUMENTATION
AND CONTROL POWER SUPPLY SYSTEM
NOTES:
ABB COMBUSTION ENG.
NUCLEAR POWER
SYSTEM 80+™
DESIGN CERTIFICATION
CLASS 1E
125VDC AND VITAL 120VAC
INSTRUMENTATION AND CONTROL
POWER SUPPLY SYSTEM
E13-00-04

FIGURE 8.3.2-2

ATTACHMENT 5

12. 440.96, 10C

The staff position requires that only the safety-grade components or systems are creditable for design basis accidents in safety analyses. All non-safety systems or components called for function are assumed to be not functionable. Therefore, the turbine stop and controlled valves should be assumed to be open and a resulting steam flow through the stop valves, in addition to 11% steam flow assumed, from the intact SG with a MSIV failed to close is expected to be included in the analysis of cases 2 and 4.

ABB-CENP Response to Item 12:

ABB-CENP has performed a review of the turbine generator design and although it is not a safety-grade system, the turbine trip function, including the turbine valves and the trip signals from the CEDMCS, incorporates levels of redundancy aimed at precluding both unnecessary trips and the potential for a single failure which would prevent the turbine from tripping.

Each unit's turbine generator consists of a double-flow, high pressure turbine and three double-flow low pressure turbines driving a direct-coupled generator. The flow of main steam is directed from the steam generators to the high-pressure turbine through four lines. Each line contains a stop valve and a control valve in series. The stop and control valves are hydraulically operated and failed closed on a loss of hydraulic fluid pressure. Since all the turbine valves are closed upon receipt of a turbine trip signal, no single valve failing to close will prevent a turbine trip (i.e., the back up to control valve closure is stop valve closure and vice versa).

When the reactor trips, the CEDMCS sends redundant trip signals to the turbine's Emergency Trip System (ETS). When the main turbine receives a signal that a condition exists requiring a turbine trip of the ETS, redundant trip valves will act to release the hydraulic fluid pressure in the valve actuators, thus rapidly closing all stop and control valves. The pressure may be released by either the electrical trip valve (ETV) or the mechanical trip valve (MTV).

In addition to the above redundancy the System 80+ turbine described in CESSAR-DC Chapter 10 includes a main steam (throttle) pressure limiter circuit designed to prevent an excessive decrease of the main steam (throttle) pressure. When throttle pressure falls below a preset level (typically 10% below the normal full power steam pressure), the circuit acts to close the turbine control valves to limit the pressure decrease. The regulation of this circuit is fixed at 10%. Thus, the control valves will start to close when main steam pressure drops 10% below the normal full power pressure and will be fully closed if pressure drops another 10%.

In the unlikely event that the turbine fails to trip following a SLB and in addition, an MSIV fails to close on the intact steam generator, then the turbine throttle pressure limiter will limit the blowdown of the intact steam generator by closing the turbine control valves in response to decreasing steam pressure.

While ABB-CENP feels that the results of the above evaluation of turbine reliability supports our position that the failure of the turbine trip to occur at the same time as a steam line break, a MSIV failure, and the failure of the most reactive CEA to insert on reactor trip is not credible, CESSAR-DC Section 15.1.5 Steam Line Break Case 2 was reanalyzed with failure of the turbine to trip. The assumptions and initial conditions and sequence of events and key figures are attached. The maximum post trip reactivity for this event is -0.[illegible]3% $\Delta\rho$ demonstrating no return to criticality.

NRC Steam Line Break Question Number 1

CESSAR-DC Section 15.1.5.2 (Steam Line Break) states that "For steam line breaks with a concurrent loss of offsite power, the events of turbine stop valve closure, termination of feedwater to both steam generators, and coast down of the RCPs are assumed to be initiated simultaneously." Justify the assumption of termination of main feedwater flow at this time.

ABB-CENP Response:

Concurrent with the loss of offsite power, main feedwater would be lost due to the loss of NPSH to the main feedwater pumps caused by the loss of the condensate pumps.

In actuality, Case 1 conservatively assumes that main feedwater is not lost at the time of the loss of a-c power. Instead main feedwater delivery continues to the steam generators until the main feedwater isolation valves close as a result of the main steam isolation signal.

TABLE 12-1

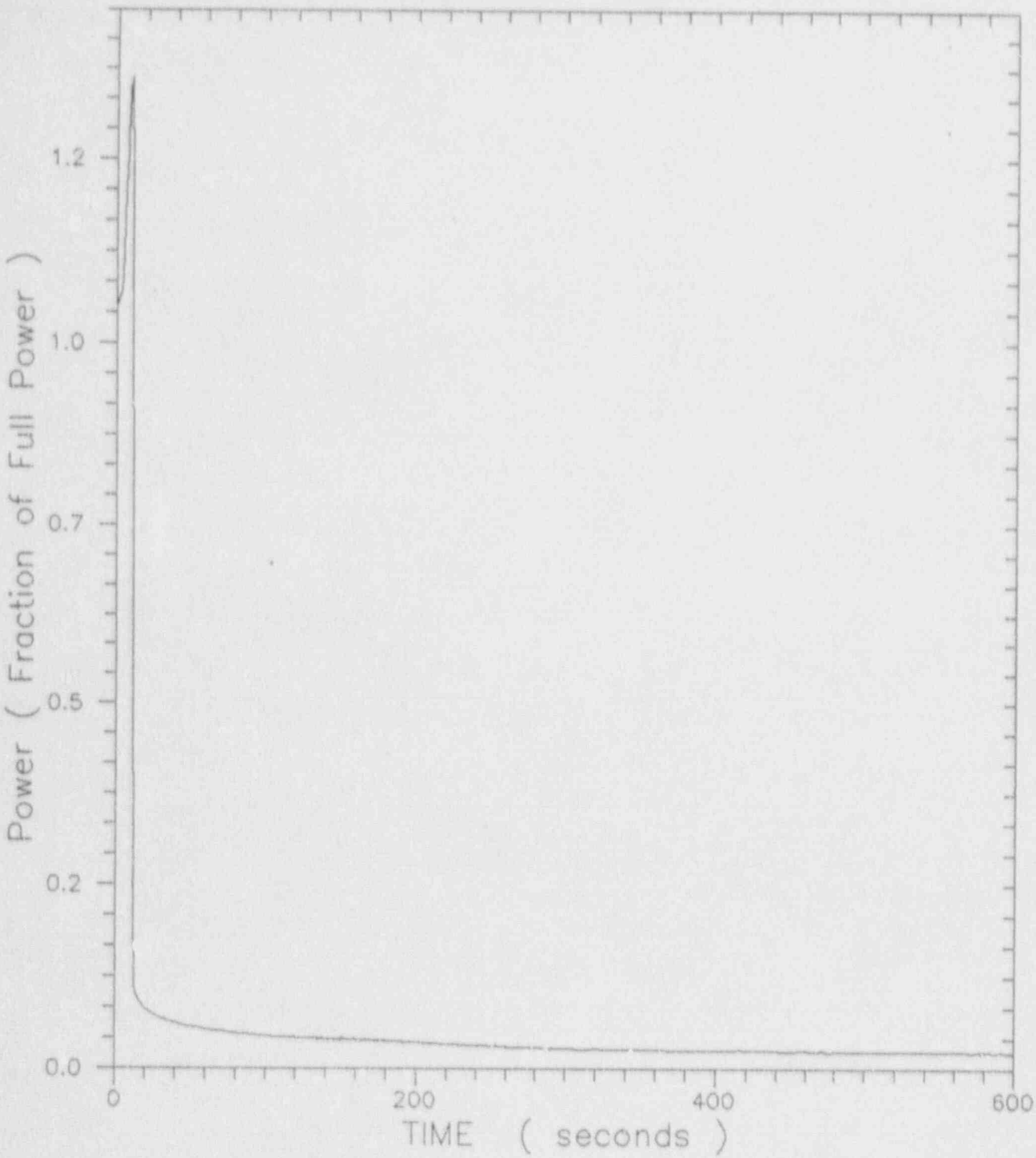
ASSUMPTIONS AND INITIAL CONDITIONS FOR REANALYSIS OF A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFP)

Parameter	Assumed Value
Initial Core Power Level, MWt	3876
Initial Core Inlet Coolant Temperature, °F	563
Initial Core Mass Flow Rate, 10^6 lbm/hr	151.89
Initial Pressurizer Pressure, psia	2400
Initial Pressurizer Water Volume, ft^3	1350
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-8.86
Initial Steam Generator Liquid Inventory, lbm	259277
One Main Steam Isolation Valve on Intact Steam Generator	Inoperative
Core Burnup	End of Cycle
Blowdown Fluid	Saturated Steam
Blowdown Area for Each Steam Line, ft^2	1.283
Turbine Trip on Reactor Trip	Inoperative

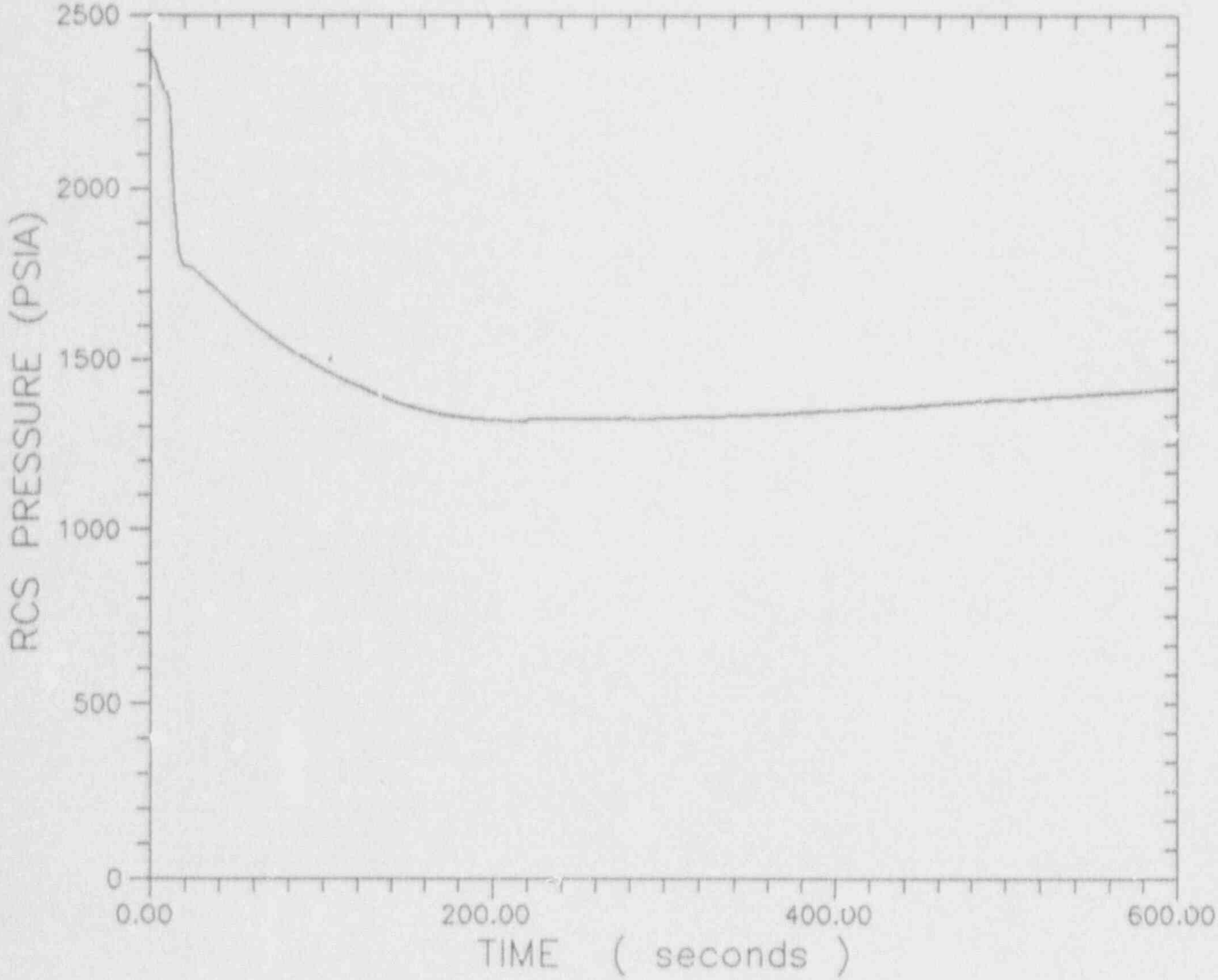
TABLE 12-2

SEQUENCE OF EVENTS FOR REANALYSIS OF A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFP)

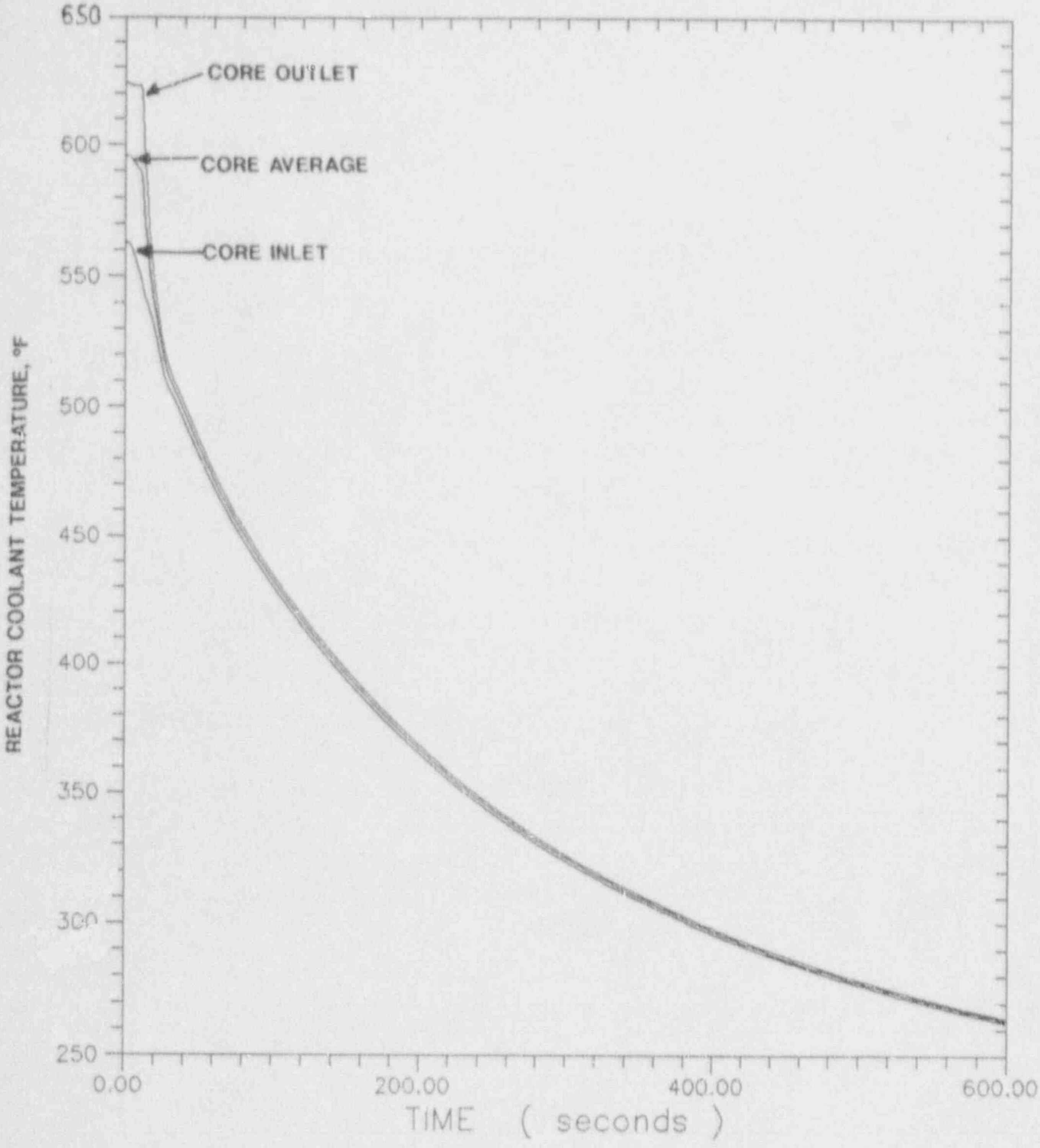
Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
7.31	CPC Variable Overpower Trip Condition Reached (% Power)	115
7.71	CPC Variable Overpower Trip Signal Generated	--
7.86	Reactor Trip Breakers Open	--
16.48	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	719
19.65	Voids Begin to Form in RV Upper Head	--
22.83	MFIVs Begin to Close	--
22.83	MSIVs Close Completely	--
38.8	Pressurizer Empties	--
73.08	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1555
113.6	Safety Injection Flow Begins	--
147.96	Safety Injection Boron Begins to Reach Reactor Core	--
185.04	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-0.35
1800	Operator Initiates Cooldown	--



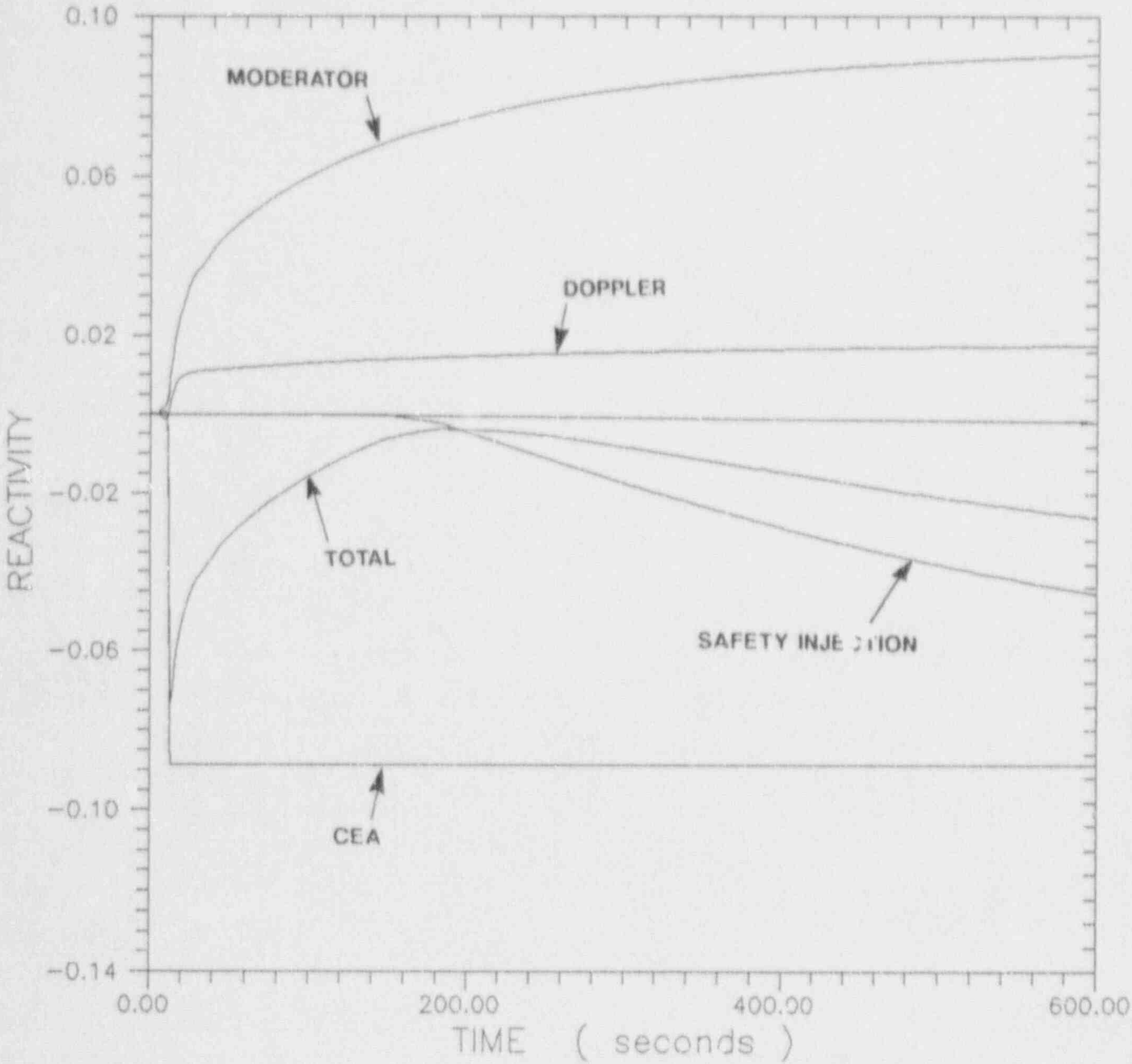
SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE CORE POWER vs TIME	Figure 12-1



SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT SYSTEM PRESSURE vs TIME	Figure 12-2



SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE REACTOR COOLANT TEMPERATURES (A) vs TIME	Figure 12-3



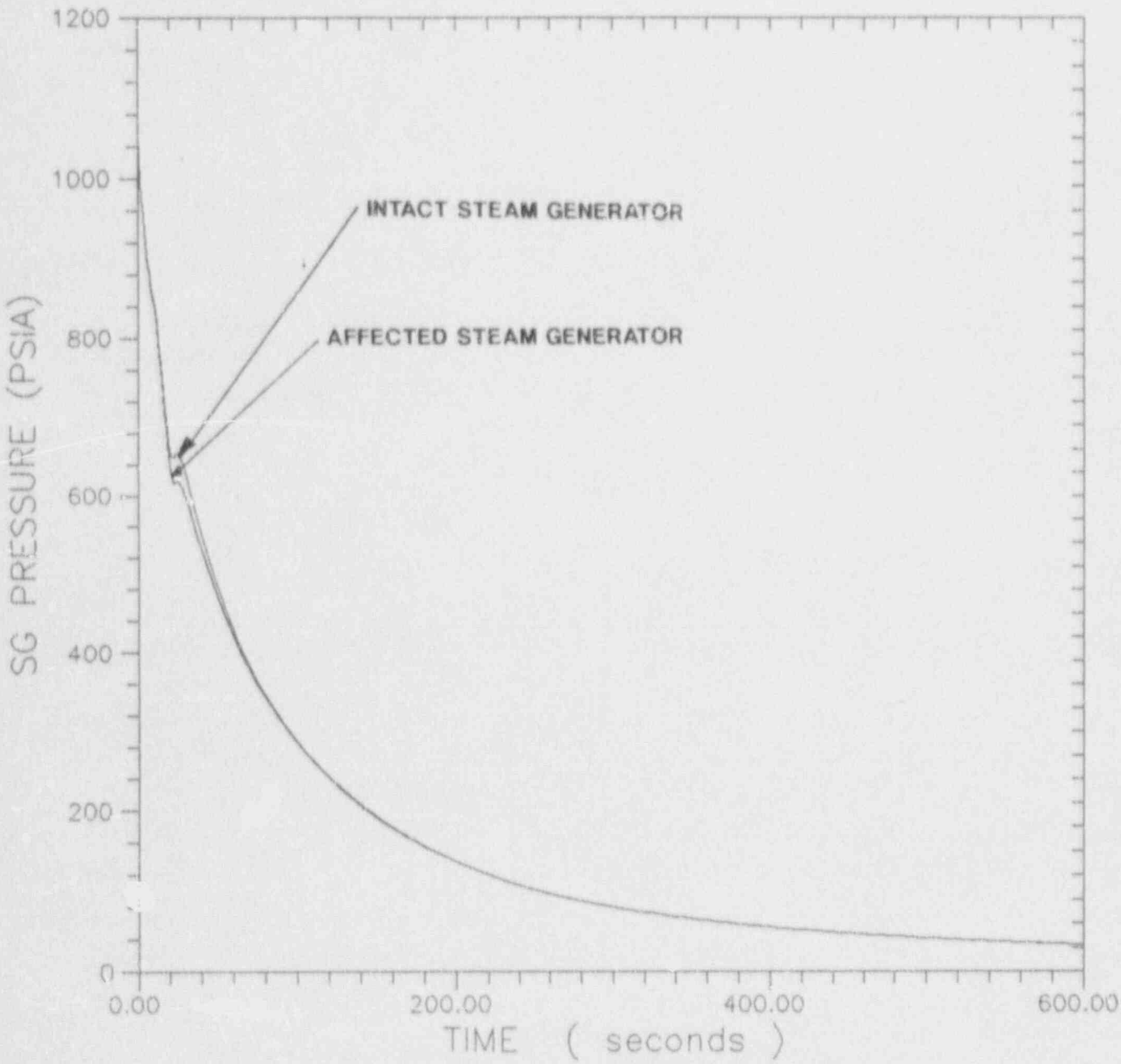
SYSTEM 80+™

FULL POWER LARGE STEAM LINE BREAK
WITH OFFSITE POWER AVAILABLE

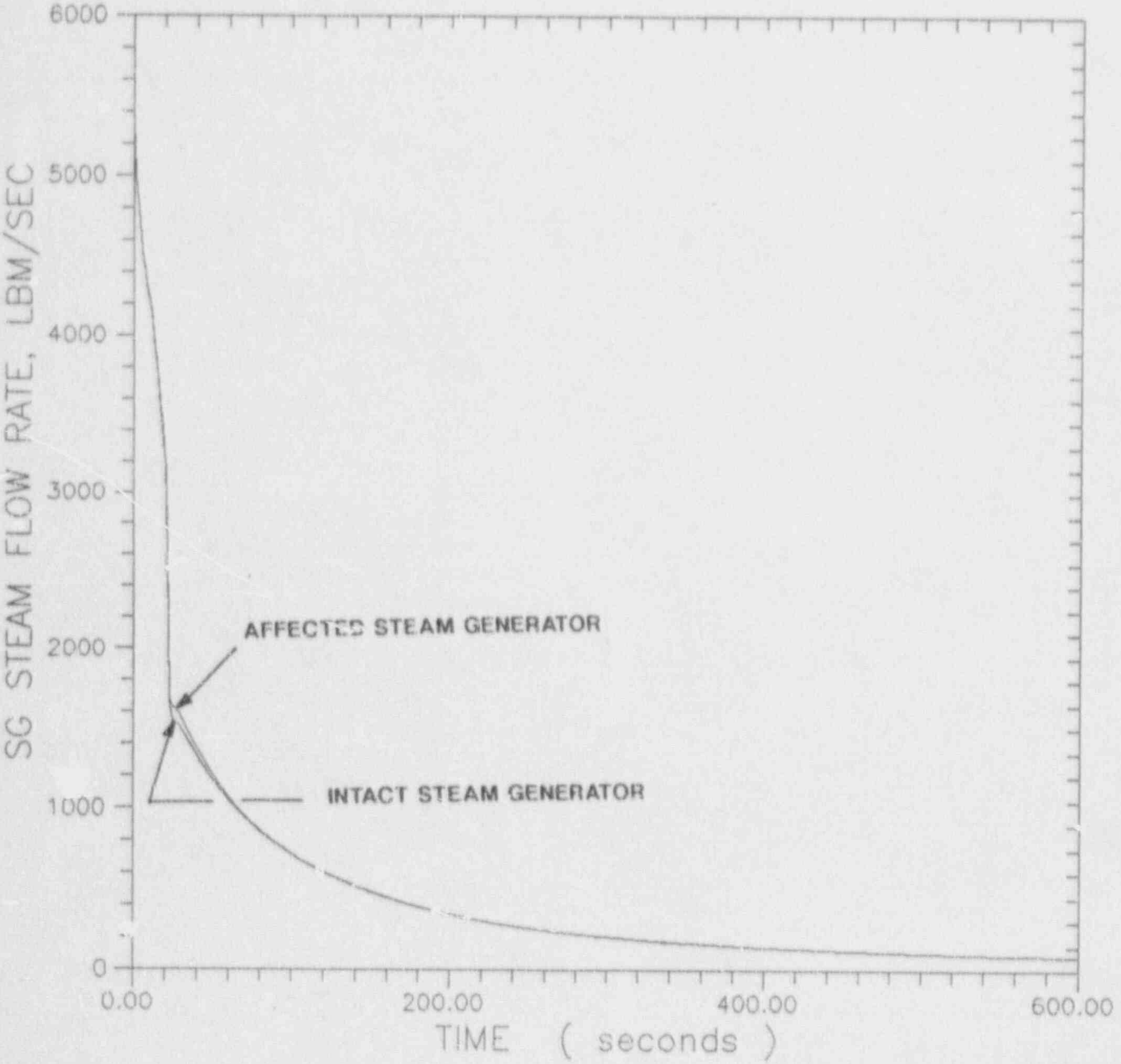
REACTIVITY vs TIME

Figure

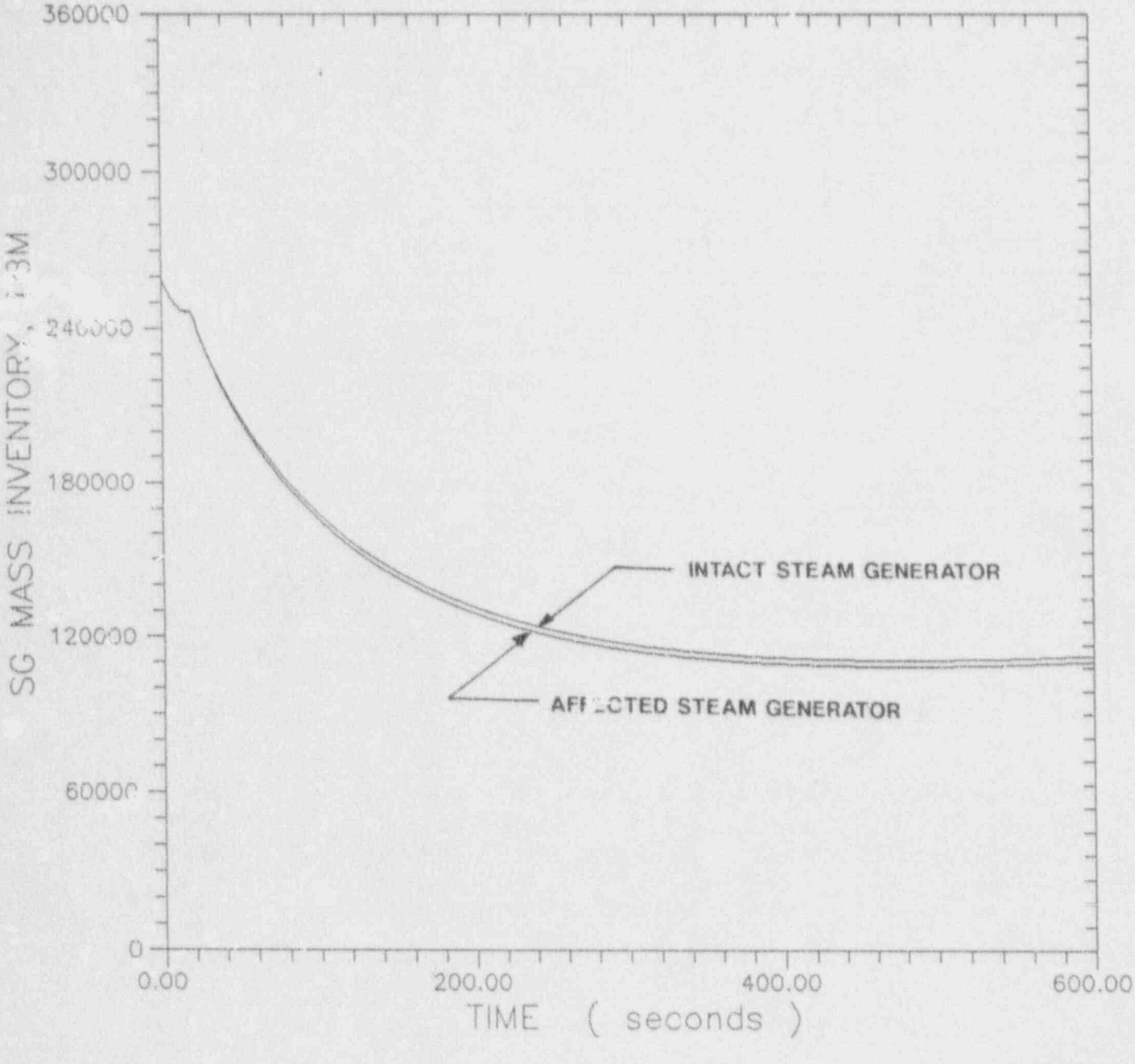
12-4



SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR PRESSURES vs TIME	Figure 12-5



SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR STEAM FLOW RATES vs TIME	Figure 12-6



SYSTEM 80+™	FULL POWER LARGE STEAM LINE BREAK WITH OFFSITE POWER AVAILABLE STEAM GENERATOR MASS INVENTORIES vs TIME	Figure 12-7

ATTACHMENT 6

13. 440.109, 86(c), 1C6(1k)

Provide discussion of the analytical results which show that the steam generator will not be overfilled without a backfilling procedure during a SG tube rupture event. The information requested should include the computer code used, assumptions made for initial conditions, single failure consideration and SG tube rupture sizes and location.

ABB-CENP Response to Item 13:

T[illegible] slides were used in the NRC/ABB-CENP meeting on March 17, [illegible] subject.

[illegible] a follow up question was asked:

[illegible] perator establish the operation of the atmospheric [illegible] r the initial cooling of the plant prior to isolation of [illegible] steam generator during the SGTR analysis presented in C[illegible] Section 15.6.3.3?

ABB-CENP Response:

For the SGTR analysis presented in CESSAR-DC Section 15.6.3.3, it is assumed that the steam bypass system and the condenser are not available for plant cooldown. The operator aligns one ADV from each steam generator for operation. The operator then sets the demand for each selected ADV with the ADV valve control as specified in the System 80+ emergency procedure guides. The demand is set to the desired percent of full open to establish a cooldown rate within that specified in the plant technical specifications to reduce RCS temperature minimizing the possibility of lifting main steam safety valves. The operator can also monitor the actual position of the ADV from indications provided in the control room.

SYSTEM 80+

STEAM GENERATOR TUBE RUPTURE ANALYSIS

MARCH 17, 1992

M. C. JACOB

ABB-COMBUSTION ENGINEERING, INC.

SYSTEM 80+
STEAM GENERATOR TUBE RUPTURE ANALYSIS

A. ANALYSIS METHOD & ASSUMPTIONS

SGTR WITH A LOOP AND A STUCK OPEN ADV IS ANALYZED USING THE FOLLOWING CODES AND ASSUMPTIONS.

1. CESEC III & CESEC III BASED COOLDOWN ALGORITHM ARE USED TO SIMULATE THE EVENT.

2. THE MOST ADVERSE INITIAL CONDITIONS (RCS PRESSURE, SG LEVEL, CORE POWER, ETC.) ARE EMPLOYED TO MAXIMIZE THE SG LEVEL AND RADIOLOGICAL RELEASES.

3. A DOUBLE-ENDED BREAK OF THE SG TUBE AT THE TUBE SHEET IS POSTULATED.

4. THE MOST LIMITING SINGLE FAILURE IS DETERMINED TO BE A STUCK OPEN ADV.

SYSTEM 80+
STEAM GENERATOR TUBE RUPTURE ANALYSIS

B. SG LEVEL CONTROL

FOR THE STEAM GENERATOR TUBE RUPTURE EVENT, THE AFFECTED SG LEVEL IS CONTROLLED BY THE FOLLOWING ACTIONS.

1. CONTROL/TERMINATE AFW TO THE AFFECTED SG.

2. MINIMIZE TUBE LEAK RATE BY MINIMIZING PRIMARY-TO-SECONDARY SIDE PRESSURE DIFFERENCE (USE OF PRESSURIZER GAS VENT, THROTTLING HPSI FLOW).

3. STEAMING FROM THE AFFECTED SG VIA THE ADVs, IF NECESSARY, TO CONTROL SG LIQUID LEVEL.

ATTACHMENT 7

16. 440.97

The staff does not consider that a steam line break accident with no-return-to-power would necessarily result in the values of DNBR remain above the safety limit DNBR. Provide the calculated DNBR curves for case 1 through 4 - post trip steam line break cases. Information provided should include the discussion of the correlation used for DNBR calculation and its applicability to the core conditions (including low flow, low pressure for the steam line break with a loss of offsite power).

ABB-CENP Response to Item 16:

ABB-CENP has evaluated the minimum DNBR for the post trip SLB cases provided in CESSAR-DC Section 15.1.5, utilizing the same methods reviewed and approved on the CESSAR FSAR and the PVNGS FSAR docket as well as the BGE Calvert Cliffs docket. The limiting case is Case 1 due to the low reactor coolant system flow caused by the loss of offsite power. For this case, the post trip minimum DNBR is significantly greater than 10.

Details of the methodology used to calculate the minimum DNBR for the post-trip steam line break case used in response to this question and on the System 80 dockets follow:

The Macbeth DNBR correlation (References 1 and 2) has been selected to represent margin to DNB during post-trip periods.

Macbeth correlates critical heat flux to mass flux, inlet subcooling, pressure, heated diameter, and channel length. Application of a channel heat balance allows the correlation to be converted to a "local conditions" form. Using this local conditions form of the correlation, critical heat flux as a function of height in the hot channel (which is located near the stuck CEA location) is calculated, where the effect of non-uniform axial heating is incorporated using the method applied by Lee (Reference 3).

Open core calculations indicate that local quality in the hot channel during post-trip steam line break conditions seldom exceeds a few percent, regardless of fission power rate or core average mass flux. This occurs due to the assembly cross-flow effects. The presence of low density liquid or of voids at the top of the hot channel causes post-trip power generation to occur near the bottom of the core. For return-to-power DNBR calculations, an integrated radial peaking factor of approximately 50 and an axial peaking factor of approximately 3 are used to bound all possible power distributions. Enthalpy as a function of height is computed by performing a closed channel heat balance. Hot channel inlet enthalpy is set equal to the average enthalpy predicted by CESEC for the fluid at the core inlet for that half of the core on the side associated with the affected steam generator. Maximum enthalpy is limited to that corresponding to 20% quality at the system pressure, to account for the cross-flow effect.

As specified in Reference 3, the Macbeth correlation is based on 17 geometries in the 1000 psia range. The ranges of applicability for other parameters are:

Mass Velocity (Mlbm/hr-ft^2)	0.01 - 7.8
Inlet Subcooling (Btu/lbm)	150 - 380
Hydraulic diameter (in)	0.113 - 0.902
Length (in)	17 - 72

For further verification, in 1969 Idaho Nuclear Corporation (INC) compared Macbeth to 1096 Critical heat flux points covering the following ranges of parameters (Reference 4).

Mass Velocity (Mlbm/hr-ft^2)	0.02 - 4.0
Inlet Subcooling (Btu/lbm)	0 - 373
Pressure (psia)	156 - 1400
Rod Diameter (in)	0.25 - 0.625
Spacing Between Rods (in)	0.022 - 0.307
Rod Length (in)	30 - 178

The results of the Reference 4 study found that the Macbeth correlation predicted 97% of the data points within the error bounds -20% to +20%.

The parameter ranges considered by INC for use of the Macbeth Correlation are met for the cases evaluated except for pressure. RCS pressure for the post-trip Case 1 at the time of maximum reactivity exceeded the above identified range by approximately 100 psi. However, ABB-CENP feels that use of the Macbeth Correlation is acceptable for this evaluation since the minimum calculated DNBR of greater than 10 is far from the minimum DNBR limit of 1.3 for this correlation. This wide margin to fuel failure allows up to approximately an 87% error in the correlation results before the potential for fuel failure would be of concern. Thus, ABB-CENP believes that fuel failure will not occur near the time of maximum reactivity for the post-trip portion of the steam line break events.

REFERENCES

1. Macbeth, R. V., "An Appraisal of Forced Convention Burn-out Data," Proc. Instn. Mech. Engrs, Vol. 180, Pt3c, pp 37-50, 1965-66.

2. Macbeth, R. V., "Burn-out Analysis - Part 5: Examination of Published World Data for Rod Bundles," A. E. E. W. Report R358, 1964.

3. Lee, D. H., "An Experimental Investigation of Forced Convection Burn-out in High Pressure Water-Part IV, Large Diameter Tubes at About 1600 psia," A. E. E. W. Report R479, 1966.

4. Idaho Nuclear Corporation, "Nuclear Safety Program Monthly Report - October 1969," NY 123-69, 11/10/69.

ATTACHMENT 8

21. 440.111

The System 80+ TS allows a positive moderator feedback (MTC) coefficient for operation of a System 80+ plant. A positive MTC design is not consistent with the requirements of the EPRI URD, which requires a non-negative MTC design. However, the ATWS analysis assumes a negative MTC to keep the calculated peak pressure to less than 3200 psia. ABB/CE is required to discuss the deviation of design MTC from the requirements of the EPRI URD.

ABB-CENP Response to Item 21:

At the meeting it was identified that the most positive best estimate moderator temperature coefficient covering 99% of the cycle was -0.3×10^{-4} delta rho/°F at 100% power. As specified in the response to RAI 440.111, the maximum RCS pressure for this ATWS event is less than 3140 psia. Because the MTC tends to become steadily more positive at lower power levels, ABB-CENP was requested to analyze the ATWS event at lower power with a more positive MTC to demonstrate the limiting case ATWS occurs at full power.

At 80% power the best estimate most positive MTC covering 99% of the cycle is -0.2×10^{-4} delta rho/°F. A reanalysis of the ATWS event at 80% power with this most positive MTC results in maximum RCS pressure less than 2800 psia. In addition, results of ATWS analyses at 90% power using the most positive MTC at 80% power, which is bounding, result in maximum RCS pressures well below the full power case.

In summary, the most limiting ATWS analyses occurs at full power with a most positive MTC of -0.3×10^{-4} delta rho/°F with a calculated maximum RCS pressure less than 3200 psia.

ATTACHMENT 9

Additional NRC Questions on Steam Generator Tube Rupture (SGTR)

NRC SGTR Question Number 1

For the CESSAR-DC SGTR W/O LOOP, the limiting case with respect to offsite radiological doses that is presented in the CESSAR design certification document has an early reactor trip. Would not a late reactor trip result in more adverse offsite doses by increasing the integrated primary to secondary leak flow?

ABB-CENP Response:

The results of a parametric study on reactor trip time for a SGTR W/O LOOP indicated that the radiological dose is the highest for the case with an early reactor trip.

The reason for this is discussed below. The radiation release to the atmosphere during a SGTR may be divided in to three parts:

a) Before reactor trip, the radioactivity is carried by steam into the condenser and released via the condenser air ejector. A condenser decontamination factor (DF) of 100 is assumed for this release. Because of the high DF in the condenser, this portion of the total radiation release is relatively small.

b) After reactor trip, in the absence of the steam bypass system, it is assumed that the steam generator MSSVs cycle and release radiation directly into the atmosphere. A portion of the leaking RCS fluid flashes on entry into the SG and is assumed to be released to the atmosphere with a DF of 1. The non-flashed portion mixes with the SG liquid and is released along with the MSSV steam flow with a DF of 100. This portion of the radiation release can be substantial depending on the duration of the MSSVs cycling.

   Irrespective of the time of reactor trip, it is assumed that at 1800 seconds after the initiation of the event, the affected SG is isolated and no further radiation release occurs from the affected SG. If the reactor trip occurs soon after event initiation, the MSSVs cycle for a longer duration prior to isolation of the affected SG, resulting in a larger radiation release. Conversely, a relatively late trip will result in a shorter period of cycling of the MSSVs and a smaller radiation release.

c) After isolation of the affected SG at 1800 seconds, the plant is cooled using the ADV of the intact SG alone. The radiation release during the cooldown period is not very sensitive to the time of the trip.

From the above discussion it becomes apparent that for a SGTR event W/O LOOP, an early reactor trip will result in a higher offsite dose. Table 1 compares the results for two cases, Case 1 with an early trip and case 2 with a late trip. The 0-2 hr and the 0-8 hr radiation releases for the early trip case is seen to be higher.

Comparison of Radiation Release for

Two SGTR W/O LOOP Cases

		Case 1 (early trip)	Case 2 (late trip)
Trip Time (Sec)		0.5	1757
Release Via the Condenser before reactor trip			
for GIS	(Ci)	0.0	0.68
for PIS	(Ci)	0.0	3.0
0 - 0.5 Hour MSSV release			
for GIS	(Ci)	11.19	1.11
for PIS	(Ci)	49.94	3.8
0.5 - 2 Hour ADV release (unaffected SG)			
for GIS	(Ci)	1.9	2.0
for PIS	(Ci)	2.13	2.0
2 - 8 Hour ADV release (unaffected SG)			
for GIS	(Ci)	32.1	30.0
for PIS	(Ci)	10.0	9.5
0- 2 Hour total release			
for GIS	(Ci)	13.1	3.8
for PIS	(Ci)	52.1	8.8
0-8 Hour total release			
for GIS	(Ci)	45.2	33.8
for PIS	(Ci)	62.1	18.3

NRC SGTR Question Number 2

For the CESSAR-DC SGTR with LOOP and a Stuck Open ADV, are non-safety grade systems (Non-class 1-E systems) required for the mitigation of the event?

ABB-CENP Response:

The mitigation of the SGTR event does not require the use of non-safety grade systems.

In CESSAR-DC Section 15.6.3.3.1, the pressurizer level control system (PLCS) and the pressurizer pressure control system (PPCS) are listed as systems that can be employed to mitigate the SGTR consequences consistent with the Emergency Procedure Guidelines (EPG). Also, Figure 15.6.3-48 of CESSAR-DC identifies the pressurizer heaters as one means of controlling the RCS pressure per the EPG. However, the use of these two non-safety grade systems is not required during a SGTR event.

In the SGTR analysis presented in CESSAR-DC Section 15.6.3.3, i.e., SGTR with a loss of offsite power and a single failure, the charging and letdown functions are conservatively assumed to operate in manual mode prior to reactor trip. After reactor trip, it is assumed that the charging and letdown functions become unavailable after the loss of offsite power. The operator then takes manual control of the safety injection system (SIS) to maintain the pressurizer water level within acceptable limits. The maintenance of desired pressurizer pressure is achieved using the SIS and the pressurizer gas vent system.

NRC SGTR Question Number 3

CESSAR-DC Table 15.6.3-1 identified the pressurizer heaters as being actuated at 16.5 seconds. Are the heaters required to mitigate the SGTR event?

ABB-CENP Response:

No. The actuation of the pressurizer heaters at 16.5 seconds makes the event consequences more adverse by keeping the RCS pressure as high as possible, thus maximizing the primary to secondary leak and the radiological consequences.

Item 5 - Question 440.54

It is noted that valve position indication for the isolation valves SI-651 through 656 are provided in the main control room. Confirm that Figure 6.3.2-1C of CESSAR-DC correctly reflects the valve position indications as designed.

Response:

Figure 6.3.2-1C of CESSAR-DC correctly reflects the valve position indications of valves SI-651 through 656.

Item 6 - Question 440.55a

ABB-CE stated that an assumed moderate-energy line break will result in a loss of 7973 cubic feet of RCS coolant and determined that sufficient inventory is available to preclude the loss of shutdown cooling (SCS). Provide the acceptable RCS inventory for operation of the SCS and discuss why a loss of 7973 cubic feet of RCS coolant will not preclude the SCS operability.

Response:

Shutdown cooling can be maintained even if the RCS level is below the hot leg centerline. The ABB-CE response to RAI 440.55 stated that a maximum of 7973 cubic feet of RCS coolant would be lost before operator action could be credited. With the loss of 7973 cubic feet, the RCS level would be 32 inches above the bottom of the 42 inch diameter hot leg. This level is more than enough to prevent the loss of shutdown cooling.

Item 9 - Tech. Spec. 3.5.2

Question:

What are the functions of valves SI-304 and 305? The surveillance requirement 3.5.2 specifies the valves to be closed with the power to the valve operator to be removed. Confirm that the valves SI-304, 305 are not misplaced with SI-321, 331 or SI-604, 609 in TS 3.5.2.

Response:

The valves in Tech. Spec. 3.5.2 should be SI-604 and SI-609. This change will be made in a future amendment to CESSAR-DC. See the attached markup.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed: Valve Number / Position / Function [SI 604] ~~[SI 304]~~ / [Shut] / [Hot Leg] Injection [SI 609] ~~[SI 305]~~ / [Shut] / [Hot Leg] Injection	12 hours
SR 3.5.2.2	Verify each SIS manual, power operated, or automatic valve in the flow path that is not locked, sealed or otherwise secured in position is in its correct position.	31 days
SR 3.5.2.3	Demonstrate SIS piping full of water.	31 days
SR 3.5.2.4	Verify each Safety Injection pump is capable of delivering [ ] GPM at a differential pressure of [ ] psid.	In accordance with the Inservice Inspection and Testing Program
SR 3.5.2.5	Demonstrate each SIS train automatic valve in the flow path actuates to its correct position on [an] actual or simulated actuation signal[s].	18 months
SR 3.5.2.6	Demonstrate each Safety Injection pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.5.2.7	Verify, by visual inspection, that each SIS division suction inlet and the IRWST Holdup Volume Tank is not restricted by debris and that the suction inlet trash racks and screens show no evidence of structural distress or abnormal corrosion.	18 months

CROSS-REFERENCES - None.

ATTACHMENT 10

NRC Tech Spec Question Number 1

CESSAR-DC Chapter 16 Table 3.3.1-1 should be revised to include the LSSS Reactor Protection System Trip Setpoints.

ABB-CENP Response:

The specific values of the tech spec allowable trip setpoints cannot be available prior to design certification because "as procured" information is required. The final setpoints will account for all instrumentation inaccuracies to ensure the setpoints assumed in CESSAR-DC Chapter 15 are preserved. The setpoints assumed for the CESSAR-DC Chapter 15 analyses are shown in CESSAR-DC Table 15.0-2.

ATTACHMENT 11

4. 440.22 (RD Valve Size)

There are two events analyzed in determination of the size of rapid depressurization (RD) valves. Two different values for the operator action delay times were assumed in the two different cases. Discuss why not use the operator delay time of 30 minutes for both cases. Also, ABB/CE is requested to include the data of the RD valve size in the appropriate Section of CESSAR-DC.

ABB-CENP Response to Item 4:

The events analyzed to determine the size of the rapid depressurization (or Safety Depressurization and Vent System (SDVS)) valves considered the Chapter 5 Engineered Safety Systems EPRI ALWR Evolutionary Plant Requirements. The EPRI requirements follow:

Paragraph 5.5.2.3.1

Requirement:

A single SDVS bleed path, in conjunction with two-of-four safety injection pumps, shall have sufficient capacity to prevent core uncovery following a TLOFW if feed and bleed is initiated immediately following the opening of primary safety valves. Analyses shall show a margin to core uncovery of at least two feet, using best estimate methods.

Rationale for Requirement:

Once primary safety valves have opened, primary inventory is being depleted and emergency procedures call for makeup. Sizing should allow for potential single failures.

and Paragraph 5.5.2.3.2

The SDVS bleed paths shall have sufficient total flow capacity (both bleed paths) with all SI pumps operating to prevent core uncovery following a TLOFW if feed and bleed is delayed up to 60 minutes from the time primary safety valves lift. Analyses shall show a margin to core uncovery of at least two feet, using best estimate methods.

Rationale for Requirement:

For investment protection, sizing should allow a large margin for operator actions.

ABB-CENP has evaluated these requirements and has used the results of this evaluation in the development of performance requirements for the RD valves. ABB-CENP has determined that a delay greater than 30 minutes after initiation of the pressurizer safety valves would result in an undesirably large RD valve. Consequently, we have taken exception to the SDVS requirements presented in paragraph 5.5.2.3.2 of the EPRI-URD. To optimize the valve size, we have selected a 30 minute time delay after primary safety valve lift as a design basis requirement for valve sizing, with no failures. A valve selected which meets this design basis requirement also meets the EPRI requirement in paragraph 5.5.2.3.1. For additional information on the safety depressurization system, refer to CESSAR-DC Section 6.7.5.

ATTACHMENT 12

PLAN FOR THE REVISION OF THE D-RAP

ABB-CE has reviewed NRC's discussion paper on the System 80+ Designer's Reliability Assurance Program (D-RAP) and in general agrees with their observations. We will revise the RAP to address NRC's comments by early fall, 1992 and, in the near future, will request a meeting with the NRC staff for discussion and clarification of the scope, purpose and contents of ABB-CE's D-RAP.

ABB-CE will expand the purpose of the D-RAP: 1) to include all SSCs that are significant contributors to risk, as shown by the PRA and other sources, 2) to ensure that the plant design provides SSCs at least as reliable as that assumed in the PRA, and 3) to give guidance to the COL applicant that the reliability levels should be maintained over the life of the plant.

The scope of the D-RAP will be clarified per NRC's suggestion. The ABB-CE RAP, Rev 00 (which NRC reviewed), was written as a general RAP that the Designer would start with and the COL applicant would inherit and expand. The items that were included in this general RAP were requested to be included in a letter from NRC, dated October 10, 1991 under Docket No. 52-002. This led to the inclusion of material in the draft RAP that we thought the COL applicant would wish to include in their RAP. We agree with NRC's comment that this approach has led to some confusion between organizational responsibilities. ABB-CE will revise the RAP to be simply a D-RAP and guidance to the COL applicant will be made in the form of general requirements. This simplification will address NRC's comments about the RAMI program, plant operating data base system, plant procedures and other issues that are the responsibility of the COL applicant. In summary, the scope of the D-RAP will limited to the designer's (ABB-CE) responsibilities only. Operational requirements will be provided to the COL applicant, but the overall O-RAP program description is not within the scope of the D-RAP for System 80+.

The RAP that was reviewed did not include tables of the SSCs that are important to safety, their reliability, or other characteristics, because this information was identified in the System 80+ PRA. These tables will be reproduced in the revised D-RAP (and expanded to include other SSCs identified from other sources).

In conclusion, the draft RAP was written specifically to include D-RAP and O-RAP information (at NRC's request). We agree with the reviewers that this structure leads to some confusion and that a simple D-RAP is preferred. We will revise our D-RAP to address the reviewers comments and will open a dialogue with the cognizant NRC staff to ensure that the contents of our D-RAP will be acceptable. The System 80+ D-RAP will be revised by early fall, 1992.

This is outside the purpose of design certification. A designer must not preclude industry initiatives (e.g. NPOC)

that defines the scope, conceptual framework, and essential elements of an effective RAP. The D-RAP also implements those aspects of the program that are applicable to the design process. In addition, the D-RAP identifies the relevant aspects of plant operation, maintenance, and performance monitoring for the risk-significant structures, systems and components (SSCs) for the owner/operator's consideration in developing the site-specific O-RAP.

The staff's position on the RAP is that a designer's submittal for design certification pursuant to 10 CFR Part 52 would include, in part, the framework for a reliability assurance program and would also implement those elements of the RAP that would be applicable to and implemented during the design phase [Tier 1 requirement]. ~~In turn, the designer would provide the framework of a RAP for a COL applicant~~. A COL applicant would augment the designer's RAP to reflect plant-specific information and implement those elements applicable during the construction and operations phases.

The staff's evaluation of CE's Reliability Assurance Program Plan for the System 80+ Nuclear Power Plant was based on the guidance contained in the supporting documentation for TMI Task Item II.C.4, "Reliability Engineering," and SECY 89-013, "Design Requirements Related to the Evolutionary Advanced Light Water Reactors (ALWRS)." The Licensee Performance and Quality Evaluation Branch (LPEB) is assigned primary review responsibility for ALWR reliability assurance programs. Some material contained in the CE System 80+ RAP is beyond the scope of LPEB's review area, such as probabilistic risk assessment (Section 2.0 of the CE System 80+ RAP submittal) and technical specifications (Section 5.0 of the CE System 80+ RAP submittal). Staff comments on areas outside of LPEB's review area can be found in the respective sections of the DSER for the CE System 80+ SSAR, as applicable.

EVALUATION

1.0 INTRODUCTION

1.1 Purpose

Section 1.1 of the CE RAP defines the RAP as a program for maintaining consistency between the System 80+ PRA and plant configuration and states that the RAP will ensure that the procedures, Technical Specifications, and plant configuration (including maintenance) are consistent with the PRA. Additionally, CE states that the PRA will be maintained and updated as design details increase and that the PRA will be maintained as a living document that reflects the operating plant as it evolves.

The staff considers that the fundamental purpose of the D-RAP is to identify those SSCs that are significant contributors to risk, as shown by the PRA and other sources, and to ensure that the plant

Not an open issue! We have always agreed. See our statement in Attachment 12 to letter LD-92-064 which clarifies our agreement.

design provides SSCs that are at least as reliable as that assumed in the PRA. The staff considers that the RAP should also identify SSCs that prevent or mitigate plant transients, or could affect a plant trip or ESF actuation, or whose failure could prevent a system from fulfilling its intended safety function, and specify appropriate operation, maintenance and monitoring requirements. During plant operation, the RAP should assure that (1) the reliability levels of these SSCs are maintained commensurate with those assumed in the design certification PRA throughout the life of the plant, (2) assure that the original bases and design assumptions are satisfied and (3) that safety margins are maintained. The staff review considers that these fundamental concepts of a RAP are not adequately addressed in Section 1.1 of the CE RAP submittal.

The staff concludes that Section 1.1 should be clarified to provide information on the RAP that (1) identifies risk-significant SSCs, (2) ensures that the plant design provides SSCs at least as reliable as that assumed in the PRA, and (3) that these reliability levels should be maintained over the life of the plant. ~~This is an open issue that must be resolved before the staff can complete its review of Section 1.1 of the CE RAP.~~

1.2 Scope

Section 1.2 of the CE RAP states that the RAP describes the elements of the program for maintaining the PRA, conducting a Reliability, Availability, Maintainability, and Inspectability (RAMI) program and a Reliability Centered Maintenance (RCM) program for the entire plant. CE further states that the RAP "should assure consistency between the PRA bases and the plant operation, maintenance and configuration."

In the staff's RAI dated October 10, 1991, the staff requested, in part, that CE describe the scope and objective of its RAP, including a discussion on selection criteria, such as a graded approach to safety that is based on the PRA and the SSCs to prevent or mitigate plant transients, and provide basic definitions for its RAP. ~~This discussion was not included in CE's response to the RAI.~~

Now provided via Att. 12 to LD-92-064.

The staff's position is that the scope of the RAP includes all risk-significant SSCs throughout plant life, using the PRA and other industry sources to identify and prioritize those SSCs that are important to prevent and mitigate plant transients or other events that could present a risk to the public.

The staff's position is that the objective of a D-RAP is to (1) identify risk significant SSCs, based on the PRA and other sources, (2) assure that the plant design provides SSCs that are at least as reliable as those assumed in the PRA, and (3) assure that these SSCs are built and operated throughout plant life at least as reliably as assumed in the PRA. In this regard, once the risk

Please present this as "confirmatory", based on Att. 12 to letter LD-92-064

significant SSCs have been identified, a D-RAP should describe the process for achieving this overall objective and should also identify key assumptions regarding any operation, maintenance, and monitoring activities that a referencing applicant should consider in developing its O-RAP. The development and implementation of the O-RAP is the responsibility of the referencing applicant, and the staff's position on the review of an O-RAP is that it will be evaluated as part of a referencing applicant's submittal for a combined operating license.

The staff concludes that Section 1.2 should more clearly define the scope and objective of a RAP, define the basic definitions and include a discussion on selection criteria. These are open issues that must be resolved before the staff can complete its review of Section 1.2 of the CE RAP.

2.0 PRA PROGRAM ELEMENTS

This may not be a good idea → repeating PRA material in RAP may create a configuration control problem. Better to only ref. the PRA

Section 2.0 of the CE RAP states that the RAP program includes the elements that are necessary to ensure that the PRA is maintained consistent with the plant configuration and operation and that this requires a living PRA that reflects the plant as it progresses from design, construction and through the operation phase. However, the discussion on PRA goals, methodology, and development from design to operations is more appropriate for Appendix B (PRA) to the CE System 80+ SSAR. The control of PRA design assumptions for the RAP should be incorporated in Section 2.0.

confirmatory

The staff also considers that risk-significant SSCs need to be identified and prioritized as part of the D-RAP. The staff agrees with the use of PRA, importance weighing, deterministic methods, or other industry sources to identify and prioritize those SSCs that are important to prevent or mitigate plant transients or other events that could present a risk to the public. Pending further clarification on the control of PRA design assumptions for the RAP, and method to identify and prioritize risk-significant SSCs, this is an open issue that must be resolved before the staff can complete its review of Section 2.0 of the CE RAP.

X

3.0 RAMI PROGRAM ELEMENTS

Section 3.0 of the CE RAP discusses how CE will develop the Reliability, Availability, Maintainability, and Inspectability (RAMI) program to predict and track plant availability in the same way that the PRA follows plant risk. The RAMI program will be conducted within the context of a RAP. This section also states that after plant startup, the utility will maintain the RAMI program and ensure that it is consistent with the plant configuration, procedures and operating history.

The staff's position is that the RAP should be seen as a program that consists of two distinct parts: the first part, which the

The designer provides "operational requirements" but not the O-RAP framework. That is the job of industry organizations such as NPOC and EPRI.

staff refers to as the D-RAP, is the responsibility of the designer and applies to vendor submittals for design certification; and the second part, which the staff refers to as the O-RAP, is the responsibility of and applies to a referencing applicant for a COL. At the design stage, the D-RAP involves a top-level program that defines the scope, conceptual framework, and essential elements of an effective RAP. The D-RAP also implements those aspects of the program that are applicable to the design process. In addition, the D-RAP identifies the relevant aspects of plant operation, maintenance, and performance monitoring for the risk significant SSCs for the owner/operator's consideration in developing the site-specific O-RAP. ~~The designer would provide the framework of the RAP to a COL applicant.~~ No. A COL applicant would augment the designer's RAP to reflect plant-specific information and implement those elements applicable during the construction and operation phases.

Furthermore, although the RAMI program will use the same data and information as the PRA, the RAMI and PRA objectives (or the desired values of the parameters that make up these objectives) may be conflicting (e.g., some of the means of maximizing plant availability may be in conflict with the objective of maintaining the risk levels assumed in the PRA). In the System 80+ RAP, it is mentioned that the RAMI should be consistent with the plant configuration, procedures and operating history without mentioning the possibility of conflicting objectives. The staff questions how such conflicts, whenever they arise, will be resolved in a way that does not violate the safety requirements and reliabilities assumed in the design certification PRA and provide an acceptable balance between risk and availability. The staff concludes that Section 3.0 should include additional information to address this issue. This is an open issue that must be resolved before the staff can complete its review of Section 3.0 of the CE RAP.

confirmatory

Section 3.1 RAMI Analysis

Section 3.1 of the CE RAP discusses how the top level quantitative capacity factor requirements are sub-divided into system level quantitative design requirements, and that failure modes and effects analysis and fault tree analyses are performed for systems determined to be important to the plant's ability to meet these quantitative requirements. This section further details how the RAMI analysis is to be performed, the iterative process used to assure goals are met by the system designers and reliability engineers and the use of design review meetings to discuss RAMI considerations and issues.

The staff considers that the use of methods similar to those used in the PRA and the interfaces between the various organizations are acceptable. The staff also considers the reliability techniques and methods described in this section to be acceptable. However, the staff needs clarification on the intent of RAMI (i.e., safety

Sections 5.0 through 5.5 of the CE RAP primarily discuss topics that are beyond the scope of this evaluation. The staff evaluation of Section 5.1 (Technical Specifications) is addressed by Section 16 of the CE System 80+ DSER. However, within the context of a D-RAP, the staff disagrees that the RAP ensures that the bases used in the PRA are consistent with plant procedures and Technical Specifications. Sections 5.2 (Plant Operating Procedures), 5.3 (Emergency Operating Procedures) and 5.4 (Severe Accident Management Procedures) and 5.5 (Security) are consider to be within scope of a referencing applicant's COL application and, therefore, were not addressed as part of this evaluation. The staff requires clarification plant CE's intent regarding consistency between the PRA and plant procedures and Technical Specifications.

Section 6.0 of the CE RAP defines that this section will contain the organization charts for the Utility, plant staff and designers who support the RAP program when such information becomes available. The staff concludes that this section should include a discussion on the organizational and administrative aspects of a D-RAP, including a discussion on organizational accountability for implementing the design portion of the RAP.

In addition to the above, CE did not respond to two items in the staff's RAI. In the RAI dated October 10, 1991, the staff requested an example of how the CE RAP would function throughout plant life (e.g., from the design phase through the end of the operating phase) using a specific SSC identified as risk significant in the PRA. In their response, CE stated that no example was given in the RAP plan, but one will be added in a future update. This remains an open issue that must be resolved before the staff can complete its review of the CE RAP submittal.

Also in the RAI, the staff asked if and how the CE System 80+ RAP will differ from the EPRI Utility Requirements Document (URD) description of a RAP. CE stated in their response that the RAP Plan is generally consistent with the EPRI description and that the EPRI description repeated many of the RAMI goals in the plan but the CE plan only refers to the goals that are in the PRA and RAMI reports. ~~CE should provide a detailed discussion on how CE's RAP differs from the EPRI URD for Evolutionary Advanced Light Water Reactors, including the rationale for the differences, if any. This remains an open issue that must be resolved before the staff can complete its review of the CE RAP submittal.~~

The EPRI URD should not be the basis for NRC acceptability. We intend to comply with NRC guidance stated in this paper. The EPRI URD is an input to our program and we believe we comply but a "detailed discussion" of compliance should not be required or reported as an open item

ATTACHMENT 13

APPLICATION OF PROBABILISTIC RISK ASSESSMENT FOR THE SYSTEM 80+ STANDARD DESIGN

MAY, 1992

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 INTRODUCTION

The System 80+ Standard Design is an evolutionary Advanced Light Water Reactor (ALWR) power plant design. The System 80+ Standard Design evolved from ABB-CE's standard System 80 design.

This document describes how Probabilistic Risk Assessment (PRA) was used as a design tool during the design of the System 80+ Standard Design.

2.0 USE OF PRA IN THE SYSTEM 80+ DESIGN PROCESS

ABB-CE, in conjunction with the U.S. Department of Energy, is working to develop and certify a standardized Advanced Light Water Reactor (ALWR) design. The System 80+ Standard Design, ABB-CE's ALWR design, has evolved from ABB-CE's certified System 80 NSSS design. A Probabilistic Risk Assessment (PRA)[1], which was initiated using the original System 80 design as a baseline at the outset of the program, has been used as an evaluation and confirmation tool throughout the design process.

Many of the major design enhancements System 80+ relative to System 80 were based on insights gained from the System 80 "Baseline" PRA as well as previous Risk assessments for both CE and non-CE plants. These design enhancements were reviewed and incorporated in the EPRI Evolutionary Plant Utility Requirements[2] as part of CE's participation in that program. They include:

1. Use of a four train Emergency Feedwater System (EFWS) with two turbine driven pumps and two motor driven pumps to provide a highly reliable emergency feedwater supply.

2. Use of a non-safety grade startup feedwater system for normal startup and shutdown operations. This reduces the demands on the EFWS.

3. Use of a four train Safety Injection System (SIS) with Direct Vessel Injection (DVI) to enhance the reliability of the inventory control function.

4. Use of an In-containment Refueling Water Storage Tank (IRWST) to eliminate the need for a Recirculation Actuation Signal (RAS).

5. Use of a larger pressurizer and larger steam generators to make the system response to transients slower and more resilient.

6. Use of a cavity specifically designed to disentrain corium in the event of a severe accident.

7. Use of a Safety Depressurization System (SDS) to provide the capability to depressurize the RCS during a severe accident to minimize the potential for direct containment heating. The SDS also provides the capability for once through core cooling.

8. Use of dedicated batteries, independent of the station batteries, to start the diesel generators.

9. Use of a combustion turbine as an alternate backup AC source to the diesel generators.

10. Use of a large volume containment to reduce the potential for early containment overpressure failures following a severe accident.

At the inception of the System 80+ design process, a "Baseline" PRA was performed for the System 80 NSSS with a Balance of Plant (BOP) design representative of those of recent vintage CE plants[3]. As the System 80+ design evolved, the models developed for this PRA were modified to reflect the latest system designs. This PRA and the associated models provided a tool for evaluating various design changes. Some specific examples are provided in the following paragraphs.

Early in the program, System 80+ had a standby, safety related Essential Component Cooling Water System and Essential Service Water System for cooling safety related loads. Demand failures of the pumps and valves in these systems were found to be significant risk contributors. Therefore, the System 80+ design was changed to a normally operating Component Cooling Water System (CCWS) and Service Water System (ESW) where the non-safety loads can be shed when required. As part of the DoE funded Advanced Reactor Severe Accident Program (ARSAP), a contractor evaluated several different component cooling water designs from a risk standpoint. The selected CCWS and ESWS have two divisions with two pumps in each division. One pump in each division is normally operating and the second pump is in standby and will start in the running pump in the same division trips. A subsequent evaluation was also made to determine if the standby pumps had to be automatically loaded on the diesel generators and started following a Loss of Offsite power. This evaluation indicated that there would be little risk impact if the standby pumps were aligned to the diesel generators following a loss of offsite power but were not started unless the previously running pump failed to restart. Thus, larger and less reliable diesels were not required.

The System 80+ Design includes two emergency diesel generators which provide power to the safety related 4.16 Kv buses following a loss of offsite power, plus a standby combustion turbine which can be aligned to either of the safety related 4.16 Kv buses in the event of a failure of one of the emergency diesel generators. In additions, the alternate AC source is sized to provide power to a set of non safety loads which, from an operational point of view, have been deemed desirable to have following a loss of offsite power. PRA was used to compare the "two diesels plus combustion turbine" configuration to a "four diesel" configuration. This comparison indicated that the "four diesel" configuration was slightly, but not significantly, more reliable than the "two diesels plus combustion turbine" configuration. However, the "four diesel" configuration did not provide power for the permanent non-safety loads. In addition, the "four diesel" configuration would have had a significant impact on plant size, cost and layout because of the need for two additional divisions of diesel support systems such as cooling water, starting power and fuel supplies.

One objective in performing the System 80+ Standard PRA was to demonstrate compliance with applicable risk goals and requirements. In the performance of the PRA, failure of the safety depressurization valves and cavity flood valves due to seismic failure of their dedicated power invertors at relatively low acceleration levels was determined to be potentially risk significant. Therefore, a design requirement for seismic isolation of these invertors was added.

The level 2 PRA analyses also indicated that without hydrogen controls, certain sequences had the potential for hydrogen deflagrations that might threaten containment with some probability. Based on this, hydrogen igniters were incorporated in the System 80+ Standard Design.

The System 80+ PRA was also used for an evaluation of Severe Accident Mitigation Design Alternatives (SAMDAs). Eleven design alternatives were evaluated. These were selected based on the Design Alternatives evaluated for Limerick[4] and the results of the System 80+ PRA. The Design Alternatives analysis used a bounding technique. It was assumed that each design alternative worked perfectly and completely eliminated the accident sequences that the design alternative was to address. This approach maximizes the benefits associated with each design alternative. Table 2-1 summarizes the results of the Design Alternatives analysis. The first column is the design alternative, the second column is the percent of the total person-rem/year reduction for each design alternative. The next column, Capital Benefit, is an equivalent present worth of the annual dose reduction. The fourth column is a rough estimate of the capital cost for each design alternative, and the final column is the net benefit (capital benefit - capital cost). The complete Design alternatives Analysis has been submitted to the NRC as a separate report[5].

TABLE 2-1

SUMMARY OF THE RISK REDUCTIONS OF THE DESIGN ALTERNATIVES

	Design Alternative	PERSON-REM REDUCTION	CAPITAL BENEFIT*	CAPITAL COST	NET CAPITAL BENEFIT
1	CONTAINMENT SPRAY	90%	$27,[illegible]0	$1,500,000	-$1,472,400
2	FILTERED VENT	86%	$26,300	$10,000,000	-$9,973,700
3	DC BATTERIES & EFWS	69%	$21,100	$2,000,000	-$1,978,900
4	RCP SEAL COOLING	16.5%	$6,034	$100,000	-$93,966
5	PRESSURIZER AUXILIARY SPRAY	6.7%	$2,050	$5,000,000	-$4,997,950
6	ATWS VALVES	4.2%	$1,290	$1,000,000	-$998,710
7	CONCRETE COMPOSITION	2.5%	$765	$5,000,000	-$4,999,244
8	REACTOR VESSEL EXTERIOR COOLING	2.5%	$765	$5,500,000	-$5,499,244
9	H2 IGNITORS	0.1%	$31	$1,000,000	-$999,969
10	HIGH PRESSURE SAFETY INJECTION	0.004%	0	$20,000,000	-$20,000,000
11	RCS DEPRESSURIZATION	0.002%	0	$500,000	-$500,000

* THE MAXIMUM CAPITAL COST ASSUMES NO MAINTENANCE OR TESTING COSTS FOR THE ADDITIONAL EQUIPMENT

3.0 COMPARISON OF SYSTEM 80+ TO SYSTEM 80

The System 80+ Standard Design evolved from the System 80 NSSS design by the incorporation of design enhancements intended to make the plant safer, more reliable and easier to operate. As shown in table 3-1, the core damage frequency for System 80+ is over two orders of magnitude less than the core damage frequency for System 80. For each initiator, the core damage frequency for System 80+ is less than the equivalent core damage frequency for System 80. Figures 3-1 through 3-5 identify the leading design enhancements that contributed to the core damage frequency reduction for the five most dominant initiators.

In achieving the safety improvement, the System 80+ design enhancements were balanced between preventive features and mitigative features. Table 3-2 presents a categorization of the major design enhancements in terms of prevention and mitigation. Note that transient mitigation features can also be considered severe accident prevention feature.

TABLE 3-1 COMPARISON OF SYSTEM 80 AND SYSTEM 80+ CORE DAMAGE FREQUENCY BY INITIATING EVENT		
INITIATING EVENT	CORE DAMAGE FREQUENCY	
	SYSTEM 80	SYSTEM 80+
Large LOCA	1.6E-06	5.0E-08
Medium LOCA	3.6E-06	9.1E-08
Small LOCA	9.4E-06	4.4E-08
Steamline/Large Secondary Side Break	9.0E-07	2.0E-10
Steam Generator Tube Rupture	1.1E-05	8.0E-08
TRANSIENTS	1.2E-05	3.3E-8
a) Loss of Feedwater Flow	(1)	5.7E-09
b) Loss of Component Cooling Water	(1)	9.0E-09
c) Loss of 125 VDC Bus	(1)	2.8E-12
d) Loss of 4.16KV Bus	(1)	2.5E-11
e) Loss of HVAC	(1)	1.4E-08
f) Other Transients	(1)	4.5E-09
Loss of Offsite Power including SBO/Battery Depletion	3.8E-05	1.0E-07
ATWS	4.8E-06	1.7E-07
Interfacing Systems LOCA	1.0E-07	3.0E-09
Vessel Rupture	1.0E-07	1.0E-07
TOTAL	8.1E-05	6.7E-07

Notes: (1) Initiating Event not evaluated separately for System 80.

FIGURE 3-1
RISK REDUCING FEATURES FOR DOMINANT SEQUENCE 1

SEQUENCE TYPE: Loss of Offsite Power (LOOP) including Station Blackout with Battery Depletion

REPRESENTATIVE DOMINANT SEQUENCE: (LOOP) (Failure of EFW)

CORE DAMAGE FREQUENCY: SYSTEM 80 - 3.8E-05
SYSTEM 80+ - 1.0E-07

FEATURES:

- Alternate AC Power Source (Gas Turbine)
- Separate Offsite Power Source that Bypasses the Switchyard
- Dedicated Battery for Each Diesel Generator
- Four Train Emergency Feedwater (Two with Turbine Driven Pumps)
- Turbine Generator Able to Run Back to Hotel Load

FIGURE 3-2
RISK REDUCING FEATURES FOR DOMINANT SEQUENCE 2

SEQUENCE TYPE: Transients

REPRESENTATIVE DOMINANT SEQUENCE: (LOFW) (Failure to Deliver EFW)

CORE DAMAGE FREQUENCY: SYSTEM 80 - 1.2E-05
SYSTEM 80+ - 3.3E-08

FEATURES:
- Four Train Emergency Feedwater System (Two with Turbine Driven Pumps)
- Redundant Sources of Emergency Feedwater (2 EFW Tanks plus condensate Storage Tanks)
- High Reliability Component Cooling Water System (Two Divisions, Two Pumps per Division, one pump in each division normally running)
- Startup Feedwater System (Supplied from Condensate Storage Tanks, Actuated before EFW)
- Full Runback Capability
- Two redundant and Diverse EFW Actuation Systems
- Once Through Core Cooling Capability

FIGURE 3-3
RISK REDUCING FEATURES FOR DOMINANT SEQUENCE 3

SEQUENCE TYPE: Steam Generator Tube Rupture

REPRESENTATIVE DOMINANT SEQUENCE: (SGTR) (Failure of Safety Injection) (Failure to Perform Aggressive Secondary Cooldown)

CORE DAMAGE FREQUENCY: SYSTEM 80 - 1.1E-05
SYSTEM 80+ - 8.0E-08

FEATURES:

- Four Train Emergency Feedwater System (Two with Turbine Driven Pumps)
- Four Train Safety Injection System
- Safety Depressurization System

FIGURE 3-4
RISK REDUCING FEATURES FOR DOMINANT SEQUENCE 4

SEQUENCE TYPE: Small LOCA

REPRESENTATIVE DOMINANT SEQUENCE: (Small LOCA) (Safety Injection Fails) (Failure to Perform Aggressive Secondary Cooldown)

CORE DAMAGE FREQUENCY: SYSTEM 80 - 9.4E-06
SYSTEM 80+ - 5.5E-08

FEATURES:

- In-Containment Refueling Water Storage Tank
- Elimination of RAS
- Four Train Emergency Feedwater System
- Safety Depressurization System

FIGURE 3-5
RISK REDUCING FEATURES FOR DOMINANT SEQUENCE 5

SEQUENCE TYPE: Anticipated Transients Without SCRAM (ATWS)

REPRESENTATIVE DOMINANT SEQUENCE: (ATWS) (Adverse MTC)

CORE DAMAGE FREQUENCY: SYSTEM 80 - 4.8E-06
SYSTEM 80+ - 1.7E-07

FEATURES:
- Larger Pressurizer
- Larger Steam Generators
- Safety Depressurization System
- Diverse Protection System

TABLE 3-2 SYSTEM 80+ PREVENTION AND MITIGATION DESIGN FEATURES	
CLASS	**DESIGN FEATURE**
Transient Prevention	Larger Pressurizer
	Larger Steam Generators
	High Pressure Shutdown Cooling System (900 psi Design, 2700 psi Ultimate)
	100% Load Rejection Capability + Pick up Hotel Loads
	Multiple Independent Connections to the Grid
	Startup Feedwater System
	Improved Control Room Design which provides additional information to operator
	Improved CCW System Design (2 trains, 2 pumps per train, normally operating)
	Facilities Designs (e.g. quadrant arrangement of subsphere)
Transient Mitigation / Severe Accident Prevention	Four Train High Pressure ECCS
	Direct Vessel Injection
	Safety Depressurization System
	Four Train EFW System (2 motor driven pumps + 2 turbine driven pumps)
	2 Diesels + Standby Combustion Turbine
	6 Vital Batteries
	8 Hour Batteries
	In-containment Refueling Water Storage Tank
	Cross-connection between Containment Spray and Shutdown Cooling Trains so that SDC and CS pumps can be used interchangeably
	Improved Control Room Design with additional information

TABLE 3-2 SYSTEM 80+ PREVENTION AND MITIGATION DESIGN FEATURES	
CLASS	DESIGN FEATURE
Severe Accident Mitigation	Large Spherical Containment (3.6E+6 Ft^3
	Large Cavity designed for Co:'um Disentrainment
	Cavity Flood System
	H_2 Igniters

4.0 CONCLUSIONS

The System 80+ Standard design, as an ALWR, is intended to be safer than the current generation of plants. As shown in the previous section, the System 80+ risk, as measured by core damage frequency, is over two orders of magnitude less than for a current generation plant.

A PRA has been performed for System 80+ in compliance with the requirements of 10 CFR Part 52. This PRA has been used as a design evaluation tool during the development of the System 80+ Standard Design. PRA insights have provided extensive input to the System 80+ design and have resulted in a safe plant. The System 80+ PRA is a dynamic PRA and will be maintained and used throughout the lifecycle of the System 80+ Standard Design.

5.0 REFERENCES

1. SYSTEM 80+ STANDARD DESIGN PROBABILISTIC RISK ASSESSMENT; ABB Combustion Engineering; DCTR-RS-02, Rev. 0; January, 1991.

2. ADVANCED LIGHT WATER REACTOR UTILITY REQUIREMENTS DOCUMENT, Revision 3, EPRI, november, 1991.

3. BASE LINE LEVEL 1 PROBABILISTIC RISK ASSESSMENT FOR THE SYSTEM 80 NSSS DESIGN; Enclosure (1)-P to LD-88-008; Combustion Engineering; January, 1988.

4. Varga, S. A.; "Supplement to the Final Environmental Statement - Limerick Generating Station, Units 1 and 2"; Docket nos. 50-353/353; August 16, 1989.

5. DESIGN ALTERNATIVES FOR THE SYSTEM 80+ NUCLEAR POWER PLANT; Rev. 0; Combustion Engineering Nuclear, Inc.; April 30, 1992.

ATTACHMENT 14

SYSTEM 80+
SEVERE ACCIDENT PREVENTION AND MITIGATION

MAY, 1992

1.0 INTRODUCTION

This document provides information regarding (1) the severe accident prevention and mitigation characteristics of the System 80+ design and (2) an assessment of the relevant severe accident phenomenology as it applies to System 80+.

2.0 SYSTEM 80+ SEVERE ACCIDENT DESIGN PHILOSOPHY

The underlying philosophy in developing System 80+ severe accident design features is to emphasize accident prevention while simultaneously providing design features to mitigate any severe accident.

3.0 SYSTEM 80+ DESIGN FEATURES INTENDED FOR SEVERE ACCIDENT PREVENTION

A primary goal in designing System 80+ was to ensure that the probability of an initiating event becoming a severe accident was for all practical purposes negligible. To accomplish this goal PRA was closely factored into the design process. This close coupling of design and PRA provided an effective means for focusing on areas in the present PWR design which could be improved and selecting effective design changes to both improve plant reliability and reduce public risk. A detailed discussion of the use of PRA in the System 80+ design process has been provided separately. That report provides a brief description of System 80+ design enhancements and discusses the balance between prevention and mitigation represented by these enhancements.

4.0 SYSTEM 80+ DESIGN ENHANCEMENTS FOR USE IN SEVERE ACCIDENT MITIGATION

In addition to systems designed to prevent severe accidents, System 80+ also contains many unique design features to enhance severe accident mitigation and management. The overall goals of the severe accident mitigation features of the System 80+ were to reduce the risk of a conditional containment failure given a core melt to 0.1 and to minimize the contribution of early containment failure events.

4.1 Mitigation Features to prevent Early Containment Failure

Existing PRAs note that early containment failures can arise as a result of various severe accident phenomena. Mechanisms contributing to early containment failure include:

1. Hydrogen Deflagration/Detonation
2. Direct Containment Heating

3. Steam Explosions (in vessel and ex-vessel)
4. Rapid Steam Generation
5. Direct Corium Attack/Missile Generation

The following sections will discuss these phenomena and the role of System 80+ design features in mitigating accident consequences.

4.1.1 Hydrogen Deflagration /Detonation

The production of hydrogen within the RCS and subsequent release to the containment has been noted to be a potential contributor to early containment failure for existing PWRs. Hydrogen combustion can challenge containment either statically, as a deflagration (slow hydrogen burn) or, dynamically, as a detonation. In light of this concern, System 80+ has been designed with several features to both mitigate and respond to this containment challenge. These features are discussed below.

4.1.1.1 SYSTEM 80+ Containment Design

The System 80+ design includes a large, spherical open, steel containment. The containment structures have been designed to enhance mixing and sized to ensure that detonable concentrations of hydrogen would not accumulate. Stress evaluations of this design indicated that the System-80+ containment is a very robust containment design with an ultimate failure pressure of between 185 to 208 psia (4 inch maximum radial strain) and ASME boiler and Pressure Vessel Service Level C limits of 155 psia. Analyses of the ALWR designs of similar size to System 80+ (Reference 1) clearly show that the worst credible deflagration would result in containment shell loadings that are below the Service Level C stress limits (See Figure 1). These evaluations were confirmed for System 80+.

4.1.1.2 Hydrogen Mitigation System

In an attempt to overwhelm the hydrogen combustion concerns, System 80+ is also equipped with an operator actuated hydrogen mitigation (igniter) system. The purpose of this system is to further minimize the potential hydrogen challenge. The HMS is described in Section 6.2.5 of CESSAR-DC. Use of the HMS early in a severe accident scenario would ensure containment hydrogen challenges would be easily manageable.

4.1.2 Direct Containment Heating

In the context of the System 80+ PRA direct containment heating (DCH) refers to a collection of severe accident process that occur upon lower head breach to pressurize an LWR containment. Processes included in DCH are (1) the blowdown of reactor coolant system steam, and hydrogen inventory into the containment, (2) the dispersal of corium into the upper containment (3) direct heating of the containment atmosphere (4) combustion of hydrogen released prior to and during the high pressure melt ejection process and (6) vaporization of available water. Several of these processes are not independent and the presence of certain processes in the DCH sequence may preclude others. However, all serious DCH threats are associated with depositing large quantities of energy directly in the containment atmosphere and thereby rapidly pressurizing the containment. In the design of System 80+, this issue is addressed by providing independent means of preventing any significant corium dispersal to the upper containment and by designing a strong, robust containment structure (See above).

As discussed above, debris dispersal into the upper compartment is necessary for a DCH threat to containment. In fact, EPRI supported analyses show that using typical System 80+ design parameters almost 50% of the total core inventory must be finely fragmented and entrained in the upper containment for a significant containment threat to develop (Reference 2, see Figure 2). To minimize the potential containment threat due to DCH ABB has incorporated [illegible] (Safety Depressurization System) and passive ("debris retentive cavity [illegible] convoluted vent") means for ensuring that most, if not all, the corium debris is retained within the reactor cavity. These systems/design features are discussed below.

4.1.2.1 Safety Depressurization System (SDS)

The safety depressurization system consists of 2 trains of operator actuated relief valves located on the top of the pressurizer. A detailed description of the SDS may be found in Section 6.7 of CESSAR-DC. As discussed in the CESSAR-DC, the SDS serves several roles in the System-80+ design. In the context of severe accident mitigation the SDS will prevent a DCH containment challenge by allowing a timely depressurization of the RCS to below the debris entrainment threshold pressure. RV failure at RCS pressures below this debris entrainment threshold pressure (approximately 250 psia for System 80+) will preclude entrainment of corium debris into the upper cavity. Successful actuation of this system is credited in the PRA to change an otherwise HPME scenario with considerable entrainment potential to a low pressure core ejection with no or very little expected corium debris entrainment.

4.1.2.2 Debris Retentive Cavity

System 80+ includes a debris retentive reactor cavity configuration with sharp turns, overhangs, flowpath offsets, convoluted vent and a "debris trap" for the specific purposes of de-entrainment and retention of corium debris. Assessments of this ALWR design concept concluded that these design features will enable the reactor cavity to trap 90% of the ejected corium debris even during High Pressure Melt Ejection (HPME) scenarios.

4.1.3 Steam Explosions

Fuel induced steam explosions refer to the rapid steam generation and concomitant hydrodynamic loadings that occur when molten metal (such as corium) discharged into a water pool rapidly fragments and transfers its energy to the surrounding fluid. Steam explosions have been hypothesized to occur both interior and exterior to the RV.

4.1.3.1 In-Vessel Steam Explosions

The In-Vessel Steam Explosion (IVSE) consists of fuel coolant interaction which can hypothetically lift the RV upper head or generate a control rod missile of sufficient energy to breach the containment steel shell. Based on conclusions of the Steam Explosion Review Group (SERG), it can be expected that the potential containment failure probability due to In-Vessel Steam Explosions (IVSEs) will be on the order of .001 (Reference 3). While this probability is very low, several members of the SERG believed this event to be even lower. In the System-80+ design the containment is protected from the consequences of an upper head or control rod by a missile shield located above the RV. Should any material bypass the missile shield, it would have to travel another 100 feet vertically, while still maintaining a sufficiently high velocity before the ejected material can pose a credible threat to containment.

4.1.3.2 Ex-Vessel Steam Explosions (EVSE)

An EVSE occurs when corium ejected from the RV lower head falls into a water pool. EVSE loads are a potential concern for LWRs in that they can induce failure of RV supporting structures which may in turn cause failure of piping penetrating the containment. EVSEs have been included in the APET (Accident Progression Event Tree) structure of the Grand Gulf BWR. However, EVSEs have not been considered to be a significant threat to operating PWRs considered in the NUREG-1150 risk assessments (See Reference 4). This conclusion is also valid for System 80+. System 80+ is equipped with a cavity flood system (See Section 6.8 of CESSAR DC). Thus, EVSE can occur in the System 80+ design when the CFS is actuated in advance of RV failure. However, the consequences of an EVSE are not expected to be significant since the loadings associated with the EVSE will not directly act upon the containment wall or any major RV or RCS supporting structure.

4.1.4 Rapid Steam Generation

Rapid steam generation refers to the containment pressurization following RV breach associated with the RV vessel blowdown and non-explosive steam generation due to the rapid quenching of the corium debris. Assessments of containment pressure loads associated from rapid steam generation indicate peak containment loadings will be below 70 psia. These loadings are well below the containment Service Level C stress limits and consequently do not pose a significant threat to containment integrity.

4.1.5 Direct Shell Attack via Corium Impingment

The System-80+ containment is constructed to provide protection against missiles and hot gases that may be generated during severe accident scenarios. This protection is provided by providing 5 feet of concrete directly below the reactor vessel (three feet around the reactor cavity edges) and containing the full RCS within a 4 foot thick crane wall extending up to the 210 ft elevation. The uppermost portion of the containment shell is protected from missile impingment by the RV upper head missile shield. Thus, the System 80+ containment is invulnerable to direct corium attack below the 210 ft elevation and marginally exposed to only those most energetic and very low probability design missiles at the uppermost containment surface.

4.2 Containment Design Features to Prevent or Prolong Late Containment Failure

The mechanisms for late containment failure include the following:

1. containment overpressurization
2. basemat melt-through
3. temperature induced failure of containment penetration sealant
4. delay hydrogen burn

Several design features of the System 80+ PWR are intended to either prevent and / or mitigate the consequences of a containment failure by prolonging the containment failure as far out in time as practical. It has been a goal of the System 80+ design to deterministically demonstrate containment integrity for 48 hours after the severe accident initiating event and to probabilistically demonstrate that the conditional probability of containment failure following a core melt scenario is less than .1

4.2.1 Containment Overpressure Failure

Containment overpressure failure will result from steaming of the cooled corium debris (or for that matter an intact core) in the absence of containment heat removal. Such sequences are of low probability due to the high reliability of the System 80+ containment heat removal (CHR) system. Severe accident analyses have demonstrated that even a partially functioning CHR system would remove sufficient energy from the containment atmosphere to maintain containment pressures well below failure limits.

In the unlikely event of a total and extended loss of DHR, MAAP analyses of the System 80+ plant demonstrates that even for an unrecoverable station blackout scenario containment pressures can be maintained below Service Level C stress limits for more than 48 hours (see Figure 3). It should be noted that the analysis presented does not include any mitigative effects of station batteries. This long time to containment overpressure is a passive feature of the System 80+ plant which is a combined effect of the availability of large quantities of in containment concrete (approximately 9% of the contaiment by volume) and a 500,000 gallon CFS coupled with a high strength containment structure.

4.2.2 Basemat Melt-Through

Basemat melt-through refers to the process of concrete decomposition and destruction associated with a corium melt interacting with the reactor cavity basemat. The basemat melt-through scenario is relatively benign. The accident progression is slow (taking from several days onward to penetrate the reactor cavity basemat) and the corium release to the environment is negligible since most of the corium will vitrify into a relatively impermeable substance within the containment's extended foundation. In the System 80+ design, more than 20 feet of concrete is provided directly below the reactor vessel as a barrier to release. System 80+ utilizes the subsphere region of the containment structure as the auxiliary building. One consequence of this design is that SI pump room is located within 10 feet of the reactor cavity below the elevation of the basemat. Consequently, there exists a small, but finite, potential for the corium to progress into the below ground portion of the auxiliary building. In this scenario, the core melt progression could be considered a filtered above ground release.

To minimize the overall risk of containment melt-through System 80+ has been equipped with a manually actuated continuous cavity flood system (CFS) and the cavity has been arranged with a floor area consistent with the EPRI debris coolability guidance of .02 m2 of cavity floor area per thermal MW of core power. A detailed description of the CFS can be found in section 6.8 of the CESSAR-DC. The intent of this design is to ensure a continuous water supply to the corium debris and to provide sufficient area so that corium accumulations will be relatively shallow (below 25 cm in depth) and coolable.

In the existing System 80+ PRA it was explicitly assumed that as a consequence of the cavity design, the availability and actuation of the CFS was sufficient to prevent a basemat melt-through scenario. While there is general agreement that water will retard the corium progression into the concrete basemat there is not yet conclusive proof that a wetted corium debris bed with a depth greater than above 25 cm will be fully coolable. It is expected that the ongoing MACE program will shortly provide this information to confirm the existing PRA position. Until that time future PRA assessments of System 80+ will allow for the potential for basemat failure in the presence of large quantities of water. It should be noted that while these sequences may progress to basemat melt-through, they will do so very slowly, extending the containment failure process to one week or more.

Dry cavity melt-through scenarios can occur if the CFS is disabled or not actuated. These sequences result in basemat melt-throughs on the order of 4 days into the severe accident. For purposes of the PRA radiological release calculations these scenarios were pessimistically considered as above ground containment failures instead of the more probable below ground soil penetration (See Appendix B to the CESSAR-DC).

4.2.3 Temperature Induced Failure of Containment Penetration Sealant

During dry cavity corium attack sequences the containment atmosphere has the potential to undergo a gradual, but significant temperature transient. Analyses of typical System-80+ accident scenarios suggest that sustained temperatures in excess of 450 F can develop throughout the containment within 48 hours after accident initiation. At these temperature levels several common penetration sealants (e.g.. Nitril, Neoprene) will begin to degrade and potentially result in a localized containment failure. On the other hand, several other penetration sealants less prone to temperature failure are available on the market. By specifying the specific sealant at the time of actual equipment procurement, use of the best material available will be ensured.

4.2.4 Delayed Hydrogen Burn

A delayed hydrogen burn can occur anytime in a severe accident once a large quantity of hydrogen is generated and the containment atmosphere is not inerted. The most common scenario where a delayed hydrogen burn can occur is when a hydrogen rich, steam inerted containment is sprayed with water. This process is typically operator initiated and can result in a hydrogen combustion event at pressures just below the steam inerting limit. Because of the large amount of steam initially available, the combustion event is far more likely to be a deflagration than a detonation. Furthermore, pressures generated during this event will generally be below the containment Service Level C and should be well below the ultimate containment failure pressure.

As discussed in Section 4.1, System 80+ is equipped with igniters to burn off steam at low concentrations. These igniters have been demonstrated effective in steam environments and therefore, if actuated sufficiently early in the transient they should serve to fully eliminate any significant hydrogen induced containment threat.

5.0 SUMMARY

The System 80+ design represents a balanced approach to severe accident mitigation and prevention. Consequently, System 80+ is adequately designed with respect to severe accidents and represents a significant improvement in overall plant safety.

6.0 REFERENCES

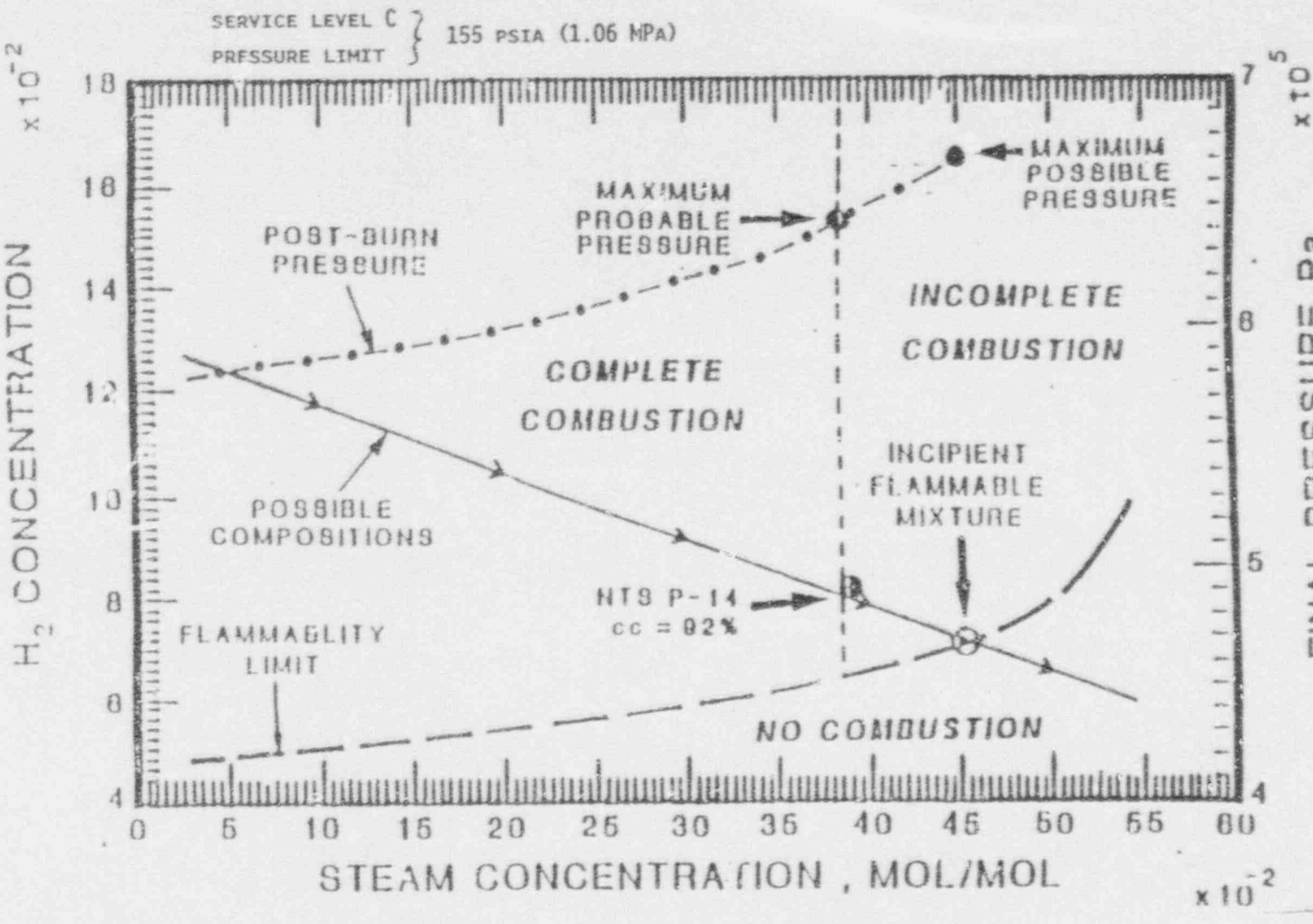
1. ARSAP Report,, "Prevention of Early Containmnet Failure Due to High Pressure Melt Ejection and Direct Containmnet Heating for ALWRs",J. Carter, et. al., March 1990.

2. Technical Support for the Hydrogen Control Requirements for the EPRI Advance LWR Requirements Document",FAI, January 1990

3. NUREG/CR-5567,"PWR Dry Containment Issue Characterization", Wang,Y., August, 1990

4. NUREG-1150,Volume 2, Appendix C, "Severe Accident Risks: An Assessment for Five Nuclear Power Plants: Appendicies", USNRC, June 1989.

FIGURE 1: COMBUSTION POTENTIAL FOR SYSTEM 80 +



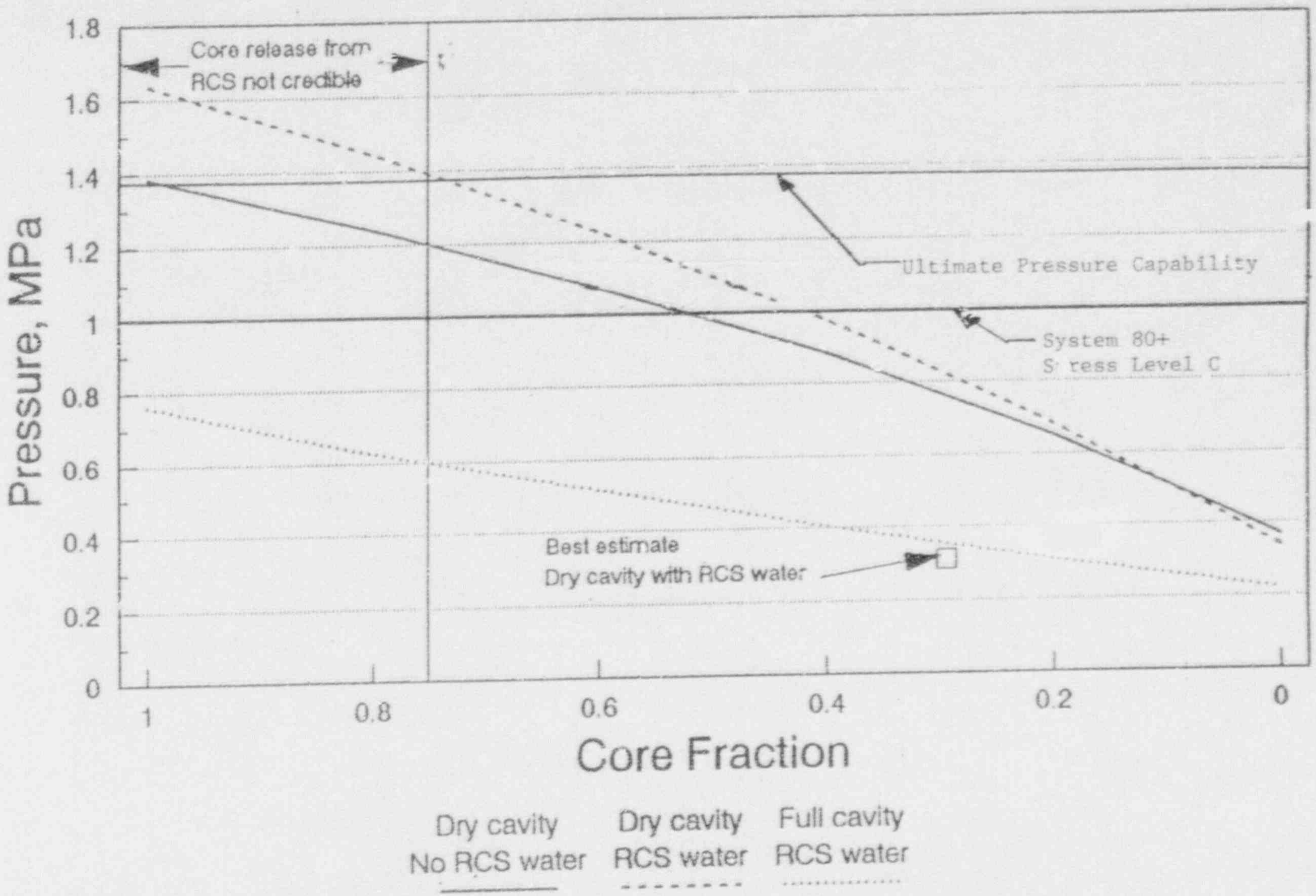
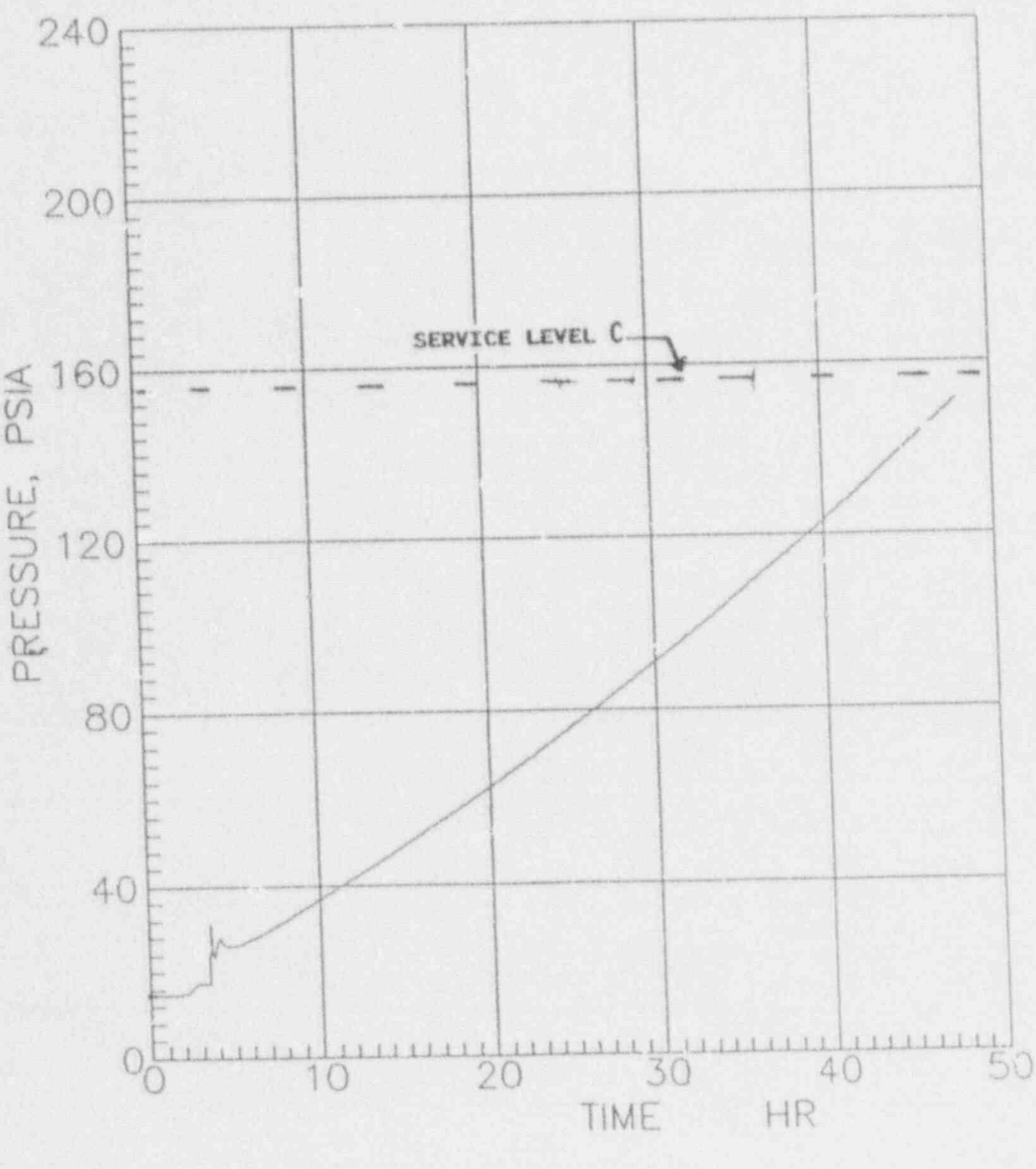


FIGURE 2: BOUNDING ESTIMATES OF ALWR CONTAINMENT RESPONSES TO DCH

FIGURE 3: RESPONSE OF SYSTEM 80+ TO A STATION BLACKOUT



ATTACHMENT 15

Question 410.156

In Section 9.2.1.1.1, two accidents -- interfacing system loss of coolant accident (ISLOCA) and steam generator tube rupture (SGTR) -- are discussed in relation to containment bypass; i.e., the release of reactor coolant outside containment. Briefly describe all accident sequences that could result in containment bypass, and explain why the releases resulting from these other events are not significant.

NOTE: SGTR events should include failure due to hot containment gases and core debris.

Response 410.156

The only initiating events which we have found which would directly result in containment bypass are ISLOCAs and SGTRs. These event types were characterized by an RHR ISLOCA and an SGTR with a stuck open ADV in the Containment Performance analysis in Chapter 9 of the System 80+ PRA report. Severe accident consequential SGTRs due to the circulation of hot containment gases or core debris was indirectly considered in the direct containment heating (DCH) evaluations. The System 80+ PRA is currently being revised. Severe accident consequential SGTRs and their impact will be explicitly considered in the updated PRA. A draft of the new severe accident phenomenology section will be provided to the NRC in July, 1992. This section will qualitatively address the severe accident consequential SGTRs. The quantitative evaluation of the severe accident consequential SGTRs will be provided to the NRC with the completed PRA update in 1993. The releases associated with the severe accident consequential SGTRs would be equivalent to those associated with a normal SGTP. However, the probability of occurrence would be lower than for the SGTR case addressed. The severe accident sequence would involve a core damage sequence with high RCS pressure at the time of core damage, consequential failure of a steam generator tube prior to the equivalent failure of a hot leg, cold leg, or surge line, plus a pre-existing failure to isolate the steam generators.

Question 410.157

Please provide drawings for potential containment bypass release paths, and include detailed physical descriptions of the points of release, including dimensions.

Response 410.157

The System 80+ design considers potential containment bypass release paths, particularly due to steam generator tube ruptures and interfacing system loss of coolant accidents (ISLOCA). The containment bypass events in the EPRI report ALWR Passive Plant Containment Performance Summary, December, 1991, were considered for applicability to the evolutionary System 80+ plant. Detailed physical descriptions of release points will not be available until detailed design and first-of-a-kind engineering is completed. However, as previously committed, ABB-CE will submit an ISLOCA report by June 15, 1992 to address containment bypass issues.

Question 410.158a

Following a SGTR severe accident with a coincident loss-of-offsite-power, reactor coolant could be released outside containment via main steam safety valves (MSSVs) that do not reseat or via stuck-open atmospheric dump valve (ADV)--particularly if the steam generator overfills. For this sequence, please provide the following:

a. the worst-case release scenario with conservative assumptions (dispersion factor, iodine spiking, X/Q, fuel failures, end-of-cycle coolant activity, release beginning at time zero, or coincident with the initial SG pressure spike, etc.)

Response 410.158a

a. The consequences of a worst case steam generator tube rupture (SGTR) with loss of offsite power (LOOP) where the containment is bypassed due to malfunction of a main steam system valve has been analyzed. The analysis presented in CESSAR-DC Section 15.6.3.3, SGTR with LOOP and Single Failure, calculated the worst-case releases for an SGTR event with LOOP and a stuck open ADV on the affected steam generator.

   The analysis simulated a double-ended break of one SG tube. The analysis contained conservative assumptions regarding atmospheric dispersion factors, initial RCS and SG activity levels, and iodine spiking. Mitigating operator actions based on the approved CE emergency procedure guidelines (EPGs), CEN-152, were simulated. The analysis showed that no fuel failures were expected for this event.

   The ADV on the affected SG was assumed to stick open when the operator tried to reseat the ADV to isolate the affected SG. After 30 minutes of steaming through the stuck-open ADV, the operator isolated this path by closing the ADV block valve. However, the leak of RCS liquid through the tube break continues for the duration of the analysis (8 hours) due to the conservative nature of the analysis models. In order to avoid overfilling the SG, the operator periodically steams from the affected SG per the EPGs. This additional steaming increased the total radiation dose. The total releases are well within regulatory limits.

Question 410.158b

Following a SGTR severe accident with a coincident loss-of-offsite-power, reactor coolant could be released outside containment via main steam safety valves (MSSVs) that do not reseat or via stuck-open atmospheric dump valve (ADV)--particularly if the steam generator overfills. For this sequence, please provide the following:

b. a description of any design features, not employed in licensed CE-designed PWRs, that limit or help mitigate the consequences of this scenario, and

Response 410.158b

The design features of licensed CE-designed PWRs are fully capable of mitigating a worst case SGTR event such as the one described in the response to 410.158a. In addition, System 80+ is designed to meet the "mitigative" requirement described in the response to RAI 410.159 and also includes new or enhanced features for the prevention of SGTRs.

Features to prevent SGTRs include:

- Steam generator tubes made of thermally treated Inconel 690, which has favorable corrosion resistance properties including superior resistance to primary and secondary stress corrosion cracking,
- A deaerator in the condensate/feedwater system for removal of oxygen,
- Condensate system with full flow condensate polisher to remove dissolved and suspended impurities,
- Main condenser with provisions for early detection of tube leaks, and segmented design permitting repair of leaks while operating at reduced power,
- Steam, feedwater and condensate systems employing materials resistant to corrosion and the generation of corrosion products which can be transported into the steam generators,
- High capacity steam generator blowdown system and SG secondary side recirculation system for chemistry control during wet layup.

The response to Unresolved Safety Issue A-4 in CESSAR-DC Appendix A further describes design features to assure SG tube integrity.

New or enhanced System 80+ features which help to mitigate SGTRs include:

- Larger steam generator secondary volume,
- Larger pressurizer,
- Four train safety injection system,

Response 410.158b (continued)

- Four train emergency feedwater system,

- Electrical system upgrades including alternate AC gas turbine and 8 hour batteries,

- Safety depressurization and vent system,

- Component cooling water system upgrade to four 100 percent capacity pumps and heat exchangers,

- Highly reliable turbine bypass system, discharging all steam to condenser, not partially to atmosphere as in earlier designs,

- Radiation monitors in the steam lines.

Question 410.158c

Following a SGTR severe accident with a coincident loss-of-offsite-power, reactor coolant could be released outside containment via main steam safety valves (MSSVs) that do not reseat or via a stuck-open atmospheric dump valve (ADV)--particularly if the steam generator overfills. For this sequence, please provide the following:

c. the risk assessment of the above scenario.

Response to 410.158c

The scenario described is considered in Chapter 15.6.3.3 of the CESSAR-DC. Results of this analysis indicate that the radiological consequences of this event are well within the 10CFR100 guidelines.

Since this transient does not progress to a core melt, it is not considered a severe accident for purposes of PRA. Consequently, a specific risk assessment of this scenario has not been performed. However, the PRA does consider STGR events that lead to core melt. These events have been categorized in the PRA under Release Class 1.4 and were quantified using a severe accident sequence analogous to the one described above (i.e., an STGR with loss of power and a stuck open ADV). The complementary cumulative distribution function (CCDF) for this severe accident sequence can be found in CESSAR-DC, Figure B6-11 of Appendix B.

Response 410.159 (General)

The EPRI ALWR Utility Requirements Document, Volume II (Evolutionary ALWR), places the following requirements on plant response to a Steam Generator Tube Rupture:

> The plant design (including turbine bypass system, reactor coolant system depressurization capability, and steam generator secondary side design pressure) shall be such that the complete and sudden rupture (double-ended guillotine or equivalent area) of one steam generator tube will not result in actuation of steam side safety valves. In the event of a tube rupture, the combination of plant trip, turbine bypass actuation, and controlled depressurization of the reactor coolant system shall have the combined capability to maintain steam generator secondary side pressure below the set point of steam side safety valves. The Plant Designer shall identify the interfacing requirements for all the supporting systems necessary to achieve this goal. The Plant Designer also shall assure that requirements have been correctly implemented in the supporting systems.

The System 80+ design meets the EPRI ALWR requirement of preventing main steam safety valve actuation following a SGTR. A reactor trip on high SG water level, actuation of the turbine bypass system and controlled depressurization of the RCS using the safety depressurization and vent system (SDVS) limit secondary side pressure below the MSSV setpoint. The turbine bypass valves discharge steam to the main condenser, which minimizes the radioactive release to the environment. The intent of the ALWR URD was to meet the above requirement on a best-estimate basis (i.e., credit for operator action and use of control-grade equipment is acceptable) to provide an effective and economical design.

Question 410.159a

The CE 80+ design includes MSSVs that vent directly to the atmosphere.

a. In light of recent operating experience showing a significant trend of challenge to steam generator tube integrity, and in light of recent PRA studies indicating that containment bypass represents a significant risk contributor, has consideration been given to diverting the release path through the MSSVs back to containment? If so, please discuss the advantages and disadvantages of such a design.

Response 410.159a

PRA assessments of the System 80+ design indicate that SGTR events do not represent a significant risk to the public. This conclusion is based on the finding that the frequency of STGRs leading to core melt conditions will be less than 8.4 x 10-8 per year (see CESSAR DC Appendix B Table B7.2-1).

As part of the Severe Accident Mitigating Design Alternatives (SAMDA) process for System 80+, the PRA results were further evaluated to assess the cost-effectiveness of a number of design enhancements including hypothetical ideal design improvements that would prevent/mitigate STGRs. Using the standard NRC guidance of $1000 per man-rem, even if a design feature could be developed to completely eliminate STGRs, it would only be cost-beneficial if the construction and operating costs were below $400 per year over the life of the plant. Thus, all reasonable enhancements to further prevent STGRs reduce radiological releases below current levels were not found to be cost-beneficial.

ABB does not plan to divert MSSV steam releases back to the containment. While such a system would reduce radiological releases to the environment for selected accident scenarios, such a system does not significantly reduce public risk and does carry several disadvantages. It should be noted that this feature does not eliminate releases to the environment.

The technical disadvantages of the MSSV-containment steam return system are summarized below for two hypothetical systems. In the first system, the steam is simply returned to the containment atmosphere. In the second system, the steam is discharged into the IRWST where it would be condensed.

Direct discharge of MSSV into containment has several serious disadvantages.

1. The secondary steam return will place an additional loading burden on the containment and restrict plant operators in responding to accidents when containment sprays are unavailable. This could lead to the addition of a containment vent to address those concerns which in itself introduces another means of inadvertent containment bypass.

2. Any condensed steam discharge will drain to the IRWST, diluting the boron concentration. A minimum IRWST boron concentration for safety injection is necessary for mitigating LOCA and non-LOCA events.

3. The release to containment atmosphere has the potential to cause personal injury.

Response 410.159a (Continued)

An MSSV return system directed to the IRWST has similar drawbacks to Items 1 and 2 described above and poses the additional complication that discharge of steam flows typical of the MSSVs may produce excessive loadings within the IRWST.

Either return path would require a major redesign effort and increase design complexity, which are not consistent with the evolutionary ALWR goals. Also, this provision will not eliminate radiological releases to the environment from a SGTR.

In summary, the issue of including an MSSV discharge return to the containment was considered from both its cost benefit and design considerations. Based on this review, such a system is not cost-beneficial and poses serious design drawbacks.

Question 410.159b

Has consideration been given to upgrading the design pressure of the secondary system (including the MSSVs) to 1500 psi to minimize containment bypass and release to environment? Please explain.

Response 410.159b

Upgrading the design pressure of the secondary system including the MSSVs to 1500 psia from the current 1200 psia was considered early in the System 80+ design process. It was determined that an increased design pressure would not significantly reduce the probability of containment bypass and release to the environment during an SGTR event.

During a SGTR with loss of offsite power, the condenser is not available for plant cooldown. The decay heat of the core and the stored energy in the primary and secondary systems (water and metal) is removed by steaming to the atmosphere via the MSSVs, then via the SG ADVs. The steaming will continue until reaching shutdown cooling system entry conditions. The total heat to be removed (or the total steam release) is only slightly reduced by increasing the secondary design pressure and MSSV setpoints. Hence, using conservative safety analysis assumptions and methods, the overall radiation release would be essentially unchanged.

During a SGTR with offsite power available, the operator will act to mitigate this event according to the Emergency Procedures Guidelines, using both control grade and safety grade equipment if required. Therefore, for a "real-world" scenario, an increased design pressure would not significantly decrease the likelihood of lifting the MSSVs.

There are several technical disadvantages of increasing the secondary system design pressure to 1500 psia:

1. Steam generator weight would increase by up to 100 tons each. The added weight would increase containment heat sinks, and increase thermal stresses on the steam generator shell and main steam piping. These factors would likely impact the volume and arrangement of the containment. The additional weight would also increase the handling difficulties during fabrication.

2. The RCS support system would need to be redesigned and/or re-evaluated to accommodate the increased loads. Any contribution to containment sizing must also be assessed.

3. For decreased heat removal events, RCS temperature and pressure would rise to a much higher value than in current plants. Pressurizer safety valve actuation would be more likely.

4. Unless the entire steam system and turbine are upgraded to 1500 psia, a second set of secondary side relief valves would be required downstream of the MSIVs to protect the lower pressure portion of the steam system.

5. Feedwater systems would have to be compatible with the higher design pressure. Increasing secondary design pressure would require a major redesign effort and increase design complexity, which are not consistent with the evolutionary ALWR goals.

Question 410.159c

Recent experience and testing indicate that safety valves designed for steam passage tend to fail to reseat after fluid is passed by the seat. Are the MSSVs employed by the CE 80+ design, designed for water passage? If so, how are the MSSVs expected to respond in a steam generator overfill scenario?

Response 410.159c

Steam generator overfill is avoided during SGTR events in the System 80+ design by periodic venting of steam or alternatively draining to the readioactive waste system using the SG Blowdown System. The spectrum of SGTR events analyzed for Chapter 15 of CESSAR-DC do not result in steam generator overfill. Therefore, the System 80+ main steam safety valves are not designed for water passage.

Question 410.159d

What is the risk associated with exceeding the radiological release limits in Part 100 during the steam generator overfill scenario?

Response 410.159d

Steam generator overfill is avoided during SGTR events in the System 80+ design by periodically venting steam. The spectrum of SGTR events analyzed for Chapter 15 of CESSAR-DC shows that results are well within the release limits of 10CFR100.

Question 410.160a

During a SGTR, isolation is normally achieved early in the event by isolating the associated main steam isolation valve (MSIV) following the identification of the faulted steam generator.

a. Again, in light of recent operating experience showing a significant trend of challenge to steam generator tube integrity; and in light of recent PRA studies which indicate that bypass represents a significant risk contributor; has consideration been given to minimizing the likelihood of containment bypass during a severe accident with tube ruptures in both steam generators, and to improving main steam line isolation reliability, with a second MSIV? Please discuss the advantages and disadvantages of this redundant isolation capability. If such an upgrade has not been considered, why not? Please explain.

Response 440.160a

ABB does not plan to add additional MSIVs. Additional valves would not significantly reduce public risk.

PRA assessments of the System 80+ design indicate that SGTR events do not represent a significant risk to the public. This conclusion is largely based on the finding that the frequency of STGRs leading to core melt conditions will be less than 8.4 x 10-8 per year. (see CESSAR DC Appendix B Table B7.2-1).

As part of the SAMDA process for System 80+, the PRA results were further evaluated to assess the cost-effectiveness of a number of design enhancements including hypothetical ideal design improvements that would prevent/mitigate STGRs. Using the standard NRC guidance of $1000 per man-rem, even if a design feature could be developed to completely eliminate STGRs, it would only be cost-beneficial if the construction and operating costs were below $400 per year over the life of the plant. Thus, all reasonable enhancements to further prevent STGRs and reduce radiological releases below current levels were not found to be cost-beneficial.

In summary, the issue of additional MSIVs was considered from both its cost benefit and design considerations. Based on this review, additional valves are not cost-beneficial and do not significantly reduce public risk.

Question 410.160b

What is the risk associated with a SGTR scenario resulting in containment bypass due to failure to isolate the main steam line?

Response 410.160b

The sequence described above, the failure to isolate the main steam line, is equivalent to a SGTR scenario with a stuck open ADV. This scenario is analyzed in CESSAR-DC Section 15.6.3.3. The analysis demonstrates that the radiological releases for this scenario are well within the 10CFR100 guidelines.

SGTR scenarios leading to core damage were evaluated in the System 80+ PRA. The core damage sequences involving an SGTR with a stuck open ADV all mapped into Release Class 1.4. This release class had a mean release of 3.7E+4 Rem, but the probability of occurrence was only 7.0E-09. Thus, the overall risk for this scenario is low. (See the response to 410.158 also.)

Question 410.160c

Are the MSIVs designed at or above primary system pressure?

Response 410.160c

The main steam isolation valves are designed to secondary system design pressure of 1200 psia.

ATTACHMENT 16

ASEA BROWN BOVERI

SUBJECT: System 80+ Soil Data

Enclosed please find the following data related to the soil analyses of the System 80+:

1. Diskette that contains the digitized CMS2 rock outcrop acceleration time histories (Horizontal 1, Horizontal 2 and Vertical).

   The format of the diskette is IBM-PC High Density (1.4 Mb). Three files are contained in the diskette:

   - h1.acc (Horizontal 1 time history)
   - h2.acc (Horizontal 2 time history)
   - v.acc (Vertical time history)

   The format of the time histories is (8F10.6). All acceleration units are in g. The time step of the time histories is 0.005 sec. For the soil analyses, the initial 4096 acceleration values from the time histories were used (for a total duration of 20.48 sec).

2. Data on the shear modulus degradation and damping variation with soil strain. Data on the low strain moduli of soil cases B3.5 and B4. (Two pages)

Maximum Modulus & Total Unit Weight Values Used

Case B-4

Depth		Max. Modulus	Unit Weight
from	to	(ksf)	(pcf)
0	5	998	125
5	10	1,054	125
10	20	1,128	125
20	30	1,122	125
30	40	1,301	125
40	52	1,384	125
52	60	18,960	125
60	80	20,358	125
80	100	22,267	125
half-space		97,000	130

Case B-3.5

Depth		Max. Modulus	Unit Weight
from	to	(ksf)	(pcf)
0	5	1,437	125
5	10	1,516	125
10	20	1,623	125
20	30	1,760	125
30	40	1,875	125
40	52	1,994	125
52	60	8,427	125
60	80	9,048	125
80	100	9,897	125
half-space		97,000	130

Modulus Reduction & Damping Curves Used for the Soil Cases

Shear Strain (percent)	Modulus Reduction, G/Gmax	Damping (percent)
0.0001	1.000	0.24
0.0003	1.000	0.42
0.001	0.990	0.80
0.003	0.960	1.40
0.01	0.850	2.80
0.03	0.640	5.10
0.1	0.370	9.80
0.3	0.180	15.50
1	0.080	21.00
3	0.050	25.00
10	0.035	28.00

Modulus Reduction & Damping Curves Used for the Rock Half-Space

Shear Strain (percent)	Modulus Reduction, G/Gmax	Damming (percent)
0.0001	1.000	0.40
0.0003	1.000	
0.001	0.988	0.80
0.003	0.953	
0.0[illegible]	0.900	1.50
0.03	0.810	
0.1	0.725	3.00
1	0.550	4.60

LETTER ALWR-444

NRC CONTAINMENT AUDIT
April 29-30, 1992

Action Item 1.

Discuss the method used to derive the design pressure for severe accident analysis, either a conditional containment failure probability (CCFP) guideline of 0.1, or a deterministic method (based on the ASME schedule). Reference SECY-90-016.

Response to Item 1.

The severe accident pressure value is derived using a deterministic method. An axisymmetric finite element model is loaded with pressure and dead weight. The pressure is increased until the maximum stress intensity reaches the ASME Boiler and Pressure Vessel Code, Subsection-NE, Service Level 'C' allowable stress intensity for the given accident temperature.

Action Item 2.

Address the 60 year life effect on the spring constant of the compressible material used in the region where the containment is embedded into the concrete.

Response to Item 2.

The compressible material used in the containment analysis is a cork material conforming to specification ASTM D-1752-73 Type II. A spring constant of 180 psi/in was derived from test results and used in the containment analysis. Because of the potential for the cork material to deteriorate or harden, a more resilient expansion material such as one which has properties of specification ASTM D-1751-83 is being evaluated. Tolerance studies of the spring constant value will be conducted and a suitable ASTM specification material specified by October 1992. Retention of spring constant properties over the life of the plant will be considered when the material is specified.

Action Item 3.

Verify the use of the elastic-plastic analysis used in the containment ultimate capacity (ASME collapse load) calculation.

LETTER ALWR-444

NRC CONTAINMENT AUDIT
April 29-30, 1992

Response to Item 3.

The containment ultimate capacity (ASME collapse load) was determined using the criteria found in Appendix II Article 1430 of Section III of the ASME Code. The containment vessel is modeled with the ANSYS computer code as a thin shell axisymmetric structure using element STIF51. The nonlinear material properties (essentially elastic-perfectly plastic) are included in the model using a tangent modulus which is equal to 0.05 x E(Young's modulus of elasticity).

A verification search of the use of the ANSYS element STIF51 and the tangent modulus of 0.05 x E is being conducted by Duke Engineering and Services, Inc. and a response will be provided by July 1, 1992.

Action Item 4.

Explain how localized strains around penetrations are handled in the ultimate capacity (ASME collapse load) analysis.

Response to Item 4.

The ultimate capacity (ASME collapse load) analysis uses an axisymmetric finite element model as described in the response to Item 3 above. The penetrations are not included in this model.

Additional work on the containment analysis is scheduled to be completed by October 1992. This work will include applying the collapse load pressure determined from the axisymmetric model to a full three dimensional finite element model which includes the reinforcement area and barrel for the equipment hatch and personnel airlocks.

Extreme fiber strains will be evaluated using Sandia Laboratory ultimate capacity strains.

Action Item 5.

Explain how localized strains in the containment embedded region are handled in the ultimate capacity (ASME collapse load) analysis.

LETTER ALWR-444

NRC CONTAINMENT AUDIT
April 29-30, 1992

Response to Item 5.

The ultimate capacity (ASME collapse load) analysis uses an axisymmetric finite element model as described in the response to Item 3 above. Extreme fiber strains in this area are computed from the axisymmetric model. These strains will be evaluated using Sandia Laboratory ultimate capacity strains. This will be completed by October 1992

Action Item 6.

Provide justification for the location of the critical buckling area. Provide prebuckling stress results from individual static load cases and combined load cases.

Response to Item 6.

Additional work on the containment stability analysis is scheduled to be completed by October 1992. This work will include verifying the critical buckling location, determining individual static load stress results, combined load stress results, buckling safety factor determination and application of the appropriate "knockdown" factor.

Action Item 7.

Provide containment stress results for Test, Design, Service Level Loadings and Stability analyses.

Response to Item 7.

Containment stress results requested are contained in Attachment 1. Intermediate static loading stability stress results will be available in October 1992 as indicated in Item 6 above. Combined static loading stability stress results for the lower region will be provided at the same time.

The containment stress results provided in Attachment 1 are all middle layer stresses along a single meridian in the containment model. The meridian corresponds to the 90 degree azimuth on the System 80+ General Arrangement drawings. Stress results are shown for two finite element models. Model 1 shown in Attachment 2 and Model 2 shown in Attachment 3. Model 2 is a model with a refined mesh up to approximately elevation 105 ft.

LETTER ALWR-444

NRC CONTAINMENT AUDIT
April 29-30, 1992

Action Item 8.

Provide results of mesh refinement studies.

Response to Item 8.

Additional containment analysis is scheduled to be completed by October 1992. This work will include additional mesh refinement studies for Service Loading and Stability analysis.

Action Item 9.

For the stability analysis;

a. Justify the use of plate elements.

b. Provide results of mesh refinement studies.

c. Compare the finite element results with a closed form solution or alternate solution.

Response to Item 9.

Additional containment analysis will be completed by the October 1992. This will include developing a finite element model of a full sphere composed of plate elements. A stability analysis with external pressure loading will be performed and compared to a classical buckling solution. A reasonable comparison of results will justify the use of plate elements, serve as a mesh refinement verification and provide a comparison to an alternate solution. These results will provide the mesh refinement for the stability analysis in Action Item 8 above.

Action Item 10.

Provide justification for stability minimum factors of safety and the "knockdown" factor used.

Response to Item 10.

Additional containment analysis will be completed by the October 1992. In addition to the analysis results, a justification for the use of stability factors of safety and the "knockdown" factor will be provided.

ATTACHMENT I TO ALWR-444

SYSTEM 80+ CONTAINMENT

STABILITY STRESS DISTRIBUTION

(Middle of Element-PSI)

(Relative stresses. Eigenvectors are normalized in ANSYS)

MODEL 1

Elevation	Element	Stress Component	Combination- Seismic(B4), Dead Weight, Pext (2 psi) SSE	OBE
245.6	2310	Sx	-722.65	-903.50
		Sy	-1502.95	-1139.00
		Sxy	284.96	105.60
		Sz	-1.00	-1.00
		SI	1600.00	1178.40
		SE	1391.00	1056.40
25[illegible]3	2347	Sx	-777.36	-806.50
		Sy	-1486.45	-1142.30
		Sxy	173.28	74.54
		Sz	-1.00	-1.00
		SI	1525.53	1157.10
		SE	1321.41	1024.10
256	2419	Sx	-1161.99	-1013.56
		Sy	-1438.50	-1124.68
		Sxy	85.75	36.77
		Sz	-1.00	-1.00
		SI	1461.90	1134.75
		SE	1329.40	1074.33
256.8	2491	Sx	-1209.01	-1009.61
		Sy	-1557.11	-1221.58
		Sxy	36.91	15.70
		Sz	-1.00	-1.00
		SI	1560.00	1221.70
		SE	1416.00	1129.94
257	2562	Sx	-1371.74	-110.75
		Sy	-1613.36	-1265.24
		Sxy	13.69	5.22
		Sz	-1.00	-1.00
		SI	1636.07	1264.40
		SE	1520.61	1194.50

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 1

Elevation	Element	Stress Component	Press(53)	Dead Weight	Thermal 120 F	Thermal 280 F	OBE Soil Case B4
256	2419	Sx	19011.00	-168.58	0.005	0.021	66.89
		Sy	18788.00	-171.72	-0.055	-0.024	75.75
		Sxy	0.31	-0.12	-0.006	-0.029	79.56
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	19638.00	171.23	0.016	0.074	159.38
		SE	18927.00	169.92	0.014	0.064	155.36
236	1987	Sx	18086.00	-40.18	0.007	0.033	509.83
		Sy	18225.00	-212.33	-0.007	-0.034	434.91
		Sxy	-71.32	0.77	-0.009	-0.040	536.78
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18281.00	212.33	0.020	0.105	1076.18
		SE	18183.00	195.37	0.020	0.091	1044.87
161	1189	Sx	18128.00	315.16	0.037	0.165	1111.19
		Sy	18135.00	-330.85	-0.022	-0.100	841.55
		Sxy	3.01	8.56	-0.048	-0.217	1148.84
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18163.00	646.23	0.112	0.508	2313.44
		SE	18158.00	559.71	0.098	0.441	2228.75
119	397	Sx	18135.00	724.41	11.330	49.284	2193.50
		Sy	18104.00	-585.19	0.055	0.194	2167.30
		Sxy	3.63	6.79	-0.211	-0.939	2580.29
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18162.00	1309.70	11.334	49.302	5160.65
		SE	18146.00	1136.30	11.309	49.214	4972.77

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 1

			Combinations		
Elevation	Element	SSE Soil Case B4	Design and Level A	Level A Secondary	Level D Soil B4
256	2419	100.06	18842.70	18869.30	18942.80
		84.40	18617.20	19287.50	1870[illegible].60
		111.70	0.19	0.15	111.89
		0.00	-26.50	0.00	-26.50
		223.95	18869.20	19287.50	19013.20
		214.76	18757.50	19081.80	18850.90
236	1987	618.63	18046.00	18063.10	18664.60
		491.47	18012.50	18074.30	18503.90
		770.25	-70.55	-185.54	699.69
		0.00	-26.50	0.00	-26.50
		1545.74	18128.20	18254.30	19315.10
		1449.16	18056.20	18071.60	18650.70
161	1189	1290.57	18442.70	18445.50	19733.30
		869.21	17304.60	17807.50	18673.80
		1671.02	11.57	13.25	1682.59
		0.00	-26.50	0.00	-26.50
		3368.50	18469.40	18445.80	20994.10
		3110.67	18158.60	18134.90	19471.30
119	397	2506.44	18859.20	19065.60	21365.60
		2455.34	17518.80	17656.70	19974.20
		3702.71	10.42	12.23	3713.13
		0.00	-26.50	0.00	-26.50
		7405.60	18885.80	19065.70	24474.10
		6876.55	18252.50	18401.70	21706.10

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 1

Elevation	Element	Stress Component	Press(53)	Dead Weight	Thermal 120 F	Thermal 280 F	OBE Soil Case B4
111	305	Sx	18011.00	829.78	-48.125	-218.360	2558.96
		Sy	18100.00	-674.23	-0.449	-1.884	2581.20
		Sxy	6.76	-5.54	-0.443	-2.029	3092.06
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18127.00	1504.00	48.129	218.380	6184.16
		SE	18082.00	1304.90	47.908	217.450	5940.38
103	217	Sx	18497.00	992.94	144.760	687.860	3251.38
		Sy	18453.00	-778.73	3.182	13.723	3125.43
		Sxy	11.20	-21.06	-0.521	-2.322	3801.76
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18524.00	1772.20	144.660	687.870	7604.57
		SE	18354.00	1538.50	143.630	681.120	7316.97
98	145	Sx	18589.00	1150.90	380.140	1460.500	3959.69
		Sy	18113.00	-881.33	-14.363	-68.121	3703.34
		Sxy	20.95	-31.33	-0.404	-1.815	4564.64
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18616.00	2033.10	394.510	1528.700	9132.89
		SE	18382.00	1765.90	387.520	1495.800	8788.50
93.5	73	Sx	12498.00	627.08	-3418.000	-15648.000	1977.[illegible]
		Sy	18151.00	-969.10	-22.230	-81.025	4240.10
		Sxy	21.65	-38.22	-0.587	-2.657	5207.22
		Sz	-26.50	0.00	0.000	0.000	0.00
		SI	18178.00	1598.00	3418.000	15648.000	10657.40
		SE	16113.00	1394.40	3407.000	15608.000	9739.08

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 1

Elevation	Element	SSE Soil Case B4	Combinations: Design and Level A	Combinations: Level A Secondary	Combinations: Level D Soil B4
111	305	2879.32	18840.50	18716.20	21719.80
		2675.75	17425.40	17413.80	20301.10
		4435.09	1.22	-3.18	4436.32
		0.00	-26.50	0.00	-26.50
		8870.19	18867.00	18716.20	25529.60
		8203.07	18200.70	18100.20	22430.00
103	217	3565.69	19489.90	20021.60	23055.60
		3413.58	17373.90	16335.70	20787.50
		5451.15	-9.86	-12.40	5441.28
		0.00	-26.50	0.00	-26.50
		10903.40	19516.40	20021.60	27506.30
		10066.80	18549.20	18456.80	23966.60
98	145	4270.70	19739.90	24503.60	24010.60
		3982.76	17232.20	27912.60	21214.90
		6544.56	-10.38	-12.88	6534.18
		0.00	-26.50	0.00	-26.50
		13092.30	19766.50	27912.60	29321.30
		12065.90	18639.50	26373.90	25426.10
93.5	73	2147.19	13125.40	-2842.96	15272.50
		4511.59	17182.00	20224.50	21693.60
		7465.88	-16.57	-34.39	7449.31
		0.00	-26.50	0.00	-26.50
		15117.80	17208.50	23067.60	26621.30
		13509.10	15581.40	21785.60	23238.00

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 2

Elevation	Element	Stress Component	Press 53 PSIG	Press 49 PSIG	Dead Weight	OBE Soil Case B4	Level B 53 PSIG	Level B 49 PSIG
256	3191	Sx	19011.00	175[illegible]6.21	-168.44	61.03	18904.10	17468.80
		Sy	18788.00	17370.04	-171.38	75.62	13692.50	17274.28
		Sxy	0.05	0.05	-0.21	75.79	75.64	75.63
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	19038.00	17576.16	171.39	152.29	18954.80	17419.11
		SE	189[illegible]7.00	17473.82	169.93	148.53	18826.10	17297.06
236	2759	Sx	18086.00	16721.02	-39.99	481.03	18527.50	17162.06
		Sy	18224.00	16848.60	-212.53	411.20	18423.10	17047.27
		Sxy	-71.72	-66.31	0.65	485.91	414.83	420.25
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18281.00	16943.13	212.53	974.31	18919.90	17108.57
		SE	18183.00	16851.71	195.63	954.46	18516.00	16700.42
161	1961	Sx	18128.00	16759.85	315.75	1032.14	19476.00	18107.74
		Sy	18135.00	16766.32	-331.43	807.46	18610.80	17242.35
		Sxy	0.22	0.20	7.80	1022.36	1030.38	1030.36
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18161.00	16766.12	647.37	2057.03	20187.40	17762.21
		SE	18158.00	16762.72	560.70	2004.89	19167.90	16756.69

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 2

Elevation	Element	Stress Component	Press 53 PSIG	Press 49 PSIG	Dead Weight	OBE Soil Case B4	Level B 53 PSIG	Level B 49 PSIG
119	1169	Sx	18099.00	16733.04	746.32	2122.34	20968.20	19602.30
		Sy	18128.00	16759.85	-584.47	2000.26	19543.80	18175.64
		Sxy	-11.77	-10.88	2.34	2318.37	2308.95	2309.83
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18159.00	16774.59	1330.80	4638.36	22698.80	18996.61
		SE	18140.00	16757.19	1155.30	4215.08	20709.80	17099.55
111	1077	Sx	18766.00	17349.70	769.42	2145.11	21680.60	20264.23
		Sy	18126.00	16758.00	-672.44	2386.56	19840.60	18472.12
		Sxy	1.68	1.55	-11.69	2779.71	2769.70	2769.57
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18793.00	17348.15	1442.00	5564.66	23705.50	19509.52
		SE	18481.00	17059.83	1249.80	5325.23	21392.80	17347.28
106.6	1010	Sx	18115.00	16747.83	-180.99	2912.47	20846.20	19479.31
		Sy	18362.00	16976.19	38.28	3048.66	21449.10	20063.13
		Sxy	-896.83	-829.14	-746.57	2668.53	1025.14	1092.82
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	19170.00	18528.12	1509.20	5649.97	22242.70	19809.53
		SE	18332.00	17750.28	1308.90	5500.99	21254.90	18780.69

ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 2

Elevation	Element	Stress Component	Press 53 PSIG	Press 49 PSIG	Dead Weight	OBE Soil Case B4	Level B 53 PSIG	Level B 49 PSIG
105	865	Sx	10121.00	9357.15	160.52	881.52	11162.70	10399.19
		Sy	18968.00	17536.45	-694.84	2387.25	20660.90	19228.86
		Sxy	-1174.10	-1085.49	-101.69	3271.90	1996.13	2084.72
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	19148.00	18763.55	879.21	6714.80	21089.80	17611.60
		SE	16588.00	16275.53	806.92	6040.50	18265.90	15282.06
101.5	721	Sx	9145.10	8454.90	23.54	1300.10	10474.70	9784.54
		Sy	18412.00	17022.42	-771.43	2873.04	20513.80	19124.03
		Sxy	323.94	299.49	15.23	3327.33	3636.04	361[illegible].59
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18450.00	16733.38	801.55	6838.02	21718.90	16746.09
		SE	15978.00	14493.09	787.06	6278.75	18871.80	14903.35
98.6	577	Sx	8424.40	7788.60	-84.15	1492.38	9832.66	9196.83
		Sy	18640.00	17233.21	-792.61	3014.24	20862.10	19454.84
		Sxy	-14.22	-13.15	-36.13	3454.51	3404.16	3405.23
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	18667.00	17246.37	794.44	7074.64	21854.70	17077.08
		SE	16190.00	14958.23	756.65	6528.04	19035.70	15263.09

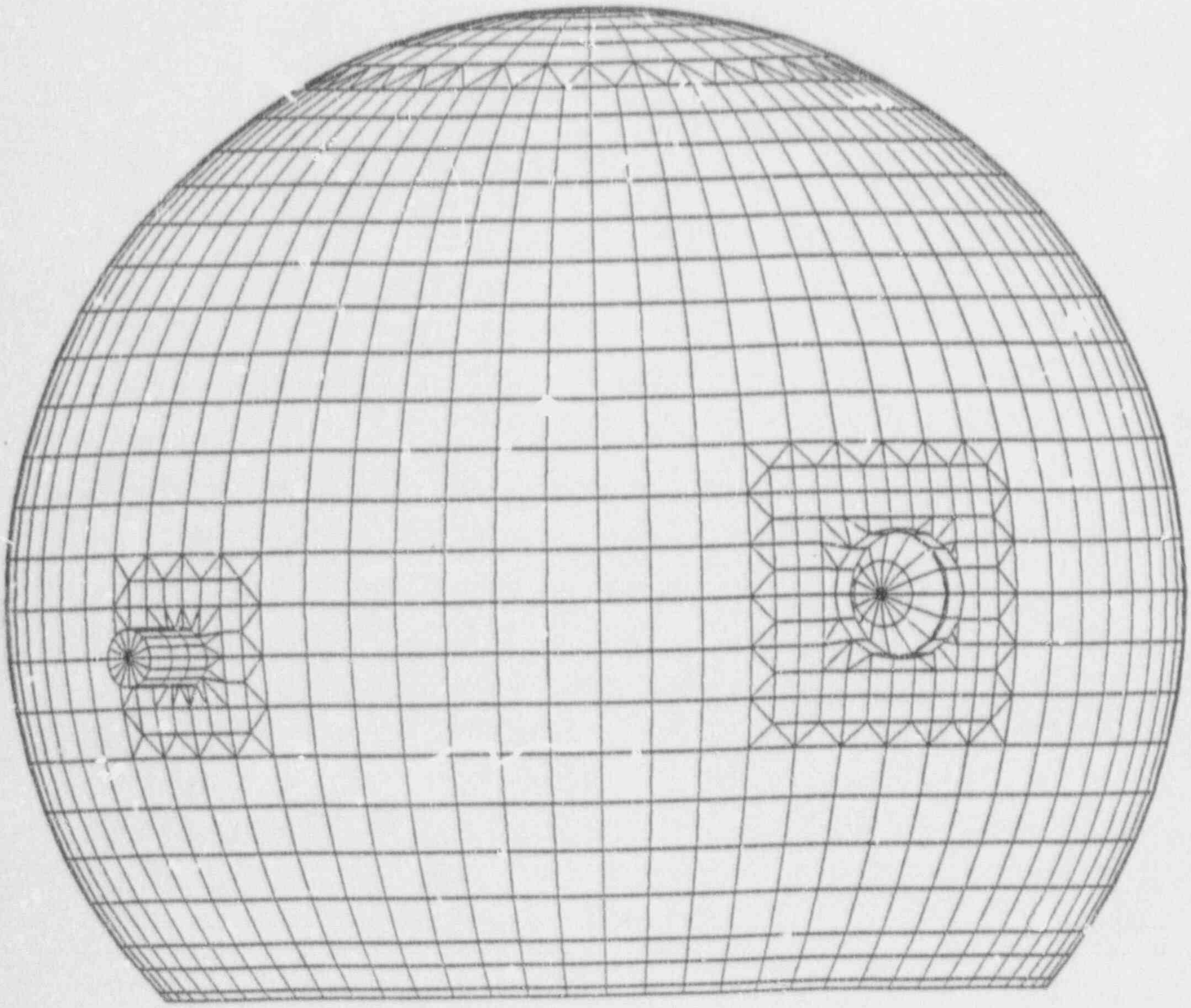
ATTACHMENT I TO ALWR-444
SYSTEM 80+ CONTAINMENT
STRESS DISTRIBUTION
(Middle of Element-PSI)

MODEL 2

Elevation	Element	Stress Component	Press 53 PSIG	Press 49 PSIG	Dead Weight	OBE Soil Case B4	Level B 53 PSIG	Level B 49 PSIG
94.6	289	Sx	8032.90	7426.64	-62.71	957.18	8927.38	8321.11
		Sy	19031.00	17594.70	-828.23	3263.46	21466.70	20[illegible]9.93
		Sxy	33.08	30.58	-33.05	3650.19	36[illegible].21	3[illegible]47.72
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	19058.00	17564.21	829.66	7656.00	22478.40	17425.62
		SE	16570.00	15273.93	800.78	6958.03	19739.70	15923.87
92.7	145	Sx	6883.20	6363.71	-101.98	856.98	7638.17	7118.71
		Sy	19266.00	17611.96	-848.92	3412.88	21829.50	20375.92
		Sxy	36.41	33.66	-32.44	3771.48	3775.46	3772.70
		Sz	-26.50	-24.50	0.00	0.00	-26.50	-24.50
		SI	19292.00	17778.40	850.32	7964.23	22797.90	17601.65
		SE	16930.00	15607.65	804.77	7220.08	20289.80	16553.03

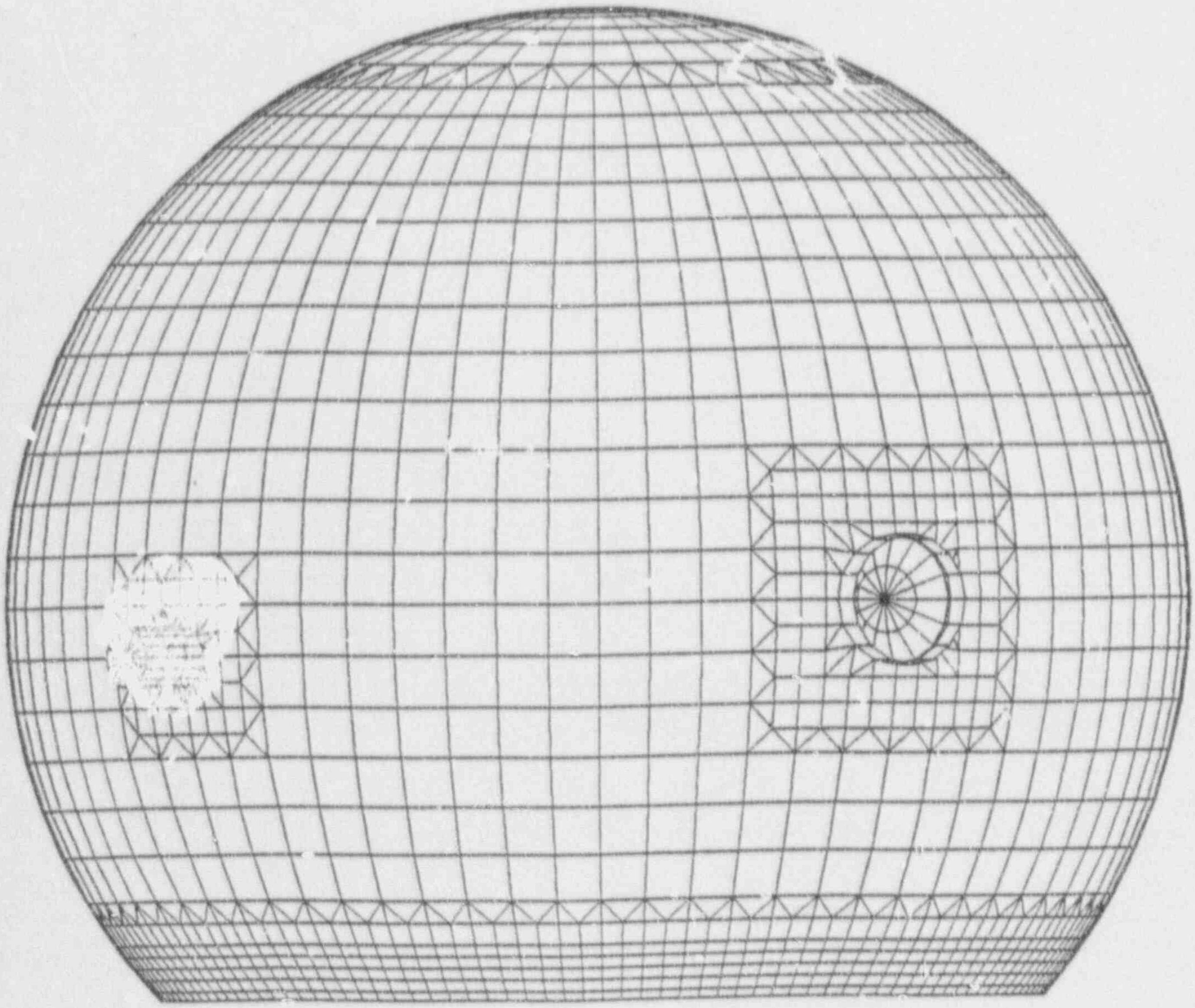
ATTACHMENT 2 to ALWR-444

SYSTEM 80+ CONTAINMENT MODEL 1



ATTACHMENT 3 to ALWR-444

SYSTEM 80+ CONTAINMENT MODEL 2



ATTACHMENT 17

Enclosure to ALWR-ME-92-037

Request: Will the following be considered in the LBB evaluations:

a) potential degradation mechanisms, steam hammer, water hammer, thermal stratification

b) leakage detection outside containment for main steam line

c) dynamic strain aging of carbon steel

d) environmental effects on fatigue

e) thermal aging of cast stainless steel

Response: For each piping system evaluated for LBB, potential degradation mechanisms, steam hammer and water hammer, and thermal stratification will be considered, as applicable, in each evaluation. In addition, dynamic strain aging of carbon steel, environmental effects on fatigue, and thermal aging of cast stainless steel pipe will be considered in each LBB evaluation as appropriate. Leakage detection outside containment will be considered for the main steam line if the anchor-to-anchor portion of the piping evaluated includes pipe which can leak outside containment.

Request: Describe what is meant by "maximum" design load?

Response: In the stability analyses portions of the LBB evaluation, the pipe with a leakage crack is subjected to a normal operation load, which is 100% power plus any long term thermal stratification, plus a design transient load which challenges the stability of the crack. The transient load can be a load due to SSE, short term thermal stratification, other critical thermal transients, or a normal operation dynamic transient such as from rapid valve closure. The maximum of these design transient loads is defined as the "maximum" design load and is combined with the total NOP load in the stability analyses.

Enclosure to ALWR-ME-92-037

Request: Clarify leak before-break acceptance criteria and how NUREG1061 Vol 3 will be employed?

Response: As noted in CESSAR-DC paragraph 3.6.2.1.3, the leak-before-break evaluation is performed using the guidelines of NUREG1061 Vol 3. Leak-before-break evaluations are performed in accordance with draft SRP 3.6.3 following the guidelines of NUREG1061 Vol 3.

Request: Clarify which pipe lines will have specific LBB evaluations performed prior to design certification?

Response: Bounding LBB evaluations based on preliminary pipe design analyses will be performed for each pipe line listed in CESSAR DC paragraph 3.6.2.1.3.

Request: Clarify which portion of each piping system will be evaluated for LBB?

Response: Each piping system listed in CESSAR-DC paragraph 3.6.2.1.3 will be evaluated from anchor point to anchor point.

Request: What leak detection capability is used to establish leakage crack size for LBB evaluations?

Response: A leak detection capability of 1.0 gpm is used with a factor of safety of 10 for calculating leakage crack length.

Request: Please provide bench mark evaluations for CE LBB methodology?

Response: Khant, L. H. and Ayres, D. J., "Benchmark Calculation for Leak Before Break Evaluation of Nuclear Piping," PVP-Vol. 218, Piping Component Analysis, Piping and Structural Dynamics, ASME Conference, San Diego, Ca., June, 1991. (attached)

Request: How will the leakage crack size for the LBB evaluations be calculated?

Response: The leakage crack size will be determined using 250 $\frac{gpm}{in^2}$ based upon PICEP correlations.

PIPING DESIGN GUIDE AUDIT

<u>Question:</u>

Is the containment material SA-537 Cl. 1 or SA-537 Cl. 2?

<u>Response:</u>

The containment material is SA-537 Cl. 2.

<u>Question:</u>

Why is System 80+ using Inconel 600 with 182 welds? The NRC would prefer the use of Inconel 690 with 82 welds.

<u>Response:</u>

C-E is continuing to evaluate industry experience with the use of Inconel within the primary coolant system. Inconel 690 has already been selected as the material of choice in the system design in some areas such as the steam generator tubes. This evaluation will continue into the procurement phase of any project at which time the experience gained by the industry will considered in specifying the material.

<u>Question:</u>

Is the primary water chemistry in conformance with the EPRI PWR Report and/or EPRI ALWR Evolutionary Plant design requirements?

<u>Response:</u>

As noted in the C-E response to RAI 281.46, the CVCS is designed to maintain the reactor coolant chemistry within the limits defined in EPRI report NP-7077 entitled "PWR Primary Water Chemistry Guidelines: Revision 2" (dated November 1990). This is consistent with the EPRI Utility Requirement Document for Evolutionary Plants.

PVP-Vol. 218, Piping Components Analysis
Piping and Structural Dynamics
ASME 1991

BENCHMARK CALCULATION FOR LEAK BEFORE BREAK EVALUATION OF NUCLEAR PLANT PIPING

L. H. Khant and D. J. Ayres
Nuclear Power
ABB Combustion Engineering
Windsor, Connecticut

ABSTRACT

An analysis of a large scale cracked pipe test was performed in order to verify the methods used to determine crack stability in leak before break (LBB) evaluations of nuclear plant piping. The test specimen was a thirty-eight foot long section of thirty-six inch diameter cracked pipe which was tested and reported by Battelle Columbus. In this test, a section of pressurized water reactor main loop piping containing a partial circumferential through wall crack was loaded in bending until significant crack extension occurred. The analysis of the experiment used essentially the same finite element models, calculation steps, and material data interpretation and extrapolation as has been used in actual plant piping LBB evaluations. The excellent agreement between the analysis predictions and the experimental results confirms the appropriateness of the methods used for actual plant LBB evaluations.

INTRODUCTION

A procedure for leak before break (LBB) evaluation of nuclear plant piping based on the NUREG 1061 Volume 3 (Ref. 1) guidelines for ductile fracture analysis has been developed by ABB Combustion Engineering (ABB-CE). This procedure has been used for several evaluations including main loop piping, surge line piping, and main steam line piping leak before break evaluations. The analysis of the pipe to determine if a hypothesized crack is stable when subjected to a given loading is a key element to the demonstration of leak before break for a piping system. The results of these analyses have been benchmarked with other analysis procedures such as the EPRI/GE estimation scheme (Ref. 2), and have been determined to be in general agreement, recognizing the conservatism and range of applicability of the simplified methods.

No experimental verification of the methodology had been attempted by ABB/CE prior to the present study. The opportunity to perform such a verification was provided when the results of a large piping test were published by Battelle (Ref. 3). Because of its direct relevance to LBB work, this test presented an ideal case for comparison of analysis and experimental results. The geometry and materials tested matched the ABB-CE designed main loop piping exactly and are also similar to the main steam lines of many operating plants. Therefore, the same methodology used in the previous and ongoing LBB analyses were applied directly to the Battelle test conditions to compare the prediction of crack instability provided by this methodology to the experimental results.

DESCRIPTION OF THE EXPERIMENT

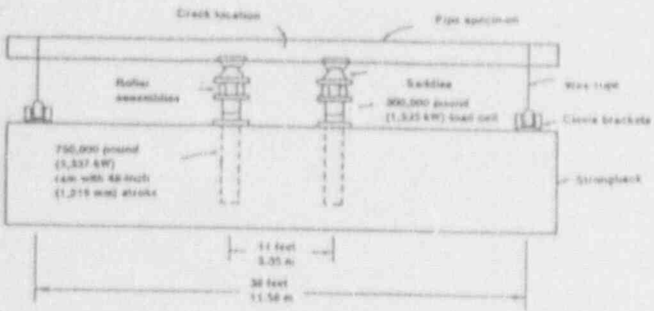
Geometry and Loading

The pipe size tested is 36.73 inches outside diameter and 3.42 inches thick. The schematic of the test frame used by Battelle is shown in Figure 1. The pipe is precracked with a 133 deg circumferential through wall crack through the center of the circumferential buttweld. The four point bending load is applied at the saddles by hydraulic rams. A plot of applied load vs. load line displacement of the test is shown in Figure 2. The same configuration is used in the finite element analysis presented here.

Materials

The pipe material is SA-516 Gr. 70 which was obtained from a cancelled nuclear power plant. The stress-strain curve of the SA-516 Gr. 70 base metal of this pipe material is shown in Figure 3. The stress strain data are obtained from the PIFRAC data base (Ref. 4) which in turn references the Battelle test specimen.

The J_d - a data for the SA-516 Gr. 70 weld material are also from Reference 4. The weld material typically has a higher yield stress and a lower J_d -Δa resistance curve than the base metal. It has been shown in previous studies performed at ABB-CE for EPRI, (Ref. 5), that using the base metal stress strain curve and the weld material J_d curve produces the best correlation to the actual behavior of the weld-base metal combined structure. The J_d data are fit to a power law for interpolation and extrapolation. The power law curve is shown in Figure 4.



Large Diameter Pipe Experiment

Fig. 1 Schematics of the test frame used in pipe bending fracture experiments (Reference 3)

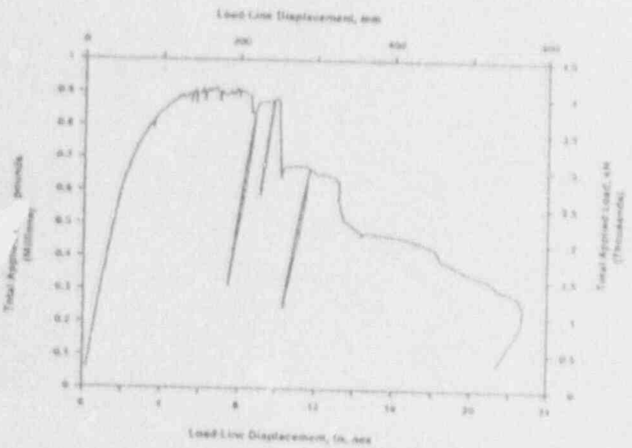


Fig. 2 Load versus load-line displacement record from cold-leg pipe experiment (Reference 3)

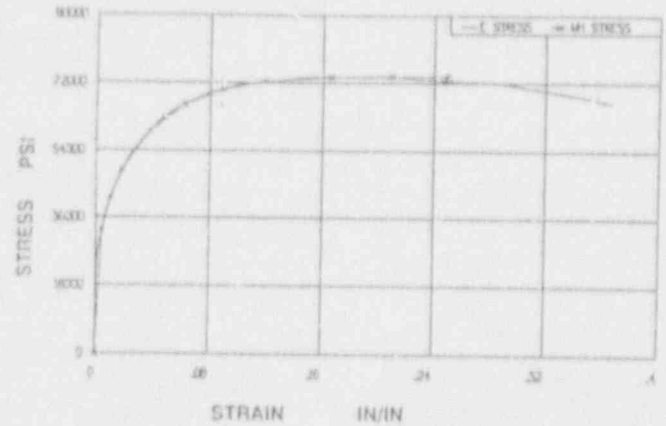


Fig. 3 Stress-strain for SA-516 Gr. 70 at 550°F (Reference 4) data values from point 1034 to 1080

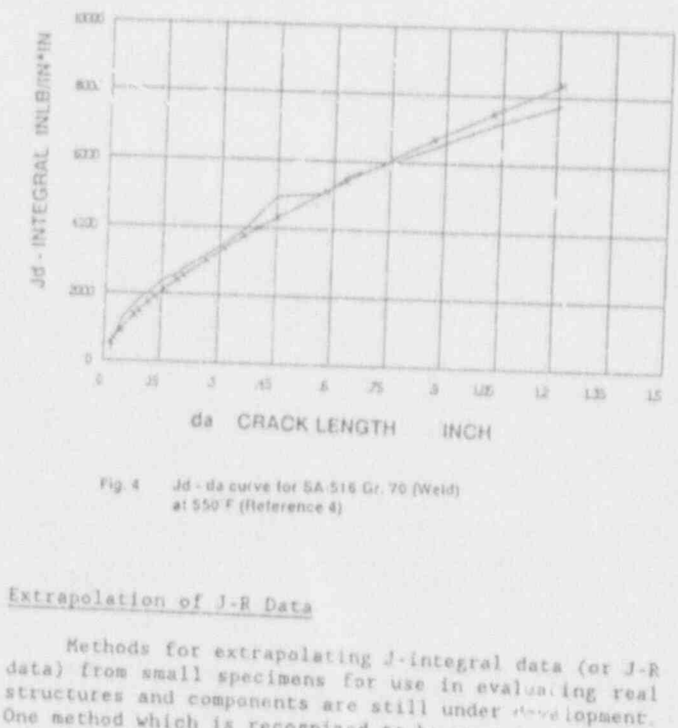


Fig. 4 Jd - da curve for SA-516 Gr. 70 (Weld) at 550°F (Reference 4)

Extrapolation of J-R Data

Methods for extrapolating J-integral data (or J-R data) from small specimens for use in evaluating real structures and components are still under development. One method which is recognized to be very conservative was developed in NUREG 1061 Vol. 3 (Ref. 6). Procedures specified in NUREG 1061 Vol. 3 state that the data is to be fit on a J vs. dJ/da plot up until the ASTM validity criterion. Then a linear extrapolation is made based upon the slope at the validity point but not to exceed twice the valid J value.

More recently a method which is still conservative but not so restrictive has been proposed in support of the Safety Issue A-11 (low upper shelf reactor vessel toughness) (Ref. 8). Additional methods have been proposed which attempt to provide a conservative representation of crack growth in a structure which could tolerate a large amount of crack growth prior to failure. Wilkowski, et. al. (Reference 7) suggests that a power law ($J = C\ (\Delta a)^N$) fit to data up to crack growth of 30% of the original uncracked ligament will provide a conservative extrapolation, yet be much less restrictive than the NUREG 1061 Vol. 3 method. A suggestion was made by Babcock and Wilcox researchers (Reference 8) to fit the data by an equation of the form

$$J = C_1 + C_2\ a + C_3\ (\Delta a)^N \qquad (1)$$

where the data is fit to crack growth up to 30% of the uncracked ligament.

All of the above methods provide conservative extrapolation of the test data. After careful evaluation of the methods suggested in the References 7 and 8, a power law equation has been chosen to fit the test data. This equation is of the form

$$J = C_1 + C_2\ (\Delta a)^N \qquad (2)$$

where the data is fit to crack growth up to 30% of the uncracked ligament.

Analytical Approach

In a LBB analysis various hypothesized cracks are subjected to severe loading conditions. The stability of a crack is first estimated using the EPRI/GE scheme and then the stability is evaluated in detail by the finite element analysis. This detailed analysis is incremental in load and uses the CE-MARC non-linear finite element analysis program. The analysis of the experiment uses essentially the same procedure.

The program uses the differential stiffness technique to compute the J-integral. The technique is based on moving nodes near the crack tip by a small amount in the direction of crack extension and computing the energy change. There are four independent paths defined to estimate the J-integral in the model chosen. Based on two elements through the thickness of the pipe, three paths for the inside, outside, and center locations and one path for the average of all the locations through the thickness are employed to compute the J-integral. The J-integral is computed for all load increments for each crack model. The average J-integral is used in the evaluation of crack stability.

The J-integral computed in this manner is the deformation J or J_d. Therefore, it is appropriate to consider the J_d material resistance curve when making a comparison of applied J and material J-integral data.

The schematic of the test frame used in the pipe bending fracture experiment is shown in Figure 1. Using symmetry, the finite element model is 19 feet long. The twenty noded isoparametric solid element of CE-MARC is used in the analysis. The model developed has 199 elements, 1302 nodes and 3664 degrees of freedom. The model is shown in Figure 5. A detailed section of the model near the crack tip is shown in Figure 6. This model is relatively coarse since it is a typical production type model which had been used in previous piping system evaluations.

Three different circumferential through wall cracks are analyzed. The cracks considered span arcs of 116 deg, 133 deg and 150 deg. The pipe tested by Battelle had a 133 deg circumferential through wall initial crack.

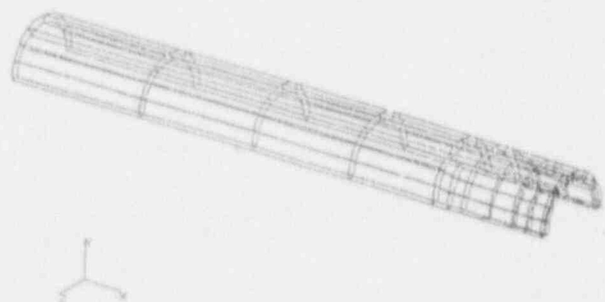


Fig. 5 Finite element model

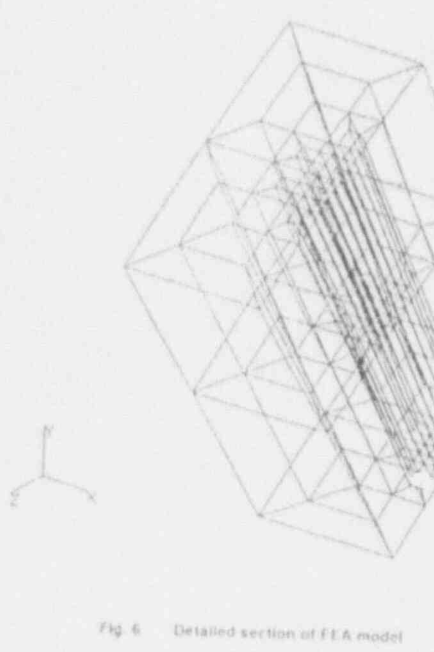


Fig. 6 Detailed section of FEA model

The constraints imposed on the pipe model are based only on symmetry. A uniform body force was applied to the model at the location where the saddle is shown in the Figure 1. This body force simulates the saddle and provides a good distribution of the applied load on the pipe. The direction of the force applied is the same as in Figure 1. In all cases, the load was applied in increments so that the analysis followed the stress-strain work hardening curve. The final load on all the models corresponded to at least 940 kips. The Battelle test report lists the maximum load as 918 kips (see Figure 2). Therefore, the analysis for all cases was carried well beyond the 918 kips maximum test load.

The applied force Vs displacement analysis results for the cases of 133 deg and 150 deg crack are presented in the Figure 7. As the load increases, the data better matches the results of the longer crack. This implies that the crack is growing as the load is increasing. This agreement between the experimental and analytical results indicates that the model is appropriate for the calculation of J-integral values. For all crack lengths considered, the average through wall J-integral for all load steps is plotted against the applied force (see Figure 8). A cross plot of the computed values of Figure 8, showing J vs. crack length for various loads is shown in Figure 9. Presenting the data in this manner is essential for relating the applied loads to the material resistance curve.

Crack Stability Evaluation

The material resistance J_d curve of Figure 4 is extrapolated to larger crack extensions using the fitted power law and plotted simultaneously with the loading results of Figure 9 in order to predict the load at crack instability. This comparison is shown in Figure 10. It is seen that J vs. crack length for the load of 890 kips is tangential to the material curve for J_d vs. crack extension. All the curves of J vs. crack length for loads higher than 890 Kips do not touch the material curve. This indicates that the maximum load which the pipe can carry is 890 Kips. The computed maximum load value of 890 Kips is just 3% less than the experimental maximum load of 918 Kips.

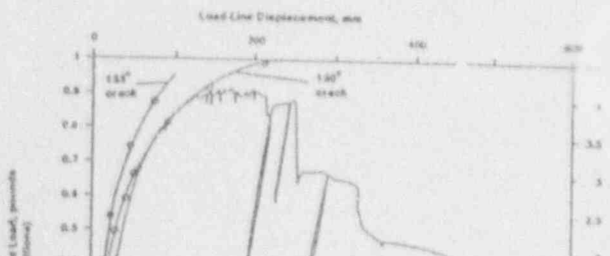


Fig. 7 Load versus load-line displacement record from cold-leg pipe experiment (Reference 3); and finite element analysis

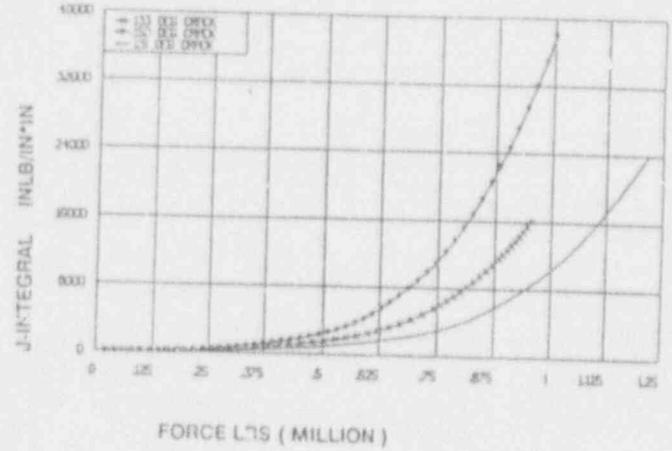


Fig. 8 Applied force vs. applied J-integral

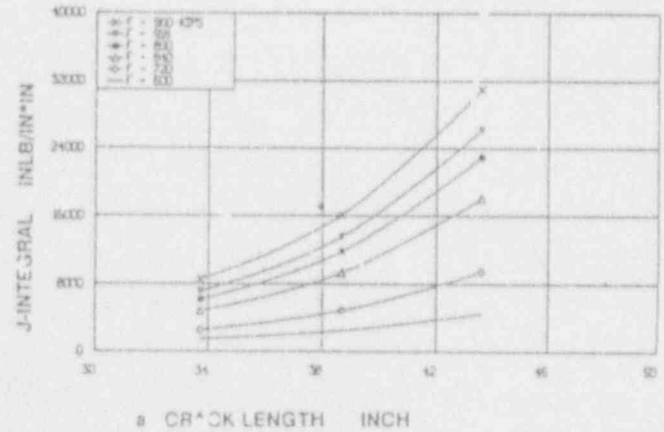


Fig. 9 Applied J vs crack length

Loads smaller than 890 Kips would cause the 133 deg circumferential crack to grow larger, perhaps as large as 150 deg, but stability would be maintained. Because the loading and material curves are tangent, the J-integral at the point of intersection is not well defined from Figure 10. In order to obtain a more precise value for the J-integral at instability, the derivatives with respect to crack length of the 890 Kip loading and the material resistance curves are plotted. These curves are plotted in terms of J_d vs. dJ/da in Figure 11. It is now clear that a J value of 22000 $inlb/in^2$ is required for the crack instability to occur.

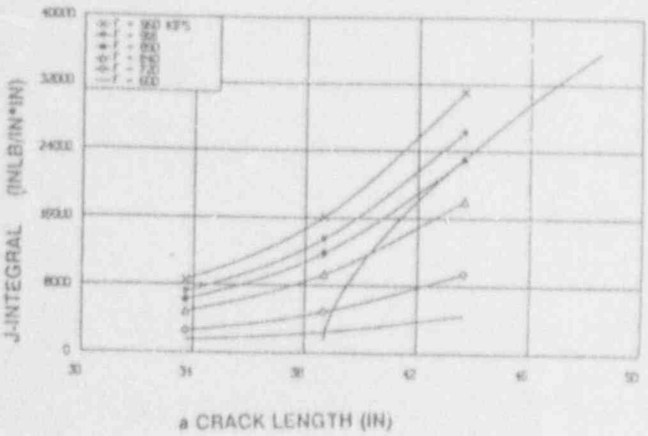


Fig. 10 Applied J vs crack length and material J vs crack length

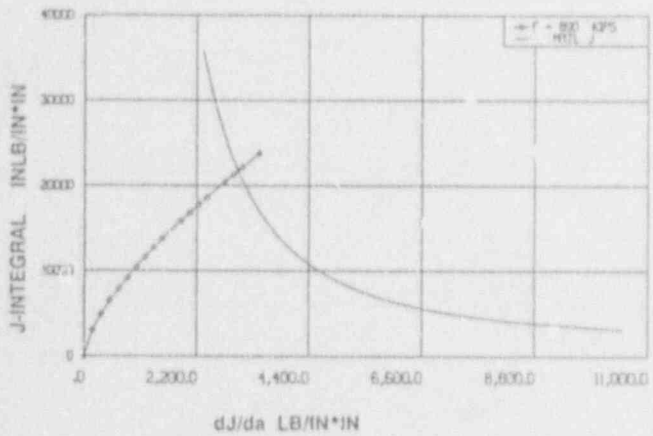


Fig. 11 Applied J vs dJ/da an - aterial J vs dJ/da

CONCLUSION

The excellent agreement between the analysis and experimental results indicate that the methods used for both the finite element analysis and the material property interpretation are capable of accurately predicting crack instability in large piping systems. This agreement demonstrates that the crack stability analysis aspect of a leak before break evaluation of nuclear piping can be performed with confidence using this evaluation methodology.

REFERENCES

1. NUREG-1061 Volume 3, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential Pipe Breaks, November 1984.

2. EPRI Rep No. NP-3596-SR, Revision 1, "PICEP Pipe Crack lluation Program (Revision 1)", special report, December 1987.

3. NUREG/CR-4082, BMI-2120, Volumes 6 to 8, "Degraded Piping Progr. s", Phase II, Battelle Columbus Division

4. PIFRAC - Material Engineering Associates, Inc., Lanham, MD.

5. EPRI Report No. NP-5057, "Analysis of Cracked Pipe Weldment," final report February 1987.

6. "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee Evaluation of Potential for Pipe Breaks," NUREG 1061 Vol. 3, USNRC, November 1984, Page A-20.

7. Wilkowski, G. M. Marschall, C. W., and Landow, M. "Extrapolation of C(T) Specimen J-R curves for use in pipe flaw evaluations," presented at ASTM 21st National Fracture Mechanics Symposium, June 1988.

8. "Test of 6 inch - Thick Pressure Vessels. Series 3: Intermediate Test Vessel V-8A-Tearing Behavior of Low-Upper-Shelf Material," K. M. Bryan et. al. Oak Ridge National Laboratory NUREG/CR4706 ORNL 6187, May 1987, Appendix I.P.

ATTACHMENT 10

Diversity and Defense-in-Depth

Diversity is to be provided for those devices in the System 80+ design that rely on software for their operation and may be, therefore, vulnerable to a common-mode failure (CMF) of software. Examples of this include processors and multiplexors but not power supplies, relays, analog circuits, and hardware portions of video display units.

For software CMF vulnerabilities, defense must be provided by diverse software (and hardware as necessary) or by non-software-based systems. These diverse systems may be non-safety systems. Diversity need not be provided where the designer can demonstrate that CMF vulnerability is not credible. Criteria to demonstrate that a credible vulnerability to CMF does not exist have not been formally established. However, simplicity of design and invariant deterministic performance would be considered as key factors in demonstrating that a credible vulnerability does not exist. Manual action (that does not rely on systems affected by the CMF) is an acceptable element of defense if time and information are available to the operator to complete a task that is part of the diverse level of defense.

ABB-CE will demonstrate that the above requirements have been satisfied by performing a Defense-in-Depth and Diversity Assessment of the proposed digital instrumentation and control systems design. This analysis must describe how the common-mode failure vulnerabilities were identified and how the remaining level of defense can mitigate the consequences of the analyzed events. The assessment:

- Should include evaluation of all Chapter 15 event initiators (individually) concurrent with the CMF. Seismic events need not be considered concurrent with the event.

- Should describe how the CMF affects system control and actuation functions within the systems incurring the CMF.

- Should include bases for demonstrating mitigation of the event (e.g., times for operator action).

- Need not assume lack of operation of non-safety control systems (such as being in manual mode), where lack of operation would tend to make the consequences of the event more adverse.

- Need not assume that low probability dependent failures (e.g., loss of offsite power following a turbine/generator trip) or pre-existing failures (e.g., failure of emergency feedwater pump) occur in addition to the postulated software CMF. High probability dependent occurrences (e.g., loss of main feedwater pumps following a loss of AC power) must be included in the evaluation).

- Should demonstrate qualitatively that expected radiological releases are within NRC regulatory limits. Where a conservative margin cannot be demonstrated qualitatively, quantitative evaluation should be employed to demonstrate that the radiological release limits are not exceeded.

Evaluations that differ from the above must be considered on a case-by-case basis.

ABB-CE is performing a Defense-in-Depth and Diversity Assessment that postulated a common-mode software error which simultaneously failed a number of systems, including all RPS reactor trips, all Engineered Safety Features Component Control System automatic and manual functions, and all functions of the Discrete Indication and Alarm System. These systems are specified by ABB-CE as having software that is diverse from the software used in the following systems: Process Component Control System (which includes the Alternate Protection System), Power Control System, Manual Reactor Trip (hardwired), and the Data Processing System. The assessment assumed the failure occurred concurrent with event initiators from CESSAR-DC Chapter 15 Accident Analyses. A qualitative assessment is being performed to highlight potential vulnerabilities and to discuss potential means for resolution, including any needed design changes. This assessment is currently under review by the staff.

The ABB-CE design methodology for defense-in-depth for CMFs appears to meet the staff requirements described above, subject to completion of staff review, including review of any resulting modifications to the instrumentation and controls design. ABB-CE expects that any such design modifications would be "low-impact" changes to the diverse non-safety systems to improve the level of defense-in-depth in vulnerable areas.

A quantitative evaluation will be performed, if necessary, to resolve any significant uncertainties in the qualitative evaluation described above and to finalize resolutions for known vulnerabilities.