CATEGORY 1

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9810220226 DOC.DATE: 98/10/14 NOTARIZED: NO DOCKET #
FACIL:50-261 H.B. Robinson Plant, Unit 2, Carolina Power & Light C 05000261
AUTH.NAME AUTHOR AFFILIATION
YOUNG,D.E. Carolina Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
Records Management Branch (Document Control Desk)

Revised 12/3/98 [illegible]

SUBJECT: Forwards rev 15 to "HB Robinson Steam Electric Plant,Unit 2 UFSAR," per requirements of 10CFR50.71(e).Submittal includes changes to QA program that do not reduce level of commitment in program.

DISTRIBUTION CODE: A053D COPIES RECEIVED:LTR 1 ENCL 11 SIZE: 2 + 1600
TITLE: OR Submittal: Updated FSAR (50.71) and Amendments

NOTES:

	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME	COPIES LTTR	COPIES ENCL
	PD2-1 PD	1	0	SUBBARATNAM	1	1
INTERNAL:	AEOD/DOA/IRB	1	1	FILE CENTER 01	2	2
	RGN2	1	0			
EXTERNAL:	IHS	1	1	NOAC	1	1
	NRC PDR	1	1			

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

NOTE TO ALL "RIDS" RECIPIENTS:
PLEASE HELP US TO REDUCE WASTE. TO HAVE YOUR NAME OR ORGANIZATION REMOVED FROM DISTRIBUTION LISTS OR REDUCE THE NUMBER OF COPIES RECEIVED BY YOU OR YOUR ORGANIZATION, CONTACT THE DOCUMENT CONTROL DESK (DCD) ON EXTENSION 415-2083

TOTAL NUMBER OF COPIES REQUIRED: LTTR 9 ENCL 7

10 CFR 50.54(a)(3)
10 CFR 50.71(e)

CP&L

Carolina Power & Light Company
3581 West Entrance Road
Hartsville, SC 29550

Dale E. Young
Vice President
Robinson Nuclear Plant

Robinson File No: 13510H
Serial: RNP-RA/98-0183

OCT 14 1998

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

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261/LICENSE NO. DPR-23

SUBMITTAL OF UPDATED FINAL SAFETY ANALYSIS REPORT REVISION 15

Sir or Madam:

In accordance with the requirements of 10 CFR 50.71(e), Carolina Power & Light (CP&L) Company is submitting one original and ten copies of Revision 15 to the Updated Final Safety Analysis Report (UFSAR) for the H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2. In accordance with the regulations, this UFSAR revision is being submitted within six months following the most recent refueling outage, which was completed on April 14, 1998. Accordingly, this revision is due to be submitted by October 14, 1998.

Revision 15 includes changes to the UFSAR in accordance with the requirements of 10 CFR 50.71(e) for the period between October 21, 1996, and April 14, 1998. These changes have been appropriately incorporated into the UFSAR.

In accordance with 10 CFR 50.54(a)(3), this submittal includes changes to the Quality Assurance Program that do not reduce the level of commitment in the Program.

As Vice President of CP&L, I certify that the information in this submittal accurately presents changes made since the previous submittal necessary to reflect information and analyses submitted to the NRC, or prepared pursuant to requirements, and changes made under the provisions of 10 CFR 50.59, but not previously submitted to the NRC.

A053 1/11

If you have any questions please contact me or Mr. T. M. Wilkerson of my staff.

Very truly yours,

Dale E. Young

Dale E. Young

JSK/jk

Enclosure

c: USNRC Resident Inspector, HBRSEP
Mr. R. Subbaratnam, NRC, NRR (w/o enclosure)
Mr. L. A. Reyes, NRC, Region II

50-261 Superseded Per Rev 15 To Robinson 2 UFSAR Dtd 10/14/98
#9810220226

EFFECTIVE PAGE LIST

VOLUME 1

Page	Amendment/Revision
General Information Tab	-
Table of Contents Tab	-
i	11
ii	11
iii	12
iv	3
v	11
vi	11
vii	3
viii	11
ix	12
x	3
xi	3
xii	13
xiii	11
xiv	11
xv	11
xvi	11
xvii	14
xviii	12
xix	12
xx	12
xxi	3
Chapter 1 Tab	-
Chapter 1 Cover Sheet	0
1-i	11
1-ii	11
1-iii	11
1-iv	12
1-v	11
Section 1.1 Tab	-
1.1.0-1	10
1.1.0-2	7
1.1.0-3	3
1.1.0-4	7
1.1.0-5	3
1.1.0-6	3
1.1.0-7	3
1.1.0-8	3
1.1.0-8a	12
1.1.0-9	10
1.1.0-10	0
1.1.0-11	0
1.1.0-12	0
1.1.0-13	0
1.1.0-14	0
1.1.0-15	0
Section 1.2 Tab	-
1.2.1-1	10
1.2.2-1	9
1.2.2-1a	9
1.2.2-2	0
1.2.2-3	7
1.2.2-4	14
Fig. 1.2.2-1	14
Fig. 1.2.2-2	8
Fig. 1.2.2-3	0
Fig. 1.2.2-4	8
Fig. 1.2.2-5	14
Fig. 1.2.2-6	14
Fig. 1.2.2-7	5
Fig. 1.2.2-8	0
Fig. 1.2.2-9	14
Fig. 1.2.2-10	13
Fig. 1.2.2-11	0
Fig. 1.2.2-12	5
Section 1.3 Tab	-
1.3.1-1	0
1.3.1-2	0
1.3.1-3	0
1.3.1-4	0
1.3.1-5	0
1.3.1-6	0
1.3.1-7	0
1.3.1-8	3
1.3.1-9	0
1.3.1-10	0
1.3.1-11	0
1.3.1-12	0
1.3.1-13	0
1.3.1-14	0
1.3.1-15	0
1.3.1-16	0
1.3.1-17	0

Page	Amendment/Revision
1.3.2-1	0
1.3.2-2	6
Section 1.4 Tab	-
1.4.0-1	0
Section 1.5 Tab	-
1.5.1-1	11
1.5.2-1	0
1.5.3-1	1
1.5.4-1	0
1.5.5-1	0
1.5.6-1	0
1.5R-1	11
Section 1.6 Tab	-
1.6.0-1	0
Section 1.7 Tab	-
1.7.0-1	0
Section 1.8 Tab	-
1.8.0-1	0
1.8.0-2	7
1.8.0-2a	2
1.8.0-3	3
1.8.0-3a	2
1.8.0-4	7
1.8.0-4a	3
1.8.0-5	14
1.8.0-6	3
1.8.0-7	7
1.8.0-8	2
1.8.0-9	2
1.8.0-10	13
1.8.0-11	13
1.8.0-11a	2
1.8.0-11b	2
1.8.0-12	3
1.8.0-13	2
1.8.0-14	14
1.8.0-14a	14
1.8.0-14b	2
1.8.0-15	3
1.8.0-15a	6

Page	Amendment/Revision
1.8.0-16	7
1.8.0-16a	3
1.8.0-17	2
1.8.0-18	3
1.8.0-18a	2
1.8.0-18b	3
1.8.0-19	10
1.8.0-20	13
1.8.0-21	13
1.8.0-21a	12
1.8.0-22	5
Chapter 2 Tab	-
Chapter 2 Cover Sheet	0
2-i	12
2-ii	11
2-iii	13
2-iv	11
2-v	1
2-vi	13
2-vii	11
2-viii	11
2-ix	11
2-x	11
Section 2.0 Tab	-
2.0-1	0
Section 2.1 Tab	-
2.1.1-1	13
2.1.1-2	13
2.1.2-1	13
2.1.3-1	13
2.1.3-2	13
2.1.3-3	13
2.1.3-4	0
2.1.3-5	0
2.1.3-6	0
2.1.3-7	0
2.1.3-8	0
2.1.3-9	0
2.1.3-10	0
2.1.3-11	0
2.1.3-12	0
2.1.3-13	0
2.1.3-14	13
2.1.3-15	12
2.1.3-16	12

Page	Amendment/Revision	Page	Amendment/Revision
2.1R-1	12	2.3.2-22	0
		2.3.2-23	10
Fig. 2.1.1-1	0	2.3.2-24	0
Fig. 2.1.1-2	13		
Fig. 2.1.1-3	13	2.3.3-1	13
Fig. 2.1.1-4	0	2.3.3-1a	12
		2.3.3-2	13
Section 2.2 Tab	-	2.3.3-3	13
2.2.1-1	12	2.3.3-4	12
		2.3.3-5	10
2.2.2-1	13	2.3.3-5a	12
		2.3.3-6	12
2.2R-1	0	2.3.3-7	0
		2.3.3-8	12
Section 2.3 Tab	-	2.3.3-9	0
2.3.1-1	0	2.3.3-10	0
2.3.1-2	0	2.3.3-11	0
2.3.1-3	0	2.3.3-12	0
2.3.1-4	10	2.3.3-13	0
2.3.1-4a	10	2.3.3-14	0
2.3.1-5	10	2.3.3-15	0
2.3.1-6	0	2.3.3-16	0
2.3.1-7	0	2.3.3-17	0
2.3.1-8	0	2.3.3-18	0
2.3.1-9	10	2.3.3-19	0
2.3.1-10	10	2.3.3-20	0
2.3.1-11	0	2.3.3-21	0
2.3.1-12	0	2.3.3-22	0
		2.3.3-23	0
2.3.2-1	10	2.3.3-24	0
2.3.2-2	10		
2.3.2-3	0	2.3.4-1	10
2.3.2-4	0	2.3.4-2	0
2.3.2-5	0	2.3.4-3	0
2.3.2-6	0	2.3.4-4	0
2.3.2-7	0	2.3.4-5	0
2.3.2-8	0	2.3.4-6	0
2.3.2-9	0	2.3.4-7	0
2.3.2-10	0	2.3.4-8	0
2.3.2-11	8	2.3.4-9	0
2.3.2-12	0	2.3.4-10	0
2.3.2-13	0	2.3.4-11	0
2.3.2-14	0		
2.3.2-15	0		
2.3.2-16	0		
2.3.2-17	0		
2.3.2-18	0		
2.3.2-19	0		
2.3.2-20	0		
2.3.2-21	0		

Page	Amendment/Revision	Page	Amendment/Revision
2.3R-1	10	Fig. 2.4.7-1	1
2.3R-2	10	Fig. 2.4.7-2	1
		Fig. 2.4.7-3	1
Fig. 2.3.1-1	0	Fig. 2.4.7-4	1
Fig. 2.3.1-2	0	Fig. 2.4.7-5	1
		Fig. 2.4.7-6	1
Fig. 2.3.2-1	0	Fig. 2.4.7-7	1
Fig. 2.3.2-2	0		
		Section 2.5 Tab	-
Fig. 2.3.4-1	0	2.5.1-1	0
Fig. 2.3.4-2	0	2.5.1-2	0
Fig. 2.3.4-3	0	2.5.1-3	0
		2.5.1-4	0
Section 2.4 Tab	-	2.5.1-5	0
2.4.1-1	0		
2.4.1-2	0	2.5.2-1	0
2.4.1-3	0	2.5.2-2	0
2.4.1-4	0	2.5.2-3	0
2.4.1-5	0	2.5.2-4	0
		2.5.2-5	0
2.4.2-1	0		
		2.5.3-1	0
2.4.3-1	0		
		2.5.4-1	0
2.4.4-1	0		
2.4.4-2	9	2.5.5-1	0
2.4.4-3	0		
		2.5R-1	0
2.4.5-1	0		
		Fig. 2.5.1-1	0
2.4.6-1	0	Fig. 2.5.1-2	0
2.4.6-2	0		
2.4.6-3	0	Fig. 2.5.2-1	0
2.4.6-4	0	Fig. 2.5.2-2	0
2.4.6-5	0	Fig. 2.5.2-3	0
2.4.7-1	1	Section 2.5A Tab	-
2.4.7-2	1	App. 2.5A Cover Sheet	0
2.4.7-2a	1	2.5A-1	0
2.4.7-2b	1	2.5A-2	0
2.4.7-3	0	2.5A-3	0
		2.5A-4	0
2.4R-1	0	2.5A-5	0
		2.5A-6	0
Fig. 2.4.1-1	0	2.5A-7	0
Fig. 2.4.1-2	0	2.5A-8	0

Page	Amendment/Revision
Section 2.5B Tab	-
App. 2.5B Cover Sheet	0
2.5B-1	0
2.5B-2	0
2.5B-3	0
2.5B-4	0
2.5B-5	0
Section 2.5C Tab	-
App. 2.5C Cover Sheet	0
2.5C-1	0
2.5C-2	0
2.5C-3	0
2.5C-4	0
2.5C-5	0
2.5C-6	0
2.5C-7	0
2.5C-8	0
2.5C-9	0
2.5C-10	0
2.5C-11	0
2.5C-12	0
2.5C-13	0
2.5C-14	0
2.5C-15	0
2.5C-16	0
Section 2.5D Tab	-
App. 2.5D Cover Sheet	0
2.5D-1	0
2.5D-2	0
2.5D-3	0
2.5D-4	0
2.5D-5	0
2.5D-6	0
2.5D-7	0
2.5D-8	0
2.5D-9	0
2.5D-10	0
2.5D-11	0
2.5D-12	0
2.5D-13	0
2.5D-14	0
2.5D-15	0
2.5D-16	0
2.5D-17	0
2.5D-18	0

Page	Amendment/Revision
Section 2.5E Tab	-
App. 2.5E Cover Sheet	0
2.5E-1	0
2.5E-2	0
2.5E-3	0
2.5E-4	0
2.5E-5	0
2.5E-6	0
Chapter 3 Tab	-
Chapter 3 Cover Sheet	0
3-i	0
3-ii	0
3-iii	0
3-iv	0
3-v	11
3-vi	11
3-vii	0
3-viii	4
3-ix	4
3-x	0
3-xi	0
3-xii	2
3-xiii	11
3-xiv	11
3-xiv-a	11
3-xv	11
3-xvi	12
3-xvii	14
3-xviii	11
3-xix	11
3-xx	12
3-xxi	12
Section 3.1 Tab	-
3.1.1-1	0
3.1.1-2	10
3.1.1-3	0
3.1.1-4	10
3.1.1-5	10
3.1.1-6	0
3.1.1-7	11
3.1.1-8	0

Page	Amendment/Revision
3.1.2-1	0
3.1.2-2	0
3.1.2-3	0
3.1.2-4	0
3.1.2-5	10
3.1.2-6	10
3.1.2-7	0
3.1.2-8	0
3.1.2-9	13
3.1.2-10	0
3.1.2-11	10
3.1.2-12	10
3.1.2-13	10
3.1.2-14	0
3.1.2-15	0
3.1.2-16	12
3.1.2-17	0
3.1.2-18	0
3.1.2-19	13
3.1.2-20	13
3.1.2-21	0
3.1.2-22	0
3.1.2-23	0
3.1.2-24	0
3.1.2-25	14
3.1.2-26	14
3.1.2-27	12
3.1.2-28	0
3.1.2-29	0
3.1.2-30	0
3.1.2-31	0
3.1.2-32	0
3.1.2-33	0
3.1.2-34	3
3.1.2-35	14
3.1.2-36	0
3.1.2-37	0
3.1.2-38	0
3.1.2-39	11
3.1.2-40	0
3.1.2-41	0
3.1.2-42	10
Section 3.2 Tab	-
3.2.1-1	9
3.2.1-2	9
3.2.1-3	12
3.2.1-4	10
3.2.1-5	0
3.2.1-6	12
3.2.1-7	3

Page	Amendment/Revision
3.2.2-1	3
3.2.2-2	0
3.2.2-3	0
3.2.2-4	0
3.2.2-5	0
3.2.2-6	1
3.2.2-7	9
3.2.2-8	0
3.2.2-9	0
3.2.2-10	0
3.2.2-11	9
Section 3.3 Tab	-
3.3.1-1	0
3.3.1-2	0
3.3.2-1	0
3.3.2-2	4
3.3.2-3	12
3.3R-1	12
Fig. 3.3.1-1	0
Section 3.4 Tab	-
3.4.0-1	0
Section 3.5 Tab	-
3.5.0-1	0
3.5.1-1	0
3.5.1-2	0
3.5.1-3	14
3.5.1-4	14
3.5.1-4a	6
3.5.1-5	7
3.5.1-6	7
3.5.2-1	0
3.5R-1	7
Fig. 3.5.1-1	14
Fig. 3.5.1-2	14
Section 3.6 Tab	-
3.6.1-1	0
3.6.1-2	0

Page	Amendment/Revision	Page	Amendment/Revision
3.6.2-1	0	Section 3.8 Tab	-
3.6.2-2	0	3.8.1-1	0
		3.8.1-2	0
3.6R-1	0	3.8.1-3	14
		3.8.1-4	14
Section 3.7 Tab	-	3.8.1-4a	14
3.7.1-1	0	3.8.1-5	14
		3.8.1-6	14
3.7.2-1	0	3.8.1-6a	4
3.7.2-2	0	3.8.1-7	0
3.7.2-3	13	3.8.1-8	0
3.7.2-4	13	3.8.1-9	0
3.7.2-5	0	3.8.1-10	0
		3.8.1-11	10
3.7.3-1	0	3.8.1-12	0
3.7.3-2	0	3.8.1-13	0
3.7.3-3	4	3.8.1-14	0
3.7.3-4	4	3.8.1-15	0
3.7.3-5	4	3.8.1-16	0
3.7.3-6	4	3.8.1-17	0
3.7.3-7	4	3.8.1-18	0
3.7.3-8	4	3.8.1-19	0
3.7.3-8a	4	3.8.1-20	0
3.7.3-9	0	3.8.1-21	0
3.7.3-10	3	3.8.1-22	0
3.7.3-11	2	3.8.1-23	0
3.7.3-11a	2	3.8.1-24	0
3.7.3-12	0	3.8.1-25	0
3.7.3-13	3	3.8.1-26	0
3.7.3-14	0	3.8.1-27	0
3.7.3-15	0	3.8.1-28	0
3.7.3-16	0	3.8.1-29	0
3.7.3-17	7	3.8.1-30	0
		3.8.1-31	0
3.7.4-1	6	3.8.1-32	0
		3.8.1-33	0
3.7R-1	2	3.8.1-34	0
		3.8.1-35	0
Fig. 3.7.2-1	0	3.8.1-36	0
Fig. 3.7.2-2	0	3.8.1-37	0
Fig. 3.7.2-3	0	3.8.1-38	0
Fig. 3.7.2-4	0	3.8.1-39	0
Fig. 3.7.2-5	0	3.8.1-40	0
Fig. 3.7.2-6	0	3.8.1-41	0
		3.8.1-42	0
Fig. 3.7.3-1	0	3.8.1-43	0
Fig. 3.7.3-2	0		
Fig. 3.7.3-3	3		
Fig. 3.7.3-4	0		
Fig. 3.7.3-5	0		

Page	Amendment/Revision
3.8.1-44	10
3.8.1-45	10
3.8.1-45a	10
3.8.1-46	0
3.8.1-47	0
3.8.1-48	0
3.8.1-49	0
3.8.1-50	0
3.8.1-51	0
3.8.1-52	0
3.8.1-53	0
3.8.1-54	0
3.8.1-55	0
3.8.1-56	0
3.8.1-57	3
3.8.1-58	0
3.8.1-59	0
3.8.1-60	0
3.8.1-61	0
3.8.1-62	0
3.8.2-1	0
3.8.3-1	0
3.8.3-2	0
3.8.3-3	0
3.8.3-4	0
3.8.3-5	0
3.8.4-1	0
3.8.4-2	0
3.8.4-3	2
3.8.4-4	2
3.8.4-4a	2
3.8.4-4b	3
3.8.4-4c	6
3.8.4-4d	2
3.8.4-5	1
3.8.4-6	1
3.8.4-7	11
3.8.4-8	11
3.8.5-1	0
3.8.5-2	0
3.8.5-3	0
3.8.5-4	0
3.8.5-5	0
3.8.5-6	0
3.8.5-7	0
3.8.5-8	0
3.8.5-9	0
3.8.5-10	0
3.8.5-11	0
3.8.5-12	0

Page	Amendment/Revision
3.8.5-13	0
3.8.5-14	0
3.8.5-15	0
3.8.5-16	0
3.8.5-17	0
3.8R-1	0
3.8R-2	0
3.8R-3	2
3.8R-4	11

EFFECTIVE PAGE LIST

VOLUME 2

Page	Amendment/Revision
3.9.3-5	7
3.9.3-6	3
3.9.3-6a	3
3.9.3-7	0
3.9.3-8	0
3.9.3-9	0
3.9.3-10	3
3.9.3-11	0
3.9.4-1	0
3.9.4-2	0
3.9.4-3	0
3.9.4-4	3
3.9.5-1	0
3.9.5-2	0
3.9.5-3	0
3.9.5-4	0
3.9.5-5	0
3.9.5-6	0
3.9.5-7	0
3.9.5-8	0
3.9.6-1	11
3.9R-1	3
3.9R-2	3
Fig. 3.9.2-1	0
Fig. 3.9.4-1	0
Fig. 3.9.4-2	0
Fig. 3.9.5-1	0
Fig. 3.9.5-2	0
Fig. 3.9.5-3	0
Section 3.10 Tab	-
3.10.0-1	10
3.10.0-2	0
3.10R-1	0
Section 3.11 Tab	-
3.11.1-1	10
3.11.1-2	10
3.11.2-1	10
3.11.2-2	10
3.11.3-1	10
3.11.4-1	12
3.11.5-1	10
3.11R-1	10
Fig. 3.11.1-1	10
Fig. 3.11.1-2	10
Fig. 3.11.5-1	10
Fig. 3.11.5-2	10
Chapter 4 Tab	-
Chapter 4 Cover Sheet	0
4-i	13
4-ii	13
4-iii	14
4-iv	11
4-v	14
4-vi	3
4-vii	13
4-viii	13
Section 4.1 Tab	-
4.1.1-1	13
4.1.2-1	13
4.1.2-2	13
4.1.2-3	12
4.1.2-4	13
4.1.2-5	3
Fig. 4.1.1-1	0
Fig. 4.1.1-2	0
Fig. 4.1.1-3	12
Fig. 4.1.2-1	3
Fig. 4.1.2-2	0
Fig. 4.1.2-3	10
Fig. 4.1.2-4	10
Section 4.2 Tab	-
4.2.1-1	13
4.2.1-2	13
4.2.1-3	13
4.2.1-4	13
4.2.1-5	13
4.2.1-6	3
4.2.2-1	13
4.2.2-2	13
4.2.2-3	13
4.2.2-4	13
4.2.2-5	13
4.2.2-6	13
4.2.2-7	13
4.2.2-8	13

Page	Amendment/Revision
4.2.3-1	13
4.2.3-2	13
4.2.3-3	13
4.2.3-4	13
4.2.3-5	13
4.2.3-6	13
4.2.3-7	13
4.2.4-1	13
4.2R-1	13
Fig. 4.2.2-1 Deletion Sheet	13
Fig. 4.2.2-2	13
Fig. 4.2.2-3	3
Section 4.3 Tab	-
4.3.1-1	14
4.3.1-2	14
4.3.2-1	13
4.3.2-2	13
4.3.2-3	0
4.3.2-4	5
4.3.2-5	0
4.3.2-6	13
4.3.2-7	0
4.3.2-8	0
4.3.2-9	0
4.3.3-1	14
4.3.3-2	14
4.3R-1	14
Fig. 4.3.2-1	3
Fig. 4.3.2-2	0
Section 4.4 Tab	-
4.4.1-1	10
4.4.2-1	14
4.4.2-2	14

Page	Amendment/Revision
4.4.3-1	13
4.4.3-2	10
4.4.3-3	3
4.4R-1	14
Fig. 4.4.3-1	13
Fig. 4.4.3-2	3
Fig. 4.4.3-3	0
Section 4.5 Tab	-
4.5.1-1	0
4.5.2-1	0
Section 4.6 Tab	-
4.6.0-1	3
Chapter 5 Tab	-
Chapter 5 Cover Sheet	0
5-i	3
5-ii	11
5-iii	13
5-iv	11
5-v	11
5-vi	11
Section 5.1 Tab	-
5.1.0-1	8
5.1.0-2	0
5.1.0-3	3
5.1.1-1	0
Fig. 5.1.1-1	7
Fig. 5.1.2-1	10
Fig. 5.1.2-2	9
Fig. 5.1.3-1	5
Section 5.2.Tab	-
5.2.1-1	0
5.2.2-1	10
5.2.2-2	5

EFFECTIVE PAGE LIST

VOLUME 3

Page	Amendment/Revision	Page	Amendment/Revision
Chapter 6 Tab	-	6.2.1-7	0
Chapter 6 Cover Sheet	0	6.2.1-8	8
6-i	0	6.2.1-9	0
6-ii	10	6.2.1-10	0
6-iii	13	6.2.1-11	0
6-iv	4	6.2.1-12	0
6-iv-a	4	6.2.1-13	0
6-v	0	6.2.1-14	10
6-vi	0	6.2.1-14a	11
6-vii	13	6.2.1-14b	10
6-viii	0	6.2.1-15	0
6-ix	14	6.2.1-16	0
6-x	14	6.2.1-17	0
6-xi	14	6.2.1-18	10
6-xii	14		
6-xiii	14	6.2.2-1	3
6-xiv	14	6.2.2-2	0
		6.2.2-3	8
Section 6.0 Tab	-	6.2.2-4	0
6.0-1	14	6.2.2-5	14
		6.2.2-6	14
Section 6.1 Tab	-	6.2.2-7	12
6.1.1-1	0	6.2.2-8	10
6.1.1-2	11	6.2.2-8a	12
6.1.1-3	11	6.2.2-9	14
6.1.1-4	11	6.2.2-10	14
6.1.1-5	3	6.2.2-11	0
6.1.1-6	1	6.2.2-12	0
6.1.1-7	13	6.2.2-13	0
6.1.1-8	3	6.2.2-14	0
6.1.1-9	9	6.2.2-15	0
6.1.1-10	0	6.2.2-16	0
6.1.1-11	0	6.2.2-17	0
6.1.1-12	4	6.2.2-18	0
		6.2.2-19	0
6.1.2-1	6	6.2.2-20	0
6.1.2-2	0	6.2.2-21	14
		6.2.2-22	14
6.1R-1	0	6.2.2-23	6
		6.2.2-24	0
Section 6.2 Tab	-	6.2.2-25	1
6.2.1-1	0	6.2.2-26	10
6.2.1-2	0	6.2.2-27	0
6.2.1-3	0	6.2.2-28	0
6.2.1-4	0	6.2.2-29	0
6.2.1-5	0	6.2.2-30	0
6.2.1-6	0	6.2.2-31	0
		6.2.2-32	0

Page	Amendment/Revision
6.2.3-1	0
6.2.4-1	0
6.2.4-2	11
6.2.4-3	14
6.2.4-4	14
6.2.4-5	14
6.2.4-6	13
6.2.4-7	13
6.2.4-8	13
6.2.4-9	13
6.2.4-10	13
6.2.4-11	12
6.2.4-12	12
6.2.4-13	12
6.2.4-14	12
6.2.4-15	14
6.2.4-16	14
6.2.4-17	14
6.2.4-18	14
6.2.4-19	14
6.2.4-20	14
6.2.4-21	14
6.2.4-22	14
6.2.4-23	14
6.2.4-24	13
6.2.4-25	12
6.2.4-26	12
6.2.5-1	3
6.2.5-2	0
6.2.5-3	3
6.2.5-3a	3
6.2.5-4	0
6.2.6-1	0
6.2.6-2	0
6.2.6-3	0
6.2R-1	10
6.2R-2	12
Fig. 6.2.1-1	0
Fig. 6.2.1-2	0
Fig. 6.2.1-3	0
Fig. 6.2.1-4	0
Fig. 6.2.1-5	0
Fig. 6.2.1-6	0
Fig. 6.2.1-7	0
Fig. 6.2.1-8	0
Fig. 6.2.1-9	0
Fig. 6.2.1-10	0
Fig. 6.2.1-11	0
Fig. 6.2.1-12	0

Page	Amendment/Revision
Fig. 6.2.1-13	0
Fig. 6.2.1-14	10
Fig. 6.2.1-15	10
Fig. 6.2.2-1	10
Fig. 6.2.2-2	12
Fig. 6.2.2-3	0
Fig. 6.2.2-4	0
Fig. 6.2.2-5	0
Fig. 6.2.2-6	6
Fig. 6.2.4-1	12
Fig. 6.2.4-2	12
Fig. 6.2.4-3	14
Fig. 6.2.4-4	12
Fig. 6.2.4-5	14
Fig. 6.2.4-6	12
Fig. 6.2.4-7	12
Fig. 6.2.4-8	14
Fig. 6.2.4-9	14
Fig. 6.2.4-10	14
Fig. 6.2.4-11	14
Fig. 6.2.4-12	14
Fig. 6.2.4-13	12
Fig. 6.2.4-14	12
Fig. 6.2.4-15	14
Fig. 6.2.4-16	14
Fig. 6.2.4-17	14
Fig. 6.2.4-18	14
Fig. 6.2.4-19	12
Fig. 6.2.4-20 Del. Sh.	12
Fig. 6.2.4-21	14
Fig. 6.2.5-1	14
Fig. 6.2.5-2	0
Section 6.3 Tab	-
6.3.1-1	7
6.3.1-2	6
6.3.1-3	0
6.3.2-1	7
6.3.2-2	1
6.3.2-3	14
6.3.2-4	14
6.3.2-4a	14
6.3.2-5	11
6.3.2-6	12
6.3.2-7	11
6.3.2-8	11
6.3.2-8a	11
6.3.2-9	11
6.3.2-10	14

Page	Amendment/Revision
6.3.2-11	14
6.3.2-12	14
6.3.2-13	11
6.3.2-14	9
6.3.2-15	13
6.3.2-16	11
6.3.2-17	0
6.3.2-18	7
6.3.2-19	14
6.3.2-20	14
6.3.2-21	14
6.3.2-22	0
6.3.2-23	7
6.3.2-24	11
6.3.2-25	9
6.3.2-26	9
6.3.2-27	9
6.3.2-28	12
6.3.2-29	0
6.3.2-30	14
6.3.2-31	7
6.3.2-32	12
6.3.2-33	0
6.3.2-34	0
6.3.2-35	0
6.3.2-36	0
6.3.3-1	0
6.3.3-2	5
6.3.3-3	0
6.3.4-1	0
6.3.4-2	13
6.3.4-3	13
6.3.4-4	13
6.3.4-5	13
6.3.5-1	0
6.3R-1	0
Fig. 6.3.2-1	13
Fig. 6.3.2-2	12
Fig. 6.3.2-3	0
Fig. 6.3.2-4	0
Fig. 6.3.2-5	0
Section 6.4 Tab	-
6.4.1-1	10
6.4.1-2	10

Page	Amendment/Revision
6.4.2-1	10
6.4.2-2 Deletion Sheet	10
6.4.2-3	13
6.4.2-4	13
6.4.3-1	10
6.4.4-1	12
6.4.4-1a	12
6.4.4-2	0
6.4.4-3	0
6.4.4-4	12
6.4.4-5	12
6.4.4-6	12
6.4.4-7	12
6.4.4-8	12
6.4.4-9	12
6.4.5-1	10
6.4.6-1	10
6.4R-1	13
Fig. 6.4.2-1	13
Fig. 6.4.4-1	12
Fig. 6.4.4-2	12
Section 6.5 Tab	-
6.5.1-1	5
6.5.2-1	3
6.5.2-2	0
6.5.2-3	0
6.5.2-4	0
6.5.2-5	0
6.5.2-6	0
6.5.2-7	0
6.5.2-8	0
6.5.2-9	0
6.5.2-10	5
6.5.3-1	0
6.5.3-2	6
6.5R-1	0
Fig. 6.5.2-1	0
Section 6.6 Tab	-
6.6.0-1	0

Page	Amendment/Revision
Section 6.7 Tab	-
6.7.0-1	0
Section 6.8 Tab	-
6.8.1-1	0
6.8.2-1	14
6.8.2-2	14
6.8.2-3	12
6.8.2-4	14
6.8.2-5	0
6.8.2-6	0
6.8.3-1	0
6.8.3-2	0
6.8.4-1	0
6.8.5-1	11
6.8.5-2	13
Fig. 6.8.2-1	3
Fig. 6.8.2-2	0
Section 6.9 Tab	-
6.9.1-1	14
6.9.2-1	14
6.9.2-2	14
6.9.2-3	14
6.9.3-1	14
6.9.4-1	14
Chapter 7 Tab	-
Chapter 7 Cover Sheet	0
7-i	11
7-ii	11
7-iii	11
7-iv	11
7-v	11
7-vi	0
7-vii	11
7-viii	10
7-ix	11
7-x	14

Page	Amendment/Revision
Section 7.1 Tab	-
7.1.0-1	14
7.1.0-2	14
Section 7.2 Tab	-
7.2.1-1	10
7.2.1-2	10
7.2.1-2a	3
7.2.1-3	7
7.2.1-4	13
7.2.1-4a	13
7.2.1-5	13
7.2.1-6	13
7.2.1-7	13
7.2.1-8	0
7.2.1-9	14
7.2.1-10	14
7.2.1-11	0
7.2.1-12	0
7.2.1-13	4
7.2.1-14	12
7.2.1-15	0
7.2.1-16	0
7.2.1-17	0
7.2.1-18	11
7.2.1-19	0
7.2.1-20	0
7.2.1-21	11
7.2.1-22	0
7.2.1-23	3
7.2.1-24	0
7.2.1-25	10
7.2.1-26	13
7.2.1-27	0
7.2.1-28	0
7.2.1-29	3
7.2.1-30	0
7.2.1-31	0
7.2.1-32	12
7.2.1-33	10
7.2.1-34	0
7.2.1-35	11
7.2.1-36	0
7.2.1-37	0
7.2.1-38	0
7.2.2-1	7
7.2.2-2	10
7.2.2-3	10
7.2.2-4	13
7.2.2-5	13
7.2.2-6	13
7.2.2-7	0

Page	Amendment/Revision
7.2.2-8	0
7.2.2-9	0
7.2.2-10	0
7.2.2-11	0
7.2.2-12	0
7.2R-1	0
Fig. 7.2.1-1	0
Fig. 7.2.1-2	0
Fig. 7.2.1-3	3
Fig. 7.2.1-4	3
Fig. 7.2.1-5	0
Fig. 7.2.1-6	0
Fig. 7.2.1-7	0
Fig. 7.2.1-8	0
Fig. 7.2.1-9	0
Fig. 7.2.1-10	0
Fig. 7.2.1-11	3
Fig. 7.2.1-12	0
Fig. 7.2.1-13	7
Fig. 7.2.1-14	0
Fig. 7.2.1-15	0
Fig. 7.2.1-16	0
Fig. 7.2.1-17	0
Fig. 7.2.1-18	12
Fig. 7.2.1-19	12
Fig. 7.2.1-20	0
Fig. 7.2.1-21	13
Fig. 7.2.1-22	0
Fig. 7.2.1-23	0
Fig. 7.2.1-24	11
Fig. 7.2.1-25	0
Fig. 7.2.1-26	14
Fig. 7.2.1-27	7
Fig. 7.2.1-28	14
Fig. 7.2.1-29	0
Fig. 7.2.1-30	14
Fig. 7.2.1-31	0
Fig. 7.2.1-32	0
Fig. 7.2.1-33	0
Fig. 7.2.1-34	0
Fig. 7.2.1-35	11
Section 7.3 Tab	-
7.3.1-1	14
7.3.1-2	14
7.3.1-2a	14
7.3.1-3	14
7.3.1-4	14
7.3.1-5	13
7.3.1-6	13
7.3.1-7	0
7.3.1-8	8

Page	Amendment/Revision
7.3.1-9	14
7.3.2-1	0
7.3.2-2	1
7.3.2-3	12
Section 7.4 Tab	-
7.4.1-1	12
7.4.1-2	12
7.4.1-3	10
7.4.1-4	10
7.4.1-5	10
7.4.1-6	10
7.4.1-7	10
7.4.1-8	10
7.4.2-1	12
7.4.2-2	12
7.4.2-3 Deletion Sheet	12
7.4R-1	12
Section 7.5 Tab	-
7.5.1-1	0
7.5.1-2	10
7.5.1-3	0
7.5.2-1	0
Section 7.6 Tab	-
7.6.1-1	13
7.6.2-1	0
7.6.2-2	0
7.6R-1	0
Fig. 7.6.1-1	11

Page	Amendment/Revision
Fig. 7.6.1-2	7
Section 7.7 Tab	-
7.7.1-1	0
7.7.1-2	4
7.7.1-3	0
7.7.1-4	0
7.7.1-5	14
7.7.1-6	14
7.7.1-7	0
7.7.1-8	7
7.7.1-9	7
7.7.1-10	0
7.7.1-11	1
7.7.1-12	13
7.7.1-13	13
7.7.1-14	13
7.7.1-15	10
7.7.1-16	6
7.7.1-17	6
7.7.1-18	6
7.7.2-1	0
7.7.2-2	0
7.7.2-3	0
7.7R-1	6
Fig. 7.7.1-1	4
Fig. 7.7.1-2	7
Fig. 7.7.1-3	0

EFFECTIVE PAGE LIST

VOLUME 4

Page	Amendment/Revision	Page	Amendment/Revision
9.1.2-5	14	9.2.3-1	12
9.1.2-6	14	9.2.3-2	11
		9.2.3-3	12
9.1.3-1	14		
9.1.3-2	14	9.2.4-1	0
9.1.3-3	14	9.2.5-1	9
9.1.3-4	14		
9.1.3-5	14	Fig. 9.2.1-1	13
9.1.3-6	14		
9.1.3-7	14	Fig. 9.2.2-1	9
9.1.3-8	14	Fig. 9.2.2-2	10
		Fig. 9.2.2-3	10
9.1.4-1	3		
9.1.4-2	11	Fig. 9.2.3-1	14
9.1.4-3	14	Fig. 9.2.3-2	10
9.1.4-4	14		
9.1.4-5	14	Section 9.3 Tab	-
9.1.4-6	14	9.3.1-1	14
9.1.4-7	14	9.3.1-2	14
9.1.4-8	14	9.3.1-3	14
9.1.4-9	14	9.3.1-4	14
		9.3.1-5	14
9.1R-1	14		
		9.3.2-1	1
Fig. 9.1.1-1	14	9.3.2-2	12
Fig. 9.1.2-1	0	9.3.2-2a	12
Fig. 9.1.2-2	2	9.3.2-3	10
Fig. 9.1.2-3	2	9.3.2-4	12
Fig. 9.1.2-4	2	9.3.2-5	12
		9.3.2-5a	12
Fig. 9.1.3-1	13	9.3.2-5b	12
		9.3.2-5c	12
Fig. 9.1.4-1	11	9.3.2-5d	12
		9.3.2-5e	12
Section 9.2 Tab	-	9.3.2-6	0
9.2.1-1	10	9.3.2-7	0
9.2.1-2	10	9.3.2-8	0
9.2.1-3	14	9.3.2-9	1
9.2.1-4	14		
9.2.1-5	10	9.3.3-1	14
9.2.1-6	0		
9.2.1-7	11	9.3.4-1	0
		9.3.4-2	3
9.2.2-1	9	9.3.4-3	14
9.2.2-2	10	9.3.4-4	14
9.2.2-3	12	9.3.4-5	14
9.2.2-4	6	9.3.4-6	14
9.2.2-5	12	9.3.4-7	14
9.2.2-6	0	9.3.4-8	14
9.2.2-7	10	9.3.4-9	14
9.2.2-8	0	9.3.4-10	14
9.2.2-9	0	9.3.4-11	14
9.2.2-10	0		

Page	Amendment/Revision
9.3.4-12	14
9.3.4-13	14
9.3.4-14	14
9.3.4-15	13
9.3.4-16	13
9.3.4-17	13
9.3.4-18	13
9.3.4-19	11
9.3.4-20	0
9.3.4-21	8
9.3.4-22	12
9.3.4-23	12
9.3.4-24	12
9.3.4-25	12
9.3R-1	0
Fig. 9.3.2-1	12
Fig. 9.3.2-2	12
Fig. 9.3.2-3	11
Fig. 9.3.4-1	9
Fig. 9.3.4-2	14
Fig. 9.3.4-3	14
Fig. 9.3.4-4	6
Fig. 9.3.4-5	14
Fig. 9.3.4-6	10
Section 9.4 Tab	-
9.4.1-1	13
9.4.1-2	13
9.4.1-3	14
9.4.2-1	13
9.4.2-2	13
9.4.2-3	13
9.4.3-1	12
9.4.3-2	12
9.4.3-3	3
9.4.3-4	5
9.4.3-4a	14
9.4.3-5	4
9.4.3-6	4
9.4.3-7	13
9.4.3-8	0
9.4.4-1	6
9.4.4-2	0
9.4.5-1	10
9.4.6-1	14
9.4.7-1	0
9.4.8-1	12
9.4.9-1	10
9.4.10-1	13
9.4.11-1	13
9.4R-1	13
Fig. 9.4.1-1	14
Fig. 9.4.1-2	13
Fig. 9.4.1-3	13
Section 9.5 Tab	-
9.5.1-1	14
9.5.1-2	14
9.5.1-3	14
9.5.1-4	14
9.5.1-5	14
9.5.1-6	14
9.5.1-7	14
9.5.1-8	14
9.5.1-9	14
9.5.1-10	14
9.5.1-11	14
9.5.1-12	14
9.5.1-13	14
9.5.1-14	14
9.5.1-15	14
9.5.2-1	13
9.5.2-2	13
9.5.2-3	13
9.5.2-4	13
9.5.2-5	0
9.5.3-1	3
9.5R-1	5
Fig. 9.5.1-1 Sh. 1	12
Fig. 9.5.1-1 Sh. 2	14
Fig. 9.5.1-1 Sh. 3	4
Fig. 9.5.1-2	14
Fig. 9.5.1-3	14
Fig. 9.5.1-4	14
Fig. 9.5.1-5	14
Fig. 9.5.1-6	14
Fig. 9.5.1-7	14
Fig. 9.5.1-8	14
Fig. 9.5.1-9	14
Fig. 9.5.1-10	14
Fig. 9.5.2-1	13

Page	Amendment/Revision
Appendix 9.5.1A Cover Sheet	14
9.5.1A-i	14
9.5.1A-ii	14
9.5.1A-iii	14
9.5.1A-1	14
9.5.1A-2	14
9.5.1A-3	14
9.5.1A-4	14
9.5.1A-5	14
9.5.1A-6	14
9.5.1A-7	14
9.5.1A-8	14
9.5.1A-9	14
9.5.1A-10	14
9.5.1A-11	14
9.5.1A-12	14
9.5.1A-13	14
9.5.1A-14	14
9.5.1A-15	14
9.5.1A-16	14
9.5.1A-17	14
9.5.1A-18	14
9.5.1A-19	14
9.5.1A-20	14
9.5.1A-21	14
9.5.1A-22	14
9.5.1A-23	14
9.5.1A-24	14
9.5.1A-25	14
9.5.1A-26	14
9.5.1A-27	14
9.5.1A-28	14
9.5.1A-29	14
9.5.1A-30	14
9.5.1A-31	14
9.5.1A-32	14
9.5.1A-33	14
9.5.1A-34	14
9.5.1A-35	14
9.5.1A-36	14
9.5.1A-37	14
9.5.1A-38	14
9.5.1A-39	14
9.5.1A-40	14
9.5.1A-41	14
9.5.1A-42	14
9.5.1A-43	14
9.5.1A-44	14
9.5.1A-45	14
9.5.1A-46	14
9.5.1A-47	14
9.5.1A-48	14

Page	Amendment/Revision
9.5.1A-49	14
9.5.1A-50	14
9.5.1A-51	14
9.5.1A-52	14
9.5.1A-53	14
9.5.1A-54	14
9.5.1A-55	14
9.5.1A-56	14
9.5.1A-57	14
Appendix 9.5.1B Cover Sheet	14
9.5.1B-i	14
9.5.1B-ii	14
9.5.1B-1	14
9.5.1B-2	14
9.5.1B-3	14
9.5.1B-4	14
9.5.1B-5	14
9.5.1B-6	14
9.5.1B-7	14
9.5.1B-8	14
9.5.1B-9	14
9.5.1B-10	14
9.5.1B-11	14
9.5.1B-12	14
9.5.1B-13	14
9.5.1B-14	14
9.5.1B-15	14
9.5.1B-16	14
9.5.1B-17	14
9.5.1B-18	14
9.5.1B-19	14
9.5.1B-20	14
9.5.1B-21	14
9.5.1B-22	14
9.5.1B-23	14
9.5.1B-24	14
9.5.1B-25	14
9.5.1B-26	14
9.5.1B-27	14
9.5.1B-28	14
9.5.1B-29	14
Appendix 9.5.1C Cover Sheet	10
9.5.1C-i	14
9.5.1C-1	10
9.5.1C-2	10
9.5.1C-3	14
9.5.1C-4	14
9.5.1C-5	14

EFFECTIVE PAGE LIST

VOLUME 5

Page	Amendment/Revision
9.5.1C-6	10
9.5.1C-7	10
9.5.1C-8	10
9.5.1C-9	10
9.5.1C-10	10
9.5.1C-11	14
9.5.1C-12	14
9.5.1C-13	14
9.5.1C-14	14
9.5.1C-15	14
9.5.1C-16	14
9.5.1C-17	14
9.5.1C-18	14
Appendix 9.5.1D-1	14
Chapter 10 Tab	-
Chapter 10 Cover Sheet	0
10-i	1
10-ii	0
10-iii	11
10-iv	7
10-v	14
Section 10.1 Tab	-
10.1.0-1	0
Fig. 10.1.0-1	11
Fig. 10.1.0-2	13
Fig. 10.1.0-3	10
Fig. 10.1.0-4	13
Fig. 10.1.0-5	14
Fig. 10.1.0-6	13
Fig. 10.1.0-7	3
Fig. 10.1.0-8	14
Section 10.2 Tab	-
10.2.1-1	7
10.2.1-2	7
10.2.2-1	7
10.2.2-2	7
10.2.3-1	0
10.2.3-2	0
10.2.3-3	0
10.2.3-4	7
10.2.3-5	0
10.2.3-6	0
10.2.3-7	0
10.2.3-8	7

Page	Amendment/Revision
10.2.3-9 Deletion Sheet	7
10.2.3-10 Deletion Sheet	7
10.2.3-11	0
10.2.4-1	0
10.2R-1	7
Fig. 10.2.2-1	12
Fig. 10.2.3-1	0
Fig. 10.2.3-2	0
Fig. 10.2.3-3	7
Fig. 10.2.3-4	0
Section 10.3 Tab	-
10.3.1-1	0
10.3.2-1	5
10.3.2-2	5
10.3.3-1	0
10.3.4-1	13
10.3.5-1	3
10.3.6-1	0
10.3R-1	13
Section 10.4 Tab	-
10.4.1-1	1
10.4.1-2	2
10.4.2-1	10
10.4.2-2	0
10.4.3-1	0
10.4.4-1	3
10.4.5-1	0
10.4.6-1	11
10.4.6-1a	11
10.4.6-2	0
10.4.6-3	3
10.4.6-4	2
10.4.6-5	2

Page	Amendment/Revision
10.4.6-6	3
10.4.7-1	12
10.4.7-2	6
10.4.8-1	11
10.4.8-1a	12
10.4.8-2	6
10.4.8-3	12
10.4.8-3a	12
10.4.8-4	12
10.4.8-5	0
Chapter 11 Tab	-
Chapter 11 Cover Sheet	0
11-i	13
11-ii	11
11-iii	10
11-iv	10
11-v	14
Section 11.1 Tab	-
11.1.1-1	0
11.1.1-2	0
11.1.1-3	0
11.1.1-4	0
11.1.1-5	0
11.1.2-1	13
11.1.2-2	13
11.1.2-3	13
11.1.2-4	13
11.1R-1	13
Fig. 11.1.2-1	13
Fig. 11.1.2-2	13
Fig. 11.1.2-3	13
Fig. 11.1.2-4	13
Fig. 11.1.2-5	13
Fig. 11.1.2-6	13
11.1.3-1	0
Section 11.2 Tab	-
11.2.1-1	5
11.2.1-2	0
11.2.1-3	0
11.2.1-4	0
11.2.1-5	0
11.2.1-6	0
11.2.1-7	14

Page	Amendment/Revision
11.2.1-8	5
11.2.1-9	14
11.2.2-1	14
11.2.2-2	14
11.2.2-3	14
11.2.2-4	14
11.2.3-1	10
11.2.3-2	1
Fig. 11.2.2-1	12
Fig. 11.2.2-2	6
Fig. 11.2.2-3	13
Fig. 11.2.2-4	2
Fig. 11.2.2-5	14
Section 11.3 Tab	-
11.3.1-1	0
11.3.2-1	0
11.3.2-2	13
11.3.2-3	13
11.3.2-4	1
11.3.2-5	0
11.3.3-1	5
Fig. 11.3.2-1	3
Fig. 11.3.2-2	13
Section 11.4 Tab	-
11.4.1-1	5
11.4.2-1	9
11.4.2-2	5
11.4.2-3	0
Section 11.5 Tab	-
11.5.1-1	10
11.5.2-1	10
11.5.2-1a	10
11.5.2-2	13
11.5.2-3	10
11.5.2-4	10
11.5.2-4a	10
11.5.2-4b	10
11.5.2-5	11
11.5.2-6	10
11.5.2-6a	10
11.5.2-6b	10
11.5.2-6c Deletion Sh.	1

Page	Amendment/Revision
11.5.2-7	10
11.5.2-8	10
Chapter 12 Tab	-
Chapter 12 Cover Sheet	0
12-i	13
12-ii	13
12-iii	13
12-iv	13
12-v	10
12-vi	14
Section 12.1 Tab	-
12.1.1-1	13
12.1.1-2	13
12.1.1-3	13
12.1.1-4	13
12.1.2-1	0
12.1.3-1	13
12.1.3-2	10
Fig. 12.1.1-1	13
Section 12.2 Tab	-
12.2.0-1	0
Section 12.3 Tab	-
12.3.1-1	0
12.3.1-2	0
12.3.1-3	14
12.3.1-4	14
12.3.1-5	0
12.3.1-6	0
12.3.1-7	0
12.3.1-8	0
12.3.1-9	0
12.3.2-1	0
12.3.3-1	10
12.3.3-2	14
12.3.3-3	10
12.3.3-4	10
Section 12.4 Tab	-
12.4.0-1	0
Section 12.5 Tab	-
12.5.1-1	13
12.5.1-2	13
12.5.1-3	13
12.5.2-1	14

Page	Amendment/Revision
12.5.2-2	14
12.5.2-3	14
12.5.3-1	13
12.5.3-2	13
12.5.3-3	13
12.5.3-4	13
12.5.3-5	13
12.5.3-6	13
12.5.3-7	13
12.5.3-8	13
12.5.3-9	13
Fig. 12.5.2-1	14
Fig. 12.5.2-2	14
Chapter 13 Tab	-
Chapter 13 Cover Sheet	0
13-i	13
13-ii	13
Section 13.1 Tab	-
13.1.1-1	14
13.1.1-2	14
13.1.1-3	13
13.1.1-4	13
13.1.2-1	13
13.1.2-2	13
13.1.2-3	13
13.1.2-4	13
13.1.2-5	13
13.1.2-6	13
13.1.3-1	0
13.1R-1	14
Fig. 13.1.1-1	13
Fig. 13.1.2-1	13
Section 13.2 Tab	-
13.2.1-1	13
13.2.2-1	13
13.2R-1	14
Section 13.3 Tab	-
13.3.0-1	13
13.3R-1	13

Page	Amendment/Revision
Section 13.4 Tab	-
13.4.0-1	13
Section 13.5 Tab	-
13.5.0-1	0
Section 13.6 Tab	-
13.6.0-1	10
Chapter 14 Tab	-
Chapter 14 Cover Sheet	0
14-i	0
14-ii	0
14-iii	0
14-iv	0
14-v	0
Section 14.1 Tab	-
14.1.0-1	0
Section 14.2 Tab	-
14.2.1-1	0
14.2.1-2	0
14.2.1-3	0
14.2.1-4	0
14.2.1-5	0
14.2.1-6	0
14.2.2-1	0
14.2.2-2	0
14.2.2-3	0
14.2.2-4	0
14.2.2-5	0
14.2.2-6	0
14.2.2-7	0
14.2.2-8	0
14.2.2-9	0
14.2.2-10	0
14.2.2-11	0
14.2.2-12	0
14.2.2-13	0
14.2.2-14	0
14.2.2-15	0
14.2.2-16	0
14.2.2-17	0
14.2.2-18	0
14.2.2-19	0
14.2.2-20	0

Page	Amendment/Revision
14.2.2-21	0
14.2.2-22	0
14.2.2-23	0
14.2.2-24	0
14.2.2-25	0
14.2.2-26	0
14.2.2-27	0
14.2.2-28	0
14.2.2-29	0
14.2.2-30	0
14.2.2-31	0
14.2.2-32	0
14.2.2-33	0
14.2.2-34	0
14.2.2-35	0
14.2.2-36	0
14.2.2-37	0
14.2.2-38	0
14.2.2-39	0
14.2.2-40	0
14.2.2-41	0
14.2.3-1	0
14.2.4-1	0
14.2.4-2	0
14.2.5-1	0
14.2.6-1	0
14.2.6-2	0
14.2.6-3	0
14.2.6-4	0
14.2.6-5	0
14.2.6-6	0
14.2.6-7	0
14.2.6-8	0
14.2.6-9	0
14.2.6-10	0
14.2.6-11	0
14.2.6-12	0
14.2.6-13	0
14.2.6-14	0
Fig. 14.2.2-1	0
Section 14.3 Tab	-
14.3.0-1	0

EFFECTIVE PAGE LIST
HBR FSAR

VOLUME 6

Page	Amendment/Revision
Chapter 15 Tab	-
Chapter 15 Cover Sheet	0
15-i	14
15-ii	14
15-iii	13
15-iv	13
15-v	13
15-vi	13
15-vii	13
15-viii	13
15-ix	14
15-x	14
15-xi	14
15-xii	13
15-xiii	14
15-xiv	14
15-xv	14
15-xvi	14
15-xvii	14
15-xviii	14
15-xix	14
Section 15.0 Tab	-
15.0.1-1	10
15.0.1-2	4
15.0.1-3	14
15.0.1-4	3
15.0.2-1	13
15.0.2-2	13
15.0.2-3	3
15.0.3-1	13
15.0.3-2	13
15.0.4-1	14
15.0.4-2	14
15.0.4-3	13
15.0.5-1	13
15.0.5-2	13
15.0.6-1	13

Page	Amendment/Revision
15.0.7-1	13
15.0.7-2	13
15.0.7-3	13
15.0.7-4	3
15.0.8-1	3
15.0.8-2	13
15.0.9-1	3
15.0.9-2	3
15.0.9-3	3
15.0.9-4	14
15.0.9-5	3
15.0.10-1	14
15.0.11-1	3
15.0.11-2	14
15.0.11-3	3
15.0.11-4	11
15.0.11-5	7
15.0R-1	14
Fig. 15.0.3-1	3
Fig. 15.0.3-2	13
Fig. 15.0.6-1	3
Section 15.1 Tab	-
15.1.0-1	0
15.1.1-1	3
15.1.2-1	3
15.1.3-1	14
15.1.3-2	14
15.1.3-3	14
15.1.3-4	14
15.1.3-5	14
15.1.4-1	13

Page	Amendment/Revision
15.1.5-1	13
15.1.5-2	13
15.1.5-3	14
15.1.5-4	14
15.1.5-5	14
15.1.5-6	14
15.1.5-7	14
15.1.5-8	13
15.1.5-9	14
15.1.5-10	13
15.1.5-11	13
15.1.5-12	13
15.1R-1	14
Fig. 15.1.3-1	13
Fig. 15.1.3-2	13
Fig. 15.1.3-3	13
Fig. 15.1.3-4	13
Fig. 15.1.3-5	13
Fig. 15.1.3-6	13
Fig. 15.1.3-7	14
Fig. 15.1.5-1	13
Fig. 15.1.5-2	13
Fig. 15.1.5-3	13
Fig. 15.1.5-4	13
Fig. 15.1.5-5	13
Fig. 15.1.5-6	13
Fig. 15.1.5-7	13
Fig. 15.1.5-8	13
Fig. 15.1.5-9	13
Fig. 15.1.5-10	13
Fig. 15.1.5-11	13
Fig. 15.1.5-12	13
Fig. 15.1.5-13	13
Fig. 15.1.5-14	13
Fig. 15.1.5-15	13
Fig. 15.1.5-16	13
Fig. 15.1.5-17	13
Section 15.2 Tab	-
15.2.0-1	14
15.2.1-1	0

Page	Amendment/Revision
15.2.2-1	14
15.2.2-2	14
15.2.2-3	14
15.2.2-4	14
15.2.3-1	3
15.2.4-1	3
15.2.5-1	3
15.2.6-1	3
15.2.7-1	13
15.2.7-2	13
15.2.7-3	13
15.2.7-4	13
15.2.7-5	13
15.2.8-1	3
Fig. 15.2.2-1	13
Fig. 15.2.2-2	13
Fig. 15.2.2-3	13
Fig. 15.2.2-4	13
Fig. 15.2.2-5	13
Fig. 15.2.2-6	13
Fig. 15.2.2-7	13
Fig. 15.2.2-8	13
Fig. 15.2.2-9	13
Fig. 15.2.2-10	13
Fig. 15.2.2-11	13
Fig. 15.2.2-12	14
Fig. 15.2.7-1	13
Fig. 15.2.7-2	13
Fig. 15.2.7-3	13
Fig. 15.2.7-4	13
Fig. 15.2.7-5	13
Fig. 15.2.7-6	13
Fig. 15.2.7-7	13

Page	Amendment/Revision
Fig. 15.2.7-8	13
Fig. 15.2.7-9	13
Fig. 15.2.7-10	13
Fig. 15.2.7-11	13
Fig. 15.2.7-12	13
Fig. 15.2.7-13	13
Fig. 15.2.7-14	13
Section 15.3 Tab	-
15.3.1-1	14
15.3.1-2	14
15.3.1-3	14
15.3.1-4	14
15.3.2-1	14
15.3.2-2	14
15.3.2-3	14
15.3.2-4	14
15.3.2-5	3
15.3.3-1	3
15.3R-1	13
Fig. 15.3.1-1	13
Fig. 15.3.1-2	13
Fig. 15.3.1-3	13
Fig. 15.3.1-4	13
Fig. 15.3.1-5	13
Fig. 15.3.1-6	14
Fig. 15.3.2-1	13
Fig. 15.3.2-2	13
Fig. 15.3.2-3	13
Fig. 15.3.2-4	13
Fig. 15.3.2-5	13
Fig. 15.3.2-6	14
Section 15.4 Tab	-
15.4.1-1	14
15.4.1-2	14
15.4.1-3	14

Page	Amendment/Revision
15.4.2-1	14
15.4.2-2	14
15.4.2-3	14
15.4.2-4	14
15.4.3-1	14
15.4.3-2	14
15.4.3-3	14
15.4.3-4	14
15.4.3-5	14
15.4.3-6	14
15.4.3-7	14
15.4.4-1	3
15.4.5-1	3
15.4.6-1	14
15.4.6-2	14
15.4.6-3	13
15.4.6-4	14
15.4.7-1	14
15.4.7-2	14
15.4.8-1	13
15.4.8-2	13
15.4.8-3	14
15.4.8-4	14

Page	Amendment/Revision
15.4.9-1	3
15.4R-1	14
Fig. 15.4.1-1	13
Fig. 15.4.1-2	13
Fig. 15.4.1-3	13
Fig. 15.4.1-4	14
Fig. 15.4.2-1	14
Fig. 15.4.2-2	14
Fig. 15.4.2-3	13
Fig. 15.4.2-4	13
Fig. 15.4.2-5	13
Fig. 15.4.2-6	13
Fig. 15.4.2-7	13
Fig. 15.4.2-8	13
Fig. 15.4.2-9	14
Fig. 15.4.3-1	13
Fig. 15.4.3-2	13
Fig. 15.4.3-3	13
Fig. 15.4.3-4	13
Fig. 15.4.3-5	13
Fig. 15.4.3-6	13
Fig. 15.4.3-7	14
Fig. 15.4.8-1	13
Fig. 15.4.8-2	13
Fig. 15.4.8-3	13
Fig. 15.4.8-4	14
Section 15.5 Tab	-
15.5.1-1	3
15.5.2-1	3
Section 15.6 Tab	-
15.6.1-1	14
15.6.1-2	14
15.6.1-3	14
15.6.2-1	7
15.6.2-2	7
15.6.2-3	14
15.6.2-4	14
15.6.2-5	13
15.6.2-6	14
15.6.2-7	13
15.6.2-8	14

Page	Amendment/Revision
15.6.3-1	3
15.6.3-2	3
15.6.4-1	0
15.6.5-1	14
15.6.5-2	14
15.6.5-2a	14
15.6.5-3	13
15.6.5-4	7
15.6.5-5	7
15.6.5-6	13
15.6.5-7	14
15.6.5-8	14
15.6.5-9	14
15.6.5-10	11
15.6.5-11	11
15.6R-1	13
15.6R-2	13
Fig. 15.6.1-1	13
Fig. 15.6.1-2	13
Fig. 15.6.1-3	13
Fig. 15.6.1-4	13
Fig. 15.6.2-1 Del. Sh.	12
Fig. 15.6.2-2 Del. Sh.	13
Fig. 15.6.2-3	7
Fig. 15.6.2-4	13
Fig. 15.6.2-5	13
Fig. 15.6.2-6	13
Fig. 15.6.2-7	13
Fig. 15.6.2-8	13
Fig. 15.6.2-9	13
Fig. 15.6.2-10	13

Page	Amendment/Revision
Fig. 15.6.5-1	13
Fig. 15.6.5-2	13
Fig. 15.6.5-3	13
Fig. 15.6.5-4	13
Fig. 15.6.5-5	13
Fig. 15.6.5-6	13
Fig. 15.6.5-7	13
Fig. 15.6.5-8	13
Fig. 15.6.5-9	13
Fig. 15.6.5-10	13
Fig. 15.6.5-11	14
Fig. 15.6.5-12	14
Fig. 15.6.5-13	13
Fig. 15.6.5-14	13
Fig. 15.6.5-15	13
Fig. 15.6.5-16	13
Fig. 15.6.5-17	13
Fig. 15.6.5-18	13
Fig. 15.6.5-19	13
Fig. 15.6.5-20	13
Fig. 15.6.5-21	13
Fig. 15.6.5-22	13
Fig. 15.6.5-23	13
Fig. 15.6.5-24	14
Fig. 15.6.5-25	14
Fig. 15.6.5-26	14
Fig. 15.6.5-27	14
Fig. 15.6.5-28 through Fig. 15.6.5-32 Del. Sh.	13
Fig. 15.6.5-33	14
Fig. 15.6.5-34 through Fig. 15.6.5-38 Del. Sh.	13
15.6.5-39	7
Section 15.7 Tab	-
15.7.1-1	11
15.7.1-2	0
15.7.1-3	0
15.7.2-1	9
15.7.2-2	0
15.7.3-1	0
15.7.4-1	0
15.7.4-2	11
15.7.4-3	14
15.7.4-4	14
15.7.4-5	11
15.7.4-6	11
15.7.5-1	14
15.7.5-2	14
15.7.5-3	14
15.7.5-4	14
15.7.5-5	14
15.7.5-6	14
15.7.6-1	0
15.7R-1	11
Chapter 16 Tab	-
Chapter 16 Cover Sheet	0
16-i	0
16.0.0-1	0
16.0R-1	0
Chapter 17 Tab	-
Chapter 17 Cover Sheet	0
17-i	0
17-ii	0
17-iii	13
17-iv	13
17-v	13
17-vi	13
Section 17.1 Tab	-
17.1.0-1	0
17.1.1-1	0
17.1.2-1	0
17.1.2-2	0
17.1.2-3	0
17.1.2-4	0
17.1.2-5	0
17.1.2-6	0
17.1.2-7	0
17.1.3-1	0
17.1.3-2	0
17.1.3-3	0
17.1.3-4	0
17.1.3-5	0
17.1.3-6	0
17.1.3-7	0

Page	Amendment/Revision
17.1.3-8	0
17.1.3-9	0
17.1.3-10	0
17.1.3-11	0
17.1.3-12	0
17.1.3-13	0
17.1.3-14	0
17.1.3-15	0
17.1.4-1	0
17.1.4-2	0
17.1.4-3	0
17.1.4-4	0
17.1.4-5	0
17.1.4-6	0
17.1.4-7	0
Fig. 17.1.3-1	0
Fig. 17.1.3-2	0
Fig. 17.1.4-1	0
Fig. 17.1.4-2	0
Fig. 17.1.4-3	1
Section 17.2 Tab	-
17.2.0-1 Deletion Sheet	13

Page	Amendment/Revision
Section 17.3 Tab	-
17.3.1-1	13
17.3.1-2	13
17.3.1-3	13
17.3.1-4	13
17.3.2-1	13
17.3.2-2	13
17.3.2-3	13
17.3.2-4	13
17.3.2-5	13
17.3.2-6	13
17.3.2-7	13
17.3.2-8	14
17.3.3-1	13
17.3.3-2	13
17.3.3-3	13
17.3.3-4	13
17.3.3-5	13

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

GENERAL TABLE OF CONTENTS (CONT'D)

TABLE 1.1.0-1 (Continued)

SAR	Safety Analysis Report
SBO	Station Blackout
SCR	Silicon Control Rectifier
SFP	Spent Fuel Pit
SHNPP	Shearon Harris Nuclear Power Plant
SG	Steam Generator
SI	Safety Injection
SIS	Safety Injection System
SOR	Senior Operator License
SRO	Senior Reactor Operator
SRWP	Standing Radiation Work Permit
SS	Stainless Steel
SSE	Safe Shutdown Earthquake
SSPC	Steel Structure Painting Council
STP	Standard Temperature and Pressure
SWP	Service Water Pump
SWPS	Solid Waste Processing System

Gaseous wastes are collected and stored in Waste Gas Decay Tanks until release or they are discharged to the environment in a manner that does not create radioactivity concentrations above 10CFR20 limits.

1.2.2.5 Fuel Handling System

The reactor is refueled with equipment designed to handle spent fuel under water. Underwater transfer of spent fuel provides an optically transparent radiation shield, as well as a reliable source of coolant for removal of decay heat. This system also provides capability for receiving, handling, and storage of new fuel.

1.2.2.6 Turbine and Auxiliaries

The turbine is a tandem-compound, 3-element, 1,800 rpm unit having 45 in. exhaust blading in the low pressure elements. Four combination moisture separator-reheater units are employed to dry and superheat the steam between the high and low pressure turbine cylinders. |7

A single-pass deaerating, radial flow surface condenser, vacuum pump air ejector, two 55 percent capacity condensate pumps, two 55 percent capacity motor-driven boiler feed pumps, and six stages of feedwater heaters are provided. Two auxiliary (motor-driven) feedwater pumps are provided, in addition to an auxiliary feedwater pump which is steam driven. The steam-driven pump may be used in the unlikely event that power to both motor-driven pumps is interrupted.

1.2.2.7 Electrical System

The main generator is an 1,800 rpm, 3 phase, 60 cycle, hydrogen innercooled unit. Three single phase main step-up transformers deliver power to the 230 kV switchyard.

The Station Service System consists of auxiliary transformers, 4160 V switchgear, 480 V motor control centers, and 125 V DC equipment.

Emergency power supplied by alternate sources including emergency diesel generators provides power required for safe shutdown of the unit and for operating post-accident containment cooling equipment, as well as for both high head and low head safety injection pumps to ensure an acceptable post-loss-of-coolant containment pressure transient.

1.2.2.8 Engineered Safety Features Protection Systems

The Engineered Safety Features Protection Systems provided for this unit have sufficient redundancy of component and power sources that, under the conditions of a hypothetical LOCA, the system can, even when operating with partial effectiveness, maintain the integrity of the containment and keep the exposure of the public below the limits of 10CFR100.

The systems provided are summarized below:

a) The Containment System provides a highly reliable, essentially leak-tight barrier against the escape of fission products. The containment vessel penetrations are tested in accordance with 10CFR50 Appendix J. Pipes penetrating the containment which could become potential paths for leakage to the environment following a LOCA are provided with Isolation Valve Seal Water System (IVSW) connections. The system provides a simple and reliable means for injection of seal water between the seats and stem packing of the closed globe and double disc types of isolation valves, and into the piping between closed diaphragm type isolation valves. The operation of the system can be monitored after the accident, and provisions are included for manually replenishing the seal water if required. These provisions minimize leakage to the environment.

b) The Safety Injection System provides borated water to insert negative reactivity and cool the core by injection into the cold and hot legs of the reactor coolant loops.

c) The Containment Air Recirculation Cooling System provides a dynamic heat sink to cool the containment atmosphere under the conditions of a LOCA. The system utilizes the normal containment ventilation and cooling equipment.

d) The Containment Spray System provides a spray of cool, chemically treated borated water to the containment atmosphere to provide iodine removal capability and backup to the Containment Air Recirculation Cooling System.

1.2.2.9 Independent Spent Fuel Storage Installation

(This section is provided as information only. The ISFSI has a separate, independent safety analysis report.)

The NUTECH Horizontal Modular Storage (NUHOMS) system is a totally passive installation that provides long-term interim storage for irradiated fuel assemblies. The fuel assemblies are confined in a helium atmosphere by a stainless steel canister. The canister is protected and shielded by a massive concrete module. Decay heat is removed by thermal radiation, conduction, and convection from the canister to an air plenum inside the concrete module. Air flows through this internal plenum by natural draft convection.

The canister containing seven irradiated fuel assemblies is transferred from the reactor fuel pool to the concrete module in a transfer cask. The cask is precisely aligned and the canister is inserted into the module by means of a hydraulic ram.

Design, construction, and operation of this facility is governed by Materials License No. SNM-2502.

1.3 COMPARISON TABLES

The comparisons given below are being submitted as part of the updated FSAR. They were considered valid at the time they were submitted. They relate to the designs of HBR 2 and the other plants compared as they existed at the time of submittal to the Nuclear Regulatory Commission (NRC). Numerous changes have occurred in HBR 2 since the original material was submitted, including the use of fuel manufactured by Exxon Nuclear Corp., which affects the reactor parameters. Also, major changes may have occurred in the plants compared to HBR 2.

1.3.1 DESIGN PARAMETERS AND PLANT COMPARISON

The design parameters of the HBR 2 are presented in tabular form in Table 1.3.1-1 along with the comparisons of the major parameters from the final designs of the Turkey Point, Indian Point 2, and Ginna plants. The purpose and evaluation of the parameter differences from the plant safety point of view among these plants are appended by reference line number.

TABLE 1.3.1-1 (Cont'd)

	ROBINSON NO. 2 FINAL REPORT	TURKEY POINT NO. 3 OR NO. 4. FINAL REPORT	INDIAN POINT NO. 2 FINAL REPORT	GINNA FINAL REPORT	REFERENCE LINE NO.
CORE MECHANICAL DESIGN PARAMETERS					
Fuel Assemblies					
Design	RCC Canless 15 x 15	RCC Canless 15 x 15	RCC Canless 15 x 15	RCC Canless 14 x 14	34
Rod Pitch, in.	0.563	0.563	0.563	0.556	35
Overall Dimensions, in.	8.426 x 8.426	8.426 x 8.426	8.426 x 8.426	7.763 x 7.763	36
Fuel Weight (as UO_2), lb	175,400	176,200	216,000	120,872	37
Total Weight, lb	225,400	226,200	276,000	152,895	38
Number of Grids per Assembly	7	7	9	9	39
Fuel Rods					
Number	32,028	32,028	39,372	21,659	40
Outside Diameter, in.	0.422	0.422	0.422	0.422	41
Diametral Gap, in.	0.0065	0.0065	0.0065	0.0065	42
Clad Thickness, in.	0.0243	0.0243	0.0243	0.0243	43
Clad Material	Zircaloy	Zircaloy	Zircaloy	Zircaloy	44
Fuel Pellets					
Material	UO_2 Sintered	UO_2 Sintered	UO_2 Sintered	UO_2 Sintered	45
Density (% of Theoretical)	94-92-91	94-92-91	94-92-91	94-93	46
Diameter, in.	0.3659	0.3669	0.3669	0.3669	47
Length, in.	0.6000	0.6000	0.6000	0.6000	48
Rod Cluster Control Assemblies					
Neutron Absorber	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	5% Cd-15% In-80% Ag.	49
Cladding Material	Type 304 SS-Cold Worked	Type 304 SS-Cold Worked	Type 304 SS-Cold Worked	Type 304 SS-Cold Worked	50
Clad Thickness, in.	0.019	0.019	0.019	0.019	51
Number of Clusters	53	53	53	29	52
Number of Control Rods per Cluster	20	20	20	16	53

TABLE 1.3.1-1 (Cont'd)

	ROBINSON NO. 2 FINAL REPORT	TURKEY POINT NO. 3 OR NO. 4. FINAL REPORT	INDIAN POINT NO. 2 FINAL REPORT	GINNA FINAL REPORT	REFERENCE LINE NO.
Core Structure					
Core Barrel, ID/OD, in.	133.875/137.875		148.0/152.5	109.0/112.5	54
Thermal Shield ID/OD, in.	142.625/148.0		158.5/164.0	115.3/122.5	55
FINAL NUCLEAR DESIGN DATA					
Structural Characteristics					
Fuel Weight (As UO_2), lb.	175,400	176,200	216,000	120,130	56
Clad Weight, lb.	36,300	36,300	44,600	22,440	57
Core Diameter, in. (Equivalent)	119.5	119.5	132.5	96.5	58
Core Height, in. (Active Fuel)	144	144	144	144	59
Reflector Thickness and Composition					
Top - Water plus Steel, in.	10	10	10	10	60
Bottom - Water plus Steel, in.	10	10	10	10	61
Side - Water plus Steel, in.	15	15	15	15	62
H_2O/U, (Cold Volume Ratio)	4.18	4.18	4.18	4.08	63
Number of Fuel Assemblies	157	157	193	121	64
UO_2 Rods per Assembly	204	204	204	179	65
Performance Characteristics					
Loading Technique	3 region, nonuniform	3 region nonuniform	3 region nonuniform	3 region nonuniform	66
Fuel Discharge Burnup, MWD/MTU					
Average First Cycle	14,500	14,500	14,200	~14,900	67
Equilibrium Core Average	27,000	13,000	24,700	~24,400	68

TABLE 1.3.1-1 (Cont'd)

	ROBINSON NO. 2 FINAL REPORT	TURKEY POINT NO. 3 OR NO. 4. FINAL REPORT	INDIAN POINT NO. 2 FINAL REPORT	GINNA FINAL REPORT	REFERENCE LINE NO.
Feed Enrichments, w/o					
Region 1 (Region 4, HBR 2)	3.12	1.85	2.2	2.44	69
Region 2 (Region 5, HBR 2)	3.00	2.55	2.7	2.78	70
Region 3 (Region 6, HBR 2)	2.20	3.10	3.2	3.48	71
Equilibrium	3.10	3.10			
Control Characteristics					
Effective Multiplication (Beginning of life)					
Cold, No Power, Clean	1.180	1.180	1.257	1.188	72
Hot, No Power, Clean	1.38	1.38	1.999	1.137	73
Hot, Full Power, Xe and Sm Equilibrium	1.077	1.077	1.152	1.080	74
Rod Cluster Control Assemblies					
Material	5% Cd-15% In-80% Ag	5% Cd-15% In-80% Ag	5% Cd-15% In-80% Ag	5% Cd-15% In-80% Ag	75
Number of RCC Assemblies	53	53	53	33	76
Number of Absorber per RCC Assembly	20	20	20	16	77
Total Rod Worth	See Table 3.2.1-3 OF THE ORIGINAL FSAR	See Table 3.2.1-3 OF THE ORIGINAL FSAR	See Table 3.2.1-3 OF THE ORIGINAL FSAR	6.8%	78
Boron Concentrations					
To shut reactor down with no rods inserted, Clean (K_{eff} = .99) Cold/hot	1250 ppm/1210 ppm	1250 ppm/1210 ppm	1480 ppm/1370 ppm	1160 ppm/820 ppm	79
To control at power with no rods inserted, clean/equilibrium xenon and samarium	1000 ppm/670 ppm	1000 ppm/670 ppm	1200 ppm/780 ppm	1310 ppm/890 ppm	80
Boron worth, Hot	7.3 $\delta k/k$	7.3 $\delta k/k$	1% $\delta k/k$ / 89 ppm	1% $\delta k/k$ /120 ppm	81
Boron worth, Cold	5.6 $\delta k/k$	5.6 $\delta k/k$	1% $\delta k/k$ / 72 ppm	1% $\delta k/k$ / 90 ppm	82

TABLE 1.[illegible]1 (Cont'd)

	ROBINSON NO. 2 FINAL REPORT	TURKEY POINT NO. 3 OR 4 FINAL REPORT	INDIAN POINT NO. 2 FINAL REPORT	GINNA FINAL REPORT	REFERENCE LINE NO.
Pressurizer Relief Tank	ASME III Class C	ASME III Class C	ASME III Class C	ASME III Class C	91
Pressurizer Safety Valves	ASME III	ASME III	ASME III	ASME III	92
Reactor Coolant Piping	USAS B31.1	USAS B31.1	USAS B31.1	USAS B31.1	93
PRINCIPAL DESIGN PARAMETERS OF THE REACTOR COOLANT SYSTEM					
Reactor Primary Heat Output, MWt	2308	2200	2758	1300	94
Reactor Primary Heat Output, Btu/hr	7877×10^6	7508×10^6	9413×10^6	4437×10^6	95
Operating Pressure, psig	2235	2235	2235	2235	96
Reactor Inlet Temperature	546.1	546.2	543	551.9	97
Reactor Outlet Temperature	604.6	602.1	596.0	601.4	98
Number of Loops	3	3	4	2	99
Design Pressure, psig	2485	2485	2485	2485	100
Design Temperature, °F	650	650	650	650	101
Hydrostatic Test Pressure (Cold), psig	3110	3110	3110	3110	102
Coolant Volume, including pressurizer, cu.ft	9315	9088	12,600	6245	103
Total Reactor Flow, gpm	265,500	268,500	358,800	180,000	104
PRINCIPAL DESIGN PARAMETERS OF THE REACTOR VESSEL					
Material	SA-302 Grade A and B, low alloy steel, internally clad with austenitic stainless steel	SA-302 Grade B., low alloy steel, internally clad with austenitic stainless steel	SA-302 Grade B, low alloy steel, internally clad with austenitic stainless steel	SA-302 Grade B, low alloy steel, internally clad with austenitic stainless steel	105

TABLE 1.3.1-1 (Cont'd)

LINE ITEM COMPARISON

H. B ROBINSON NO. 2 - TURKEY POINT NO. 3 AND NO. 4 - INDIAN POINT NO. 2 - GINNA

Line Item	Notes
5.-6.	The reactor coolant system design pressure for the four plants is 2500 psia. For all conditions the system pressure is limited by code safety valves set to open at design pressure and sized to prevent system pressure from exceeding code limitations. Equipment capabilities for overpressure protection are established by the complete loss of load without an immediate reactor trip. The maximum overpressure for this transient is therefore a function of the safety valve capacity and the maximum pressurizer surge rate and is not dependent on the value of the nominal operating pressure. The operating pressure is selected to ensure that desired thermal conditions are maintained in the core. The operating pressure is established and maintained between the upper and lower reactor trip limits to permit transient variations in either direction with the assistance of the Pressure Control System.
7.-8.	There are no significant differences among the hot channel factors. For a detailed discussion, see Section 4.4.
9.	The differences in the departure from nucleate boiling ratio (DNBR) at nominal conditions are due to the slight differences in operation conditions.
10.	Same for all plants.
11.	The flow varies from plant to plant due to pump design and number of loops.
12.	The effective flow rate for heat transfer is essentially proportional to the total flow rate as determined by the core geometry.
13.	Effective flow area for heat transfer is determined by the mechanical design of fuel assemblies and core.
14.-24.	There are no significant changes for these parameters from the previous plants.
25.	The active surface area is determined by the mechanical design of the core.

TABLE 1.3.1-1 (Cont'd)

LINE ITEM COMPARISON

H. B ROBINSON NO. 2 - TURKEY POINT NO. 3 AND NO. 4 - INDIAN POINT NO. 2 - GINNA

Line Item	Notes
26.-29.	The heat transfer parameters are determined by the required heat output, the heat transfer surface area and the design peaking factors for the core. They are related to clad integrity in that these conditions must be within the capability of the fuel and must also meet the thermal-hydraulic design criteria of DNB and fuel temperature. Extensive experience indicates that no problem exists at these thermal outputs.
30.	Same for all plants.
31.-32.	The fuel central temperatures are not significantly different than those for the other plants. The temperatures are well below the UO_2 melting temperature of 5000^{o}F.
33.	The overpower linear power density is similar to that of Indian Point No. 2 and is still well within the fuel capability.
34.-36.	The fuel assembly design is not significantly changed with respect to type, rod pitch and overall dimensions.
37.	The total amount of fuel utilized is primarily a function of the nominal power rating. The fuel weight is reduced as a result of effects of having pressurized fuel rods.
38.	The total weight of each fuel assembly includes the weight of the fuel, clad, grids, rod cluster control (RCC) guide tubes, and top and bottom nozzles.
39.	The number of grids per assembly is primarily a function of the core length and the average coolant velocity along the fuel rods.
40.	The total number of fuel rods is consistent with the fuel assembly design and number of fuel assemblies.
41.-44.	Same for all plants.
45.-48.	The design of the fuel pellets is not substantially different. The Robinson fuel pellets are smaller as a result of pressurized fuel rods.
49.-53.	The rod cluster control design is the same for all four plants. The number of RCC assemblies for each plant is determined based upon the control requirements.

TABLE 1.3.1-1 (Cont'd)

LINE ITEM COMPARISON

H. B ROBINSON NO. 2 - TURKEY POINT NO. 3 AND NO. 4 - INDIAN POINT NO. 2 - GINNA

Line Item	Notes
54.-55.	The core barrel and thermal shield diameters are consistent with the core diameter.
56.-57.	The same comments as for line items 37 and 38 apply here.
58.	The core equivalent diameter is primarily a function of the nominal power rating.
59.-62.	Same for all plants.
63.	The water to uranium ratio is equivalent to that of Indian Point No. 2 and Turkey Point No. 3 and No. 4. The Ginna ratio is slightly lower because of the different fuel element geometry.
64.	The number of fuel assemblies required is primarily a function of nominal power rating.
65.	The number of fuel rods per assembly is primarily a function of core diameter and determined by use of 15 x 15 rather than 14 x 14 lattices. Any fuel assembly can be placed over an in-core instrumentation penetration and can accept a neutron flux probe.
66.	The core loading procedures are the same.
67.-68.	The average first cycle and first burnups are not significantly different but are affected by the burnable poison.
69.-71.	The core enrichment requirements do not vary significantly among all plants.
72.-74.	The beginning-of-life effective multiplications are not significantly different.
75.-77.	The same comments as for Line Items 49., 50., and 51. apply here.
78.	The total control rod worth is not significantly different.
79.-82.	The boron rquirements for reactor shutdown and control are primarily a function of core life and temperature.

1.3.2 COMPARISON OF FINAL AND PRELIMINARY INFORMATION

1.3.2.1 Partial Length Rod Cluster Control Assemblies

Eight partial length rod cluster control assemblies were added to improve control of long term xenon oscillations.

1.3.2.2 Burnable Poison Rods

Burnable poison rods were added to assure a zero or negative moderator temperature coefficient of reactivity at all times.

1.3.2.3 Safety Injection System Trip Signal

The actuating signal for the Safety Injection System was revised to any of the following signals:

a) Two out of three high containment pressure (~10 percent design pressure)

b) One out of three pairs low pressurizer pressure coincident with low pressurizer level (subsequently, the low pressurizer level was removed)

c) Two out of three steam line differential pressure (between steam generator header and main header) for any loop

d) High steam line flow coincident with low T_{avg} or low steam line pressure (in steam generator header), and

e) Manually.

These signals increase the initiation reliability and increase protection in the case of a steam line rupture.

1.3.2.4 Containment Spray System Signal

The actuating signal for the Containment Spray System was revised to operate from two sets of two-out-of-three containment high pressure signal channels.

1.3.2.5 Spray Additive

The containment spray chemical additive for inorganic iodine removal in case of a primary system rupture is changed from sodium thiosulphate to sodium hydroxide.

1.3.2.6 Rod Stop and Reactor Trip on Startup

The automatic rod stop signal is actuated by an intermediate range flux level setting, and the reactor trip signal on startup is supplied by a high flux level setting.

1.3.2.7 Spent Fuel Pit Cooling Loop

The spent fuel pit heater exchanger cooling is supplied from the component cooling loop rather than from the Service Water System.

1.3.2.8 Fuel Transfer System Drive

An air-motor drive replaced the cable drive for the fuel transfer conveyor car.

1.3.2.9 Steam Line Flow Nozzles

Steam line flow nozzles were incorporated to limit the consequences of a steam line rupture.

1.3.2.10 Isolation of the Control and Protection Systems

Isolation of the entire control and protection systems was increased to include all channels except those for the pressurizer level and steam generator level.

1.3.2.11 DC Station Batteries

A second DC station battery was provided for redundancy of emergency instrumentation, control and lighting power supply.

1.3.2.12 Service Water Booster Pumps

Two service water booster pumps were added to increase the water flow to the containment fan-coolers.

1.3.2.13 Boron Injection Tank

A boron injection tank was added to the discharge of the safety injection pumps going to the cold legs.

1.3.2.14 Strong Motion Recorders

Two strong motion recorders were installed to detect and record vibrations caused by earthquakes.

6

1.5.5 BLOWDOWN CAPABILITY OF REACTOR INTERNALS

The forces exerted on reactor internals and the core, following LOCA, were initially computed by employing the BLODWN-1 digital computer program developed for the space-time-dependent analysis of multi-loop PWR plants.

Regulatory Guide 1.94	QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTION, AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWER PLANTS (APRIL 1976) 3
ANSI Standard N45.2.5-1974	SUPPLEMENTARY QUALITY ASSURANCE REQUIREMENTS FOR INSTALLATION, INSPECTIONS, AND TESTING OF STRUCTURAL CONCRETE AND STRUCTURAL STEEL DURING THE CONSTRUCTION PHASE OF NUCLEAR POWR PLANTS

The original specification requirements, applicable guidance contained in Regulatory Guide 1.94, or acceptable alternatives based on an engineering evaluation will be utilized in the event future structural work is to be performed which falls under the established requirements of the Robinson 2 QA Program.

Regulatory Guide 1.137 | FUEL OIL SYSTEMS FOR STANDBY DIESEL GENERATORS (REVISION 1)

HBR 2 will comply with Regulatory Guide 1.137 with the following exceptions:

Regulatory Position C.1 is not applicable to HBR 2 per NRC's letter dated January 13, 1978 which distributed Regulatory Guide 1.137 and provided additional guidance regarding NRC's implementation of this guide for all nuclear power plants. Position C.1 was to be evaluated on a case by case basis for application to all construction permit cases under review whose Safety Evaluation Report had not been issued as of November 1, 1979. Since HBR 2 had an operating license as of this date, Position C.1 is not applicable.

Regulatory Position C.2 is applicable to HBR 2 per NRC's letter dated January 13, 1978 except as follows:

A. The analyses performed will be limited to API or specific gravity, water and sediment, and viscosity. The specifications that will be met will be those recommended by the emergency diesel generator manufacturer.

B. Since the Unit No. 2 diesel fuel oil storage tank is filled from site storage tanks used for a fossil-fired peaking unit and light off oil for a coal-fired unit, the sampling frequency will be as described below:

   1. The site storage tank being used will be sampled and analyzed prior to the transfer of oil to the diesel fuel oil storage tank.

   2. The Unit No. 2 diesel fuel oil storage tank will be sampled monthly.

Diesel Generator (DG) fuel oil is controlled under the QA Program by virtue of the procedures for testing of DG fuel oil being incorporated in the Plant Operating Manual which is part of the approved QA Program.

The above position is based on the following references:

(1) NRC letter, Robert B. Minogue (NRC) to Regulatory Guide Distribution List (Division 1), regarding Regulatory Guide 1.137 dated January 13, 1978.

(2) NRC letter, D. G. Eisenhut (NRC) to All Power Reactor Licenses, January 7, 1980, Incoming Document No. NLU-80-48.

(3) CP&L letter, NO-80-725, M. A. McDuffie (CP&L) to D. A. Eisenhut (NRC), "Quality Assurance Requirements for Diesel Generator Fuel Oil", May 14, 1980.

(4) NRC letter, Steven A. Varga (NRC) to J. A. Jones (CP&L), September 30, 1981, Incoming Document No. NLU-81-482.

(5) CP&L letter, NO-81-1914, November 20, 1981, S. R. Zimmerman (CP&L) to S. A. Varga (NRC), "Quality Assurance Requirements Regarding Diesel Generator Fuel Oil"

(6) NRC letter, S. A. Varga (NRC) to J. A. Jones (CP&L), December 10, 1981, Incoming Document No. NLU-81-607.

Regulatory Guide 1.144 — AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS (JANUARY 1979)

ANSI Standard N45.2.12-1977 — REQUIREMENTS FOR AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS

1. CP&L will follow the requirements and recommendations of paragraphs C.1, C.2, C.3.a.2, C.3.b, and C.4. Our position on paragraph C.3.a.1 is as follows:

Audits of operational phase activities, as outlined in Section 6, H. B. Robinson Technical Specifications, shall be performed at the frequencies specified in the Technical Specifications.

2. CP&L performs both internal and external audits as defined in ANSI N45.2.12. Generally the term "assessments" applies to internal audits of operational phase activities and the term "assessors" applies to individuals who perform assessments of those activities. Implementing procedures provide specific applications of those terms.

2.1 Geography and Demography

2.1.1 Site Location and Description

2.1.1.1 Specifications of Location. The Robinson Plant is located in northwest Darlington County, South Carolina, approximately 3 miles west-northwest of Hartsville, South Carolina; 24 miles northwest of Florence, South Carolina; 34 miles north-northeast of Sumter, South Carolina; and 54 miles east-northeast of Columbia, South Carolina. The North Carolina border is 28 miles north of the site and the Atlantic Ocean is about 88 miles southeast (Figure 2.1.1-1).

The plant is on the southwest shore of Lake Robinson, a cooling impoundment of Black Creek. Coordinates are 34° 24' 12" north latitude and 80° 09' 30" west longitude. Universal Transverse Mercator (UTM) coordinates are 3,806,800 north and 577,500 east.

The plant is located in the Coastal Plain physiographic province, approximately 15 miles southeast of the Piedmont province. Topography of the region (Figure 2.1.1-2) is characterized by rolling sand hills interspersed with water courses.

2.1.1.2 Site Area Map. An aerial photograph of the plant area is shown in Figure 2.1.1-3, and a map of the site showing property lines (site boundary) is provided in Figure 2.1.1-4. The site presently covers approximately 2,500 acres of land and surrounds Lake Robinson, a 2280-acre impoundment. Carolina Power & Light Company owns all land below the 230 ft. contour surrounding the lake.

Since the original purchase of the land, CP&L sold lots on the lake's west shore. In addition to these lots, CP&L sold 4.4 acres of land to the New Market United Methodist Church for expansion of church facilities. In all cases, CP&L retained ownership of land below the 230 ft. contour. However, property owners were allowed to lease land between the 230 ft. contour and the lake (220 ft. contour normal operating level) and to construct piers, boathouses, and ramps. Provisions were also made for means of access to the lake by the general public. As a result, three privately owned recreational areas, one private sailboat club, and numerous access points throughout the lake allow for the use of the lake by the local population.

Carolina Power & Light Company owns and operates a 185 Mwe fossil-fueled generating plant (Unit 1) adjacent to the nuclear unit (Unit 2). Unit 1 was placed in service in 1960, prior to the construction of Unit 2. Additionally, CP&L leases the Darlington IC Plant, a 572 Mwe internal combustion (oil) plant, from General Electric. The Darlington Plant is located approximately 1 1/3 miles NNW of the plant on land originally included as part of the Robinson site property.

Approximately 1000 ft from the reactor, CP&L operates the Robinson Visitor's Center. As part of the center's facilities there is a covered picnic pavilion, located on the southwest shore of Lake Robinson.

A spur track of a commercial railroad enters the immediate plant area (see Section 2.1.2) north of the plant and allows for delivery of coal to Unit 1.

The exclusion zone is defined as the 1400 ft radial area surrounding the plant. There are no residences or agricultural activities inside of the exclusion zone.

TABLE 2.1.3-3

1995 LOCATION OF INDUSTRIAL WORK FORCE

22 1/2 DEGREE SECTOR	RANGE - MILES										
	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	8-9	9-10	TOTAL
N/A	788[1]	250[8]									1038
E					80[3]						80
ESE						2685[4]					2685
SE				420[6]		75[7]					495
SSE								180[5]			180
NW								900[2]			900
TOTAL	788	250		420	80	2760		1080			5378

NOTES: [1]Estimated labor force at Robinson Nuclear Power Plant: estimated peak labor for both Robinson Unit 1 (fossil) during outage and Robinson Unit 2 during normal operation.

[2]A. O. Smith Company (900).

[3]International Mineral & Chemical Corporation (80).

[4]BIFCO (25); Sonoco Products (2500); Amspak (160).

[5]Roller Bearing Corporation of South Carolina (180).

[6]Sara Lee Hosiery (420).

[7]Hartsville Alert Center (75).

[8]Tally Metals (250).

References 2.1.3-2 (for locations)

TABLE 2.1.3-4

1993 LOCATION OF SCHOOL POPULATION

22 1/2 DEGREE SECTOR	RANGE - MILES 3-4	4-5	5-6	6-7	7-8	8-9	9-10	TOTALS
ENE							575[1]	575
E		525[2]	375[3]		250[11]			1150
ESE		2300[4]	2625[5]					4925
SE			250[6]			225[7]		475
SSE	575[8]							575
S							125[9]	125
NW					782[10]			782
TOTALS	575	2825	3250		1032	225	700	8607

NOTES:

[1]West Hartsville Elementary (575)

[2]North Hartsville Elementary (525)

[3]Sonavista Elementary (375)

[4]Hartsville Sr. High School (1800), Carolina Elementary (500)

[5]Washington St. Elementary (450), Thornwell Elementary (475) Coker College (600), Governor's School (175) Hartsville Jr. High (925)

[6]Southside Elementary (250)

[7]Thomas Hart Academy (225)

[8]West Hartsville Elementary (575)

[9]Ebenezer School (55)

[10]McBee Elementary (364), McBee High School (418)

[11]Emanuel Baptist (250)

Reference 2.1.3-2

2.2.2 Descriptions

Residential development along the shores of Lake Robinson is concentrated along the shores of the lake and in the direction of Hartsville. Since 1960 numerous permanent and vacation homes have been built above the 230 ft contour. Below the 230 ft contour, property owners have constructed small private piers, boat docks, and ramps; access is provided by lease agreements between landowners and CP&L.

Public recreational areas include Easterling's Landing, 1.7 miles NNE (a beach, picnic and paved boat launch area); Atkinson's Landing, 1.2 miles NNE (a beach and boat launch area); and J & M Marina 4300 ft E (a beach, paved boat launch, and boat gasoline facility). A small private sailboat club is also located on the lake, 2 miles NNE. All facilities are on the eastern lake shore. Several other areas provide recreational access to the lake, but this use is limited compared to that of other facilities.

East and adjacent to the nuclear unit (Unit 2), CP&L owns and operates a 185 Mwe coal fired electric generating plant (Unit 1). Unit 1 was placed in service in 1960.

The Darlington IC Plant (1 1/3 miles NNW) is a 572 Mwe internal combustion (oil) electric generating plant. The plant is owned by General Electric, but leased and operated by CP&L.

South Carolina Electric & Gas Company transports natural gas via an underground pipeline (2 miles N). The pipeline transects Lake Robinson in an east/west direction. That part of the pipeline which crosses the discharge canal extends above ground.

Other industrial development within 10 miles of the plant is not extensive, and includes seven firms which employ more than 100 people (Table 2.1.3-3). Principal products are paper products, textiles, fertilizer, seeds, bearings, and metal works (Reference 2.2.2-1). All of these firms are located in or near Hartsville (3 miles SSE).

Agricultural development has occurred within the five-mile area especially in areas north and west of the plant. Acreage to the north includes numerous peach orchards. Associated with the peach orchards is a fruit processing firm which processes and distributes local peaches, as well as other non-local produce.

Principal transportation routes include SC 151 (1/2 mile E), a highway running north and south and numerous state maintained secondary roads.

A small private airport is located 2 1/2 miles east of the plant. Only small aircraft use the runway.

2.3.3 Onsite Meteorological Measurements Program

2.3.3.1 Onsite Operational Program. Collections of HBR onsite meteorological data began in April, 1974. A guyed, openlatticed tower supports the lower and upper levels of instrumentation. Wind direction, wind speed, and wind variance (sigma theta) are recorded at both levels. Ambient and dewpoint temperatures are measured at the lower level. The differential temperature between the upper and lower levels is measured by twin, redundant delta temperature systems operating simultaneously. Solar radiation, barometric pressure and precipitation are collected near ground level. The wind sensors are mounted on 12-foot booms oriented perpendicular to the general NE-SW prevailing wind flow to minimize tower shadow effects. The temperature probes and lithium chloride dewpoint sensor are housed in Climet aspirated shields mounted on 8-foot booms. A complete specification of major system component operating conditions is presented in Table 2.3.3-1; component manufacturer and manufacturer model numbers may be found in Table 2.3.3-2. Operational sensor elevations are displayed in Table 2.3.3-3. Component sensor accuracies are outlined in Table 2.3.3-4.

The meteorological tower is located about 0.53 miles north of the Containment Building. The base of the tower is at the plant grade level of about 225 feet above mean sea level.

An environmentally controlled shelter, which houses recording instruments, signal conditioning devices, and remote data access equipment, is located near the tower, perpendicular to the prevailing wind flow to minimize air trajectory deviations.

The Westinghouse Environmental Monitoring System was the primary data collection system. This system converted sensor outputs to a proportional number of discrete pulses that were electronically integrated and recorded on magnetic tape in 15-minute averaging periods. Also, a direct readout of any parameter was possible with this system. A test jack for each parameter was provided so that a pulse test counter could be plugged into it. The counter summed the pulses produced in a specific time interval, and the subsequent pulse total could then be converted to engineering units by use of a formula of the form $y = mx + b$.

Esterline Angus Twin Strip Chart Recorders were used for providing an analog record of both the upper and lower level wind direction and speed to back up the Westinghouse System. The Esterline Angus recorders were replaced with a Yokogawa Corporation Hybrid Recorder Model HR2300 in February of 1993. The Esterline Angus recorders provided analog traces for only the wind speeds and wind directions. The Yokogawa hybrid recorder provides trend traces and hard copy printouts of fifteen-minute averaged data for wind speeds, wind directions, ambient air temperature, differential temperatures, and dew point temperature. In addition, the hybrid recorder has a memory card that allows storage of over 30 days of retrievable fifteen-minute averaged data. Both the recorder configuration and the memory card are battery backed up to alleviate any loss of power problems. An RS232 communication port is also provided to remotely retrieve the hybrid recorder digital fifteen-minute averaged data from the HBR meteorological site via standard telephone lines to an approved contractor. This feature provides capabilities of detecting malfunctions of these parameters.

A micro-computer based sensor-system has also been installed at the HBR 2 meteorological site. This micro-computer (ADAC Model #1200) manufactured by ADAC Corporation, is based upon the Digital Equipment Corporation (DEC) LSI-11/23 micro-computer system. This system was selected because of its proven reliability in remote operation in the food processing and steel industries whose operational environments place a high demand upon the system integrity. Because the system was being adapted to collect electronic signals representing meteorological parameters, the software for the system was developed internally by the CP&L meteorological staff.

The ADAC system software scans each meteorological sensor input, except precipitation, once every ten (10) seconds. The precipitation input is scanned for a contact closure once per second. Each contact closure represents .01 in. of precipitation. These are then summed for a 15-minute total precipitation value. All other 10-second scan values are summed for a 15-minute period, then the average value for each meteorological parameter is obtained by performing a 15-minute mathematical average. If during a 15-minute averaging period, more than 33% of the 10-second scan values (30 individual scans) are not valid, the entire 15-minute averaged interval is then indicated to be unavailable (i.e., set to 9999.00).

The 15-minute averaged values for each parameter are stored internally within the CMOS memory of the ADAC system. The CMOS memory has the capacity to store up to four days of historical 15-minute averaged data. All CMOS memory is battery backed-up to prevent the loss of any stored data during brief power outages. The internal clock is completely battery operated. Thus, once time has been set, the clock remains running even during periods the system may be off or during brief power outages. Each 15-minute average data interval is marked with the current date and time, so that the "date/time" stamp on each recorded 15-minute averaged interval represents the ending time of the 15-minute average.

The ADAC hardware and software configuration allows up to three (3) remote locations to access this meteorological data acquisition system simultaneously. Each access port can display either the 15-minute averaged data for the most current period, a user specified previous period (up to four days previously), or the current 10-second scans of the meteorological sensors. The multitasking nature of the ADAC allows all of these actions to be accomplished without interruption of the sensor scanning or mathematical averaging of the data.

The HBR 2 ERFIS computer system accesses the ADAC meteorological sensor-system every 15-minutes to acquire the latest 15-minute averaged data. This information is stored in the ERFIS system and displayed in the Control Room on demand from the ERFIS terminal.

The ADAC meteorological sensor-system was developed by the CP&L meteorological staff and placed in operational service during 1987. To assure that the methodology employed by the ADAC system provided information which was consistent with that collected by the Westinghouse sensor-system, both meteorological data collection systems were operated simultaneously for at least 18 months to provide conclusive proof that major differences did not exist between the systems.

Data comparisons between the ADAC sensor system and the Westinghouse sensor system showed no significant differences between the data. Therefore, the meteorological historical data base was converted from the Westinghouse sensor system to the ADAC sensor system in September of 1992.

Since the ADAC sensor system is now the primary data acquisition system and the Westinghouse sensor system represented twenty-year-old technology that was no longer maintainable, the Westinghouse system was removed from service in February of 1993. The Yokogawa Corporation hybrid recorder described above now serves as the back up sensor system to the ADAC sensor system.

2.3.3.2 Data Reduction. When the Westinghouse sensor-system was the primary data acquisition system, the magnetic tape cassettes were changed and brought back to the general office for monthly processing. Computer programs converted all parameter pulse totals into engineering units. Since the ADAC sensor system is now the primary data acquisition system, data is retrieved via a different methodology than that which was used for the Westinghouse sensor system. A host computer located with an approved contractor retrieves the meteorological data from the HBR ADAC sensor system daily via a Company owned and operated dedicated microwave link. A backup standard telephone line is also available for data retrieval if the dedicated circuit is inoperable. This data is reviewed for potential immediate data problems by approved contractor personnel on a daily basis (excepting weekends and holidays). The ADAC data is then rigorously checked for consistency with the onsite hybrid recorder data and periodically, if out of line, with the National Weather Service data. Erroneous data is then discarded prior to insertion into the historical data base. The edited 15 minute averaged data is then stored on magnetic history tapes. Routine computer outputs include:

1. Monthly data summaries listing maximum temperature, minimum temperature, average temperature, barometric pressure, precipitation, solar radiation, and lower level dewpoint temperature as a daily average and monthly average.

2. Hourly averages of precipitation, barometric pressure, ambient temperature, differential temperature, lower level dewpoint, upper and lower level wind direction and wind speed, upper and lower level wind direction variance (sigma theta), Pasquill stability classes (as outlined in Regulatory Guide 1.23) computed from the average of the two delta temperature systems, and accumulated solar radiation (langleys/minute).

3. The 15-minute averages of both upper level and lower level wind direction, speed, and sigma theta, barometric pressure, and accumulated solar radiation.

4. Joint wind frequency distributions by direction (as outlined in Regulatory Guide 1.23) for both upper and lower levels, showing average wind speeds and number of unrecovered data hours.

The analog trend charts produced by the hybrid recorder are changed twice per month. They are used as backup data to provide checks on the other systems and to provide consistency of data.

2.3.3.3 Maintenance and Calibration. An onsite maintenance and calibration program was initiated in January 1976. Regulatory Guide 1.23 data recovery requirements are met by performing scheduled calibrations carried out in accordance with Robinson Emergency Plan requirements such that:

1. All wind systems are changed and replaced with National Bureau of Standards traceable calibrated wind sensors, per Regulatory Guide 1.23.

2. All ambient and differential temperature systems are changed and replaced with NBS traceable calibrated systems, per Regulatory Guide 1.23.

3. The Lithium chloride dewpoint sensor bobbin is changed.

4. Calibrations of the barometric pressure, solar radiation, and precipitation systems are verified (sensors are changed on an annual basis).

5. All other onsite sensor system equipment is calibrated or its calibration is verified.

A further enhancement of data recovery is achieved by operating twin, redundant delta temperature systems simultaneously. Comparison of the two systems on a real time basis through the data received at an approved contractor office gives us the capabilities to remotely detect discrepancies in either system, usually within 24 hours (except weekends).

2.3.3.4 Onsite Data. Westinghouse System onsite joint wind percentage frequency distributions (compiled per Regulatory Guide 1.23) for both upper and lower sensor elevations for the period January 1976 through December 1981 is presented in Tables 2.3.3-5 and 2.3.3-6. Data recovery percentages for this period are 98.1 percent for the lower level and 96.5 percent for the upper level.

All onsite joint wind frequency distributions were compiled by using the delta temperature stability classifications, as outlined by Regulatory Guide 1.23.

Average onsite windpseeds for the total six-year period at the lower and upper levels are 5.2 mph and 9.6 mph, respectively. Representation of the data to long term, area, climatological averages are discussed in Sections 2.3.1 and 2.3.2.

TABLE 2.3.3-1

OPERATING CONDITIONS

Wind Sensor:	-40°F to +120°F, up to 100 percent relative humidity, up to 125 mph wind speed
Temperature Sensors:	-50°F to +130°F
Aspirated Temperature Shields:	-60°F to +150°F
Honeywell Dew Point Sensor	-40°F to +160°F, 11 percent relative humidity and above
Total Precipitation Sensor:	No Limitations (equipped with heater)
Solar Radiation Sensor	No Limitations
Barometric Pressure Sensor:	-30°F to +170°F, 0 - 90 percent relative humidity
Transmuter	-40°F to +120°F, 5 percent to 95 percent relative humidity
Signal Conditioning Devices, Remote Data Access Equipment, and Data Acquisition Equipment:	+32°F to +131°F
Hybrid Recorder	+32°F to +122°F

TABLE 2.3.3-2

MAJOR SYSTEM COMPONENTS

COMPONENT	MANUFACTURER	MODEL NUMBER
SENSORS:		
Wind Sensor	Meteorology Research, Inc.	1074-22
Single-Element Temperature Sensor	Rosemount	78N0200N040
Dual Element Temperature Sensor	Rosemount	494-62232-4
Dew Point Sensor	Honeywell	SSPO29DO21
Total Precipitation Sensor	Weathermeasure Corp.	P-511E
Solar Radiation Sensor	Eppley Laboratory, Inc.	8-48
Barometric Pressure Sensor	Yellow Springs Instrument Co.	2014-28/32-HA
SIGNAL CONDITIONING DEVICES:		
Temperature transmitter for differential temperature	Rosemount	3044CA1B4E5
Temperature transmitter for ambient temperature	Rosemount	3044CA1B4E5
Power Supply for temperature transmitters	Rosemount	SPS-2021-P
Amplifier for solar radiation	Acromag	311-BX-TV
Transmuter for Wind Sensor	Meteorology Research, Inc.	1001
Tachometer circuit card	Meteorology Research, Inc.	12905
540° azimuth amplifier circuit card	Meteorology Research, Inc.	14303
Dual buffer amplifier circuit card	Meteorology Research, Inc.	14159

Table 2.3.3-2 (Continued)

COMPONENT	MANUFACTURER	MODEL NUMBER
Sigma azimuth amplifier circuit card	Meteorology Research, Inc.	14312
Power supply circuit card	Meterology Research, Inc.	12784
Pulse transmitter for Honeywell dew point	Westinghouse	S1B4
Translator:		
Mainframe	Climatronics Corp.	F460
Temperature Translator Card	Climatronics Corp.	100869
Dew Point Translator Card	Climatronics Corp.	100870
Power Supply Card	Climatronics Corp.	F460
RECORDING DEVICES:		
Hybrid recorder for wind speeds and directions, differential temperatures, ambient air temperature, and dew point temperature	Yokogawa Electric Corporation	HR2300

Table 2.3.3-2 (Continued)

COMPONENT	MANUFACTURER	MODEL NUMBER
REMOTE DATA ACCESS EQUIPMENT:		
Dialup modems	General Data Comm., Inc.	212A/SL
	Smart Modem	M-24
Dedicated 4-wire modem General Data	General Data Comm., Inc.	202S/T
SUPPORT EQUIPMENT:		
Secondary power arrestor for input power lines	Dale	SPA-100
Isolation transformer	Topaz, Inc.	0111T25SR
Aspirated temperature shield for single-element temperature sensor	Climet	016-1
Aspirated temperature shield for dual-element temperature sensor and Honeywell dew point sensor	Climet	016-2
DATA ACQUISITION SYSTEM:		
Microcomputer Data Acquisition System	ADAC Corp.	System 1200
LSI-11/23 96Kb CMOS battery backup	ADAC Corp.	1816CMOS
A/D Converter 12 bit	ADAC Corp.	1012
Multiplexer Expander Card	ACAC Corp	1012EX
Contact Closure Detector	ADAC Corp.	1616 CCI
Asynchronous Serial line Interface	ADAC Corp.	1750
Clock Card Battery Backup	Digital Pathways, Inc.	TU-50
CRT Display	Televideo	950

TABLE 2.3.3-3

OPERATIONAL SENSOR ELEVATIONS

SENSORS	OPERATIONAL ELEVATIONS ABOVE TOWER BASE (METERS)
Wind	11.0 and 62.3
Honeywell Dew Point	10.0
Solar Radiation	1.5
Differential Temperature	9.3 to 60.8
Precipitation	1.5
Barometric Pressure	1.5

TABLE 2.3.3-4

COMPONENT ACCURACY

Wind Sensor:	
Wind Speed:	±0.4 mph or 1 percent, whichever is greater = 1.0 mph
Wind Direction, 0 to 540	±5.4 degrees
Honeywell Dew Point Sensor:	±2°F at or above 11 percent relative humidity
Solar Radiation Sensor: (pyranometer)	±0.04 calories/square centimeter/minute (langleys)
Differential Temperature System:	±0.51°F over ambient temperature range from -50 to +30°F
Ambient Temperature System:	±.31°F
Hybrid Recorder:	(0.05% rdg + 2 digits)
Total Precipitation Sensor:	±0.5 percent (calibrated at 0.5 in. per hour)
Barometric Pressure Sensor:	±0.006 of mercury. (Temperature effect: -0.1 in. of mercury per 100 degrees of Fahrenheit operating temperature span.)
Climatronics Signal Conditions	±0.5% of full scale
ADAC A/D Converter:	±0.025% of full scale range
Amplifiers:	±.25% of full scale

CHAPTER 3
DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS

CHAPTER 3
DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 3
DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 3
DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

TABLE OF CONTENTS (Cont'd)

The reactor containment is defined as a Class I structure for purposes of seismic design (Section 3.8). Its structural members have sufficient capacity to accept without exceeding yield stresses a combination of normal operating loads and tornado; or functional loads due to a LOCA and the loadings imposed by the maximum wind velocity; or those due to design earthquake, whichever is the larger.

All electrical systems and components vital to plant safety, including the emergency diesel generators (DG) are designed as Class I and designed or arranged so that their integrity is not impaired by the maximum hypothetical earthquake, wind storms, floods, tornado winds, or disturbances on the external electrical system. Power wires, control cabling, instrument cabling, motors, and other electrical equipment required for operation of the engineered safety features (ESF) are suitably protected against the effects of either a nuclear system accident or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event that their use is required.

3.1.2.3 Fire Protection

Criterion: The facility is designed so that the probability of fires and explosions and the potential consequences of such events do not result in undue risk to the health and safety of the public. Noncombustible and fire-resistant materials shall be used throughout the facility wherever necessary to preclude such risk, particularly in areas containing critical portions of the facility such as containment, Control Room, and components of ESF. (GDC 3)

Response:

Fire prevention in all areas of the nuclear unit is provided by structure and component design which optimizes the containment of combustible materials and maintains exposed combustible materials below their ignition temperature in the design atmosphere. Fire control requires the capability to isolate or remove fuel from an igniting source, or to reduce the combustibles temperature below the ignition point, or to exclude the oxidant, and preferably, to provide a combination of the three basic control means. The latter two means are fulfilled by providing fixed or portable fire-fighting equipment of capacities proportional to the energy that might credibly be released by fire.

This plant was designed on the basis of limiting the use of combustible materials in construction and of using fire-resistant materials to the greatest extent possible. Also, fire barrier seals (electrical seals, fire doors, and fire dampers) are used to prevent the spread of fires.

The fire protection system has the design capability to extinguish any probable combination of simultaneous fires which might occur at the station.

The reactor containment system is designed to maintain the capability in case of fire to safely shut down the reactor and isolate the containment.

The Containment and Auxiliary Building Ventilation Systems are operable from the Control Room. Smoke or heat detectors and Control Room alarms are provided for key ventilation systems (Section 9.5.1).

An extensive fire detection system exists in the Containment and Auxiliary Building that provides automatic fire suppression.

Containment liner thermal insulation and insulation adhesives do not support combustion.

3.1.2.4 Sharing of Systems

Criterion: Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public. (GDC 4)

Response:

The residual heat removal (RHR) pumps and heat exchangers serve dual functions. Although the normal duty of the RHR exchangers and RHR pumps is performed during periods of reactor shutdown, during all plant operating periods this equipment is aligned to perform the low head safety injection (SI) function. In addition during the recirculation phase of a LOCA, the system may be used for the core cooling and the containment spray cooling functions. Demonstration testing of the system, performed during each refueling period before plant startup, provides assurance of correct system alignment for the safety function of components.

During the injection phase, the SI pumps do not depend on any portion of other systems. During the recirculation phase, if RCS pressure stays high due to a small break accident, suction to the SI pumps is provided by the RHR pumps.

The Containment Air Recirculation System also serves the dual function of containment cooling during normal operation and containment cooling after an accident. Since the method of operation for both cooling functions is the same, the dual aspect of this system does not affect its function as an ESF.

3.1.2.5 Records Requirements

Criterion: The reactor licensee shall be responsible for assuring the maintenance throughout the life of the reactor of records of the design, fabrication, and construction of major components of the plant essential to avoid undue risk to the health and safety of the public. (GDC 5)

Response:

Records of the design, of the major RCS components, and the related ESF components are maintained in the offices of Carolina Power and Light Company (CP&L) and will be retained there throughout the life of the plant.

Records of fabrication are maintained in the manufacturers' plants as required by the appropriate code, or other requirements pending submittal to Westinghouse or CP&L. They are available at any time to CP&L throughout the life of the plant. Construction records are available at the construction site and in the offices of CP&L where they will be retained for the life of the plant.

Records of the design, fabrication, construction, and testing of the reactor containment will be maintained throughout the life of the reactor.

3.1.2.6 Reactor Core Design

Criterion: The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. (GDC 6)

Response:

The reactor core, with its related control and protection system, was designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under all expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations, including the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater, and loss of all offsite power.

The Reactor Control and Protection System is designed to actuate a reactor trip for any anticipated combination of plant conditions, when necessary, to ensure a minimum Departure from Nucleate Boiling (DNB) ratio equal to or greater than the safety limit specified in Section 4.4.

The integrity of the fuel cladding is ensured by preventing excessive fuel swelling, excessive cladding overheating, and excessive cladding stress and strain. This is achieved by designing the fuel rods so that the following conservative limits are not exceeded during normal operation or any anticipated transient condition:

a) Minimum DNB ratio equal to or greater than the safety limit specified in Section 4.4

b) Fuel center temperature below melting point of UO_2

c) Internal gas pressure less than the nominal external pressure (2250 psia) even at the end of life

d) Clad stresses less than the Zircaloy yield strength

e) Clad strain less than 1 percent, and

f) Cumulative strain fatigue cycles less than 80 percent of design strain fatigue life.

The ability of fuel designed and operated to these criteria to withstand postulated normal and abnormal service conditions is shown by analyses to satisfy the demands of plant operation well within applicable regulatory limits (Chapter 15.0).

The reactor coolant pumps (RCP) are supplied with sufficient rotational inertia to maintain an adequate flow coastdown in the event of a simultaneous loss of power to all pumps. The flow coastdown inertia is sufficient to ensure that the reduction in heat flux obtained with a low flow reactor trip prevents core damage.
In the unlikely event of a turbine trip from full power without an immediate reactor trip, the subsequent reactor coolant temperature increase and volume insurge to the pressurizer results in a high pressurizer pressure trip and thereby prevents fuel damage for this transient. A loss of external electrical load of 100 percent of full power or less is normally controlled by rod cluster insertion together with a controlled steam dump to the condenser and atmosphere to prevent an unacceptable temperature and pressure increase in the RCS. In this case, the overpower-overtemperature protection would guard against any combination of pressure, temperature, and power which could result in a DNB ratio less than the safety limit during the transient.

In neither the turbine trip nor the loss-of-flow events do the changes in coolant conditions provoke a nuclear power excursion because of the large system thermal inertia and relatively small void fraction. Protection circuits actuated directly by the coolant conditions identified with core limits are therefore effective in preventing core damage.

3.1.2.7 Suppression of Power Oscillations

Criterion: The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed. (GDC 7)

Response:

The potential for axial oscillations of power distributions has been shown to exist for cores the size of HBR 2 when power changes occur. The Axial Power Distribution Monitoring System (APDMS) provides the capability when required by the Technical Specifications to measure the core axial power shape employing two of the movable incore detectors. For xenon oscillations caused by changes in power level and/or rod movements, plant procedures exist which provide for operator initiated damping of the oscillations by control rod movement. Adverse axial power distributions caused by xenon shifts which result from routine load changes during power operation are controlled using Power Distribution Control 3 (PDC-3) procedures. The PDC-3 procedure limits the peaking factor to the Technical Specification limit by restricting xenon redistribution during power changes. This is done by monitoring the power difference between the top and bottom of the core as a function of different power levels and core conditions.

Both incore and out-of-core instrumentation are provided to obtain necessary information concerning power distribution. This instrumentation is adequate to enable the operator to monitor and control xenon induced oscillations. (Incore instrumentation is used to periodically calibrate and verify the information provided by the out-of-core instrumentation.)

3.1.2.17 <u>Monitoring Radioactivity Releases</u>

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (GDC 17)

Response:

The containment atmosphere, the ventilation exhausts from the RHR pumps compartments, the plant vent, the containment fan-coolers service water discharge, the component cooling loop liquid, the condenser vacuum pump exhaust, the steam generators blowdown effluents, the waste disposal system liquid effluents, and the fuel handling building lower level exhaust are monitored to support normal operation. In addition to the sources monitored to support normal operation, the fuel handling building upper level exhaust is monitored to support transient conditions. To support accident conditions, the main steam lines are monitored plus the sources that are monitored for normal operation and transient conditions. High radiation activity from any of these sources is indicated and alarmed in the Control Room.

All accidental spills of liquids are contained within the Reactor Auxiliary Building, Radwaste Building or E&RC Building and collected in the building sumps for processing. Any contaminated liquid effluent released to the condenser circulating water canal is monitored. For the case of leakage from the reactor containment under accident conditions, the plant area radiation monitoring system, supplemented by portable survey equipment kept in the Control Room, provides adequate monitoring of releases during an accident. An outline of the procedures and equipment to be used in the event of an accident are discussed in Chapter 11.0. The environmental monitoring program is described in Section 11.5.

3.1.2.18 <u>Monitoring Fuel and Waste Storage</u>

Criterion: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels. (GDC 18)

Response:

Monitoring and alarm instrumentation are provided for fuel and waste storage and handling areas to detect inadequate cooling and to detect excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids.

The spent fuel pit cooling loop is flow monitored to assure proper operation.

A ventilation system removes gaseous radioactivity from the atmosphere of the fuel handling building and discharges it to the atmosphere through roughing and high-efficiency particulate air filters (HEPA). An area radiation monitor is in continuous service in this area and it actuates a high-activity alarm on the control board annunciator.

3.1.2.19 Protection Systems Reliability

Criterion: Protection system shall be designed for high functional reliability and in-service testability necessary to avoid undue risk to the health and safety of the public. (GDC 19)

Response:

The reactor uses a higher speed version of the Westinghouse magnetic-type control rod drive mechanisms (CRDM) used in the San Onofre, and Connecticut Yankee plants. Upon a loss of power to the coils, the full length RCCA are released and fall by gravity into the core.

The reactor internals, fuel assemblies, RCCA, and drive system components are designed as Class I equipment. The RCCA are fully guided through the fuel assembly and for the maximum travel of the control rod into the guide tube.

The alignment of the mating sections in each guide tube assembly is maintained by dowel pins to assure free rod movement under both normal operating and credible accident conditions. The alignment between the guide tube assemblies and the guide thimbles in the fuel assemblies is maintained by the guide pin in the upper core plate which mates with the fuel assembly top nozzle. As a further safeguard against "hang up" of the RCCA, the length and travel of the absorber rods are set to prevent them from being totally withdrawn from the fuel assembly guide thimbles during operation.

As a result of these design safeguards and the flexibility designed into the RCCA, abnormal loadings and misalignments can be sustained without impairing operation of the RCCA.

An analogous system has successfully undergone 4132 hr of testing in the Westinghouse Reactor Evaluation Center during which about 27,200 ft of step-driven travel and 1461 trips were accomplished with test misalignments in excess of the maximum possible misalignment that may be experienced when installed in the plant.

Protection channels are designed with sufficient redundancy for individual channel calibration and test to be made during power operation without degrading the reactor protection. Bypass removal of one trip circuit is accomplished by placing that channel in a partial-tripped mode; i.e., two-out-of-three channel becomes a one-out-of-two channel. Testing will not cause a trip unless a trip condition exists in a concurrent channel.

Reliability and independence is obtained by redundancy within each tripping function. In a two-out-of-three logic, for example, the three channels are equipped with separate primary sensors. Each channel has its own independent electrical source. Failure on the part of one channel to de-energize when required would affect only that particular channel. The trip signal furnished by the two remaining channels would be unimpaired in this event.

3.1.2.20 Protection Systems Redundancy and Independence

Criterion: Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure on removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served. (GDC 20)

Response:

The RPS is designed so that the most probable modes of failure in each channel result in a signal calling for the protective trip. The protection system design combines redundant sensors and channel independence with coincident trip philosophy so that a safe and reliable system is provided in which a single failure will not defeat the channel function, cause a spurious plant trip, or violate reactor protection criteria.

Channel independence is carried throughout the system extending from the sensor to the relay actuating the protective function. When the protective and control functions are combined, it is done only at the sensor. The protective and control functions are fully isolated in the remaining part of the channel, control being derived from the primary protection signal path through an isolation amplifier. Therefore, failure in the control circuit does not affect the protection channel.

The ESF equipment is actuated by one of the redundant ESF channels. Each coincident network energizes an engineered safety actuation device that operates the associated ESF equipment motor starters and valve operators. As an example, the control circuit for a SI pump is typical of the control circuit for a large pump operated from switchgear. The actuation relay, energized by the ESF Instrumentation System, has normally open contacts. These contacts energize the circuit breaker closing coil to start the pump when the control relay is energized. The ESF Instrumentation System actuates (depending on the severity of the condition) the SIS, containment isolation, and the Containment Air Recirculation Cooling System.

In the RPS, two reactor trip breakers are provided to interrupt power to the RCCA drive mechanisms. The breaker main contacts are connected in series (with the power supply) so that opening either breaker interrupts power to all full length RCCA, permitting them to fall by gravity into core.

Further detail on redundancy is provided through the descriptions of the respective systems covered by the various subsections in this section. Required continuous power supply for the protection systems is discussed in Section 8.3.1.

In summary, reactor protection is designed to meet all presently defined reactor protection criteria and is in accordance with the proposed Institute of Electrical and Electronic Engineers (IEEE) 279 "Standard for Nuclear Plant Protection Systems" August, 1968.

<u>3.1.2.21 Single Failure Definition</u>. Refer to Sections 3.1.2.20, 3.1.2.31, and 7.2.

<u>3.1.2.22 Separation of Protection and Control Instrumentation</u>. The physical arrangement of the redundant elements of the protection system are such that the probability is reduced that a single physical event will impair the vital function of the system (Section 3.1.2.23).

<u>3.1.2.23 Protection Against Multiple Disability for Protection Systems</u>.

Criterion: The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some other basis. (GDC 23)

Response:

The components of the protection system are designed and laid out so that the mechanical and thermal environment accompanying any emergency situation in which the components are required to function does not interfere with that function.

The physical arrangement of all elements associated with the protective system reduces the probability of a single physical event impairing the vital functions of the system.

Isolation of redundant analog channels originates at the process sensors and continues along the field wiring and through containment penetrations to the analog protection racks. Physical separation is used to the maximum practical extent to achieve isolation of redundant transmitters. Isolation of field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Analog equipment is isolated by locating redundant components in different protection racks. Each channel is energized from a separate AC instrument bus.

System equipment is separated between instrument cabinets so as to reduce the probability of damage to the total system by some single event.

Wiring between vital elements of the system outside of equipment housing is routed and protected so as to maintain the true redundancy of the systems with respect to physical hazards.

<u>3.1.2.24 Emergency Power for Protection Systems</u>. Redundancy in emergency power is provided in that there are two DG sets capable of supplying separate 480 volt buses. One complete set of safety features equipment is therefore independently supplied from each DG. A third dedicated shutdown diesel is provided for redundant power for loads required for safe shutdown of the reactor in the event of a fire (10CFR50, Appendix R) or Station Blackout (10CFR50.63).

Diesel engine cranking is accomplished by a stored energy system supplied solely for the associated DG. The stored energy (air start) systems for each DG are cross connected such that either system will start either DG. The cross connection is normally isolated. The undervoltage relay scheme is designed so that loss of 480 volt power does not prevent the relay scheme from functioning properly.

The ability of the DG sets to start within the prescribed time and to carry load can periodially be checked. The DG breaker is not closed automatically after starting during this testing. The generator may be manually synchronized to the 480 volt bus for loading. Blocking the closure of the DG breaker causes the bus tie breaker to close after a time delay (10 sec) sufficient for normal DG starting.

Emergency power is discussed in Section 8.3.1.

3.1.2.25 Demonstration of Functional Operability of Protection Systems

Criterion: Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred. (GDC 25)

Response:

Each protection channel in service at power is capable of being calibrated and tripped independently by simulated signals to verify its operation without tripping the plant. The testing scheme includes checking through the trip logic to the trip breakers. Thus, the operability of each trip channel can be determined conveniently and without ambiguity.

3.1.2.26 Protection System Failure Analysis Design

Criterion: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced. (GDC 26)

Response:

Each reactor trip circuit is designed so that trip occurs when the circuit is de-energized; an open circuit or loss of channel power, therefore, causes the system to go into its trip mode. In a two-out-of-three circuit, the three channels are equipped with separate primary sensors and each channel is energized from independent electrical buses. Failure to de-energize when required is, therefore, a mode malfunction that can affect only one channel. The trip signal furnished by the two remaining channels is unimpaired in this event.

Reactor trip is implemented by simultaneously interrupting power to the magnetic latch mechanisms on each drive allowing the full length rod clusters to insert by gravity. The entire protection system is thus inherently safe in the event of a loss of power. This equipment is selected to withstand the most adverse environmental conditions to which it will be subjected including post-accident conditions within the containment.

The ESF actuation circuits are designed on the same "de-energized to operate" principle as the reactor trip circuits with the exception of the containment spray actuation circuit which is energized to operate in order to avoid spray operation on inadvertent power failure.

Certain fires may cause multiple failures which could prevent reactor shutdown; therefore, a dedicated shutdown system was installed to bring the plant to a safe shutdown condition.

3.1.2.27 Redundancy of Reactivity Control

Criterion: Two independent control systems, preferably of different principles, shall be provided. (GDC 27)

Response:

One of the two reactivity control systems employs rod cluster control assemblies to regulate the position of the neutron absorbers within the reactor core. The other reactivity control system employs the Chemical and Volume Control System to regulate the concentration of boric acid solution neutron absorber in the Reactor Coolant System. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

3.1.2.28 Reactivity Hot Shutdown Capability

Criterion: The reactivity control systems provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition. (GDC 28)

Response:

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes. The maximum excess reactivity expected for the core occurs for the cold, clean condition at the beginning of life of the initial core.

The RCCA are divided into two categories comprising control and shutdown rod groups. The control banks used in combination with chemical shim control provides control of the reactivity changes of the core throughout the life of the core at power conditions. This group of RCCA is used to compensate for short term reactivity changes at power that might be produced due to variations in reactor power requirements or in coolant temperature. The chemical shim control is used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion and fission product buildup and decay.

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes. The maximum excess reactivity expected for the core occurs for the cold, clean condition at the beginning of life of the initial control rods and soluble neutron absorber (boron).

3.1.2.29 Reactivity Shutdown Capability.

Criterion: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn. (GDC 29)

Response: The reactor core, together with the Reactor Control and Protection System is designed so that the minimum allowable DNBR is at least 1.17 and there is no fuel melting during normal operation including anticipated transients.

The shutdown groups are provided to supplement the control group of RCCA to make the reactor at least one percent subcritical (K_{eff} = 0.99) following a trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCCA remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to avoid fuel damage during the most severe anticipated cooldown transient associated with a single active failure, e.g., accidental opening of a steam bypass, or relief valve. This is achieved with combination of control rods and automatic boron addition via the emergency core cooling system with the most reactive rod assumed to be fully withdrawn. Manually controlled boric acid addition is used to maintain the shutdown margin for the long term conditions of xenon decay and plant cooldown.

3.1.2.30 Reactivity Holddown Capability.

Criterion: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (GDC 30)

Response: The reactivity control systems provided are capable of making and holding the core subcritical under accident conditions in a timely fashion with appropriate margins for contingencies. Normal reactivity shutdown capability is provided within 2 sec following a trip signal by control rods with boric acid injection used to compensate for the long term xenon decay transient and for plant cooldown. Any time that the reactor is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection always exceeds that quantity required for the normal cold shutdown. This quantity always exceeds the quantity of boric acid required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

Boric acid is pumped from the boric acid tanks by one of two boric acid transfer pumps to the suction of one of three charging pumps which inject boric acid into the reactor coolant. Any charging pump and either boric acid transfer pump can be operated from diesel generator power on loss of offsite power. Boric acid can be injected by one pump at a rate which takes the reactor to hot shutdown with no rods inserted in less than forty-five minutes. In forty-five additional minutes, enough boric acid can be injected to compensate for xenon decay although xenon decay below the equilibrium operating level does not begin until approximately 15 hr after shutdown. If two boric acid pumps are available, these time periods are reduced. Additional boric acid injection is employed if it is desired to bring the reactor to cold shutdown conditions.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components, thus achieving the measure of reliability implied by the criterion.

Alternately, boric acid solution at lower concentration can be supplied from the refueling water tank. This solution can be transferred directly by the charging pumps or alternately by the SI pumps. The reduced boric acid concentration lengthens the time required to achieve equivalent shutdown.

3.1.2.31 Reactivity Control Systems Malfunction.

Criterion: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31)

Response: The RPS is designed to limit reactivity transients to DNBR ≥ the safety limit (specified in Section 4.4) due to any single malfunction in the deboration controls.

The RPS is capable of protecting against any single anticipated malfunction of the reactivity control system, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with rods is completely independent of the normal rod control functions since the trip breakers completely interrupt the power to the rod mechanisms regardless of existing control signals.

Details of the effects of continuous withdrawal of a control rod and continuous deboration are described in Sections 15.4 and 9.3.4, respectively.

3.1.2.32 Maximum Reactivity Worth of Control Rods

Criterion: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot:

a) Rupture the RCPB, and

b) Disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core. (GDC 32)

Response:

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot:

a) Rupture the reactor coolant pressure boundary, and

b) Disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The reactor control system employs control rod clusters, approximately half of which are fully withdrawn during power operation, serving as shutdown rods. The remaining rods comprise the controlling group which are used to control load and reactor coolant temperature. The rod cluster drive mechanisms are wired into preselected groups, and are, therefore, prevented from being withdrawn in other than their respective groups. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel.

The maximum insertion rate is analyzed in the detailed plant analysis assuming two of the highest worth groups to be accidentally withdrawn at maximum speed, yielding reactivity insertion rates of the order of 8×10^{-4} Δk/sec. This value is well within the capability of the overpower-overtemperature protection circuits to prevent core damage.

No credible mechanical or electrical control system malfunction can cause a rod cluster to be withdrawn at a speed greater than 77 steps per minute (~48 in. per minute).

3.1.2.33 RCPB Capability

Criterion: The RCPB shall be capable of accommodating without rupture the static and dynamic load imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition. (GDC 33)

Response:

The reactor coolant boundary is shown to be capable of accommodating without rupture the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection. Details of this analysis are provided in Section 15.4.

The operation of the reactor is such that the severity of an ejection accident is inherently limited. Since control rod clusters are used to control load variations only and boron dilution is used to compensate for core depletion, only the RCCA in the controlling groups are inserted in the core at power, and at full power these rods are only partially inserted. A rod insertion limit monitor is provided as an administrative aid to the operator to ensure that this condition is met.

By using the flexibility in the selection of control rod groupings, radial locations, and position as a function of load, the design limits the maximum fuel temperature for the highest worth ejected rod to a value which precludes any resultant damage to the primary system pressure boundary, from possible excessive pressure surges.

The failure of a rod mechanism housing resulting in a rod cluster being rapidly ejected from the core is evaluated as a theoretical, though not a credible accident. While limited fuel damage could result from this hypothetical event, the fission products are confined to the RCS and the reactor containment. The environmental consequences of rod ejection are less severe than from the hypothetical LOCA, for which public health and safety is shown to be adequately protected.

3.1.2.34 <u>RCPB Rapid Propagation Failure Prevention</u>

Criterion: The RCPB shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given:

a) To the provisions for control over service temperature and irradiation effects which may require operational restrictions

b) To the design and construction of the reactor pressure vessel (RPV) in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range, and for absorption of energy by plastic deformation

c) To the design and construction of RCPB piping and equipment in accordance with applicable codes. (GDC 34)

Response:

The RCPB is designed to reduce to an acceptable level the probability of a rapidly propagating type failure.

In the core region of the reactor vessel it is expected that the notch toughness of the material will change as a result of exposure to fast neutrons. This change is evidenced as a shift in the Nil-ductility Transition Temperature (NDTT), which is factored into the operating procedures in such a manner that full operating pressure is not reached until the affected vessel material is above the now higher Design Transition Temperature (DTT), and in the ductile material region. The pressure during startup and shutdown at the temperature below NDTT is maintained below the threshold of concern for safe operation.

The DTT is a minimum of NDTT plus 60^{o}F and dictates the procedures to be followed in the hydrostatic test and in station operations to avoid excessive cold stress. The value of the DTT is increased during the life of the plant as required by the expected shift in the NDTT temperature, and as confirmed by the experimental data obtained from irradiated specimens of reactor vessel materials during the plant lifetime.

All pressure-containing components of the RCS are designed, fabricated, inspected, and tested in conformance with the applicable codes (Section 3.2).

3.1.2.35 RCPB Brittle Fracture Prevention

Refer to Sections 3.1.2.34, 3.1.2.36, and 5.3.

3.1.2.36 RCPB Surveillance

Criterion: RCPB components shall have provisions for inspection, testing, and surveillance of criteria areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided. (GDC 36)

Response:

The design of the reactor vessel and its arrangement in the system permits access during the service life to the entire internal surfaces of the vessel and to the following external zones of the vessel:

a) The flange seal surface

b) The flange outside diameter (OD) down to the cavity seal ring

c) The closure head except around the drive mechanism adapters, and

d) The nozzle to reactor coolant piping welds.

The reactor arrangement within the containment provides sufficient space for inspection of the external surfaces of the reactor coolant piping, except for the area of pipe within the primary shielding concrete.

Monitoring of the NDTT properties of the core region plates forgings, weldments, and associated heat treated zones are performed in accordance with American Society for Testing and Materials (ASTM) E185 Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors (the revision in effect when the vessel was designed). Samples of reactor vessel plate materials were retained and catalogued in case future engineering development shows the need for further testing.

The material properties surveillance program includes not only the conventional tensile and impact tests, but also fracture mechanics tests. The fracture mechanics specimens are the Wedge Opening Loading type specimens. The observed shifts in NDTT of the core region materials with irradiation will be used to confirm the calculated limits on startup and shutdown transients.

To define permissable operating conditions below DTT, a pressure range is established which is bounded by a lower limit for pump operation and an upper limit which satisfies reactor vessel stress criteria. To allow for thermal stresses during heatup or cooldown of the reactor vessel, an equivalent pressure limit is defined to compensate for thermal stress as a function of rate of change of coolant temperature. Since the normal operating temperature of the reactor vessel is well above the maximum expected DTT, brittle fracture during normal operation is not considered to be credible.

3.1.2.37 Engineered Safety Features Basis for Design

Criterion: Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the RCPB, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends. (GDC 37)

Response:

The design, fabrication, testing and inspection of the core, RCPB and their protection systems give assurance of safe and reliable operation under all anticipated normal, transient, and accident conditions. However, engineered safety features are provided in the facility to back up the safety provided by these components. These engineered safety features have been designed to cope with any size reactor coolant pipe break up to and including the circumferential rupture of any pipe assuming unobstructed discharge from both ends, and to cope with any steam or feedwater line break up to and including the main steam or feedwater headers.

The release of fission products from the reactor fuel is limited by the SIS which, by cooling the core, keeps the fuel in place and substantially intact and limits the metal water reaction to an insignificant amount ($\leq$ one percent).

The SIS consists of high and low head centrifugal pumps driven by electric motors, and passive accumulator tanks which are self actuated and act independently of any actuation signal or power source.

The release of fission products from the containment is limited in three ways:

a) Blocking the potential leakage paths from the containment. This is accomplished by:

1) A steel-lined, concrete reactor containment with testable penetrations and liner weld channels

2) Isolation of process lines by the Containment Isolation System (CIS) which imposes double barriers in each line which penetrates the containment

3) An Isolation Valve Seal Water System which creates a leaktight seal between the valves in each line which penerates the containment water

b) Reducing the fission product concentration in the containment atmosphere by spraying chemically treated borated water which removes airborne elemental iodine vapor by washing action.

c) Reducing the containment pressure and thereby limiting the driving potential for fission product leakage by cooling the containment atmosphere using the following independent systems of essentially equal heat removal capacity:

1) Containment Spray System

2) Containment Air Recirculation Cooling System

3.1.2.38 Reliability and Testability of Engineered Safety Features

Criterion: All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public. (GDC 38)

Response:

A comprehensive program of plant testing is formulated for all equipment systems and system control vital to the functioning of engineered safety features. The program consists of performance tests of individual pieces of equipment in the manufacturer's shop, integrated tests of the system as a whole, and periodic tests of the actuation circuitry and mechanical components to assure reliable performance, upon demand, throughout the plant lifetime.

The initial tests of individual components and the integrated test of the system as a whole, complement each other to assure performance of the system as designed and to prove proper operation of the actuation circuitry.

The engineered safety features components are designed to provide for routine periodic testing.

Plant Technical Specifications specify the test frequency and acceptance criteria to be used for periodic verification of the operability of engineered safety features actuation circuits and components.

The testing of the analog channel inputs is accomplished in the same manner as for the reactor protection system. The engineered safety features logic system is tested by means of test switches to simulate inputs from the analog channels. The test switches interrupt the logic matrix output to the master relay to prevent actuation. Verification that the logic is accomplished is indicated by the matrix test light. Upon completion of the logic checks, verification that the circuit from the logic matrices to the master relay is complete is accomplished by a continuity check. Additional verification is provided by periodically operating the safeguards pumps by means of their normal controls.

3.1.2.39 Emergency Power.

Criterion: An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component. (GDC 39)

Response:

Independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby and emergency power sources as follows:

1. The normal source of auxiliary power during plant operation is the generator. Power is supplied via the unit auxiliary transformer which is connected to the main leads of the generator.

2. Power required during plant startup, shutdown, and after reactor trip is supplied from the CP&L 115 kV system by a tap from the Robinson 115 kV switchyard to startup transformer No. 2.

3. Two diesel generator sets are connected to the emergency buses to supply power in the event of loss to all other AC auxiliary buses.

4. A dedicated shutdown system exists which will bring the plant to a safe shutdown condition in the event of a fire (10CFR50, Appendix R) or Station Blackout (10CFR50.63).

5. Emergency power supply for vital instruments, control, and some emergency lighting is supplied from two 125 V DC station batteries.

The DG sets are located in the Reactor Auxiliary Building and are connected to separate 480 V auxiliary system buses. Each set will be started automatically on a SI signal or upon under-voltage on its corresponding 480 V auxiliary bus. Each diesel is adequate to supply the engineered safety features for the hypothetical accident concurrent with loss of outside power. This capacity is adequate to provide a safe and orderly plant shutdown in the

event of loss of outside electrical power. The dedicated shutdown diesel is located in a separate enclosure and carries loads to bring the plant to a safe shutdown if all other power and control is lost including the DG (Section 8.3).

3.1.2.40 Missile Protection.

Criterion: Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures. (GDC 40)

Response:

The dynamic effects during blowdown following a LOCA are evaluated in the detailed layout and design of the high pressure equipment and barriers which afford missile protection. Fluid and mechanical driving forces are calculated, and consideration is given to possible damage due to fluid jets and secondary missiles which might be produced.

The steam generators are supported, guided, and restrained in a manner which prevents rupture of the steam side of a generator, the steam lines and the feedwater piping as a result of forces created by a RCS pipe rupture. These supports, guides and restraints also prevent rupture of the primary side of a steam generator as a result of forces created by a steam or feedwater line rupture.

The mechanical consequences of a pipe rupture are restricted by design such that the functional capability of the engineered safety features is not impaired.

A LOCA or other plant equipment failure might result in dynamic effects or missiles. For such engineered safety features as are required to ensure safety in the event of such an accident or equipment failure, protection from these dynamic effects or missiles was considered in the layout of plant equipment and missile barriers. Fluid and mechanical driving forces were calculated, and consideration was given to the possibility of damage due to fluid jets and missiles which might be produced by the action jets. Consideration was given during the design to potential sources of missiles.

Layout and structural design specifically protect injection paths leading to unbroken reactor coolant loops against damage as a result of the maximum reactor coolant pipe rupture. Individual injection lines penetrate the main missile barrier, and the injection headers are located in the missile-protected area between the missile barrier and the containment outside wall for the hot leg SIS and RHR system or outside containment for the cold leg SIS. Individual injection lines, connected to the injection header, pass through the barrier and then connect to the loops. Separation of the individual injection lines is provided to the maximum extent practicable. Movement of the injection line, associated with rupture of a reactor coolant loop, is accommodated by line flexibility and by the design of the pipe supports such that no damage outside the missile barrier is possible.

The containment structure is capable of withstanding the effects of missiles originating outside the containment and which might be directed toward it so that no LOCA can result.

All hangers, stops, and anchors were designed in accordance with United States American Standards (USAS) B31.1 Code for Pressure Piping and ACI 318 Building Code Requirements for Reinforced Concrete which provide minimum requirements on material, design and fabrication with ample safety margin for both dead and dynamic loads over the life of the plant.

3.1.2.41 Engineered Safety Features Performance Capability

Criterion: Engineered safety features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public. (GDC 41)

Response:

Each engineered safety feature provides sufficient performance capability to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the public.

The extreme upper limits of public exposure are taken as the levels and time periods presently outlined in 10CFR100, i.e. 300 rem to the thyroid in two hours at the exclusion radius and 300 rem to the thyroid over the duration of the accident at the low population zone distance. The accident condition considered is the hypothetical case of a release of fission products per the Atomic Energy Commission's technical information report TID 14844. Also, the total loss of all outside power is assumed concurrently with this accident. However, operation of the SIS, considering the single failure criterion, limits the release of fission products from the core to only the gap activity between the fuel pellet and clad.

Under the above accident condition, the Containment Air Recirculation System and the CSS were designed and sized so that either system is able to supply the necessary post-accident cooling capacity to rapidly reduce the containment pressure following blowdown and cooling of the core by SI. The spray system was designed to provide adequate iodine removal with partial system effectiveness. Partial effectiveness is defined as operation of a system with one active component failure.

Each of the auxiliary cooling systems which serves an emergency function provides sufficient capability in the emergency operational mode to accommodate any single failure of an active component and still function in a manner to avoid undue risk to the health and safety of the plant personnel and the public.

3.1.2.42 Engineered Safety Features Components Capability

Criterion: Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a LOCA to the extent of causing undue risk to the health and safety of the public. (GDC 42)

Response:

All active components of the SIS (with the exception of the hot leg SIS isolation valves) and the CSS are located outside the containment and not subject to containment accident conditions. The accumulators are located in a missile shielded area.

Instrumentation, motors, cables, and penetrations located inside the containment are selected to meet the most adverse accident conditions to which they may be subjected. These items are either protected from containment accident conditions or are designed to withstand, without failure, exposure to the worst combination of temperature, pressure, and humidity expected during the required operational period (Section 3.11).

The SIS pipes serving each loop are anchored at the missile barrier in each loop area to restrict potential accident damage to the portion of piping beyond this point. The anchorage is designed to withstand, without failure, the thrust force of any branch line severed from the reactor coolant pipe and discharging fluid to the atmosphere, and to withstand a bending moment equal to the ultimate strength of the pipe or equivalent to that which produces failure of the piping under the action of free end discharge to atmosphere or motion of the broken reactor coolant pipe to which the emergency core cooling pipes are connected. This prevents possible failure at any point upstream from the support point including the branch line connection into the piping header.

3.1.2.43 Accident Aggravation Prevention

Criterion: Protection against any action of the engineered safety features which would accentuate significantly the adverse after-effects of a loss of normal cooling shall be provided. (GDC 43)

Response:

The reactor is maintained subcritical following a primary system pipe rupture accident. Introduction of borated cooling water into the core results in a net negative reactivity addition. The control rods insert and remain inserted.

The delivery of cold SI water to the reactor vessel following accidental expulsion of reactor coolant does not cause further loss of integrity of the RCS boundary (See Section 5.3).

3.1.2.44 Emergency Core Cooling System Capability

Criterion: An Emergency Core Cooling System with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty. (GDC 44)

Response:

Adequate emergency core cooling is provided by the SIS (which constitutes the Emergency Core Cooling System) whose components operate in three modes. These modes are delineated as passive accumulator injection, active SI and residual heat removal recirculation.

The primary purpose of the SIS is to automatically deliver cooling water to the reactor core in the event of a LOCA. This limits the fuel clad temperature and thereby ensures that the core will remain intact and in place, with its heat transfer geometry preserved. This protection is afforded for:

a) All pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant loop, assuming unobstructed discharge from both ends

b) A loss of coolant associated with the rod ejection accident, and

c) A steam generator tube rupture.

The basic design criteria for LOCA evaluations are:

a) The cladding temperature is to be less than:

1) The melting temperature of Zircaloy-4

2) The temperature at which gross core geometry distortion, including clad fragmentation may be expected

b) The total core metal-water reaction will be limited to less than one percent.

Thus the core geometry is retained to such an extent that effective cooling of the core is not impaired.

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the SIS adds shutdown reactivity so that with a stuck rod, no offsite power and minimum engineered safety features, there is no consequential damage to the RCS and the core remains in place and intact.

Redundancy and segregation of instrumentation and components is incorporated to assure that postulated malfunctions will not impair the ability of the system to meet the design objectives. The system is effective in the event of loss of normal plant auxiliary power coincident with the loss of coolant, and can accommodate the failure of any single component or instrument channel to respond actively in the system. During the recirculation phase of a LOCA, the system can accommodate a loss of any part of the flow path since back up alternative flow path capability is provided.

3.1.2.45 Inspection of Emergency Core Cooling System

Criterion: Design provisions shall, where practical, be made to facilitate physical parts of the Emergency Core Cooling System, including reactor vessel internals and water injection nozzles. (GDC 45)

Response:

Design provisions are made to facilitate access to the critical parts of the reactor vessel internals, injection nozzles, pipes, valves, and SI pumps for visual or boroscopic inspection for erosion, corrosion, and vibration wear evidence, and for non-destructive inspection where such techniques are desirable and appropriate.

3.1.2.46 Testing of Emergency Core Cooling System Components

Criterion: Design provisions shall be made so that components of the Emergency Core Cooling System can be tested periodically for operability and functional performance. (GDC 46)

Response:

The design provides for periodic testing of active components of the SIS for operability and functional performance.

Power sources are arranged to permit individual actuation of each active component of the SIS.

The SI pumps can be tested periodically during plant operation using the minimum flow recirculation lines provided. The residual heat removal pumps are used every time the residual heat removal loop is put into operation. All remote operated valves can be exercised and actuation circuits can be tested during routine plant operation.

3.1.2.47 Testing of Emergency Core Cooling System

Criterion: Capability shall be provided to test periodically the operability of the Emergency Core Cooling System up to a location as close to the core as is practical. (GDC 47)

Response:

An integrated system test can be performed during the late stages of plant cooldown when the residual heat removal loop is in service. This test would not introduce flow into the RCS but would demonstrate the operation of the valves, pump circuit breakers, and automatic circuitry upon initiation of SI.

The accumulator tank pressure and level are continuously monitored during plant operation and flow from the tanks can be checked at any time using test lines.

The accumulators and the SI piping up to the final isolation valve is maintained full of borated water at refueling water concentration while the plant is in operation. The accumulators and injection lines will be refilled with borated water as required by using the SI pumps to recirculate refueling water through the injection headers. A small bypass line and a return line are provided for this purpose.

Flow in each of the hot leg injection lines and in the main flow line for the residual heat removal pumps in monitored by a flow indicator. Pressure instrumentation is also provided for the main flow paths of the high head and residual heat removal pumps. Level and pressure instrumentation are provided for each accumulator tank.

3.1.2.48 Testing of Operational Sequence of Emergency Core Cooling System

Criterion: Capability shall be provided to test initially, under conditions as close as practical to design, the full operational sequence that would bring the Emergency Core Cooling System into action, including the transfer to alternate power sources. (GDC 48)

Response:

The design provides for capability to test initially, to the extent practical, the full operational sequence up to the design conditions for the SIS to demonstrate the state of readiness and capability of the system. These functional tests provide information to confirm valve operating times, pump motor starting time, the proper automatic sequencing of load addition to the DG, and delivery rates of the injection water to the RCS.

3.1.2.49 Containment Design Basis

Criterion: The reactor containment structure, including openings and penetrations, and any necessary containment heat removal systems, shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a LOCA, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system will not result in undue risk to the health and safety of the public. (GDC 49)

Response:

The following general criteria were followed to assure conservatism in computing the required structural load capacity:

a) In calculating the containment pressure, rupture sizes up to and including a double-ended severance of reactor coolant pipe were considered.

b) In considering post-accident pressure effects, various malfunctions of the emergency systems were evaluated. Contingent mechanical or electrical failures are assumed to disable one of the DG, two of the four fan-cooler units and one of the two containment spray units.

c) The pressure and temperature loading obtained by analyzing various LOCA conditions, when combined with operating loads and maximum wind or seismic forces, do not exceed the load-carrying capacity of the structure, its access opening or penetrations.

The most stringent case of these analyses is summarized below:

Discharge of reactor coolant through a double-ended rupture of the main loop piping, followed by operation of only these engineered safety features which can run simultaneously with power from one emergency on-site DG (one high head SI pump, one residual heat removal pump, two fan cooler units, one spray pump), results in a sufficiently low radioactive materials leakage from the containment structure that there is not undue risk to the health and safety of the public.

3.1.2.50 NDT Requirement for Containment Material

Criterion: The selection and use of containment materials shall be in accordance with applicable engineering codes. (GDC 50)

Response:

The selection and use of containment materials comply with the applicable coded and standards tabulated in Section 3.2.

The reinforced containment is not susceptible to a low temperature brittle fracture.

The containment liner is enclosed within the containment and thus will not be exposed to the temperature extremes of the environs. The containment ambient temperature during operation will be between 50 and 120^{o}F which is expected to be well above the NDTT + 30^{o}F for the liner material. Containment penetrations which can be exposed to the environment have been designed to the NDTT + 30^{o}F Criterion.

3.1.2.51 Reactor Coolant Pressure Boundary Outside Containment

Does not apply to HBR 2.

3.1.2.52 Containment Heat Removal System

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Response:

Adequate containment heat removal capability for the Containment is provided by two separate, full capacity, engineered safety feature systems, the CSS (Section 6.2.2) whose components operate in sequential modes, and the Containment Air Recirculation Cooling System (Section 6.2.2).

The primary purpose of the CSS is to spray cool water into the containment atmosphere when appropriate in the event of a LOCA and thereby ensure that containment pressure does not exceed its design value which is 42 psig at 263^{o}F (100 percent relative humidity). This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Although the water in the core after a LOCA is quickly subcooled by the SIS, the CSS design is based on the conservative assumption that the core residual heat is released to the containment as steam.

The Containment Air Recirculation Cooling System is designed to recirculate and cool the containment atmosphere in the event of a LOCA and thereby ensure that the containment pressure cannot exceed its design value of 42 psig at
3 264.7°F (100 percent relative humidity). Although the water in the core after a LOCA is quickly subcooled by the SIS, the Containment Air Recirculation Cooling System is designed on the conservative assumption that the core residual heat is released to the containment as steam:

Any of the following combinations of equipment will provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value, assuming that the core residual heat is released to the containment as steam:

a) All four containment cooling units

b) Both containment spray pumps, and

c) Two of the four containment cooling units and one containment spray pump.

Each of the auxiliary cooling systems which serves an emergency function to prevent exceeding containment design pressure, provides sufficient capability in the emergency operational mode to accommodate any single failure of an active component and still perform its required function.

3.1.2.53 Containment Isolation Valves

Criterion: Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus. (GDC 53)

Response:

Isolation valves are provided as necessary for all fluid system lines penetrating the containment to assure at least two barriers for redundancy against leakage of radioactive fluids to the environment in the event of a LOCA. These barriers, in the form of isolation valves or closed systems, are defined on an individual line basis. In addition to satisfying containment isolation criteria, the valving is designed to facilitate normal operation and maintenance of the systems and to ensure reliable operation of other engineered safeguards systems.

With respect to numbers and locations of isolation valves, the criteria applied are generally those outlined by six classes described in Section 6.2.4.

3.1.2.54 Initial Containment Leakage Rate Testing

Criterion: Containment shall be designed so that integrated leakage rate testing can be conducted at the peak pressure calculated to result from the design basis accident after completion and installation of all penetrations and the leakage rate shall be measured over a sufficient period of time to verify its conformance with required performance. (GDC 54)

Response:

After completion of the containment structure and installation of all penetrations and weld channels, an integrated leak test was performed in accordance with American Nuclear Society Standard, ANS 7.60 on the total containment volume to ensure that the leakage rate was not greater than 0.1 percent by weight of the containment volume per 24 hr period.

Following the initial integrated leak test a structural strength test on the containment was conducted.

After successful completion of the initial integrated leak and tests an initial sensitive leakage rate test was conducted in accordance with American Nuclear Society Standard, ANS 7.60.

3.1.2.55 Periodic Containment Leakage Rate Testing.

Criterion: The containment shall be designed so that an integrated leakage rate can be periodically determined by test during plant lifetime. (GDC 55)

Response:

A leak rate test at the peak calculated accident pressure using the same method as the initial sensitive leak rate test can be performed at any time during the operational life of the plant.

3.1.2.56 Provisions for Testing of Penetrations.

Criterion: Provisions shall be made to the extent practical for periodically testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at the peak pressure calculated to result from occurrence of the design basis accident. (GDC 56)

Response:

A permanently piped system is provided such that all penetrations can be intermittently pressurized throughout the operating life of the plant.

Penetrations are designed with double seals so as to permit pressurization of the interior of the penetration. The large access openings such as the equipment hatch and personnel air locks are equipped with double gasket seals with the space between them connected to the pressurization system. The system utilizes a supply of clean, dry, compressed air which will place the penetrations under an internal pressure greater than the peak calculated accident pressure.

When in Service, leakage from the pressurization system is checked by measurement of the makeup air flow. In the event excessive leakage is discovered, each penetration can than be checked separately at any time.

3.1.2.57 Provisions for Testing of Isolation Valves

Criterion: Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occured and for determining that valve leakage does not exceed acceptable limits. (GDC 57)

Response:

Capability is provided to the extent practical for testing the functional operability of valves and associated apparatus during periods of reactor shutdown.

Initiation of containment isolation employs coincident circuits which allow checking of the operability and calibration of one channel at a time. Removal or bypass of one signal channel places that circuit in the half-tripped mode.

The main steam and feedwater barriers and isolation valves in systems which connect to the RCS are hydrostatically tested.

Valves in the Residual Heat Removal System are not considered to be isolation valves in the usual sense inasmuch as the system would be in operation under accident conditions.

3.1.2.58 Inspection of Containment Pressure Reducing Systems

Criterion: Design provisions shall be made to the extent practical to facilitate the periodic physical inspection of all important components of the containment pressure reducing systems, such as pumps, valves, spray nozzles, and sumps. (GDC 58)

Response:

Where practicable, all active components and passive components of the CSS are inspected periodically to assure system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves. During operational testing of the containment spray pumps, the portions of the systems subjected to pump pressure are inspected for leaks.

Design provisions are made to the extent practical to facilitate access for periodic visual inspection of all important components of the Containment Air Recirculation Cooling System.

3.1.2.59 Testing of Containment Pressure - Reducing Systems Components

Criterion: The containment pressure reducing systems shall be designed, to the extent practical so that active components, such as pumps and valves, can be tested periodically for operability and required functional performance. (GDC 59)

Response:

All active components in the CSS were adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after any component maintenance. Testing of the components of the SIS used for containment spray purposes are described in Section 6.5.2.

The component cooling water pumps and the service water pumps which supply the cooling water to the residual heat exchanger are in operation on a relatively continuous schedule during plant operation. Those pumps not running during normal operation may be tested by changing the operation pump(s).

The Containment Air Recirculation Cooling System was designed to the extent practical so that the components can be tested periodically, and after any component maintenance, for operability and functional performance.

The air recirculation cooling units, and the service water pumps and booster pumps which supply the cooling units, are in operation on an essentially continuous schedule during plant operation; and therefore no additional periodic tests are required to assure the system is operational. However, periodic tests are conducted as described in Section 3.9 to verify certain operational parameters.

3.1.2.60 <u>Testing of Containment Spray System</u>

Criterion: A capability shall be provided to the extent practical to test periodically the delivery capability of the containment spray system at a position as close to the spray nozzles as is practical. (GDC 60)

Response:

Permanent test lines for both the containment spray loops are located so that all components up to the isolation valves at the containment may be tested. These isolation valves are checked separately.

The air test lines, for checking that spray nozzles are not obstructed, connect downstream of the containment spray isolation valves. Air flow through the nozzles is monitored by the use of thermographs.

3.1.2.61 <u>Testing of Operational Sequence of Containment Pressure-Reducing Systems</u>

Criterion: A capability shall be provided to test initially under conditions as close as practical to the design and the full operational sequence that would bring the containment pressure-reducing systems into action, including the transfer to alternate power sources. (GDC 61)

Response:

Capability is provided to test initially, to the extent practical, the operational startup sequence beginning with transfer to alternate power sources and ending with near design conditions for the CSS, including the transfer to the alternate emergency DG power source.

Means are provided to test initially to the extent practical the full operational sequence of the Air Recirculation Cooling System including transfer to alternate power sources.

3.1.2.62 Inspection of Air Cleanup Systems

Criterion: Design provisions shall be made to the extent practical to facilitate physical inspection of all critical parts of containment air cleanup systems, such as ducts, filters, fans, and damper. (GDC 62)

Response:

Access is available for visual inspection of the CSS components.

3.1.2.63 Testing of Air Cleanup Systems Components

Criterion: Design provisions shall be made to the extent practical so that active components of the air cleanup systems, such as fans and dampers, can be tested periodically for operability and required functional performance. (GDC 63)

Response:

All active components of the CSS are adequately tested both in pre-operational performance tests in the manufacturer's shop and in place testing after installation. Thereafter, periodic tests are also performed after component maintenance and in accordance with a periodic maintenance schedule.

3.1.2.64 Testing Air Cleanup Systems

Criterion: A capability shall be provided to the extent practical for onsite periodic testing and surveillance of the air cleanup systems to ensure (a) filter bypass paths have not developed and (b) filter and trapping materials have not deteriorated beyond acceptable limits. (GDC 64)

Response:

Permanent test lines are provided for the containment spray headers and located so that all components up to the isolation valve at the containment may be tested. These isolation valves are checked separately. Air test lines for checking the spray nozzles are connected downstream of the isolation valves. Air flow through the nozzles is monitored by a smoke generator or tell tales.

3.1.2.65 Testing of Operational Sequence of Air Cleanup Systems

Criterion: A capability shall be provided to test initially under conditions as close to design as practical, the full operational sequence that would bring the air cleanup systems into action, including the transfer to alternate power sources and the design air flow delivery capability. (GDC 65)

Response:

Means are provided to test initially under conditions as close to design as is practical the full operational sequence that would bring the CSS into action, including transfer to the emergency DG power source.

3.1.2.66 Prevention of Fuel Storage Criticality

Criterion: Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (GDC 66)

Response:

During reactor vessel head removal and while loading and unloading fuel from the reactor, the boron concentration is maintained such that $\geq$ 6% $\Delta k/k$ shutdown margin exist in the core on the basis of all RCC assemblies inserted and a complete core installed. This shutdown margin maintains the core subcritical even if all control rods are withdrawn from the core as required by the Post-LOCA sub-criticality event. Weekly checks of the refueling water storage tank boron concentration ensure the proper shutdown margin. A check is made once per shift during core refueling operations and strict administrative controls are used to monitor any dilution of the refueling water in the reactor vessel.

The new and spent fuel storage racks are designed so that it is impossible to insert assemblies in other than the prescribed fuel cell locations. In addition, the spent fuel pit has an area set aside for accepting the spent fuel shipping casks. This operation is also done under water. Borated water is used to fill the spent fuel storage pit at a concentration to match that used in the reactor cavity and refueling canal during refueling operations. The fuel in the spent fuel and new fuel storage pits is stored vertically in an array with the sufficient center-to-center distance or neutron absorbing material between assemblies to assure $K_{eff} \leq 0.95$ even if unborated water were to fill the space between the assemblies.

Detailed instructions are available for use by refueling personnel. These instructions, the minimum operating conditions, and the design of the fuel handling equipment, incorporating built-in interlocks and safety features, provide assurance that no incident could occur during the refueling operations that would result in a hazard to public health and safety.

3.1.2.67 Fuel and Waste Storage Decay Heat

Criterion: Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which would result in undue risk to the health and safety of the public. (GDC 67)

Response:

The refueling water provides reliable and adequate cooling medium for spent fuel transfer and heat removal from the spent fuel pit is provided by a cooling system with redundant 100 percent capacity pumps. Connections are provided to the component cooling water system for alternative cooling.

3.1.2.68 Fuel and Waste Storage Radiation Shielding

Criterion: Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities. (GDC 68)

Response:

Auxiliary shielding for the Waste Disposal System and its storage components is designed to limit the dose rate to levels not exceeding 1 mR/hr in normally occupied areas, to levels not exceeding 2.5 mR/hr in intermittently occupied areas and to levels not exceeding 15 mR/hr in controlled occupancy areas.

Gamma radiation is continuously monitored at various locations in the Auxiliary Building. A high level signal is alarmed locally and annunciated in the Control Room.

Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining low radiation levels, less than 2.5 mR/hr, for periodic occupancy of the area by operating personnel. Pit water level is indicated, and water removed from the pit must be pumped out since there are no gravity drains. Shielding is provided for waste handling and storage facilities to permit operation within requirements of 10CFR20.

Gamma radiation is continuously monitored in the Auxiliary Building. A high level signal is alarmed locally and is annunciated in the Control Room.

3.1.2.69 Protection Against Radioactivity Release from Spent Fuel and Waste Storage

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

There are many machines as large as, and larger than these, that are designed to run at speeds in excess of first shaft critical. However, it is considered desirable in a superior product to operate below first critical speed, and the reactor coolant pumps are designed in accordance with this philosophy. This results in a shaft design which, even under the severest postulated transient, gives very low values of actual stress. While it would be possible to present quantitative data of imposed operational stress relative to maximum tolerable levels, if the mode of postulated failure were clearly defined, such figures would have little significance in a meaningful assessment of the adequacy of the shaft to maintain its integrity under operational transients. However, a qualitative assessment of such factors gives assurance of the conservative stress levels experienced during these transients.

So in each of these cases, where it is the functional requirements of the component that controls its dimensions, it can be seen that if these are met, the stress-related failure cases are more than adequately satisfied.

It is thus considered to be out of the bounds of reasonable credibility that any bearing or shaft failure could occur that would endanger the integrity of the pump flywheel.

The flywheels were visually examined at the first refueling. At the fourth refueling the outside surfaces were examined by ultrasonic methods as part of a plant surveillance program.

During normal operation, the reactor coolant pumps are supplied from the unit auxiliary bus and are therefore tied to the turbine generator frequency (speed). On occurrence of unit (turbine) trip the pump electrical buses are tripped from the auxiliary transformer without any intentional delay.

On most electrical and mechanical events which cause the turbine to be tripped, the reactor coolant pump buses and the unit are tripped simultaneously and the pumps will therefore not exceed their normal or pretrip running speed. If for some unlikely reason the only plant trip is a turbine overspeed trip (mechanical-hydraulic trip), then the pump trip will be initiated by the turbine hydraulic system and the trip point will be between 106 and 110 percent of the turbine generator synchronous speed. The turbine overspeed trip point will be set at 111.0 percent of synchronous speed (1998 rpm), and the maximum resulting turbine overspeed will be 120 percent. If it is further postulated that a failure in the pump trip occurs at the same time, then this would result in a maximum overspeed for that pump equal to that of the turbine, i.e., 120 percent. The design overspeed of the pump is 125 percent.

3.5.1.2 NSSS Valves. All the valves installed in the Nuclear Steam Supply System (NSSS) have stems with back seats. This rules out the probability of ejecting valve stems as analysis shows that even if it were assumed that the stem threads fail, the back seat or the upset end cannot penetrate the bonnet and thereby become a missile. Additional interference is encountered with air and motor operated valves.

Valves with nominal diameter larger than 2 in. have been designed against bonnet-body connection failure and subsequent bonnet ejection by the following means:

a) Using the design practice of American Society of Mechanical Engineers (ASME) Section VIII which limits the allowable stress of bolting material to less than 20 percent of its yield strength

b) Using the design practice of ASME Section VIII for flange design; and,

c) By controlling the load during the bonnet body connection stud tightening process.

The pressure containing parts except the flange and studs were designed per criteria established by the US of America Standard (USAS) B16.5. Flanges and studs were designed in accordance with ASME Section VIII. Materials of construction for these parts were procured per ASTM A182, F316; or A351,
GR CF8M.

Stud and nut material is ASTM A193-B7 and A194-2H. Design criteria limit the stress of the studs to the allowable limits established in the ASME Code, i.e., 20,000 psi. This stress level is far below the material yield, i.e., about 105,000 psi. The complete valves were hydrotested per USAS B16.5 (1500 lb USAS valves were hydrotested to 5400 psi). Inservice bolting stresses in these valves are maintained below values determined from Section VIII, ASME code. These inservice allowable bolting stresses exceed the design criteria of 20% of yield strength. This practice is allowed by Section VIII to ensure a leak-free connection. The cast stainless steel bodies and bonnets are radiographed and dye penetrant tested to verify soundness.

An alternative approach to a thru c is to design, fabricate and maintain the valves in accordance with ASME Section III, Class 1 and Class 2 requirements.

Valves with nominal diameters of 2 in. or smaller were forged and have screwed bonnet with canopy seals. The canopy seal is the pressure boundary while the bonnet threads are designed to withstand the hydrostatic end force. The pressure containing parts were designed per criteria established by the USAS B16.5 specification.

3.5.1.3 <u>Turbine Missiles</u>.

3.5.1.3.1 Consequences of Turbine Generator Unit Overspeed.

3.5.1.3.1.1 High Pressure Turbine. Due to the very large margin between the high pressure spindle bursting speed and the maximum speed at which the steam can drive the unit with all the admission valves fully open, the probability of spindle failure is practically zero.

Based on the admission steam thermodynamic properties and blade geometry, the maximum theoretical speed at which the unit may run is 208 percent of nominal.
Based on the stress analysis of the low pressure disks, the maximum actual speed at which the unit may run is 175 percent of nominal.

The minimum bursting speed of the spindle, based on the minimum specified mechanical properties of the spindle material, is 270 percent of nominal. The actual bursting speed is closer to 300 percent of nominal than 270 percent.

3.7.2.4 Containment Crane. The containment crane was analyzed as a single mass coupled to the multi-mass model of the reactor containment inner structure which serves as its support. The first five mode shapes and the associated periods of vibration were computed utilizing stiffness matrix techniques. The response of each mode of vibration was computed utilizing the methods of modal analysis for the operational response spectra 0.1g and 0.2g design response spectra. Design values of total response were obtained by combining the individual modal contributions on a root-mean square basis. The model used in design is shown in Figures 3.7.2-5 and 3.7.2-6.

An examination of the mode shapes reveals that the first mode of vibration represents (almost entirely) the vibration of the crane structure above the operating floor. The second and higher modes are primarily the rocking and translational vibration of the reactor containment inner structure with very minor contribution of the crane structure.

Both the trolley and the crane columns are provided with positive stop devices to prevent motion when the crane is not in operation. In addition, rail anchorages are provided to prevent the crane from leaving the rails if uplift should occur. The crane is always in the parked and locked condition when the reactor is in operation.

3.7.2.5 Intake Structure. The intake structure is a Class I structure and as such has been dynamically analyzed in accordance with the procedure described for the containment structure. In addition, the load due to the contained and surrounding water has been computed under seismic conditions in accordance with the procedures in "Nuclear Reactor and Earthquakes" - TID 7024, Chapter 6. The intake structure was designed for this load. The structure was designed in accordance with the stress limits in ACI 318-63 part IVB.

3.7.2.6 Spent Fuel Pit and Superstructure. The spent fuel pit was designed to withstand the anticipated earthquake loading as a Class I structure. A dynamic analysis was performed to determine the dynamic characteristics and responses of the superstructure [Fuel Handling Building (FHB)] and the refueling crane (FHB crane) subjected to ground excitations due to earthquake loading.

The FHB is a Class III structure and was designed for seismic loads in accordance with the Uniform Building Code. The building was also designed to carry a 150 ton crane and all its associated loads. The actual crane installed has a rated hook load of 125 tons and an auxiliary hook rated at 5 tons. Based on the overdesign of the FHB steel for a 150 ton crane and the induced impact to longitudinal loads associated with the design of the crane and its supports, no failure of the FHB superstructure is expected for the design basis (hypothetical, 0.2g) earthquake. The spent fuel cask handling crane can be parked for periods of approximately sixteen hours to facilitate safe maintenance activities provided the activity is worked continuously to completion, the crane is continuously attended, or the crane is returned to its normal storage location if unattended. The Superintendent - Mechanical Systems or his designee shall be notified in advance of any anticipated work requiring parking of the crane over the spent fuel pit. The FHB crane will not be stored in a position over the spent fuel pit. Maximum loading of this crane would occur during the lifting of the cask with the spent fuel elements.

Hold down lugs have also been provided on both trucks and trolley of the refueling crane to prevent its wheels from lifting from its rails when subject to a vertical earthquake force of 0.133 times the unladen weight of the crane for the lugs on the truck or 0.133 times the deadweight of the trolley for the lugs on the trolley. These lugs were designed so as to cause no interference to crane or trolley motion. The crane is also provided with stops to prevent lateral movements of the crane when in a parked position.

3.7.2.7 Foundation Models. In the course of design, four different foundation models were considered:

1. Fixed Base

T_1 = 0.151 sec

2. Rotational spring with stiffness computed from pile test data

T_1 = 0.2613 sec
T_2 = 0.0932 sec
T_3 = 0.0490 sec

3. Rotational spring plus translational spring computed from lateral pile test data, and

T_1 = 0.2625 sec
T_2 = 0.1544 sec
T_3 = 0.0573 sec

4. Rotational spring plus translational spring computed from the properties of the soil mass assuming no contribution from the pile group

T_1 = 0.3150 sec
T_2 = 0.2524 sec
T_3 = 0.0601 sec

Analysis of the above models led to the conclusion that for case c) and d) above an increase in damping would be justified to account for significantly greater energy dissipation in the ground. These analyses resulted in reduced response accelerations throughout the structure. In addition, the range of natural period was such that it would not significantly effect the ultimate response characteristics of equipment and piping which are arranged and supported to be rigidly attached within the structure.

It was decided that a conservative design would result from the model described in the Preliminary Safety Analysis Report (PSAR) which is case b) above.

Where the dome reinforcing is anchored in the top of the wall an anchorage detail consisting of an anchor plate backed up by a cadwell sleeve is provided at the end of each bar. The plate and the sleeve are designed to develop the full ultimate strength of the bar. As for all other cadwelds in the structure, 2 percent of the production cadwelds of this anchorage detail were laboratory tested for strength.

3.8.1.1.5 Containment liner. The containment liner is designed to serve as a leakproof membrane and is not relied upon for the structural integrity of the containment except for resisting tangential shears in the dome. It is anchored to the concrete by means of "KSM" shaped steel studs. The liner is not anchored to the concrete base slab hence does not act compositely with it. It was laid loose on the base slab and the butt weld backing strips were set in grooves in the base slab. After welding, the distortions in the liner were considered too great and a neat cement grout was flowed beneath it to fill the voids. A bond breaker, form oil, was flowed first on the base slab to prevent the liner from acting compositely with the slab.

Stress conditions in the liner under all conditions of design have been analyzed to assure that the principle stresses do not exceed the yield or buckling stresses as provided in design stress criteria. Fatigue, accident, and operational loads are discussed in Section 3.8.1.4. Sample buckling calculations are shown indicating maximum loading conditions that prevail. A discussion on the liner anchors and transfer on their loads into the concrete has been submitted in the Containment Design Report (Reference 3.8.1-1).

The loading condition which produces maximum biaxial compression in the liner is that of winter operation combined with 1.0 times the hypothetical earthquake. Under this condition, the allowable buckling stress is not exceeded.

The steel liner and its welded seam joints are covered by carbon steel channels with pressurizing connections. These seam weld channels can be used to determine the leak-tightness of the liner seam welds.

3.8.1.1.6 Containment penetrations. In general, a penetration consists of a sleeve embedded in the concrete wall and welded to the containment liner. The weld to the liner is shrouded by a channel which was used to demonstrate the integrity of the penetration-to-liner weld joint. The pipe, electrical conductor cartridge, or duct passes through the embedded sleeve and the ends of the resulting annulus are closed off, either by welded end plates, bolted flanges, or a combination of these. Provisions are made for differential expansion and misalignment between pipe or cartridge, and sleeve. Pressurizing connections are provided to demonstrate the integrity of the penetration assemblies.

An exception to this are the ten electrical penetrations C1, C2, C3, C5, C9, C10, D9, E1, E10 and F1. These penetrations have double pressure barrier protection in their header plate and therefore an endplate is required at one end only. See Section 3.8.1.2 for codes and standards applicability.

3.8.1.1.6.1 Electrical penetrations. Cartridge type penetrations are used for all electrical conductors passing through the containment, with the exception of the penetration at sleeve numbers C9, C10, D9 and E10 in the north cable vault sleeve numbers C1, C2, C3, C5, E1 and F1 in the south cable vault; which are of the capsule type design. The penetration cartridge is a hollow cylinder closed on both ends, through which the conductors pass. This cartridge is provided with a pressure connection to allow continuous or intermittent pressurization of the penetration. Figure 3.8.1-14 shows a typical cartridge type electrical penetration. Figure 3.8.1-14a shows a typical capsule design electrical penetration. The method used to seal the joint between the cartridge end plate and the conductor depends upon the type of cable involved. In general, there are four types used:

1. Type 1 - High voltage power, 4160 volts

2. Type 2 - Power, control, and instrumentation, 600 volts and below

3. Type 3 - Thermocouple leads

4. Type 4 - Coaxial and triaxial cables

Type 1 penetrations are rubber insulated copper rods. These insulated rods will pass through a leak tight gland fitting threaded into each end plate of the cartridge. Either alumina insulating bushings or fused glass seals may be used to provide the double barrier.

Type 2 penetrations are single or multiconductor mineral insulated cable with a metallic sheath. This cable will pass through a leak tight gland threaded into each end of the penetration cartridge. The ends of the mineral insulated cable are potted with epoxy resin. Copper rod conductors with fused glass seals in the cartridge and plates is an alternate which may be used.

Type 3 penetrations are the same as Type 2 except the conductors will be thermocouple material. The sealing methods are the same as for the Type 2 penetrations.

Type 4 penetrations are used for coaxial and triaxial cables. In addition to the leak tight gland fittings in the cartridge end plate, a plug and receptacle connection provides a double barrier to leakage through the cable itself. An alternate method uses fused glass seals in the cartridge end plates and fused glass seals between the conductors of the coaxial or triaxial cable.

In the capsule penetration design, a single stainless plate is machined with the required quantity of feed-through ports which are interconnected by peripherally machined gun drills which creates a manifold system for pressure monitoring. Feed-throughs are assembled through the plate and sealed in place with a patented metal compression fitting assembly which creates seal zones at the front and backside of the plate, while allowing for a chamber to form between the seal zones to accommodate leakage monitoring.

The capsule series penetration is designed for a weldment interface to the containment nozzle. The weldment interface is by a transition ring,

factory welded to the penetration header plate, and field welded to the containment nozzle.

The penetration sleeves to accommodate the electrical penetration assembly cartridges are 10 in., Schedule 80 carbon steel pipe, except where otherwise noted. Sleeves are equipped with standard 150 lb steel flanges which are supplied with special double O-ring seal grooves, and drilled with two 1/4 in. paths to pressurization channels testing. Suitable mating blind flanges are supplied with paths for pressurization channel. For the electrical penetrations C1, C2, C3, C5, C9, C10, D9, E1, E10, and F1, the header plate and conductors are pressurized. All O-rings are silicon elastomeric material capable of withstanding an internal temperature of 310°F. There are 50 electrical penetrations.

3.8.1.1.6.2 Piping penetrations. Double barrier piping penetrations are provided for all piping passing through the containment. The pipe is centered in the embedded sleeve which is welded to the liner, except for small pipes where several pipes may pass through the same penetration sleeve.

The penetrations for the main steam, feedwater, blowdown, and sample lines are designed so that the penetration is stronger than the piping system and that the vapor barrier will not be breeched due to a hypothesized pipe rupture.

End plates are welded to the pipe at both ends of the sleeve. Several pipes may pass through the same embedded sleeve to minimize the number of penetrations required. In this case, each pipe is welded to both end plates. A connection to the penetration sleeve is provided to allow continuous or intermittent pressurization of the compartment formed between the piping and the embedded sleeve. In the case of piping carrying hot fluid, the pipe is insulated, and cooling is provided to maintain the concrete temperature adjoining the embedded sleeve below 150°F. The RHR supply pipe is insulated to keep the concrete surrounding the embedded sleeve below 200°F. Figure 3.8.1-15 shows typical hot and cold pipe penetrations. There are 46 containment penetrations sleeves for pipes. Pipes are anchored to the structural steel girders as close as possible to the inside of the wall or to the crane wall. Loads due to pipe ruptures within the containment or due to thermal stresses are not transferred to the liner.

An exception to this is the steam generator blowdown penetrations and two safety injection penetrations (RHR penetrations S-14 and S-15). The end plate is welded directly to the sleeve. The sleeve is welded to the liner reinforcement plate. Piping loads are transmitted to the concrete wall, except for torsion loads which are carried by the liner plate. However, the torsion loads are below the liner allowable stress.

The hot pipe penetration cooling water system consists of cooling water coils firmly attached to the inside surface of the penetration sleeve. This system is designed to maintain the penetration sleeve temperature at 150°F or less when supplied with water from the Service Water System. The cooling water discharge line from each penetration is fitted with a flow switch to alarm upon loss of flow of cooling water for each penetration that would exceed 200°F steady state without cooling.

Two piping penetrations are provided in the containment sump area.

3.8.1.1.6.3 Equipment and personnel access hatches. An equipment hatch is provided which is fabricated from welded steel and furnished with a double-gasketed flange and bolted dished door. Equipment up to a diameter of approximately 18 ft can be transferred into and out of containment via this hatch. The hatch barrel is embedded in the containment wall and welded to the liner and is a portion of the structural frame embedded in the wall. Provision is made to pressurize the space between the double gaskets of the door flanges and the weld seam channels at the liner joint, hatch flanges, and dished door. Pressure is relieved from the double gasket spaces prior to opening the door.

The personnel hatch is a double door, hydraulically-latched, welded steel assembly. It is attached to the structural frame embedded in the wall of which the frame barrel forms the central portion of the lock. A quick-acting type, equalizing valve connects the personnel hatch with the interior of the containment vessel for the purposes of equalizing pressure in the two systems when entering or leaving the containment.

The personnel hatch doors are interlocked to prevent both being opened simultaneously and to ensure that one door is completely closed before the opposite door can be opened. Indicating lights and annunciators situated in the control room indicate the door operational status.

Provision is made to permit bypassing the door interlocking system to allow doors to be left open during plant cold shutdown. Each door lock hinge is designed to be capable of independent three-dimensional adjustment to assist proper seating. An Emergency Lighting and Communication System operating from an external emergency supply is provided in the lock interior. Emergency access to either the inner door, from the containment interior; or to the outer door, from outside, is possible by the use of special door unlatching tools.

3.8.1.1.6.4 Fuel Transfer Penetration

A fuel transfer penetration is provided for fuel movement between the refueling transfer canal in the reactor containment and the spent fuel pit. The penetration consists of a 20 in. stainless steel pipe installed inside a 24 in. pipe (See Figure 3.8.1-16). The inner pipe acts as the transfer tube and is fitted with a double-gasketed blind flange in the refueling canal and a standard gate valve in the spent fuel pit. This arrangement prevents leakage through the transfer tube in the event of an accident. The outer pipe is welded to the containment liner and provision is made by use of a special seal ring for testing all welds essential to the integrity of the penetration. Bellows expansion joints are provided on the pipes to compensate for any differential movement between the two pipes or other structures.

3.8.1.1.6.5 Containment Supply and Exhaust Purge Ducts

The ventilation system purge ducts are each equipped with two quick-acting tight-sealing butterfly valves for isolation purposes. The valves are manually opened for containment purging, but are automatically actuated to the closed position upon a safety injection signal or high containment radiation level signal.

3.8.1.1.7 Containment Dome

The dome is a hemispherical dome 65 ft inside diameter and 2 ft 6 in. thick reinforced concrete. The difference in cylinder and dome thickness is effected on the outside surface, the transition between thicknesses being accomplished 13 ft above the springline of the dome at the anchor surface of the cylinder prestressing steel tendons. The general masonry outline of the dome is shown on Figure 3.8.1-9. The inside of the dome is insulated from the springline to a point above the anchor surface of the cylinder prestressing steel tendons. The outer surface of the dome is covered with a membrane roof to provide weather protection.

The dome is reinforced with a radial - circumferential pattern of ASTM A432 (60,000 psi yield strength) reinforcing steel. At two lines where the stresses in the radial reinforcing steel is one-half of the theoretical reinforcing steel stress due to the convergence of the bars the radial reinforcing steel is anchored to structural steel assemblies which transfer the load to one-half the number of reinforcing bars anchored to the other side of the structural steel

The materials for penetrations, including the personnel and equipment access hatches together with the mechanical and electrical penetrations, are carbon steel, conforming with the requirements of the ASME Nuclear Vessels Code, and exhibit ductility and welding characteristics compatible with the main liner material. As required by the Nuclear Vessels Code, the penetration materials shall meet the necessary Charpy V-notch impact values at a temperature 30°F below lowest service temperature which is 50°F within containment and 20°F outside containment.

Electrical penetrations are designed and demonstrated by test to withstand, without loss of leaktightness, the containment post-accident environment and to meet the National Electric Code, IEEE - Proposed Guide for Electrical Penetration Assemblies in Containment Structures for Stationary Nuclear Power Reactors or subsequent issues of this standard, IEEE Electric Penetration Assemblies in Containment Structure for Nuclear Power Generating Stations.

3.8.1.3 Loads and Loading Combinations

The pressure retaining components of the containment structure are designed for the maximum probable earthquake ground motion of the site combined with the simultaneous loads of the design basis accident as follows:

a) The liner is designed to ensure that no strains greater than the strain at the guaranteed minimum yield point occur at the factored loads

b) The prestressed concrete is designed on the basis of a resultant concrete compression or zero tension due to primary membrane forces resulting from the factored loads.

The following loadings were considered in the design of the containment in addition to the pressure and temperature conditions described above:

a) Structure dead load

b) Live loads

c) Internal test pressure

d) Earthquake

e) Wind

f) Uplift due to buoyant forces

g) Internal negative pressure, and

h) Tornado.

3.8.1.3.1 Loads

The following loads can act upon the containment structure creating stresses within the component parts:

a) Dead load consists of the weight of the concrete wall, dome, liner insulation, base slab, and all internal concrete. Weights used for dead load calculations were as follows:

1)	Concrete	143 pcf as determined from laboratory tests
2)	Reinforcing Steel and Prestressing Steel	489 pcf using nominal cross-sectional areas of reinforcing as defined in ASTM for bar size and nominal cross-sectional areas of prestressing tendons
3)	Steel Liner	489 pcf using nominal cross-sectional area of liner
4)	Insulation	4 pcf PVC

b) Live load consists of snow and construction loads on the dome and major components of equipment which are supported on the containment base slab. Snow and ice loads were applied uniformly to the top surface of the dome at an assumed value of 10 pounds per horizontal square foot (psf) which is equivalent to about 12 1/2 in. of snow. This is considered to be conservative since the slope of the dome tends to cause much of any snow which falls on it to slide off. Construction live load for the dome was assumed at 12 psf as specified by the Uniform Building Code.

Equipment loads were those specified by the manufacturers of the various pieces of equipment. Table 3.8.1-1 lists the weights of the major pieces of equipment.

c) Internal pressure due to a loss-of-coolant accident cause containment stresses. This is a time dependent variable as discussed in Section 6.2.1.

d) Thermal expansion stresses due to an internal temperature increase caused by a loss-of-coolant accident cause thermal loads. Thermal loads on the containment liner can be broken into two areas:

1) Insulated cylinder

2) Uninsulated dome

The cylinder liner does not begin to feel the thermal effects of the accident until after the containment pressure is brought well below the maximum accident value, since it is insulated, and this rise in temperature is considered in the design.

The basic equation for analysis is:

$$D \frac{d^4 w}{dy^4} + \frac{Eh}{r^2} w = P_z \qquad (1)$$

where: $\frac{Eh}{r^2}$ = the equivalent to the foundation modulus for a beam on an elastic foundation; here taken as the modulus of the hoop reinforcing steel (Reference 3.8.1-2)

Earthquake shears are computed in the cylinder wall by the theory of shear flow.

3.8.1.4.3.1 Membrane Design

The hoop reinforcing steel is designed to resist the hoop load due to internal pressure and the internal bending moment due to thermal gradients. The prestressing steel tendons are designed to resist the membrane uplift load due to the dome pull under internal pressure.

The liner is not relied upon for structural integrity in the cylinder but has been analyzed to assure that all strains, as the liner acts in composite with the concrete shell, do not jeopardize the integrity of the liner (i.e., no strain greater than the strain at the guaranteed yield point will occur at the factored loads).

3.8.1.4.3.2 Tangential Shear Design

The membrane stress on any horizontal plane where the concrete is relied upon to resist shear is maintained at a value such that the provisions concerning shear of the ACI Code Part IV-B are met under the factored load conditions by providing sufficient post-tensioning force.

3.8.1.4.3.3 Longitudinal Shear Design

The design of the cylinder assumes that the concrete is vertically cracked under internal pressure load.

For the cylindrical portion of the vessel, resistance to the vertical shears resulting from the earthquake or wind loading is developed in the circumferential reinforcing by dowel action across the vertical cracks. The resulting principal stresses in the reinforcement does not exceed 0.95 x yield stress as provided in the design stress criteria.

Design of the structure provides for a minimum spacing of cracks in concrete tension members of twice the concrete cover dimension. To develop the vertical shear by dowel action the dowels must develop a bearing stress on the concrete no greater than the ultimate bearing strength of the concrete. The dowels (hoop reinforcing steel) are designed so as not to cause local crushing of the concrete at a crack. In addition, the liner aids in resisting the vertical shear across the cracks; however, this is not accounted for in determining the capacity of the cracked section to resist the vertical shear.

For reinforced concrete in direct tension, Broms has determined that the minimum crack spacing in the concrete will be equal to twice the thickness of the concrete cover measured from the center of the reinforcing bar (Reference 3.8.1-3). Broms found by experimental means that the crack spacing did not decrease beyond a steel stress of 20,000 - 30,000 psi for a cover of 1.25 to 3.0 in. and about 50,000 psi for a cover of 6.0 in.

For purposes of computation a cover of 4.0 in. has been used for the hoop reinforcing steel in the containment vessel. In actuality this is the cover dimension from the edge of the bar and not the center and is therefore a conservative assumption resulting in a smaller value of crack spacing. The crack spacing was assumed as twice this dimension or 8 in. This is further conservative since Broms found that for a deeper cover the critical steel stress at which the minimum crack spacing was reached was higher and the average steel stress will be about 30,000 psi which is probably somewhat below the critical stress for the cover used.

All of these conservative assumptions result in a larger number of cracks than will probably occur. The crack width will be the total elongation of the hoop reinforcing steel divided by the number of cracks. The important consequence of the assumption is the increase in the magnitude of bearing stress on the concrete by the dowel. By decreasing the crack spacing this stress increases; therefore, the smallest crack spacing should be used for a conservative solution for this stress.

The total vertical shear is assumed to be transferred across the vertical cracks by the hoop reinforcing bars acting as dowels. The vertical shear is the same unit shear stress as exists due to shear flow on the horizontal plane. This stress is summed and divided equally into the number of horizontal hoop reinforcing bars and the individual bar shear stress computed. Computations indicate that dowel shear stresses of about 5000 psi exist for the maximum hypothetical earthquake. A principal stress analysis of the steel dowels indicates that the maximum shearing stress will be about 16,000 psi resulting in a margin against shear failure of about 1.25 or an actual ϕ factor of 0.80. This is more conservative than the limiting factors established in the Design Stress Criteria.

Computations indicate a maximum bearing stress on the concrete due to dowel action of about 6300 psi as computed by beam on elastic foundation theory. The Report of Sub-Committee III - ACI Committee 325 published in the July 1956 Journal of the American Concrete Institute indicates that concrete bearing strength for a dowel of about 2 in. diameter is 1.75 times the compressive strength of the concrete. This results in a bearing strength of 7000 psi for the concrete to be used (f_c = 4000 psi) and an actual ϕ value of 0.90 - equal to the ϕ value for flexure stipulated in the Design Stress Criteria.

The following discussion presents further justification for the acceptability of the 6300 psi stress level. As noted in Table 6 of the ACI Committee 325 paper, a ratio of ultimate bearing stress to f′c of 1.78 was achieved for a 2 in. diameter dowel. For a 4000 psi concrete then an ultimate bearing strength of 7100 psi can be expected for a 2 in. dowel. This is all that this paper was utilized for. The allowable capacity of dowels and allowable bearing stresses are intended for a joint in which there is a continual repetition of loading since it is intended for pavement joints and is, therefore, not applicable to

the use intended in the containment structure. They are further intended for use with a normal working strength design and are not compatible with the factored load design of the Robinson containment. Utilizing a Ø factor of 0.90 for bearing, then an allowable bearing stress of 6400 psi is obtained as a guide which compares favorably with the 6300 psi value presented.

It should be noted here that all of the vertical shear will be assumed as transmitted by the dowels. In actuality, some of the shear will be transmitted by the concrete crack interfaces since cracks of only 0.01 in. are expected and the cracks will be ragged. Therefore, the stresses computed are conservatively high.

The capacity of the dowels to resist and transfer shear across a vertical crack was analyzed utilizing the data presented in the Report by Sub-committee III, ACI Committee 325 entitled "Structural Design Considerations for Pavement Joints" as published in the Journal of the American Concrete Institute, July, 1956. The data presented in this report are obtained mostly from a report by Henri Marcus (Reference 3.8.1-4). Marcus' data are based upon a series of dowel tests which he performed.

Computations have been made to demonstrate the actual participation of the liner in resisting longitudinal shear. This is a computation of the composite action of the liner and cracked concrete wall.

The philosophy of this type of analysis is outlined in the Preliminary Facility Description and Safety Analysis Report for H.B. Robinson Unit 2 - Amendment 7, page VIII A 12 (a) 1-3.

The composite section analysis shows that for the Robinson containment the wall will carry two-thirds of the longitudinal shear and the liner one third where vertical cracks occur.

Principal stress analyses show that with this distribution of longitudinal shear the maximum shearing stresses and principal stresses are below design stress limits.

3.8.1.4.3.4 Radial Shear Design

As can be seen in the Containment Loading Diagrams the major radial shears occur at the spring line and at the base of the cylinder. The tensile vertical membrane stress in the cylinder at the spring line is such that the minimum membrane stress in the concrete is 0 psi under the governing factored load condition and is net compression under the design basis load. The cylinder at the base will always have a net compression on the horizontal plane. The combined radial and lateral shears are resisted by the concrete and, where required, supplementary reinforcing steel. Design for these shears is based upon ACI 318-63, Part IV-B, requirements.

ACI 318-63, Part IV-B is applicable to this structure since in essence it is a cantilever beam when a vertical section of wall is viewed. A substantial amount of reinforcement is provided in the vertical direction in the areas where radial shear is of a large magnitude. The provisions in ACI 318-63 require tensile reinforcing. They further use as a basis of development a cracked section analysis. The areas subjected to large radial shear will be slightly cracked due to bending.

The basic analysis of the combination of loads at the base of the wall is a highly complex problem which does not readily lend itself to theoretical analysis. The shear provisions in ACI 318-63 are empirical and as stated in the report of ACI Committee 326 which established these provisions:

"Sufficient tests data are available to indicate that the proposals of this report for the design of beams without web reinforcement, are adequate at any section along the length of a member, regardless of concrete strength used, the strength of the reinforcement, the manner of loading and supporting the beam, or the cross-section shape of the member involved."

The formulas in ACI 318-63 are somewhat conservative as they define a lower limit rather than a mean shear resistance.

ACI Committee 326 report further states, in regard to the design concept of providing reinforcing steel for the shear more than that resisted by the concrete, that "neither laboratories tests nor field observation of performance in service have indicated a lack of safety resulting from current design methods such as those of ACI 318-56." The design methods of ACI 318-56 are similar to those of ACI 318-63 with minor modifications made for ultimate strength design.

In designing for shear in the cylinder the combination of radial and lateral shears was used in determining the nominal shear stress on a horizontal section. When this combined shear was factored into the equation in ACI 318-63, Part IV-B, along with applicable hoop tension and vertical loads and bending moment and found to be more than the allowable ACI limits, then the two components of shear, namely the radial and lateral vectors, were reinforced in proportion to their total values for only the excess shears above allowed ACI limits. The reinforcing consists of stirrup bars for the radial shear and, for the lateral shears, the hoop reinforcing steel which in the areas of high radial and lateral shears is subjected to very low hoop stresses and is therefore available to act as stirrup shear reinforcing since at the base of the wall, membrane tension does not exist.

In addition, a principal stress analysis has been pursued in areas of high radial and lateral shears. The results of this analysis were used to verify the adequacy of the reinforcing layout as acknowledged by ACI Committee 326, a principal stress analysis on a reinforced concrete member subjected to shear and bending is a somewhat unsure approach as several of the stresses acting on the member cannot be truly defined in magnitude. It should be noted here that the shear provisions of ACI 318-63, Part IV-B, are based on principal stress analysis backed-up by empirical data.

Each penetration of the containment creates a discontinuity around which stresses must be carried. Where the penetrations are relatively small, the horizontal reinforcing steel has been shifted slightly up or down and the vertical prestressing tendons have been shifted slightly to each side of the penetration placed between tendons.

At penetrations too large to pass reinforcing steel around by slight shifting of the bars, structural steel frames have been provided. The reinforcing steel is attached to these frames by means of Cadweld splices, the splice sleeves being welded to the frames.

The liner plate was protected against corrosion as follows: The entire inside surface of the dome and walls was sandblasted. Above operating deck level, the plate received one shop coat of alkyd based metal primer and two field costs of alkyd based finish. Below operating deck, the liner and penetrations received one shop coat of zinc filled inorganic primer such as Carbo Zinc II and one field coat of phenolic type paint such as Phenoline 305. All painted surfaces were inspected after erection and any damaged areas reprimed before finishing. The face of the liner plate in contact with the concrete has no primer or paint applied; the intimate contact with the concrete provides corrosion protection.

The only exception to the above described Liner Protection coating and inspection is in the areas of the field welds at the new Conax Cartridge Type Electrical Penetrations. The inside surface of the field weld is inaccessible after installation, and the coating and inspection described above cannot take place. These welds are radiographed at installation. Because the inside surface of the weld (inside the penetration nozzles) cannot be coated, the weld will be periodically subjected to ultrasonic testing to detect any deterioration in wall thickness due to corrosion.

3.8.1.6.1.6 Equipment Hatch and Personnel Lock

Specifications for the equipment hatch and personnel lock materials are:

a) Barrels and covers ASTM A516 Grade 60 firebox quality to ASTM A300 with Charpy V-notch impact tests in accordance with ASTM Pressure Vessel Code Section III at -40°F

b) Equipment hatch flanges ASTM A516 Grade 55 firebox quality to ASTM A300 with Charpy V-notch impact tests in accordance with ASME Pressure Vessel Code Section III at -40°F.

3.8.1.6.1.7 Insulation

Containment liner insulation consists of 44 in. x 84 in. x 1 1/4 in. thick, 4 lb/ft^3 density cross-linked PVC foam with an outer covering of 24 gauge stainless steel. Panels are erected with the 44 in. dimension vertical and the 84 in. dimension horizontal.

3.8.1.6.1.8 Pipe Pile (See Section 3.8.5)

3.8.1.6.2 Quality Assurance

3.8.1.6.2.1 General Program

Quality of both materials and construction of the containment vessel was assured by a continuous program of quality control and inspection by Ebasco Services and Westinghouse Atomic Power Division (WAPD). Ebasco Services Incorporated was the Engineer-Constructor and, as such, had direct responsibility for inspection and quality control. An Ebasco quality control group not reporting to field production management was directly responsible for implementing and administering the inspection and quality control programs. Ebasco maintained a staff of factory inspectors who inspected and verified the quality of all manufactured products used in the construction of the containment. Ebasco was responsible for assuring quality of the materials

used in the manufacture of the concrete and for the proper placement, erection, construction procedures and practices in the actual construction of the containment. Working under the direction of the quality control field engineer was a staff of qualified engineers and inspectors. Design engineers thoroughly familiar with the design were at the site as required during the critical phases of containment erection to ensure conformance to design standards. The testing of all steel products and concrete was done by a qualified independent testing laboratory. Radiographic inspection of welds was done under the supervision of the Nondestructive Testing Laboratory of

Ebasco. Copies of all quality control reports were forwarded to CP&L, WAPD, and the design engineering department of Ebasco. It was the direct responsbility of the Ebasco engineering department to approve the quality control reports; however, as a parallel effort, WAPD and CP&L reviewed these reports for compliance with quality control procedures. In addition, WAPD reviewed and approved all radiographs, whether conducted in the field or in the shop of the supplier. WAPD furnished for CP&L review copies of nondestructive tests conducted by Westinghouse or its suppliers.

3.8.1.6.2.2 Prestressed Steel Tendons

The manufacturer's quality control audited by periodic visits of Ebasco Quality Compliance Representatives to the manufacturer's plant combined with the inspection of the material upon arrival at the HBR site provided assurance that prestressing bars whose ultimate strength of at least 160,000 psi were received. A description of the quality control maintained in manufacturing the prestressed bars is given in the Containment Design Report, Reference 3.8.1-1 as follows:

a) The hot-rolled bars were purchased in accordance with ASTM A-20 and ASTM A-322. The bars were AISI 5160, with it chemistry modified as permitted by Section 3 of ASTM A-322-64. Mill test reports (chemical and physical properties) for each heat of bar material used were submitted with each shipment. Processing the bars consisted of cold working, furnace heating, threading, and assembling. Heat identification of all bars was maintained at all times after their receipt. In addition, all bars received for the HBR project were stored in a pre-established area of the shop.

b) Cold working involved pulling a bar to a predetermined minimum force of 208,000 lb. This load was determined by a machine gage and light bulb which indicated when the required hydraulic pressure was obtained. The function of the gage and the light was to indicate that the prescribed minimum elongation for each bar was met.

c) Heating the bars at 700^{o}F for four hours improves the yield strength and ductility. The heating cycle was documented by using temperature recorders. After furnace heating, the bars were cut to length, threaded, and assembled into tendons. The bars were identified at each stage of the process.

d) Four unprocessed bars from each heat of material to be used were randomly selected upon receiving them from the bar manufacturer and sent to an independent laboratory for tensile testing. After a minimum of 50 percent of a heat of bars was cold stretched and stress relieved, four random samples were selected and tensile tested by an independent laboratory. The heat of steel tested was acceptable if the minimum required properties were obtained.

e) The couplers which are AISI 4130 steel require that a mill test report for each heat used in the manufacturing of the couplers must be submitted for approval and that the threads be magnetic particle inspected. From each heat of material used, one coupler was randomly selected from every 200 pieces manufactured and tested, with threaded bars to determine if the coupler would develop a minimum ultimate tensile strength of 238 kip. The batch of couplers from which the tested sample came were rejected if required minimum ultimate strength was not met. A minimum of two samples were tested from each batch. All couplers were color coded.

c) The type of instrumentation.

In the event that any measurements were outside the tolerable differences, an analysis was made to determine the reasons for and the implications of the difference.

The measurement program conducted concurrently with the pressure test was basically that described in VIII E.(1) (b), Fourth Supplement to PSAR, modified as follows:

a) Linear variable differential transducers (LVDT) were employed instead of dial gauges where radial displacements of the wall and base, up to a height of about 10 ft., were measured. The LVDT and associated instrumentation have a resolution of better than 0.001 in. and an accuracy of 0.002 to 0.005 in.

b) Radial displacements of the wall at quarter points 10 ft or more above the base were measured by means of transits sighted on scales mounted on these points.

c) The vertical movement of the top of the wall was measured with suspended invar tapes with tensioning weights and attached scales.

d) LVDT were used to measure out-of-plane displacements within the reactor sump. These were located in the center of each of the walls and the floor, and were supported on telescoping columns with pinned ends to eliminate the effects of their end motions.

No permanent instrumentation was installed to monitor behavior of the structures. The design, fabrication, inspection, and preoperational testing of the containment building ensures a structure capable of offering continued structural integrity over the life of the plant. It is therefore believed that there is no need for a special insurance surveillance program other than visual inspection of the exposed surfaces.

No post-operational structural surveillance program has been established.

The purpose of the structural proof test is to demonstrate the structural design and as-constructed adequacy of the containment. No mechanism has been identified which has not been considered in design that would lead to the degradation of this containment after initial proof testing and for this reason periodic structural proof testing is not required.

3.8.1.7.2 Tendon Surveillance

The applicant, its engineer-constructor, and its consultants believe that there is sufficient evidence in the history of the prestressed concrete industry to justify the specifying of an uniaxially prestressed concrete containment vessel such as the H.B. Robinson containment with full confidence that it will perform within the criteria set in its design. Conservative values have been used in estimating qualities of materials which affect the net prestressing force.

As an example of the conservatism used, consider creep and shrinkage. Design values of 0.0003 in. shrinkage and 2.25 for coefficient of creep (creep stain/elastic strain) were specified. It is expected that values of 0.0001 in. shrinkage and 1.7 for coefficient of creep are realistic values based on preliminary estimates using as a guide (Reference 3.8.1-17).

Such a conservative design can only result in higher precompression stresses in the concrete and higher tensile stresses in the tendons. This is of little interest, since even with these higher tensile stresses, the tendons will never reach the tensile stress imposed upon them with the initial prestressing operation.

There is no practical method of surveying the tendon stress and corrosion, creep and shrinkage of the concrete for a grouted tendon. Known conservative analytical procedures, in addition to successful experience application for grouted tendons, do not warrant a surveillance program. However, two surveillance tendons similar to the service tendons and in a similar environment are provided. These may be uncovered at any time for surveillance of any corrosion.

The surveillance tendons consist of two short tendons similar to the service tendons. Each tendon consists of six - 1-3/8 in. ∅ bars in 6 in. pipe sheath with anchor plates, prestressing hardware, and grout pipe identical except for length to the working tendons. They are embedded in a section of concrete approximating the same environment as that of the service tendons.

The program for inspection consists of removing one tendon after 5 years and the other after 25 years.

The removed tendons are sent to a commercial laboratory qualified to perform material tests and analysis. The tendon bars are removed from the sheath and the grout removed. The visual inspection is performed to detect and record evidence of corrosion. Tensile tests are then performed on selected bars to develop stress-strain diagrams and determine the bars' ultimate tensile strengths. The results of these tests are compared with the original properties to determine any significant changes. CP&L retains a qualified engineering firm to assess the results of these tests and make recommendations.

The first containment surveillance tendon sample was removed in March, 1976. The reports detailing the results of examination are contained in References 3.8.1-31 through 3.8.1-33.

Based on the information presented in the reports, and on other available data on the Robinson containment system, the tendon surveillance program appears to be satisfactory. The tests showed that all twelve specimens exceeded the minimum breaking load of 238,000 pounds given in the FSAR. It can be safely assumed that similar results would be obtained if bars from the actual containment tendons were tested.

3.8.1.7.3 Initial and In-Service Leakage Rate Tests

Initial and in-service leakage rate tests are discussed in Section 6.2.6.

REFERENCES: SECTION 3.8 (Cont'd)

3.8.1-28 Thalmann, E. H., "Cathodic Protection in the Design of Power Plants," Pacific Coast Electrical Assoc., Joint Session of Substation and Design Group, Berkeley, California, March 31 - April 1, 1960.

3.8.1-29 Peabody, A. W., "Control of Pipeline Corrosion," p. 122.

3.8.1-30 Trouard, S. E., "Cathodic Protection of the Coated Steel Gas Main Distribution System in New Orleans," Corrosion, March 1967.

3.8.1-31 Meyer, Steigel, W. N., Waters, G. E., and Slater, J. E., "Inspection of Containment Prestressing Surveillance Tendon from H.B. Robinson Unit No. 2 Plant," Battelle Columbus Laboratories, September 28, 1976.

3.8.1-32 Meyer, Steigel, W. N., Berry, W. E., and Boyd, W. K., "Failure Analysis of a Reinforcing Rod from the Containment Prestressing Surveillance Tendon from H.B. Robinson Unit No. 2 Plant," Battelle Columbus Laboratories, March 25, 1977.

3.8.1-33 "Incidence of Corrosion on Prestressing Steel Tendons at H.B. Robinson Steam Electric Plant, 1970 - 700,000 KW Extension - Unit No. 2," CP&L/Ebasco, March 1968.

3.8.3-1 Fauske, H. K., "The Discharge of Saturated Water Through Tubes," Seventh Annual National AIche-ASME Conference, August 1964.

3.8.4-1 "Waste Evaporator Enclosure - Design and Analysis Report," Carolina Power and Light Company, H.B. Robinson Steam Electric Plant, 700,000 KW Extension - Unit 2, Ebasco Services, Inc., April 1977.

3.8.4-2 Letter, NO-80-1015, dated July 7, 1980, from B. Furr (CP&L) to J. O'Reilly (NRC) Response to IE Bulletin 80-11, H.B. Robinson Steam and Electric Plant, Unit 2.

3.8.4-3 Letter, NO-80-1633, dated November 5, 1980, from B. Furr (CP&L) to J. O'Reilly (NRC) Response to IE Bulletin 80-11 (180 Day Response), H.B. Robinson Steam and Electric Plant, Unit 2.

3.8.4-4 Letter, LAP-83-01, dated February 4, 1983, from S. R. Zimmerman (CP&L) to Director of Nuclear Reactor Regulation (NRC), IE Bulletin 80-11, Masonry Wall Design.

3.8.4-5 Letter, LAP-83-87, dated April 5, 1983, from W. J. Hurford (CP&L) to S. A. Varga (NRC), IE Bulletin 80-11, Masonry Wall Design.

3.8.4-6 Letter, LAP-83-324, dated July 25, 1983, from S. R. Zimmerman (CP&L) to S. A. Varga (NRC), IE Bulletin 80-11, Masonry Wall Design. 2

3.8.4-7 Attachment to Letter NO-80-1759 dated December 1, 1980, E. E. Utley (CP&L) to S. A. Varga (NRC), Request for License Amendment - Spent Fuel Storage Expansion.

3.8.4-8 Letter NO-81-1055, dated June 18, 1981, from E. E. Utley (CP&L) to S. A. Varga (NRC), Revision to Request for Licensing Amendment, Spent Fuel Pool Storage Expansion.

3.8.4-9 Letter NO-81-1420, dated August 28, 1981 from E. E. Utley (CP&L) to S. A. Varga (NRC), Request for Additional Information Concerning Spent Fuel Pool Expansion.

3.8.4-10 Letter, dated April 2, 1982 from S. R. Zimmerman (CP&L) to S. A. Varga (NRC), Request for Additional Information Concerning Spent Fuel Pool Expansion.

3.8.4-11 Letter, RNPD-90-2791, dated September 5, 1990 from CP&L to NRC, Supplemental Response to I. E. Bulletin 80-11, H. B. Robinson Steam Electric Plant, Unit 2.

3.8.5-1 Hetenyi, M., "Beams on Elastic Foundation," The Univ. of Mich. Press, Ann Arbor, Mich. (1946).

3.8.5-2 Johnson, S. M., "Determining the Capacity of Bent Piles," Proc., Jour. of Research, Nat'l. Bur. of Stds., 66C, No. 3, 223-224 July-September (1962).

3.8.5-3 Rmonoff, Melvin, "Corrosion of Steel Piping in Soils," Jour. of Research, Natl. Bur. Stds, 66C, No. 3, 223-224 (1962).

3.9 MECHANICAL SYSTEMS AND COMPONENTS

The seismic classification and industrial codes used for systems, supports, and components are presented in Section 3.2. The seismic analysis of Class I piping and equipment is presented in Section 3.7.3.

3.9.1 SPECIAL TOPICS FOR MECHANICAL SYSTEMS

All components in the Reactor Coolant System (RCS) were designed to withstand the effects of cyclic loads due to reactor system temperature and pressure changes. These cyclic loads are introduced by normal power changes, reactor trip, and startup and shutdown operation. The number of thermal and loading cycles used for design purposes and their bases are given in Table 3.9.1-1. During unit startup and shutdown, the rates of temperature and pressure changes are limited as indicated in Section 5.3.2. The cycles were estimated for equipment design purposes (40-year life), and were not intended to be an accurate representation of actual transients or actual operating experience. For example, the number of cycles for plant heatup and cooldown at 100^{o}F per hour was selected as a conservative estimate based on an evaluation of the expected requirements. The resulting number, which averages five heatup and cooldown cycles per year, could be increased significantly; however, it was the intent to represent a conservative realistic number rather than the maximum allowed by the design.

Although loss of flow and loss of load transients are not included in Table 3.9.1-1, since the tabulation is only intended to represent normal design transients, the effect of these transients has been analytically evaluated and is included in the fatigue analysis for primary system components.

Over the range from 15 percent full power up to 95 percent of full power, the RCS and its components were designed to accommodate 20 percent of full power step changes in plant load and 15 percent of full power per minute ramp changes without reactor trip. The plant will accept a complete loss of load from full power without reactor trip.

A small amount of water also flows between the baffle plates and core barrel to provide additional cooling of the barrel. Similarly, a small amount of the entering flow is directed into the vessel head plenum and exit through the vessel outlet nozzles.

Vertically downward loads from weight, fuel assembly preload, control rod dynamic loading, and earthquake acceleration are carried by the lower core plate partially into the lower core plate support flange on the core barrel shell and partially through the lower support columns to the bottom support plate, and thence, through the core barrel shell to the core barrel flange supported by the vessel head flange. Transverse loads from earthquake acceleration, coolant cross flow, and vibration are carried by the core barrel shell to be shared by the lower radial support to the vessel head flange. Transverse acceleration of the fuel assemblies is transmitted to the core barrel shell by direct connection of the lower core support plate to the barrel wall and by a radial support type connection of the upper core plate to slab sided pins pressed into the core barrel.

The main radial support system of the core barrel is accomplished by "key" and "keyway" joints to the reactor vessel wall. At equally spaced points around the circumference, an Inconel block is welded to the vessel ID. Another Inconel block is bolted to each of these blocks, and has a "keyway" geometry. Opposite each of these is a "key" which is attached to the internals. At assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. With this design, the internals are provided with a support at the furthest extremity, and may be viewed as a beam fixed at the top and simply supported at the bottom.

Radial and axial expansion of the core barrel are accommodated, but transverse movement of the core barrel is restricted by this design. With this system, cycle stresses in the internal structures are within the American Society of Mechanical Engineers (ASME) Section III limits.

3.9.5.1.2 Upper Core Support Assembly

The upper core support assembly, shown in Figure 3.9.5-2, consists of the top support plate, deep beam sections, and upper core plate between which are contained support columns and guide tube assemblies. The support columns establish the spacing between the top support plate, deep beam sections, and the upper core plate, and are fastened at top and bottom to these plates and beams. The support columns transmit the mechanical loadings between the two plates and serve the supplementary function of supporting thermocouple guide tubes. The guide tube assemblies, shown on Figure 3.9.5-3, sheath and guide the control rod drive (CRD) shafts and control rods, and provide no other mechanical functions. They are fastened to the top support plate and are guided by pins in the upper core plate for proper orientation and support. Additional guidance for the control rod drive shafts is provided by the control rod shroud tube which is attached to the upper support plate and guide tube.

The upper core support assembly, which is removed as a unit during the refueling operation, is positioned in its proper orientation with respect to the lower support structure by flat-sided pins pressed into the core barrel which in turn engage in slots in the upper core plate. At an elevation in the core barrel where the upper core plate is positioned, the flat-sided pins are located at equal angular positions. Slots are milled into the core plate at the same

positions. As the upper support structure is lowered into the main internals, the slots in the plate engage the flat-sided pins in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design. Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place. Proper alignment of the lower core support structure, the upper core support assembly, the fuel assemblies, and control rods is thereby assured by this system of locating pins and guidance arrangements. The upper core support assembly is restrained from any axial movements by a large circumferential spring which rests between the upper barrel flange and the upper core support assembly and is compressed by the reactor vessel head flange.

Vertical loads from weight and fuel assembly preload are transmitted through the upper core plate via the support columns to the deep beams and top support plate and then to the reactor vessel head. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the top support plate and upper core plate. The top support plate is particularly stiff to minimize deflection.

3.9.5.1.3 In-Core Instrumentation Support Structures

The in-core instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom.

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are in turn fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouples are carried through these port columns and the upper support plate at positions above their readout locations. The thermocouple conduits are supported from the columns of the upper core support system. The thermocouple conduits are sealed stainless steel tubes.

In addition to the upper in-core instrumentation, there are reactor vessel bottom port columns which carry the retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal line. The minimum bend radii are about 90 in. and the trailing ends of the thimbles (at the seal line) are extracted approximately 13 ft during refueling of the reactor in order to avoid interference within the core. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.

Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. During normal operation, the retractable thimbles are stationary and move only during refueling or for maintenance, at which time a space of approximately 13 ft above the seal line is cleared for the retraction operation. Section 7.2 contains more information on the layout of the in-core instrumentation system.

3.9.6 In-Service Testing of Pumps and Valves

Attachment A of Reference 3.9.6-1 describes the Class 1, 2, and 3 (safety-related) pump and valve In-Service Inspection (ISI) Program for HBR 2. This program was developed in accordance with 10CFR 50.55a(g)(4)(ii) and was updated to Subsections IWP and IWV of ASME Section XI, 1986 Edition. Steam generator inspections will continue to be inspected under Plant Technical Specifications. Specific reliefs are requested in accordance with 10CFR 50.55a(g)(5)(iii).

The second ten (10) year Interval Inservice Inspection/Testing Program commenced on March 7, 1981 and was applicable through March 7, 1991. Due to the 1984 steam generator replacement outage duration of 349 days, the second ten year program was extended an equivalent period to February 19, 1992, as allowed by the ASME Section XI Code (IWA-2400(C)).

The ISI Program was developed employing the classification guidelines contained in 10CFR 50.2(v) for Quality Group A. Regulatory Guide 1.26, Revision 2 was used for classification of items in Quality Groups B and C, along with ANSI N18.2, 1973, and ANSI N18.2a, 1975. Quality Groups A, B, and C are the same as ASME classes 1, 2, and 3 respectively.

In response to IE Bulletin 79-17, the nondestructive examination program to be implemented for portions of systems containing stagnant borated water is presented in References 3.9.6-2 and 3.9.6-3. No evidence of intergranular stress corrosion cracking was found during any of the inspections (Reference 3.9.6-3).

REFERENCES: SECTION 3.9 (Cont'd)

3.9.6-3 Letter, GD-79-3118, dated December 6, 1979, B. Furr (CP&L) to J. O'Reilly (NRC), Response to IE Bulletin 79-17.

3.10 SEISMIC QUALIFICATION OF SEISMIC CATEGORY I INSTRUMENTATION AND ELECTRICAL EQUIPMENT

Electrical and control equipment which initiates reactor trips and/or actuates safeguards systems must be capable of performing its functions during and after an earthquake that has occurred at the plant site. To demonstrate the ability of this equipment to perform under earthquake conditions, selected types of this essential equipment representative of all protection and safeguards circuits and equipment were subjected to vibration tests which simulated the seismic conditions for the low seismic" class of plants. The "low seismic" class consists of those plants having a Design Basis Earthquake (DBE) horizontal acceleration less than or equal to 0.2g.

During the tests, equipment operation was monitored to prove proper performance of functions. The results show that there were no electrical malfunctions for the equipment tested as described in Reference 3.10.0-1. Based on these results, it was concluded that the equipment tested will perform their design functions during, as well as following, a "low seismic" earthquake. Reference 3.10.0-1 applies to H. B. Robinson (HBR) except Section 2.2 (Process Control Equipment). Analysis of seismic test results for the HBR process control equipment indicated that there were no electrical problems.

Dynamic analyses of the buildings for the plant DBE show that the significant horizontal and vertical accelerations of the building floor where the equipment is located are within the specified "low seismic" test envelopes given in Figure B-2 of Reference 3.10.0-1.

In addition to the specific equipment listed in Reference 3.10.0-1, consideration has been given to metal-clad and metal-enclosed switchgear. To provide proper functioning of the safeguards circuits and associated equipment during and following earthquake conditions, this switchgear equipment has been specified and designed to withstand acceleration in excess of 0.2g horizontally and 0.133g vertically. This capability was a matter of procurement specification of Westinghouse and its design agents and design action of the vendors.

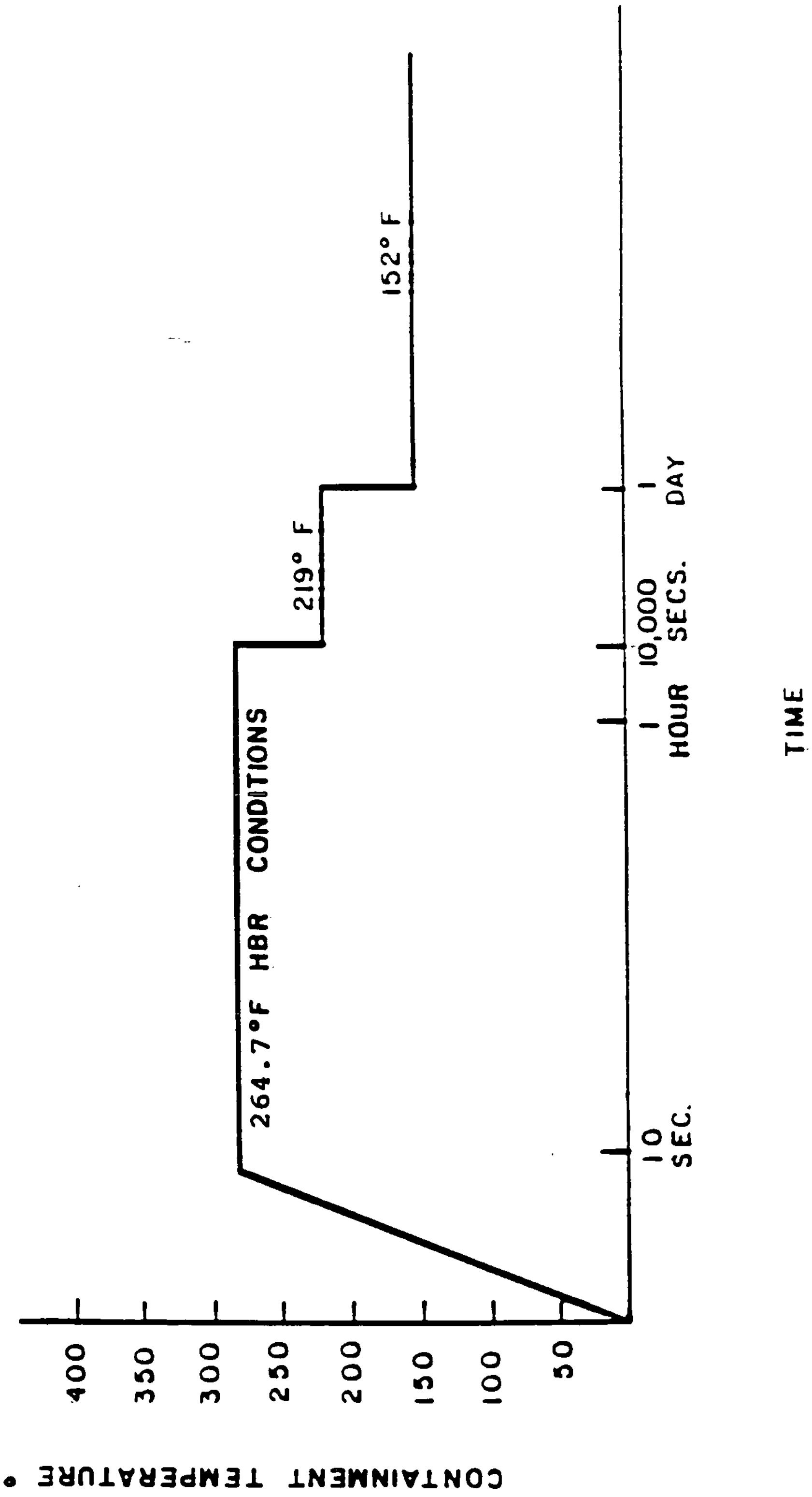
The safeguards circuits employ Westinghouse Models DB and DH circuit breakers and associated metal-enclosed or metal-clad switchgear. Review of these switchgear for proof of adequacy of the seismic resistance designs determined that the Model DB breakers mounted in the metal enclosures have been shock tested and proven to remain fully operable for shocks of at least 3g in any direction.

Proof of resistance of the Model DH metal-clad switchgear to a seismic response spectrum established for HBR 2 has been demonstated by vibration testing of typical, equivalent metal-clad switchgear incorporating the Model DHP circuit breakers. The Model DH circuit breakers installed in HBR 2 are an earlier design than the Model DHP. However, the general configuration weight, distribution and vibration resistant design approach of the Model DH are essentially identical to the Model DHP. When subjected to the seismic testing spectrum, there was no loss of functions of the Model DHP metal-clad switchgear.

Analyses of selected plant components to demonstrate their ability to withstand a seismic event are described in Section 3.7.3.3.

REFERENCES: SECTION 3.10

3.10.0-1 Vogeding, E. L. "Seismic Testing of Electrical and Control Equipment", WCAP-7397-L, January, 1970.



AMENDMENT NO. 10

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	ENVIRONMENTAL CONDITIONS FOR EQUIPMENT TESTING TEMPERATURE VS TIME	FIGURE 3.11.1-1

CHAPTER 4
REACTOR

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont'd)

CHAPTER 4
REACTOR

TABLE OF CONTENTS (Cont'd)

TABLE OF CONTENTS (Cont'd)

4.0 REACTOR

4.1 Summary Description

4.1.1 General Description of Core

The H. B. Robinson Unit 2 (HBR 2) reactor core is comprised of an array of 157 fuel assemblies. The core is cooled and moderated by light water at a normal operating pressure of 2250 psia in the Reactor Coolant System (RCS). The Reactor Coolant System contains boron as a neutron poison. The concentration of boron in the reactor coolant is varied as required to control relatively slow reactivity changes including the effects of fuel burnup.

The reactor core and reactor vessel internals are shown in elevation in Figures 4.1.1-1, 4.1.1-2 and a typical loading pattern is shown in Figure 4.1.1-3.

The HBR 2 reactor core contains 157 fuel assemblies manufactured by Siemens Power Corporation (SPC). Each assembly normally contains 204 fuel rods, twenty rod cluster control (RCC) guide tubes, and one instrumentation tube in a 15 x 15 fuel rod array. The standard fuel rods consist of slightly enriched UO_2 pellets inserted into zircaloy tubes. Beginning with Region 11 fuel, integrated burnable absorber rods have been used in varying numbers in the core, in the form of rods containing trace amounts of gadolinia (Gd_2O_3) in various concentrations in UO_2, for peaking control and reduction of the BOC critical boron. The RCC guide tubes and the instrumentation tubes are also made of zircaloy. Each assembly contains seven spacers; six of which are located within the active fuel region. In the older design, all of these are bi-metallic. Starting with Region 17 (ANF-11) fuel, only the bottom spacer is bi-metallic, the rest are a High Thermal Performance (HTP) all-zircaloy design. There are also three Intermediate Flow Mixer (IFM) grids and a debris-resistant lower tie plate on the HTP fuel. The lower tie plate design introduced for Cycle 16 makes use of an array of curved blades to provide a highly efficient debris trap.

There are two features that reduce the fast neutron fluence reaching the pressure vessel wall: axially blanketed fuel, and Part Length Shield Assemblies (PLSAs). The axial blanketed fuel contains a region of natural uranium at the top and at the bottom of each fuel assembly. All gadolinia-bearing pins, prior to Region 20 (ROB-14), contain 12 inches of natural uranium at the top and bottom of the fuel pin, while the non-gad pins contain 6 inches of natural uranium at the top and bottom. Beginning with Region 20 (ROB-14), the gadolinia-bearing pins contain six inches of enriched uranium between six inches of natural uranium at the top and bottom of the fuel rod, and the central gadolinia column. The PLSAs contain a steel insert in the bottom of each fuel rod and a natural uranium blanket for the top six inches of the active core. The steel insert at the bottom reduces the active fuel length, but has no effect on the outside dimensions of the assembly.

4.1.2 General Description of Fuel

Figures 4.1.2-1 and 4.1.2-2 depict the fuel assembly interface dimensions for the fuel design which was loaded prior to Cycle 14. Figures 4.1.2-3 and 4.1.2-4 depict the interface dimensions for the HTP fuel design. Mechanical, thermal-hydraulic and neutronic design values for a typical core loading are shown in Tables 4.1.2-1, 4.1.2-2 and 4.1.2-3, respectively.

The UO_2 (or UO_2 - Gd_2O_3 mixture) is in the form of dished cylindrical pellets made by compacting and sintering the UO_2 (or UO_2 - Gd_2O_3) powder. The pitch of the rods is maintained by seven grid spacers located along the length of the 204 rods. The spacers are welded to the guide tubes; the guide tubes are mechanically attached and secured to the upper and lower tie plates. The instrumentation tube is mechanically captured between the tie plates. Beginning with Region 20 (ROB-14), in addition to being mechanically captured, the instrument tube is welded at the bottom spacer location. The spacers, guide tubes, and tie plates form the structural skeleton of the fuel bundle.

TABLE 4.1.2-1

MECHANICAL DESIGN VALUES

A. FUEL PELLETS

Initial Enrichment, wt% U-235	0.711 to 4.50
Form	right cylinder
Average UO_2 Density, % Theoretical (through Region 17 (ANF-11)/ Region 18 (ANF-12) and later)	94/95
Pellet Diameter, in. (through Region 17 (ANF-11)/ Region 18 (ANF-12) and later)	0.3565/0.3570

B. FUEL ROD

Number of Rods per Assembly	204
Active Length, in.	144.0 (102.0 for PLSA rod)
Overall Rod Length, in. (through Region 19 (ROB-13)/ Region 20 (ROB-14))	152.065/151.950
Rod Pitch, in.	.563
Fill Gas	Helium

C. CLADDING

Material	Zircaloy-4
Outside Diameter, in.	.424
Wall Thickness, in.	.030

D. FUEL ASSEMBLY

Geometry	15 x 15
Number of Assemblies	157 (12 PLSAs, 145 non-PLSAs)
Fuel Assembly Pitch, in.	8.466
Overall Length, in.	159.71 (excluding upper tie plate leaf spring)

E. CONTROL ROD GUIDE TUBE

Number/Assembly	20
Material	Zircaloy-4
ID, Upper Section, in.	.511
ID, Dashpot, in.	.455
Dashpot Length, in.	24.5

F. INSTRUMENTATION TUBE

Number/Assembly	1
Material	Zircaloy-4
ID, in.	.511

TABLE 4.1.2-1 (Continued)

G. BI-METALLIC SPACER GRIDS

Number per assembly	1
Material	Zircaloy-4/Inconel 718

H. HTP SPACER GRIDS

Number per HTP assembly	6
Material	Zircaloy-4

I. IFM Grids

Number per HTP assembly	3
Material	Zircaloy-4

J. COMPONENT WEIGHTS

Weights per Assembly:	
Fuel	1080 lb (Non-PLSAs, Non-Gad)
Cladding and End Caps	255 lb
Bi-metallic Spacers	
Zircaloy-4	1.42 lb/spacer
Inconel	0.20 lb/spacer
Control Rod Guides	21 lb
Other Hardware	40 lb
Total Assembly Weight, lb	1417 (Non-PLSAs)
Uranium Weight per Assembly, kg	432.0 (Non-PLSAs, non-gad)

K. INSERT USED WITH PLSA FUEL RODS (ONLY)

Material	304 stainless steel
Diameter, In.	0.350
Length, In.	42.0

Note: The values in Sections J and K are from Cycle 12 and are representative.

4.2 Fuel System Design

4.2.1 Design Bases

4.2.1.1 Summary. The fuel design for the H. B. Robinson plant has been modified as follows:

1. Region 17 (ANF-11) incorporated HTP and IFM spacers, and a debris resistant lower tie plate. The burnup was increased to 52.5 GWd/MtU peak assembly. Previous axial blanket fuel designs have been analyzed to a peak fuel rod burnup of 53.9 GWd/MtU and a peak fuel assembly burnup of 49.0 GWd/MtU.

2. Region 19 (ROB-13) incorporated the FUELGUARD™ debris resistant lower tie plate design and included part length shielding assemblies (PLSA).

3. Region 20 (ROB-14) incorporated a shorter fuel rod design for higher burnups, and six inch enriched cutback zones between the reduced length (six inch) natural uranium blankets and the central enriched zones of the gadolinia fuel rods. Peak fuel rod burnups were analyzed to 62.0 GWd/MtU, and peak fuel assembly burnups to 57.0 GWd/MtU.

Mechanical design analyses were performed to evaluate cladding steady-state strain, transient stress and strain, fatigue, creep collapse, corrosion, fuel rod internal pressure, elongation, and fuel assembly growth. Design criteria consistent with current Siemens Power Corporation (SPC) methodology were used in the analysis. Bounding power histories have been used. The results indicate that all the mechanical design criteria are satisfied.

1. The maximum end-of-life (EOL) steady-state cladding strain was less than the 1.0 percent design limit.

2. The cladding strain during power ramps, calculated under different overpower conditions, does not exceed the 1.0 percent strain limit.

3. The cladding fatigue usage factor is within the design limit.

4. The end-of-life fuel rod internal pressure is less than the approved design limit.

5. The criterion for the prevention of creep collapse is satisfied.

6. The maximum calculated EOL thickness of the oxide corrosion layer is within the design limit of 130 microns.

4.2.1.2 Fuel Rod Design Basis.

4.2.1.2.1 Cladding physical and mechanical properties. Zircaloy-4 combines a low neutron absorption cross section, high corrosion resistance, and high strength and ductility at operating temperatures. Principal physical and mechanical properties including irradiation effects on Zircaloy-4 are provided in Section 4.2.2.3.

4.2.1.2.2 Cladding stress limits. The design basis for the fuel cladding stress limits is that the fuel system will not be damaged due to fuel cladding stresses exceeding material capability. Conservative limits shown in Table 4.2.1-1 are derived from the ASME Boiler and Pressure Vessel Code, Section III, Article III-2000 (Reference 4.2.1-1).

4.2.1.2.3 Cladding strain limits. Tests on irradiated tubing (References 4.2.1-2 and 4.2.1-3) indicate potential for failure at relatively low mean strains. The data on tensile, burst and split ring tests, indicate a ductility ranging between 1.2 percent and 5 percent at normal reactor operating temperatures. The failures are usually associated with unstable or localized regions of high deformation after some uniform deformation. To prevent cladding failure due to plastic instability and localization of strain, the total mean hoop cladding strain for steady-state conditions is limited to 1 percent, and the increment of the thermal creep during a transient is also limited to 1 percent.

4.2.1.2.4 Strain fatigue. Cyclic PCI loading combined with other cyclic loading associated with relatively large changes in power can cause cumulative damage which may eventually lead to fatigue failure. Cyclic loading limits are established to prevent fuel failures due to this mechanism. The design life is based on correlations which give a safety factor of 2 on stress amplitude or a safety factor of 20 on the number of cycles whichever is more conservative (Reference 4.2.1-4).

4.2.1.2.5 Fretting corrosion and wear. The design basis for fretting corrosion and wear is that fuel rod failures due to fretting shall not occur. Since significant amounts of fretting wear can eventually lead to fuel rod failure, the spacer grid assemblies are designed to prevent such wear.

4.2.1.2.6 Corrosion. Cladding oxidation and corrosion product buildup are limited in order to prevent significant degradation of clad strength. A PWR clad external temperature limit is chosen so that corrosion rates are very slow below this temperature and therefore overall corrosion is limited. An external corrosion layer limit is also specified so that this amount of corrosion will not significantly affect thermal and mechanical design margins. This decrease in clad thickness does not increase clad stresses above allowable levels.

4.2.1.2.7 Hydrogen absorption. The as-fabricated cladding hydrogen level and the fuel rod cladding hydrogen level during life are limited to prevent adverse effects on the mechanical behavior of the cladding due to hydriding. Hydrogen can be absorbed on either the outside or the inside of the cladding. Excessive absorption of hydrogen can result in premature cladding failure due to reduced ductility and the formation of hydride platelets. Hydrogen absorption is controlled by the oxide layer. Maintaining the oxide layer thickness within the oxide layer limit (130 microns - peak local) controls the amount of hydrogen absorption into the zircaloy within design limits.

4.2.1.2.8 Creep collapse. The design basis for creep collapse of the cladding is that significant axial gaps due to fuel densification shall not occur and therefore that fuel failure due to creep collapse shall not occur. Creep collapse of the cladding can increase nuclear peaking, inhibit heat transfer, and cause failure due to localized strain.

If significant gaps form in the pellet column due to fuel densification, the pressure differential between the inside and outside of the cladding can act to increase cladding ovality. Ovality increase by clad creep to the point of plastic instability would result in collapse of the cladding. During power changes, such collapse could result in fuel failure.

Through proper design, the formation of axial gaps and the probability of creep collapse can be significantly reduced. Typical SPC pellets are stable dimensionally.

A compressive Inconel plenum spring is included in the fuel rod design and the rods are pressurized with helium to help prevent the formation of gaps in the pellet column.

An analysis is performed in order to guard against the unlikely event that sufficient densification occurs to allow pellet column gaps of sufficient size for clad flattening to occur. The analysis ensures a gap exists between the cladding and the pellet through the densification period of the fuel column.

4.2.1.2.9 Fuel rod internal pressure. The internal gas pressure of the fuel rods may exceed the external coolant pressure up to the NRC approved design limit. Significant outward circumferential creep which may cause an increase in pellet-to-cladding gap must be prevented since it would lead to higher fuel temperature and higher fission gas release.

4.2.1.2.10 Creep bow. Differential expansion between the fuel rods and lateral thermal and flux gradients can lead to lateral creep bow of the rods in the span between spacer grids. The design basis for fuel rod bowing is that lateral displacement of the fuel rods shall not be of sufficient magnitude to impact thermal margins. The fuel has been designed to minimize creep bow. Extensive post-irradiation examinations have confirmed that such rod bow has not reduced spacing between adjacent rods by more than 50 percent. The potential effect on thermal margins is negligible.

4.2.1.2.11 Overheating of cladding. The design basis for fuel rod cladding overheating is that transition boiling shall be prevented. Prevention of potential fuel failure from overheating of the cladding is accomplished by minimizing the probability that boiling transition occurs on the peak fuel rods during normal operation and anticipated operational occurrences.

4.2.1.2.12 Overheating of fuel pellets. Prevention of fuel failure from overheating of the fuel pellets is accomplished by assuring that the peak linear heat generation rate (LHGR) during normal operation and anticipated operational occurrences does not result in fuel centerline melting. The melting point of the fuel is adjusted for burnup in the centerline temperature analysis.

4.2.1.3 Fuel Assembly Design Bases.

4.2.1.3.1 Structural design. The structural integrity of the fuel assemblies is assured by setting design limits on stresses and deformations due to various handling operational and accident loads. These limits are applied to the design and evaluation of upper and lower tie plates, grid spacers, guide tubes, holddown springs, and locking hardware.

The design bases for evaluating the structural integrity of the fuel assemblies are:

1. Fuel Assembly Handling - Dynamic axial loads approximately 2.5 times assembly weight.

2. For all applied loads for normal operation and anticipated operational events - The fuel assembly component structural design criteria are established for the two primary material categories, austenitic stainless steels (tie plates) and Zircaloy (guide tubes, grids, spacer sleeves). The stress categories and strength theory for austenitic stainless steel presented in the ASME Boiler and Pressure Vessel Code, Section III are used as a general guide.

3. Loads during postulated accidents - Deflections or failure of components shall not interfere with reactor shutdown or emergency cooling of the fuel rods.

4. The fuel assembly structural component stresses under faulted conditions are evaluated using primarily the methods outlined in Appendix F of the ASME Boiler and Pressure Vessel Code, Section III.

4.2.1.3.2 Coolability during postulated accidents. The fuel assembly design basis for earthquakes and postulated pipe breaks is that the fuel assembly shall maintain a coolable geometry and control rod insertability during the occurrence of the design seismic/LOCA event.

4.2.1.3.3 Fuel rod and assembly growth. The design basis for fuel rod and assembly growth is that adequate clearance shall be provided to prevent any interference which might lead to buckling or damage. Fuel cladding and guide tube growth measurements are used in establishing the growth correlations used for calculations. Beginning with Reload Region 17 (ANF-11), additional axial fuel rod growth from the higher burnups is provided for with a change in the lower tie plate design that increases the room between the upper and lower tie plates. Reload Region 20 (ROB-14) provides additional growth space for higher burnups through a shorter fuel rod design.

4.2.1.3.4 Assembly holddown. The design basis for fuel assembly holddown is that the holddown springs, as compressed by the upper core plate during reactor operation, will provide a net positive downward force during steady-state operation, based on the most adverse combination of component dimensional and material property tolerances. In addition, the holddown springs are designed to accommodate the additional load associated with a pump overspeed transient, and to continue to ensure fuel assembly holddown following such an occurrence.

<u>4.2.1.4 Core Components Design Bases</u>. The reactor internal components are designed to withstand the stresses resulting from startup, steady state operation with any number of pumps running, and shutdown conditions. No damage to the reactor internals occurs as a result of loss of pumping power.

Lateral deflection and torsional rotation of the lower end of the core barrel are limited to prevent excessive movements resulting from seismic disturbances and thus prevent interference with rod cluster control

assemblies. Core drop in the event of failure of the normal supports is limited so that the rod cluster control assemblies do not disengage from the fuel assembly guide thimbles.

The structural internals are designed to maintain their functional integrity in the event of a major loss-of-coolant accident (LOCA). The dynamic loading resulting from the pressure oscillations because of a LOCA does not prevent rod cluster control assembly (RCCA) insertion.

The cladding is designed to be free-standing under all operating conditions and will maintain encapsulation of the absorber material throughout the absorber rod design life. Allowance for wear during operation is included in the RCCA cladding thickness.

Adequate clearance is provided between the absorber rods and the guide thimbles which position the rods within the fuel assemblies so that coolant flow along the length of the absorber rods is sufficient to remove the heat generated without oveheating of the absorber cladding. The clearance is also sufficient to compensate for any misalignment between the absorber rods and guide thimbles and to prevent mechanical interference between the rods and guide thimbles under any operating conditions.

4.2.2 Design Description

4.2.2.1 Fuel Assembly. The 15x15 fuel assembly array includes 20 guide tubes, 204 fuel rods and one instrumentation tube. Six of the seven grid spacers are an all-zircaloy High Thermal Performance (HTP) design. The bottom spacer grid is bi-metallic. There are three Intermediate Flow Mixer (IFM) grids, which along with the HTP grids, have internal slanted channels that improve the fuel rod heat transfer and coolant mixing. The fuel assembly tie plates are stainless steel castings with Inconel holddown springs. Beginning with the reload Region 19 (ROB-13), the FUELGUARD debris resistant lower tie plate was incorporated into the fuel assembly design. The FUELGUARD lower tie plate consists of a curved blade and rod grid brazed into a cast frame. The FUELGUARD is designed to prevent coolant entrained debris from passing into the fuel assembly. The fuel pellet design was changed slightly beginning with reload Region 18 (ANF-12). The pellet diameter was increased from 0.3565 to 0.3570, pellet density increased from 94% to 95% theoretical density and the UO_2 pellet length increased from 0.273 to 0.410 inches. Fuel assembly characteristics are summarized in Table 4.2.2-1. The bi-metallic and HTP fuel assemblies are shown in Figures 4.1.2-1 and 4.1.2-3.

The grid spacers are welded to the Zircaloy-4 guide tubes, and the guide tubes are mechanically attached and secured to the upper and lower tie plates. The instrumentation tube is welded to the bottom spacer (beginning with the reload Region 20 (ROB-14)) and is also mechanically captured between the tie plates. The fuel rods are axially positioned within the skeleton with approximately equal spacing at both ends. The upper tie plates are designed to be removed and reinstalled by underwater remote handling techniques.

Proper orientation of fuel assemblies is specifically addressed through the design of the upper tie plate. As shown in Figure 4.1.2-1, it has two locating holes in opposite corners for receiving the locating pins in the upper core support plate. A third hole of smaller diameter is located in a third corner for the purpose of orienting the assembly. This hole receives the indexing pin from the manipulator grapple.

4.2.2.1.1 Fuel assembly material properties. The material properties used in the design evaluation are described in this section.

4.2.2.1.2 Zircaloy-4 chemical properties. Zircloy-4 is used in three forms: (a) cold worked and stress relieved cladding; (b) recrystallized annealed tubing; and (c) recrystallized annealed strip.

4.2.2.1.3 Fissile material (Uranium Dioxide). Chemical composition is as follows:

1. Uranium Content - The uranium content shall be a minimum of 87.7 percent by weight of the uranium dioxide on a dry weight basis.

2. Stoichiometry - The oxygen-to-uranium ratio of the sintered fuel pellets shall be within the limits of 1.99 and 2.01.

Mechanical properties are as follows:

1. Mechanistic Fuel Swelling Model - The irradiation environment and fissioning events cause the fuel material to alter its volume and, consequently, its dimensions.

2. Fission Gas Release - For design evaluations of end-of-life pressures, pellet-cladding interaction and general thermal mechanical conditions, a physically based two-stage release model is used. First stage fission gas release is to grain boundaries, and then the second stage release is from the grain boundaries to the interconnected free gas volume.

3. Melting Point - The value used for the UO_2 melting point (unirradiated) is 2790°C (5054°F). Based on measurements by Christensen, et al (Reference 4.2.2-1), the melting point is reduced linearly with irradiation at the rate of 12.2°C (22.0°F) per 10^{22} fiss/cm^3 or 32°C (57.6°F) per 10^4 MWd/MTU.

4.2.2.1.4 Inconel springs. Coil springs are fabricated from Inconel X-750 wire or rod with an alloy composition in accordance with AMS 5699B. Leaf springs are fabricated from Inconel sheet or strip.

4.2.2.2 Fuel Rod. The fuel rods consist of cylindrical UO_2 pellets in Zircaloy-4 tubular cladding.

The Zircaloy-4 fuel rod cladding is cold worked and stress relieved. Zircaloy-4 plug type end caps are seal welded to each end. The upper end cap has external features to allow remote underwater fuel rod handling. The lower end cap has a truncated cone exterior to aid fuel rod reinsertion into the fuel assembly during inspection and/or reconstitution.

Each non-PLSA fuel rod contains a 132.0 inch column of enriched UO_2 fuel pellets, and a 6 inch column of natural UO_2 fuel pellets at each end except for gadolinia bearing fuel rods which have a 12-inch natural uranium blanket at the top and bottom of the fuel rod. Beginning with reload Region 20 (ROB-14), the gadolinia bearing fuel rods contain a 6-inch natural uranium blanket, and a 6-inch enriched uranium column between the natural blanket and the central gadolinia fuel column at the top and bottom of the fuel rod. Each PLSA fuel rod has the bottom 42 inches of fuel replaced by stainless steel.

The fuel rod upper plenum contains an Inconel compression spring to prevent fuel column separation during fabrication and shipping, and during in-core operation.

Fuel rods are pressurized with helium which provides a good heat transfer medium and assists in the prevention of clad creep collapse. The fuel rod is shown in Figure 4.2.2-2.

4.2.2.3 Core Components.

4.2.2.3.1 Rod cluster control assembly. The RCCA are provided to control the reactivity of the core under operating conditions. These assemblies, one of which is shown in Figure 4.2.2-3, each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. RCCA details are presented in Table 4.2.2-2.

The absorber material used in the control rods is silver-indium-cadmium alloy which is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded single length rods which are sealed in

stainless steel tubes to prevent the rods from coming in direct contact with the coolant.

The overall control rod length is such that when the assembly has been withdrawn through its full travel, the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble. Prototype tests have shown that the RCCA are very easily inserted and not subject to binding even under conditions of severe misalignment.

The spider assembly is in the form of a center hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive shaft are machined into the upper end of the hub. A spring pack is assembled into a skirt integral to the bottom of the hub to stop the RCCA and absorb the impact energy at the end of a trip insertion. The radial vanes are joined to the hub and the fingers are joined to the vanes by furnace brazing. A centerpost which holds the spring pack and its retainer is threaded into the hub within the skirt and welded to prevent loosening in service. All components of the spider assembly are made from Type 304 Stainless Steel, except for the springs, which are Inconel X-750 alloy, and the retainer, which is of 17-4 PH material.

The absorber rods are secured to the spider so as to assure trouble free service. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness, after which the pins are welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

In construction, the silver-indium-cadmium rods are inserted into coldworked stainless steel tubing which is then sealed at the bottom and the top by welded end plugs. Sufficient diametral and end clearances are provided to accommodate relative thermal expansions and to limit the internal pressure to acceptable levels.

The bottom plugs are made bullet-nosed to reduce the hydraulic drag during a reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

Stainless steel clad silver-indium-cadmium alloy absorber rods are resistant to radiation and thermal damage thereby ensuring their effectiveness under all operating conditions.

4.2.2.3.2 Neutron source assembly. The H. B. Robinson core normally utilizes one to two neutron source assemblies. Historically, these sources have been composed of four secondary source rods, however, beginning in Cycle 14 source assemblies with eight secondary source rods will be used to increase source strength (this does not preclude a return to sources with four secondary rods in the future). The increased source strength is necessary to overcome the shielding effect of the PLSA assemblies which are located between the sources and the source range detectors. The rods in the secondary source assemblies (both 4 and 8 finger) are fastened to a spider-hub at the top similar to a rod cluster control assembly (RCCA) spiders. In the core, the

neutron sources assemblies are inserted into fuel assembly guide tubes at locations that are unrodded and with which there will be mechanical compatibility between the spider-hub and the reactor upper internals. Figure 4.3.2-1 illustrates the preferred secondary source locations of H-03 and H-13.

General design criteria similar to that for the fuel rods are used for the design of the source rods; i.e., the cladding is free-standing, internal pressures are always less than reactor operating pressure, and internal gaps and clearances are provided to allow for differential expansions between the source material and cladding. Typically, secondary source rods used at H. B. Robinson have utilized cold-worked Type 304 Stainless Steel cladding material (nominal 0.431 in. OD, 0.3935 in. ID) with Sb-Be source pellets of stack height 67.87 in. Alternative designs are possible provided they meet the general design criteria.

In some cases more than two source assemblies may be used in the core to provide an active source during startup while transitioning from old previously irradiated sources to new inactive sources; at the completion of a "source transition cycle" the old sources are typically removed and disposed of. In this circumstance, some source assemblies must be located in core locations other than the preferred locations H-03 and H-13. The following alternative core locations provide mechanical compatibility between the reactor upper internals and the spider-hub type source assemblies utilized at H. B. Robinson:

A-07	A-09	B-07	B-09	B-11	C-04	C-05	C-06
C-10	C-11	D-07	D-09	D-11	D-13	E-02	E-03
E-06	E-13	F-07	G-04	G-10	G-12	G-14	H-01
H-03	H-07	H-13	J-01	J-04	J-06	J-08	J-14
J-15	K-07	K-09	K-13	L-02	L-03	L-04	L-10
L-13	M-05	M-07	M-13	N-05	N-11	N-12	P-05
P-09	P-11	R-08	R-09				

If the purpose of a given source located in a core position other than H-03 or H-13 is to provide counts for the source range detectors, acceptable (but not necessarily exclusive) alternative locations taken from the mechanically compatible list are:

G-04 G-12 G-14 J-04 J-14

In locating a new inactive source for irradiation and use in the following cycle, an additional consideration in choosing its location is that the host assembly should experience a relative power of at least 0.5 to provide sufficient activation.

4.2.2.3.3 Thimble plug assembly. In order to limit bypass flow through the RCC guide thimbles in fuel assemblies which do not contain either control rods or source assemblies, the fuel assemblies at those locations are fitted with plugging devices. The plugging devices consist of a flat plate with short rods suspended from the bottom surface and a spring pack assembly attached to the top surface. At installation in the core, the plugging devices fit into the fuel assembly top nozzles and rest on the adaptor plate. The short rods project into the upper ends of the thimble tubes to reduce the bypass flow area. The spring pack is compressed by the upper core when the

upper internals package is lowered into place. Similar short rods are also used on the source assemblies to fill the ends of all vacant fuel assembly guide thimbles.

All components in the plugging device, except for the springs, are constructed from Type 304 Stainless Steel. The springs are wound from an age hardenable nickel-base alloy.

TABLE 4.2.2-1

FUEL ASSEMBLY DESIGN

FUEL PELLET	
Fuel Material	UO_2 Sintered Pellets
Pellet Diameter, (in.) Through Region 17 (ANF-11)/Region 18 (ANF-12)	0.3565/0.3570
CLADDING	
Clad Material	Zircaloy-4 Cold Worked and Stress Relieved
Clad ID, (in.)	0.364
Clad OD, (in.)	0.424
Clad Thickness, Nominal, (in.)	0.030
FUEL ROD	
Diameter Gap, Cold Nominal, (in.) Through Region 17 (ANF-11)/Region 18 (ANF-12)	0.0075 0.0070
Active Length, (in.)	144.0
Total Rod Length, (in.) Through Region 19 (ROB-13)/Region 20 (ROB-14)	152.065/151.950
Fill Gas	Helium
BI-METALLIC SPACER	
Number per assembly	1
Material	Zr-4 & Inconel 718
Envelope (in.)	8.426 square
HIGH THERMAL PERFORMANCE (HTP) SPACER	
Number per assembly	6
Material	Zircaloy-4
Maximum unloaded condition envelope (in.)	8.436 square
INTERMEDIATE FLOW MIXER (IFM) GRID	
Number per assembly	3
Material	Zircaloy-4
Maximum unloaded condition envelope (in.)	8.405 square

TABLE 4.2.2-1

FUEL ASSEMBLY DESIGN (CONTINUED)

GUIDE TUBE	
Material	Zr-4, Fully Annealed
OD/ID Above Dashpot (in.)	0.544/0.511
TIE PLATES	
Material	Stainless Steel
HOLDDOWN SPRINGS	
Material	Inconel
CAP SCREWS	
Materials	Inconel Stainless Steel
FUEL ASSEMBLY	
Array	15x15
Rod Pitch	0.563
No. Bi-metallic Spacers: HTP/non-HTP	1/7
No. Zircaloy Spacers: HTP/non-HTP	6/0
No. IFM Grids: HTP/non-HTP	3/0
No. Fuel Rods	204
No. Guide Tubes	20
No. Instrumentation Tubes	1

4.2.3 Mechanical Design Evaluation

4.2.3.1 Reactor Operating Conditions for Design. The fuel assembly design is based on the following reactor operating conditions:

Core Power Level	
Nominal	2300 MWt
Design Basis (18% Thermal Overpower)	2714 MWt
Coolant Operating Pressure (Nominal)	2250 Psia
Coolant Flow Rate (Nominal @ Nominal Power)	
Total	107.3 X 10^6 lb/hr
Active Core	102.5 X 10^6 lb/hr
Heat Generation Fraction Fuel Rods	97.4 percent
Average Flow Velocity	15.2 ft/sec
Coolant Inlet Temperature (Nominal)	547.6°F
Core Average Coolant Temperature	575.4°F
Number of Assemblies in Core	157 (153.5 active)

The fuel shall be capable of load-follow operation between 50 percent and 100 percent of rated power, and not preclude the transients set forth in the UFSAR.

4.2.3.2 Fuel Rod Evaluation.

4.2.3.2.1 Design criteria.

1. Cladding steady state stresses shall not exceed the established limits.

2. Maximum cladding strain shall not exceed 1.0 percent at end-of-life (EOL), or 1.0 percent during steady state or expected transients. (Maximum hoop stresses are bounded by strain limits. See Reference 4.2.3-7 for analysis of hoop stresses.)

3. The cumulative usage factor for cyclic stresses shall not exceed 0.67.

4. The fuel rod internal pressure at the end of the design life may exceed the system operating pressure up to the NRC approved design limit.

5. Cladding creep collapse shall not occur.

6. The thickness of the corrosion layer shall not exceed design limits.

7. The fuel elongation must be accommodated by the clearance between fuel rods and tie plates.

8. Fuel rod creep bow throughout the design life of the assemblies shall be limited so as to maintain licensing and operational limit restraints.

9. The fuel rod plenum spring shall maintain a positive compression on the fuel column during shipping and during the fuel densification stage.

10. Cladding temperatures shall not exceed the design limits.

11. Pellet temperatures shall not exceed the melting temperature during normal operation and anticipated transients.

4.2.3.2.2 Fuel rod analysis. The fuel rod analysis considers the high burnup design with natural uranium axial blankets. The fuel temperatures of the neutron absorbing fuel (NAF) pellets shall be less than the UO_2 pellets during limiting fuel cycle operation. The analyses described in this Section are detailed and documented in References 4.2.3-1, 4.2.3-2, and 4.2.3-6.

1. Steady State Stresses - The cladding steady-state stresses are highest at beginning-of-life except for a bending stress due to ovality. Since the cladding eventually is supported by the pellets, the ovality bending stress is eliminated as a factor for the end-of-life condition at higher burnup. The cladding stresses are within the established limits.

The stress analysis is performed at the lower end cap since the maximum temperature gradients occur at this end.

The mechanical stress is caused by the pressure differential across the rod wall and by the axial load of the pellet stack weight and the plenum spring force. The thermal stress is caused by the temperature gradient between the end cap and the heat generating pellets.

The ANSYS code, which allows thermal as well as stress analyses, was used to model the subject rod region. The maximum weld stress intensity is well below the design limit.

2. Steady State Strain Analyses - The cladding steady-state strain was evaluated with the RODEX2 code. The code calculates the thermal, mechanical and compositional state of the fuel, and cladding for a given duty history. Conservative input values were used in the strain analysis. Dimension values covering all reloads have been analyzed.

The criterion of 1 percent maximum at EOL is satisfied.

3. Ramp Strain Analysis - The clad response ramping power changes is calculated with the RAMPEX code. This code calculates the pellet-cladding interaction during a power ramp. The initial conditions are obtained from RODEX2 output. The RAMPEX code considers the thermal condition of the rod in its flow channel and the mechanical interactions that result from fuel creep, crack healing, and cladding creep at any desired axial section in the rod during the power ramp.

The power histories assumed for this analysis include the maximum exposure rods and high power first cycle, second cycle, third cycle, and fourth cycle histories. The high power cycles were used to evaluate large power swings resulting from fuel shuffling.

The conditions at the end of each cycle obtained with the RODEX2 code are used as input data for the RAMPEX code. The rods under consideration were ramped to the maximum power. The maximum strains due to each ramp were examined. The maximum strains, including primary and secondary thermal creep, were less than the 1 percent strain limit.

4. Cladding Fatigue Usage Factor - In addition to the ramp strain analyses, a fatigue usage factor for the cladding was calculated. The calculations were based upon the typical duty cycles. Cladding stress amplitudes for the various power cycles were determined from RAMPEX analyses. RAMPEX analyses were run for each cycle at the plane of maximum contact pressure which resulted in conservatively high stresses for the fatigue analysis. The overall fatigue usage factor is within the 0.67 design limit.

5. Internal Pressure - A RODEX2 analysis was performed to evaluate the internal fuel rod pressure throughout the fuel lifetime. To prevent cladding instability, the rod internal pressure cannot exceed the approved design limit or else the cladding may creep away from the pellet, which increases the fuel rod pellet temperatures. Higher fuel temperatures result in increased fission gas release and, therefore, higher internal rod pressures. The results of this analysis show the EOL internal rod pressure does not exceed the NRC approved design limit. The fuel rod will, therefore, remain stable throughout the expected power history.

6. Creep Collapse - The collapse calculation is done using the RODEX2 and COLAPX codes to determine the temperature and pressure conditions throughout the fuel rod lifetime, and to determine the clad creepdown. These conditions are used as input for COLAPX. The COLAPX code then predicts the time dependent creep ovality deformations in an infinite length tube subjected to external pressure, internal pressure, and linearly varying temperature gradients through the thickness of the cylinder.

If significant gaps are not allowed to form, then tube ovality, as predicted by the COLAPX evaluation, cannot occur beyond the point of fuel support.

In order to guard against the highly unlikely event that enough densification occurs to form pellet column gaps of signficant size to allow clad flattening, an evaluation was performed. The cladding ovality increase was calculated with COLAPX, and the creepdown was calculated with RODEX2. The combined creepdown at the cladding minor axis was determined not to exceed the minimum level to allow the fuel column to relocate axially without the formation of axial gaps.

7. Rod Bowing - Fuel rod bow is determined throughout the life of the fuel assembly so that reactor operating thermal limits can be established. These limits include the minimum critical heat flux ratio associated with protection against boiling transition and the maximum fuel rod LHGR associated with protection of metal-water reaction and peak cladding temperature limits for a postulated loss of coolant accident (LOCA).

Rod bow measurements have been used to establish an empricial model for determining rod bow as a function of burnup which is used to calculate thermal limits.

The gap spacing data shows that the bow tends to stabilize at higher burnups. In addition, the fuel at high burnups is not limiting from a thermal margin standpoint due to its lower power.

8. Corrosion Layer Analyses - The thickness of the corrosion layer has been evaluated with the RODEX2 code for the peak discharge fuel rod power history. The oxide thickness is within the design limits.

9. Fuel Rod Growth - Growth data has been correlated to fast fluence. Based on this correlation, with an added uncertainty, the rod growth for the maximum discharge exposure fuel rod was calculated. A minimum end of life (EOL) clearance margin for this growth is available. An additional 0.2 inch allowance for fuel rod growth was created in the HTP assemblies by taking that much off the lower tie plate legs and using it as space between the tie plates. The overall guide tube length was also increased by 0.2 inch. Additional space was provided for the higher burnup Region 20 (ROB-14) fuel by shortening the fuel rod length.

10. Cladding Temperature - Prevention of potential fuel failure from overheating of the cladding is also established by minimizing the probability that DNB occurs on limiting fuel rods during normal operation and anticipated operating events.

11. Fuel Pellet Temperature - Prevention of fuel failure from overheating of the fuel pellets is accomplished by insuring that the peak LHGR during normal operation and anticipated transients does not result in calculated centerline melt.

4.2.3.3 Fuel Assembly Evaluation.

4.2.3.3.1 Design criteria. The mechanical design criteria for the fuel assembly are listed below:

1. The fuel assemblies shall be mechanically compatible with the reactor core, fuel handling system, and core components.

2. The upper tie plate shall be removable from the fuel assembly to permit access for removal of fuel rods for replacement or inspection.

3. The fuel assembly shall be designed to withstand operating, handling, and accident loads.

4. The fuel assembly shall support the fuel rod, providing sufficient spring force to minimize flow-induced vibrations and to prevent fretting corrosion at the spacer-fuel rod contact points.

5. The assembly shall be designed to provide clearance for irradiation induced guide tube growth without exceeding the core plate-to-core plate spacing.

4.2.3.3.2 Fuel assembly analysis.

1. Stresses and Deflections - The guide tubes along with the upper and lower tie plates and grid spacers provide the principal structure for the fuel assembly. Guide tubes are considered as restrained columns and are analyzed accordingly, using appropriate load combinations. Column deflection is permissible within constraints of allowable bending stress, allowable displacement, and allowable approach to column instability. The allowable total stress, primary plus bending, is less than the yield strength of the material at the temperature of the load conditions (Reference 4.2.3-3).

As the power level of the reactor is increased, differential thermal expansion between the Zircaloy guide tubes and the hotter Zircaloy clad fuel rod would tend to put the guide tube in tension. Therefore, there is no concern as to the stability of the guide tube on approach to normal operating conditions. After some period at power, vibration loads would tend to reduce or eliminate loads caused by differential thermal expansion. Upon reduction in power, differences in temperature between the guide tubes and fuel rods would decrease causing compression loading on the guide tube. Thus, the stability of Zircaloy guide tubes is of most concern as the power level is reduced.

The Zircaloy spacer was analyzed using a finite element structures code. The structural integrity was confirmed through strength tests. Some tests used a hydrided spacer in order to simulate in-reactor conditions.

The most severe normal loading condition is the situation where the lower tie plate becomes hung up on a spacer edge during fuel handling. Both analyses and tests indicate that the spacer structure can take such loading.

Cyclic loading due to differential thermal expansion between the fuel rods and guide tubes is less severe than the assumed refueling load described above. In this latter case the maximum load is uniformly distributed across the spacer structure as compared to the refueling situation load which is concentrated at local regions at the spacer edge. Thus, loading due to differential thermal expansion of the structure should not result in stresses sufficient to cause fatigue failures.

2. Fuel Rod Support - The Inconel spacer springs are known to relax during irradiation and the fuel rod cladding tends to creepdown. Together, these two characteristics combine to reduce the spacer spring force on a fuel rod during its lifetime. These characteristics have been considered in the design of the spring to assure an adequate holding force when the assembly has completed its design operating life.

The prevention of fretting corrosion in the Zircaloy HTP and IFM spacers is demonstrated by a combination of analysis and fretting tests. The design analysis determines the projected maximum end-of-life gap, considering spring relaxation, clad creepdown, minimum fuel rod outer diameter, and minimum initial spring deflection. Flow test data are used to confirm that fretting corrosion will not occur for the largest possible projected gaps.

3. Fuel Assembly Growth - The limiting condition for fuel assembly growth is at end-of-life after cooldown. Because of the higher coefficient of thermal expansion for the stainless steel core structure relative to the Zr-4 guide tubes, differential thermal expansion increases the assembly/internals structure clearance during heatup and reduces the clearance upon cooldown. Axial growth data for the fuel designs of interest are given in References 4.2.3-1, 4.2.3-2, and 4.2.3-6. Allowing for measurement error and other uncertainties, the maximum EOL fuel assembly length predicted from the upper limits of the data leaves a clearance with the minimum as-built core plate to core plate separation.

4. Combined Shock and Seismic Loading (Internals) - The results of a detailed study of the blowdown plus seismic excitation of the reactor internal indicated that the maximum deflections and stresses in the critical structures are below the established allowable limits. For the transverse excitation, it was shown that the upper barrel would not buckle during a hot-leg break and that it would have an allowable stress distribution during a cold-leg break. Even though control rod insertion is not required for plant shutdown, the analysis shows that none of the guide tubes will deform beyond the "no loss of function" limits established experimentally for control rod insertion, and 52 out of 53 guide tubes would deform less than the conservatively established allowable limit. Consequently, it is concluded that the reactor internals will be able to withstand the assumed accident conditions without becoming distorted enough to prevent adequate core cooling or reactor shutdown.

5. Combined Shock and Seismic Loading (Fuel Assembly) - The reload fuel was evaluated for combined seismic and loss-of-coolant accident (LOCA) mechanical response (Reference 4.2.3-4). The postulated accident condition considered was a 0.2-g seismic event combined with a 144-square-inch pipe break at the cold leg reactor pressure vessel inlet nozzle.

The lateral core plate motions for the seismic and LOCA events were combined based on maximum fuel assembly loads and displacements. The vertical forces from the pipe break at the cold leg reactor pressure vessel inlet nozzle were determined from a summation of pressure differentials acting across a given element, flow stagnation, orifice losses, and friction losses. In addition to these hydraulic forces, gravity forces, buoyancy forces, and holddown spring preload were also included in the analysis.

The combined seismic-LOCA structural analyses were performed utilizing essentially four primary finite element models.

1. Lateral Core Model,

2. Lateral Fuel Assembly Model,

3. Vertical Internals Model,

4. Vertical Fuel Assembly Model

The basic criteria for acceptability for the postulated faulted condition is to provide high assurance that the reactor core can be brought safely to a cold shutdown condition. To demonstrate acceptability, the response of the spacer grid, guide tube, and fuel rod fuel assembly components were evaluated. The evaluations were based on structural responses derived from the finite element models.

Based on the dynamic analysis for the spacer grid response loads, two evaluations were performed. First, a quantified amount of permanent deformation of the spacer grid was compared to an allowable deformation value which would ensure no more than a 5 percent reduction in DNB margin. The grid permanent deformation was determined by comparison to test data. Second, control rod insertion capability was evaluated based on misalignment of the guide tubes in the deformed grid. A combination of test data and analytical calculations was used to show that insertability was not impaired.

The control rod guide tubes were evaluated for maximum stress intensity and critical buckling load. The guide tube stresses were generated by ratioing test strain data based on the lower nozzle axial impact load and maximum fuel assembly lateral deflection. These stresses and the axial load obtained from these stresses were compared to the design limit stress intensity and a factored Euler critical buckling load.

The fuel rods were evaluated for maximum stress intensity. Operational steady-state fuel rod stresses were determined from a detailed static finite element analysis. As was done for the guide tubes, the fuel load stresses were generated by ratioing test strain data. The final stress intensities were compared to the design limit stress intensity.

From the above evaluations, the overall acceptability of the reload fuel for Westinghouse PWR's subjected to the combined postulated seismic-LOCA event was demonstrated.

4.3 Nuclear Design

4.3.1 Design Basis

Nuclear design bases have been established to assure that the reactor core is operated within the HBR 2 Technical Specifications, Appendix A to Facility Operating License No. DPR-23.

4.3.1.1 Fuel Burnup. The length of each reload cycle shall be determined on the basis of a cycle length consistent with the previous reload burnup. Fuel burnup is restricted by limits on peak assembly burnup, specifically, 52,500 MWD/MTU for the non-HTP fuel assemblies and 52,500 MWD/MTU for the HTP fuel assemblies in reloads Region 17 (ANF-11) through Region 19 (ROB-13) and for those non-HTP fuel assemblies specified in Reference 4.3.3-14. The assembly burnup limit for reloads Region 20 (ROB-14) and beyond is 57,000 MWD/MTU.

The 57000 MWD/MTU represents the burnup limit for the mechanical evaluation only. Utilization of the full extent of this mechanical burnup limit is contingent on the burnup limit established in the radiological assessments of Chapter 15.

For Cycle 18 an evaluation has been performed to demonstrate the acceptability of four specific fuel assemblies (ROB-13 originally loaded in Cycle 16) slightly exceeding the above referenced 52,500 MWD/MTU burnup value up to as much as 53,000 MWD/MTU. That evaluation determined that the mechanical design of the assemblies would support the marginal burnup extension and the radiological consequences of extending the burnup of these four specific assemblies was still bounded by the radiological analysis of record which assumed the 52,500 MWD/MTU.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficients). The initial core and all reload cores are not allowed to have a positive moderator temperature coefficient when operating above 50% power.

4.3.1.3 Control of Power Distributions. The full loading pattern shall achieve power distributions such that the peak F_Q (including uncertainties) shall not not exceed the limit in the Technical Specification in any single fuel rod throughout the cycle under nominal full power operations.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate. The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited so as to preclude rupture of the reactor coolant pressure boundary or disruption of the core internals to a degree which would impair core cooling capacity due to a rod withdrawal or a rod ejection accident.

4.3.1.5 Shutdown Margins. The fuel loading pattern shall achieve control rod reactivity worths such that the scram worth of all rods minus the most reactive rod shall exceed the beginning of cycle (BOC) and end of cycle (EOC) shutdown requirements.

4.3.1.6 Stability. The protection system ensures that the nuclear core limits are not exceeded during the course of axial xenon oscillations.

4.3.1.7 Emergency Shutdown Capability. Redundant equipment is provided to add soluble poison to the reactor coolant in the form of boric acid to maintain shutdown margin when the reactor is cooled to ambient temperatures.

4.3.2 Description

4.3.2.1 Nuclear Design Description. The HBR 2 reactor core consists of 157 assemblies, each having a 15 x 15 fuel rod array. Each assembly normally contains 204 fuel rods, 20 rod cluster control (RCC) guide tubes, and one instrumentation tube. The fuel rods consist of slightly enriched (in U-235) UO_2 or UO_2 - Gd_2O_3 pellets inserted into Zircaloy tubes. The uranium enrichment in the gadolinia pins varies roughly inversely with the gadolinia concentration. The RCC guide tubes and the instrumentation tube are also Zircaloy tubes. Each SPC assembly contains 6 Zircaloy spacers and 1 Bimetallic spacer with Inconel 718 springs. Six of the spacers are located within the active fuel region. There are also three Intermediate Flow Mixer (IFM) grids.

The average enrichment for each SPCF reload is consistent with the specified reactor energy requirement for the projected effective full power days for that cycle and subsequent cycles. A loading pattern for each cycle is identified which satisfies the criteria on the peak $F_{\Delta H}$ and the largest calculated axial peaking factor. The fuel centerline melt criterion for the UO_2 rods is set to ensure that the gadolinia pins are never the limiting pins in the assembly, even taking into account the reduced thermal conductivity and melting point in these pins due to the gadolinia. For each specified cycle length the calculated end of cycle critical boron concentration is determined.

The excess reactivity control characteristics are determined for each cycle. These include the differential boron worth at full power conditions as a function of cycle lifetime and control rod worths, including the stuck and ejected rod worths. Control rod shutdown margins and reactivity coefficients are also determined for each fuel cycle.

The effective delayed neutron fractions at BOC and EOC are also calculated for each fuel cycle.

Table 4.1.2-3 presents a summary of some key neutronic characteristics for a typical core loading.

4.3.2.2 Power Distributions. Power distribution control is necessitated by reactor safety considerations. The reactor must be capable of safe operation throughout core life, under both steady state and transient conditions, without exceeding acceptable fuel damage limits. If this performance objective is met, the release of unacceptable amounts of fission products to the reactor coolant is prevented.

To this end, two criteria have been chosen as a design basis for fuel performance related to fission gas release, pellet temperature, and cladding mechanical properties. First, the peak value of linear power density must not exceed 21.1 kW/ft. Second, the minimum departure from nucleate boiling ratio (DNBR) in the core must not be less than the safety limit in normal operation or in short-term transients.

In addition to the above design basis for fuel performance, the initial steady state conditions for the peak linear power for a loss-of-coolant accident (LOCA) must not exceed the values assumed in the accident evaluation (Chapter 15.0). This limit is required in order for the maximum clad temperature attained during a postulated LOCA to remain below that established by the Emergency Core Cooling System (ECCS) Acceptance Criteria.

To aid in specifying the limits on power distribution the following hot channel factors are defined:

1. F_Q, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

2. F_Q^N, Nuclear Heat Flux Hot Channel Factor, is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and rod dimensions.

3. F_Q^E, Engineering Heat Flux Hot Channel Factor, is defined as the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, surface area of the fuel rod and eccentricity of the gap between pellet and clad. Combined statistically the net effect is a factor of 1.03 to be applied to fuel rod surface heat flux.

4. $F_{\Delta H}^N$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

It should be noted that $F_{\Delta H}^N$ is based on an integral and is used as such in the DNB calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal (x-y) power shapes through the core. Thus, the horizontal power shape at the point of maximum heat flux is not necessarily directly related to $F_{\Delta H}^N$.

It has been determined by extensive analysis of possible operating power shapes that the design limits on peak local power density and on minimum DNBR at full power are met, provided the values of F_Q and $F_{\Delta H}$ specified in the HBR 2 Technical Specifications are not exceeded.

In the specified limit of F_Q^N, there is a 5 percent allowance for uncertainties which means that normal operation of the core within the defined conditions and procedures is expected to result in a measured F_Q^N 5 percent less than the limit for example., at rated power even on a worst case basis. When a measurement is taken, experimental error must be allowed for and 5 percent is the appropriate allowance for a full core representative map taken with the movable incore detector flux mapping system.

REFERENCES: SECTION 4.3

4.3.3-1 XN-NF-75-27(A), "Exxon Nuclear Neutronics Design Methods for Pressurized Water Reactors", Exxon Nuclear Company, June 1985.

4.3.3-2 XN-NF-75-27(A), Supplement 1 to Reference 4.3.3-1, September 1976.

4.3.3-3 XN-NF-75-27(A), Supplement 2 to Reference 4.3.3-1, December 1977.

4.3.3-4 XN-NF-75-27(A), Supplement 3 to Reference 4.3.3-1, November 1980.

4.3.3-5 XN-CC-21, Revision 2, "XPOSE - The Exxon Nuclear Revised LEOPARD," Exxon Nuclear Company, April 1975.

4.3.3-6 XN-CC-26, Revision 1, "XPIN: The Exxon Nuclear Revised HAMBUR," Exxon Nuclear Company, December 1975.

4.3.3-7 XN-CC-28, Revision 5, "XTG - A Two Group Three-Dimensional Reactor Simulator Utilizing Coarse Mesh Spacing (PWR Version)," Exxon Nuclear Company, July 1979.

4.3.3-8 W. R. Caldwell, "PDQ7 Reference Manual," WAPD-TM-678, Westinghouse Corporation, January 1967.

4.3.3-9 D. J. Breen, et al., "HARMONY: System for Nuclear Reactor Depletion Computation," WAPD-TM-478, Westinghouse Corporation, January 1965.

4.3.3-10 Deleted by Revision No. 14

4.3.3-11 Deleted by Revision No. 14

4.3.3-12 ANF-88-054(P)(A), "PDC-3: Advanced Nuclear Fuels Corporation Power Distribution Control for Pressurized Water Reactors and Application of PDC-3 to H. B. Robinson Unit 2," Advanced Nuclear Fuels Corporation, October 1990.

4.3.3-13 XN-NF-78-44(A), "A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors", Exxon Nuclear Company, October 1983.

4.3.3-14 V.N. Gallacher (SPC) to D. D. Davis (CP&L), VNG: 95.005,"Design Reports for the Fuel Assemblies in H. B. Robinson Cycle 17," February 3, 1995.

4.3.3-15 XN-NF-75-27(A), Supplement 4 to Reference 4.3.3-1, December 1986.

4.3.3-16 STUDSVIK/NR-81/3, "CASMO-2 A Fuel Assembly Burnup Program," March 1981.

4.3.3-17 EMF-93-164(P)(A), "Power Distribution Measurement Uncertainty for INPAX-W in Westinghouse Plants," Siemens Power Corporation, February 1995, transmitted to NRC by letter dated February 13, 1995.

4.4.2 Description

The following sections describe the thermal-hydraulic design of the reactor core. Chapter 5 of the Updated FSAR contains a description of the thermal-hydraulic design of the RCS.

4.4.2.1 Definition of Departure from Nucleate Boiling (DNB) Ratio. The ratio of the heat flux causing DNB at a particular core location to the existing heat flux at the same core location, is the DNB ratio. A DNB ratio equal to the safety limit corresponds to a 95 percent probability at a 95 percent confidence level that DNB does not occur. This value is chosen as the margin to DNB for all operating conditions.

DNB is not, however, an observable parameter during reactor operation. Therefore, the observable parameters, reactor power, reactor coolant temperature and reactor coolant pressure have been related to DNB through the DNB correlation. The ANFP correlation for High Thermal Performance fuel has a DNBR safety limit of 1.154 (Reference 4.4.2-3). Curves presented in the HBR 2 Technical Specifications represent the loci of points of reactor power, reactor coolant pressure and inlet temperature for which the DNB ratio is less than the safety limit. The area of safe operation is the lower inlet temperature and higher reactor coolant pressures limited by one specified curve of the reactor power parameter family of curves shown. The parameters used in the development of the curves are checked in the course of plant startup tests, and the curves are modified if necessary.

4.4.2.2 Hot Channel Factors. The enthalpy rise factors are thermal-hydraulic performance indicators. These factors indicate the effect on the enthalpy rise in the hot subchannel resulting from the geometry and components of the ANF fuel design. Each of the enthalpy rise factors was developed from the results of the thermal-hydraulic calculations. The ANF DNB methodology using the XCOBRA-IIIC computer code is described in Reference 4.4.2-1.

4.4.2.2.1 Engineering enthalpy rise factor. Because of tolerances in the manufacture of the fuel, in particular variations from the nominal design values of pellet density, pellet diameters, and enrichment over the active length, the local heat flux in the highest enthalpy rise subchannel could have been higher than nominal by three percent (engineering heat flux factor). The engineering enthalpy rise factor was evaluated by XCOBRA-IIIC computer runs with and without the three percent increase in local heat flux for the hottest fuel rod adjacent to the high enthalpy rise subchannel.

4.4.2.2.2 Inlet plenum maldistribution factor. The inlet plenum maldistribution is a reactor vessel characteristic that is specified in the HBR FSAR to be ± 5 percent. To assume a 5 percent increase in enthalpy rise in the hot subchannel would be overly conservative because of the effects of subchannel turbulent and cross flow mixing which tend to neutralize this inlet flow situation at the point of MDNBR. Because of the effects of turbulent and crossflow mixing, the enthalpy rise factor resulting from a ±5 percent inlet flow maldistribution is unaffected.

4.4.2.2.3 Flow mixing enthalpy rise factor. The enthalpy rise factor in the hot channel is adjusted for turbulent mixing in the XCOBRA III-C code. The turbulent mixing model is the ROWE-ANGLE model. See Reference 4.4.2-4.

4.4.2.2.4 Flow redistribution. The enthalpy in the hot subchannel is increased by flow diversion resulting from the higher frictional losses which result from subcooled nucleate boiling. The flow that is diverted from the hot subchannel due to the effect of subcooled voiding was found to cause a significant increase in the enthalpy rise.

4.4.3 Instrumentation Requirements

The following sections describe the instrumentation requirements for the reactor core. Chapter 5 of the Updated FSAR contains a description of the instrumentation requirements for the RCS.

4.4.3.1 Incore Instrumentation. The incore instrumentation system consists of 48 dual element bottom-mounted (one element is a spare thermocouple) thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations; and 48 flux thimbles, which run the length of selected fuel assemblies for measurement of the neutron flux distribution within the core. Five movable miniature neutron flux detectors with associated control and readout equipment may be used to scan the length of selected fuel assemblies to provide remote reading of the axial flux distribution. The incore instrumentation system is shown in Figure 4.4.3-1.

The experimental data obtained from the incore temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitations which determine the maximum core capability.

The incore instrumentation provides information which may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and to estimate the coolant flow distribution.

4.4.3.2 Overtemperature and Overpower ΔT Instrumentation. The overpower ΔT reactor trip prevents power density anywhere in the core from exceeding the fuel power density corresponding to fuel centerline melt and includes corrections for axial power distribution, change in density, and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors. The specified setpoints meet this requirement and include allowance for instrument errors.

The overpower and overtemperature protection system setpoints have been revised to include effects of fuel densification and the increase in rated thermal output to 2300 Mwt on core safety limits. The revised setpoints in the Technical Specifications ensure the combination of power, temperature, and pressure will not exceed the core safety limits shown in Figure 4.4.3-2.

4.4.3.3 Instrumentation to Limit Maximum Power Output. The Reactor Control and Protection System is designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and thermal power level that would result in a DNB ratio of less than the safety limit (specified in Section 4.4) based on

steady state nominal operating power levels less than or equal to 100 percent, steady state nominal operating RCS average temperature less than or equal to 575.4°F, and a steady state nominal operating pressure of 2235 psig. Allowances are made in initial conditions assumed for transient analyses for steady state errors of +2 percent in power, +4°F in RCS average temperature, and ~30 psi in pressure. The combined steady state errors result in the DNB ratio at the start of a transient being 10 percent less than the value at nominal full power operating conditions. The steady state nominal operating parameters and allowances for steady state errors given above are also applicable for two loop operation except that the steady state nominal operating power level is less than or equal to 45 percent.

4.4.3.4 Core Subcooling Monitor

The purpose of the subcooling monitor is to provide a continuous indication of margin to saturated conditions. The monitor uses inputs from core outlet thermocouples, RCS hot and cold leg resistance temperature detectors and RCS system pressure to drive a micro-processor which calculates saturation temperature and determines the margin to saturation based on the inputs. The individual inputs as well as the margin to saturation can be displayed on the monitor's plasma display panel. The monitor has 2 independent channels, and each channel has its own plasma display panel.

4.4.3.5 Digital Metal Impact Monitoring System

The Digital Metal Impact Monitoring System (DMIMS) uses an array of accelerometers externally mounted to the major components to the reactor system, signal conditioning equipment, recording and alarm equipment, and diagnostic equipment and software. This system collects information that may be used by the operator in the detection, location, and identification of loose parts within the reactor coolant system.

4.4.3.5.1 Design Basis

The system components of the DMIMS within the containment are designed and installed to function following all seismic events that do not require plant shutdown (i.e., up to and including OBE). Recording equipment need not function without maintenance following the specified seismic event provided the audio or visual alarm capability remains functional.

The system is designed to facilitate the maintenance and repair of malfunctioning components with minimum occupational radiation exposure.

4.4.3.5.2 System Description

There are ten (10) loose parts monitoring sensors (accelerometers) located in pairs to provide for sensor redundancy. Sensors are provided at the reactor vessel head lug, the reactor vessel bottom, and at each steam generator primary and secondary side.

Instrumentation channel components (including cabling and preamplifiers) associated with the sensors at each location are physically separated up to a point in the plant that is always accessible for maintenance during full power operation.

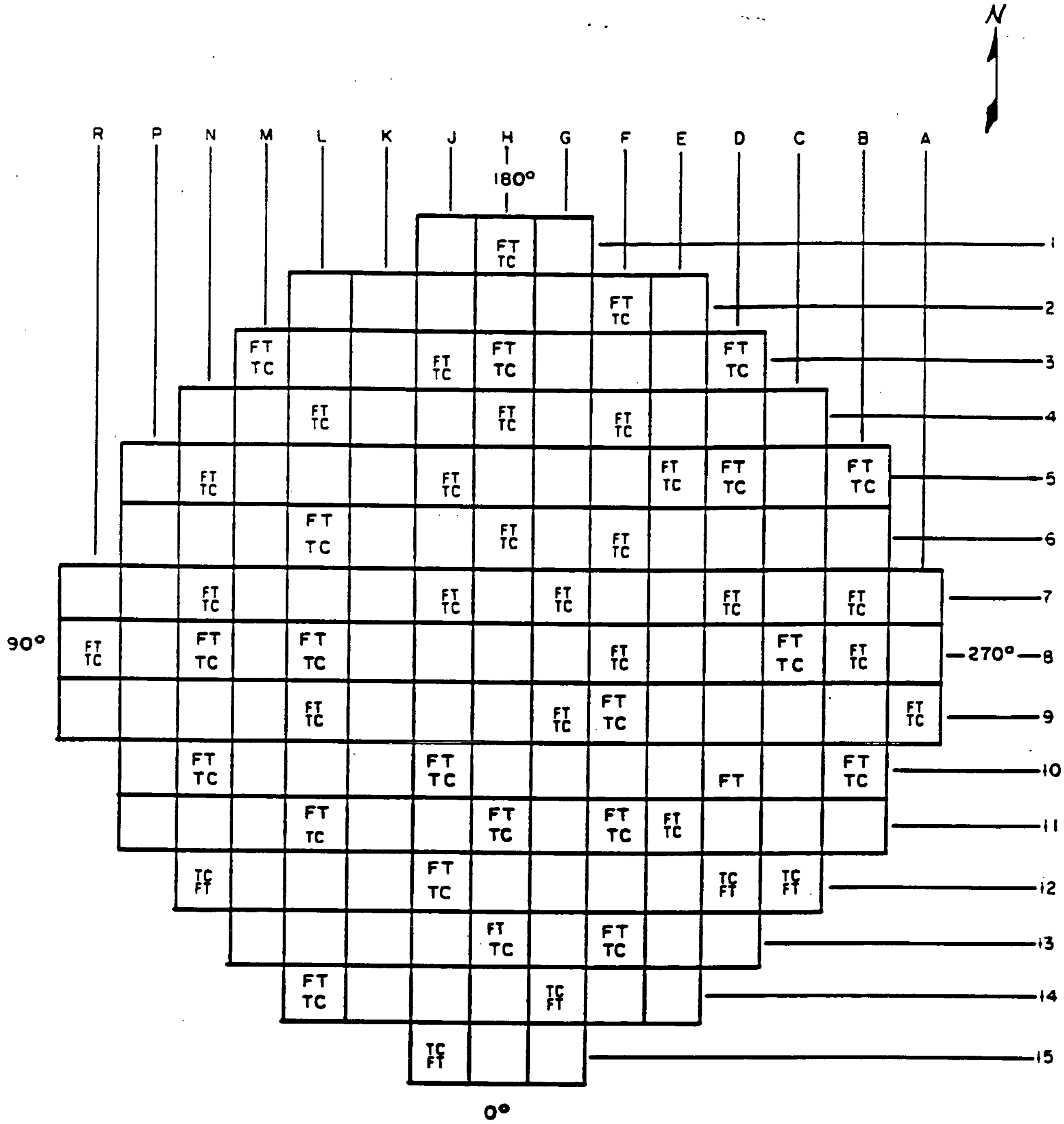
REFERENCES: SECTION 4.4

4.4.2-1 XN-NF-82-21 (P)(A) - "Application of Exxon Nuclear Computer PWR Thermal Margin Methodology to Mixed Core Configuration," September 1983.

4.4.2-2 Deleted by Revision No. 14

4.4.2-3 ANF 1224 (P) - "Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel", May 1989.

4.4.2-4 XCOBRA-IIIC: "A Computer Code to Determine the Distribution of Coolant during Steady State and Transient Core Operation," XN-NF-75-21A, Revision 2, Exxon Nuclear Company, Richland, WA, January 1986.



TC = Thermocouple
FT = Flux thimble

Revision No. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	X - Y VIEW OF H. B. ROBINSON CORE	FIGURE 4.4.3 - 1

CHAPTER 5
REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

LIST OF FIGURES

5.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The Reactor Coolant System (RCS) consists of three similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a pump, loop piping, and instrumentation. The pressurizer surge line is connected to one of the loops. Auxiliary system piping connections into the reactor coolant piping are provided as necessary.

The principal heat removal systems which are interconnected with the RCS are the Steam and Power Conversion, Safety Injection, and Residual Heat Removal Systems. The RCS is dependent upon the steam generators, and the steam, feedwater, and condensate systems for stored and residual heat removal from normal operating conditions to a reactor coolant temperature of approximately 350°F.

The RCS transfers the heat generated in the core to the steam generators where steam is generated to drive the turbine generator. Borated demineralized light water is circulated at the flow rate and temperature consistent with achieving the reactor core thermal hydraulic performance presented in Section 4. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber used in chemical shim control.

The RCS provides a boundary which contains the coolant under operating temperature and pressure conditions. It serves to confine radioactive material and limits to acceptable values its uncontrolled release to the secondary system and to other parts of the plant under conditions of either normal or abnormal reactor operation. During transient operation the systems heat capacity attenuates thermal transients generated by the core or extracted by the steam generators. The RCS accommodates coolant volume changes within the protection system criteria.

The RCS design and operating pressure are listed in Table 5.1.0-1 together with the safety, power relief and pressurizer spray valves set points, and the protection system set point pressures. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

Coolant enters the reactor vessel through inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel. There it reverses direction to flow upward through the core. Approximately ninety-five percent of the total coolant flow is effective for heat removal from the core. The remainder of the flow includes the flow through the rod cluster control guide thimbles, the leakage across the reactor pressure vessel nozzles, and the flow deflected into the head of the vessel for cooling the upper flange. All the coolant is united and mixed in the upper plenum, and the mixed coolant stream then flows out of the vessel through exit nozzles located on the same plane as the inlet nozzles. | 8

A one piece thermal shield, concentric with the reactor core, is located between the core barrel and the reactor vessel. The shield is bolted and welded to the top of the core barrel. The shield, which is cooled by the coolant on its downward pass, protects the vessel by attentuating much of the gamma radiation and some of the fast neutrons which escape from the core. This shield minimizes thermal stresses in the vessel which result from heat generated by the absorption of gamma energy.

Fifty core instrumentation nozzles are located on the lower head.

Elbow taps are used in the primary coolant system as an instrument device that indicates the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow rate has occurred. The correlation between flow reduction and elbow tap read out has been well established by the following equation:

$$\frac{\Delta P}{\Delta P_o} = \frac{\omega}{\omega_o}^{1.8}$$

where:

ΔP_o	=	the referenced pressure differential at ω_o
ω_o and ω	=	reference flow rate
ΔP	=	the pressure differential at ω
ω	=	reference flow rate

The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The technique has been well established in providing core protection against low coolant flow in Westinghouse pressurized water reactor plants. The expected absolute accuracy of the channel is within ± 10 percent and field results have shown the repeatability of the trip point to be within ± 1 percent.

Pressure in the system is controlled by the pressurizer, where water and steam pressure is maintained through the use of electrical heaters and sprays. To minimize pressure variations due to contraction and expansion of the coolant, steam can either be formed by the heaters or condensed by a pressurizer spray. Instrumentation used in the pressure control system is described in Chapter 7. Spring loaded steam safety valves and power operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water.

By appropriate selection of the inertia of the reactor coolant pump (which affects pump coastdown), the thermal hydraulic effects which result from a loss of flow situation are reduced to a safe level. The layout of the system ensures natural circulation capability following a loss of flow to permit plant cooldown without overheating the core. Part of the system's piping is used by the Emergency Core Cooling System to deliver cooling water to the core during a loss-of-coolant accident.

In the event the condensers are not available to receive the steam generated by residual heat, the water stored in the feedwater system may be pumped into the steam generators and the resultant steam vented to the atmosphere. The auxiliary feedwater system will supply water to the steam generators in the event that the main feedwater pumps are inoperative. The system is described in Section 10.4.8.

TABLE 5.2.3-1

MATERIALS OF CONSTRUCTION OF THE
REACTOR COOLANT SYSTEM COMPONENTS

COMPONENT	SECTION	MATERIALS
Reactor Vessel	Pressure Plate	SA-302, Gr. A SA-302, Gr. B
	Flange and Nozzle Forgings	A-508 Class II
	Cladding, Stainless Weld Rod	Type 304 equivalent
	Thermal Shield and Internals	A-240, Type 304
	Insulation	SS-SS Foil - SS
	Head Closure Bolting	A-540*
Steam Generator	Shell, Original	SA-302, Gr. B
	Channel Head Castings, Original	SA-216 WCC
	Heat Transfer U-Tubes	SB-163 thermally treated Code Case N-20
	Tube Plate	SA-508 Class 2A
	Lower Shell, Stub Barrel, and Shell Transition	SA-302 Gr. B
	Cladding, Tube Sheet	Inconel
	Cladding, Channel Head	Type 304 or equivalent
Pressurizer	Shell	SA-302, Gr. B
	Heads	SA-216 WCC

4

*Code case 1335.2 invoked.

TABLE 5.2.3-2

REACTOR COOLANT WATER CHEMISTRY SPECIFICATION

Electrical Conductivity	Determined by the concentration of boric acid and alkali present. Expected range is < 2.0 μ mho/cm at 25°C
Solution pH	Determined by the concentration of boric acid and alkali present. Expected values range between 4.2 (high boric acid concentration) to 10.5 (low boric acid concentration) at 25°C
Oxygen, ppm, max	0.1
Chloride, ppm, max	0.15
Fluoride, ppm, max	0.15
Hydrogen, cc (STP)/kg H_2O	25-50
Total Suspended Solids, ppm, max	1.0
pH Control Agent (Li^7OH)	strong base alkali, 0.22 to 3.5 ppm as Li-7 | 7
Boric Acid as ppm B	Variable from 0 to 3000

c) During the manufacturing stage, selected areas of the reactor vessel were ultrasonic tested and mapped to facilitate possible future in-service inspection. The areas which were ultrasonically mapped include:

1) Vessel flange radius, including the vessel flange to upper shell weld

2) Middle shell course

3) Lower shell course above the radial core supports

4) Exterior surface of the closure head from the flange knuckle to the cooling shroud

5) Nozzle to upper shell weld

6) Middle shell to lower shell weld

7) Upper shell to middle shell weld

The preoperational ultrasonic testing of these areas was performed after final stress relief.

Plans for in-service inspection of the reactor coolant system pressure envelope are discussed in Section 4.2 of the Technical Specifications and Section 3.9 of the Updated FSAR.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

The existence of leakage from the RCS to the containment, regardless of the source of leakage, is detected by one or more of the following conditions:

a) Two radiation sensitive instruments provide the capability for detection of leakage from the RCS. The containment air particulate monitor is quite sensitive to low leak rates. The containment radiogas monitor is much less sensitive but can be used as a backup to the air particulate monitor.

b) The humidity detector is a third instrument used in leak detection. This provides a means of measuring overall leakage from all water and steam systems within the containment but is less sensitive than the radiation monitors. The humidity monitoring method is therefore used as a backup to the radiation monitoring methods.

c) A leakage detection system is included which determines leakage losses from all water and steam systems within the containment, including that from the RCS. This system collects and measures moisture condensed from the containment atmosphere by the cooling coils of the containment air recirculation cooling units. It relies on the principle that all leakages up to sizes permissible with continued plant operation will be evaporated into the containment atmosphere. This system provides a dependable and accurate means of measuring integrated total leakage, including leaks from the cooling coils themselves which are part of the containment boundary.

d) An increase in the amount of coolant makeup water which is required to maintain normal level in the pressurizer, or an increase in containment sump level are also used as leakage detection systems. However, these are less sensitive means of detection leakage.

5.2.5.1 System Description

5.2.5.1.1 Radiation Monitors

The sensitivity of the air particulate monitor to an increase in reactor coolant leak rate is dependent upon the magnitude of the normal base-line leakage into the containment. The sensitivity is greatest where base-line leakage is low as was demonstrated by the experience of Indian Point Unit 1, Yankee Rowe and Dresden Unit 1. Where containment air particulate activity is below the threshold of detectability, operation of the monitor with stationary filter paper would increase leak sensitivity to a few cubic centimeters per minute. Assuming a low background of containment air particulate radioactivity, a reactor coolant corrosion product radioactivity (Fe, Mn, Co, Cr) of 0.2 μCi/cc (a value consistent with little or no fuel cladding leakage), and complete dispersion of the leaking radioactive solids into the containment air, the air particulate monitor is capable of detecting leaks as small as approximately 0.013 gpm (50 cc/min) within twenty minutes after they occur. If only ten percent of the particulate activity is actually dispersed in the air, leakage rates of the order of 0.13 gpm (500 cc/min) are well within the detectable range.

For cases where base-line reactor coolant falls within the detectable limits of the air particulate monitor, the instrument can be adjusted to alarm on leakage increases from two to five times the base-line value.

The containment air particulate monitor together with the other radiation monitors mentioned in this Section are further described in Section 12.

The containment radioactive gas monitor is inherently less sensitive (threshold at 10^{-6} μCi/cc) than the containment air particulate monitor, and would function in the event that significant reactor coolant gaseous activity exists from fuel cladding defects. The measuring range is 10^{-6} to 10^{-3} μCi/cc.

Assuming a reactor coolant activity of 0.3 μCi/cc, the occurrence of a leak of 2 to 4 gpm would double the zero leakage background in less than 1 hour. In these circumstances this instrument is a useful backup to the air particulate monitor.

5.2.5.1.2 Humidity Detector

The humidity detection instrumentation offers another means of detection of leakage into the containment. Although this instrumentation has not nearly the sensitivity of the air particulate monitor, it has the characteristics of being sensitive to vapor originating from all sources within the containment including the reactor coolant and steam and feedwater systems. Plots of containment air dew point variations above a base-line maximum established by the cooling water temperature to the air coolers should be sensitive to incremental leakage equivalent to 2.0 to 10 gpm.

The sensitivity of this method depends on cooling water temperature, containment air temperature variation and containment air recirculation rate.

5.2.5.1.3 Condensate Measuring System

This leak detection method is based on the principle that the condensate collected by the cooling coils matches, under equilibrium conditions, the leakage of water and steam from systems within the containment. This principle applies because conditions within the containment promote complete evaporation of leaking water from hot systems. The air and internal structure temperatures are normally held near 120°F, the relative humidity of the air is well below the saturation point, and the cooling coils provide the only significant surfaces at or below the dew point temperature.

The containment cooling coils are designed to remove the sensible heat generated within the containment. The resulting large coil surface area has the effect that the exit air from the coils has a dew point temperature which is very nearly equal to the cooling water temperature.

Measurement of the condensate drained from each of the fan cooler units is made to determine condensation rate and thus leak rate.

Should a leak occur, the condensation rate will increase above the previous steady state due to the increased vapor content of the fan cooler air intake. A new equilibrium rate will be approached within approximately 30 minutes

5.3.1.5 Vessel Integrity

The ability of the steel pressure vessel that contains the reactor core and its primary coolant to resist fracture constitutes an important safety issue. The beltline region of the RPV is the most critical region of the vessel because it is subjected to neutron bombardment. The overall effects of fast neutron irradiation on the mechanical properties of low alloy ferritic pressure vessel steels such as ASTM-A302 Grade A and B parent material of the H. B. Robinson Unit 2 (HBR 2) RPV are reported in the literature. Generally, low alloy ferritic materials show an increase in hardness and other strength properties and a decrease in ductility. In pressure vessel material, the most important mechanical property changes are the reduction in the upper shelf impact strength and an increase in the temperature for the transition from brittle to ductile fracture. 6

The method for guarding against fast fracture in reactor pressure vessels presented in 10CFR50 Appendix G, "Protection Against Non-Ductile Failure," to Section III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code utilizes fracture mechanics concepts and is based on the reference nil-ductility temperature, RT_{NDT}.

RT_{NDT} is defined as the greater of:

a) The drop weight nil-ductility transition temperature (NDTT per ASTM E-208), or

b) The temperature 60°F less than the 50 ft-lb (or 35 mils lateral expansion) temperature as determined from Charpy specimens oriented in a direction normal to the major working direction of the material.

In addition to the Appendix G requirements, the NRC staff developed in 1983, proposed generic screening criteria for resolution of the Pressurized Thermal Shock (PTS) issue (Reference 5.3.1-1). Methods for determining the original reference temperature for welds were included. A proposed rule published on February 7, 1984 (Reference 5.3.1-10) was subsequently refined and issued as 10CFR50.61.

6

5.3.1.5.1 Pressurized Thermal Shock Evaluation Programs

CP&L has produced the following programs designed to resolve the concerns associated with the PTS issue for the HBR2 reactor pressure vessel:

a) Reduction of fast neutron flux to areas of the vessel experiencing a potentially significant increase in RT_{NDT},

b) Probabilistic analysis to assess the risk associated with PTS, and

c) Materials research program to establish a better estimate of the chemistry of the pressure vessel weld materials and bases for a plant specific radiation damage trend line for the HBR2 surveillance weld.

These programs provide the means to resolve the PTS concerns for HBR2.

5.3.1.5.1.1 Flux Reduction Program

The Flux Reduction Program described in Reference 5.3.1-9 concluded that HBR2 can be operated, as a minimum, to the end of the operating license prior to the critical pressure vessel weld reaching the NRC PTS screening criteria. Conservative calculations in the report contained in Reference 5.3.1-9 shows a flux reduction factor in excess of 9 for the part length shield assemblies (PLSAs) design which were loaded for Cycle 10 (startup in 1985) and which extend the time at which the screening criteria is reached to beyond the end
6 of the operating license. References 5.3.1-14 and 5.3.1-15 include the updated end of license fluence based on the flux reduction program.

5.3.1.5.1.2 Pressurized Thermal Shock Risk Study

The PTS Risk Study described in Reference 5.3.1-8 was designed to build on the generic probabilistic PTS work done by the Westinghouse Owners' Group (WOG) in May, 1982 to provide a plant specific estimate of PTS risk for HBR2 which would be comparable to the methodologies accepted by the NRC in formulating the proposed PTS screening criteria. The conclusions of Reference 5.3.1-8 are as follows:

a) The screening criterion calculated for HBR2 that compares to the NRC generically determined screening criterion was determined to be 340°F.

b) The single major contribution to this improvement is the circumferential versus axial orientation for the welds of interest.

6

c) The above result demonstrates the considerable conservatism in the NRC proposed screening criterion of 300°F RT_{NDT} for circumferential welds. (CP&L
6 is limiting the end of license RT_{NDT} for the critical circumferential weld to 300°F).

d) The frequency of significant flaw extension beyond 75 percent of the reactor vessel wall for HBR2 was determined to be 7×10^{-7} occurrences per reactor year at the end of plant life with current flux reductions and loading of PLSAs for Cycle 10.

CP&L believes that Reference 5.3.1-8 demonstrates that the PTS risk associated with HBR2 is considerably less than the generic case used to set the PTS screening criteria.

5.3.1.5.1.3 Reactor Vessel Materials Program

The Reactor Vessel Materials Program described in Reference 5.3.1-12 concluded that the reactor vessel beltline welds are significantly less sensitive to embrittlement from neutron radiation than previously assumed. This program included research in examining weld records associated with the HBR2 beltline welds, review of available documentation for welds similar to the HBR2 beltline welds, and sampling and analyzing welds similar to the HBR2 beltline welds. Subsequent records research detailed in Reference 5.3.1-15 has further refined the assigned weld chemistry of the HBR2 vessel beltline circumferential welds and demonstrated that the welds were even less susceptible to radiation embrittlement than previously predicted by the Materials Program. Based on the results of this program, CP&L has recalculated the end of current license RT_{NDT} values for the HBR2 beltline welds. The actual calculations are contained in References 5.3.1-14 and 5.3.1-15 and utilize the methodology outlined in the proposed PTS rule published in 10CFR50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events." The fluence values utilized are based on the Flux Management Program outlined in Reference 5.3.1-9. The results of the calculations are provided in References 5.3.1-14 and 5.3.1-15. 6

6

These results show that the upper girth weld is the limiting weld for PTS concerns. It will have a 31°F margin at the end of license using the PTS Rule equations.

Also, Reference 5.3.1-14 contains calculations made in accordance with the rule on PTS to show that the reactor vessel plate material will not approach the proposed PTS screening criteria prior to the expiration of the HBR2 operating license.

6 Based on the combined results of the Flux Reduction Program, the PTS Risk Study and the Reactor Vessel Materials Program CP&L has concluded that the PTS issue is completely resolved for HBR2. The NRC issued an SER (Reference 5.3.1-16) approving CP&L's position as described in Reference 5.3.1-14 and 5.3.1-15.

5.3.1.6 Material Surveillance

In the reactor vessel surveillance program, the evaluation of radiation damage is based on pre-irradiation and post-irradiation testing of Charpy V-notch, tensile and wedge opening loading (WOL) test specimens. A description of the program basis including the material to be tested, specimen, and capsule design, and pre-irradiation test results is presented in Reference 5.3.1-6. This program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach, and will be revised to be in accordance with ASTM E185, "Recommended Practice for Surveillance Tests on Structural Materials in Nuclear Reactors" after the PTS Response.

The original reactor vessel surveillance program used eight specimen capsules which are located about 3 in. from the vessel wall directly opposite the center portion of the core (see Figure 5.3.1-4). The capsules contain reactor vessel steel specimens of shell plate as located in the core region of the reactor and associated surveillance weld made with the same filler metal and flux as used in the upper circumferential weld. In addition, correlation monitors made from fully documented specimens of SA302 Grade B material obtained through ASTM Subcommittee E10 on Radioisotopes and Radiation Effects are inserted in the capsules. The capsules contained at least 27 tensile specimens, 200 Charpy V-notch specimens and 36 WOL specimens. Dosimeters including pure Ni, Al-Co, (0.15 percent), Cd shielded Al-Co, Cd shielded Np-237 and Cd shielded U-238 are used in some of the capsules (see Reference 5.3.1-2 for details). The dosimeters permit evaluation of the flux seen by the specimens and vessel wall. In addition, thermal monitors made of low melting alloys can provide proof of high temperatures experienced by specimens. All of the materials are enclosed in a tight-fitting stainless steel sheath to prevent corrosion.

The analytical methodology and the design basis currently used to predict time averaged fast neutron flux and fluence levels within the pressure vessel/surveillance capsule geometry are discussed in detail in Reference 5.3.1-3. Additional HBR 2 plant specific analyses have been performed to include geometric, material, and power distribution information fully consistent with the above methodology and to provide a sound basis for the prediction of the long term fast neutron environment to which the pressure vessel will be exposed (Reference 5.3.1-9).

Geometric information for use in neutron transport calculations is provided in Figures 5.3.1-2 through 5.3.1-4. In Figure 5.3.1-2, a plan view of the reactor at the core midplane is depicted. This figure shows the reactor core, lower internals, pressure vessel, and the inner diameter of the primary biological shield. Pertinent dimensional information is also included in Figure 5.3.1-2. In Figure 5.3.1-3, a detailed description of the surveillance capsule geometry and associated structure is provided. This information is sufficient to allow accurate determinations of capsule lead factors as well as spectrum averaged reaction cross-sections for dosimetry applications. In Figure 5.3.1-4, the azimuthal location of each of the capsules included in the reactor vessel surveillance program is illustrated.

Since initial startup when the surveillance program was established based on Reference 5.3.1-6, four surveillance capsules have been withdrawn from the HBR

reactor. In 1973, Capsule S and Z were removed from the 280° and 230° azimuthal position while in the 1975-1976 outage, Capsule V was withdrawn from the 290° location. Neutron dosimetry from both capsules S and V were evaluated by Southwest Research Institute (SWRI), and the results were documented in SWRI 02-3574 and SWRI 02-4397, respectively. Early in 1977, the results for Capsule V (Reference 5.3.1-2) were revised in a letter from E. B. Norris to T. Clements (Reference 5.3.1-7). Capsule Z has not received enough radiation to be analyzed. During the 1982 refueling outage (Cycle 9), Capsule T was removed. Also, two capsules were moved from lag positions and placed in lead positions, and an additional capsule was installed on the thermal shield which has been used to confirm the calculated reduction in flux from the low leakage core.

The calculated reduction in neutron flux at the lower circumferential weld and the axial variation is being checked by special advanced dosimetry at three azimuths in the reactor cavity. NRC Research, the National Bureau of Standards, and Westinghouse Hanford Engineering Laboratories are actively participating in this program.

Capsule T was shipped to the Westinghouse Waltz Mill Facility for testing. The results of these tests are documented in Reference 5.3.1-11. Charpy V notch test points were grouped in the transition regions as opposed to the shelf regions to better define the 30 foot pound shift. The RT_{NDT} shift for weld metal irradiated at 288°F to 4.11 x 19^{19} n/cm^2 was 285°F at 30 foot pounds or 50 foot pounds. The comparison of actual RT_{NDT} versus the predicted using the methods of Regulatory Guide 1.99 Revision 1 for weld metal, plate material, and monitor correlation material is given by Figure 5.3.1-5.

The following tabulates the remaining schedule for removal of the Reactor Vessel Materials Surveillance Capsules X, U, V, and W:

Capsule	Calendar Years (See Note 1)
X (See Note 2)	30
U (See Note 3)	40
V (See Note 4)	55
W (See Note 4)	70

Note 1: Capsules are to be removed during the refueling outage immediately after or prior to the end of the designated calendar year.

Note 2: The projected amount of irradiation exposure (fluence) on Capsule X will represent predicted reactor vessel plate and weld fluence values beyond the end of the current license (EOL) of 40 calendar years.

Note 3: The projected amount of irradiation exposure (fluence) on Capsule U will represent predicted reactor vessel plate and weld fluence values well beyond EOL to support extension of the current operating license.

Note 4: Capsules V and W will be repositioned after 40 calendar years to accelerated flux positions to provide additional support for license extension.

A comparison of calculated and measured results based on the Fe^{54} (n, p) Mn^{54} reaction is provided in Table 5.3.1-4.

The temperature monitors in capsule T did not melt showing the temperature remained below 579°F for the first eight fuel cycles.

5.3.1.7 Reactor Vessel Fasteners. The reactor closure head and the reactor vessel flange are joined by fifty (50) 7-inch diameter studs. Two metallic O-rings seal the reactor vessel when the reactor closure head is bolted in place. A leakoff connection is provided between the two O-rings to monitor leakage across the inner O-ring. In addition, a leakoff connection is also provided beyond the outer O-ring seal.

The stud material is ASTM A-540, which at design temperature has a minimum yield strength of 104,400 psi in accordance with Code Case 1335.2. The membrane stress in the studs when they are at the steady state operational condition is approximately 37,500 psi. This means that as few as nineteen of the fifty studs are required in order to withstand the hydrostatic end load on vessel head without the membrane stress exceeding yield strength of the stud material at design temperature.

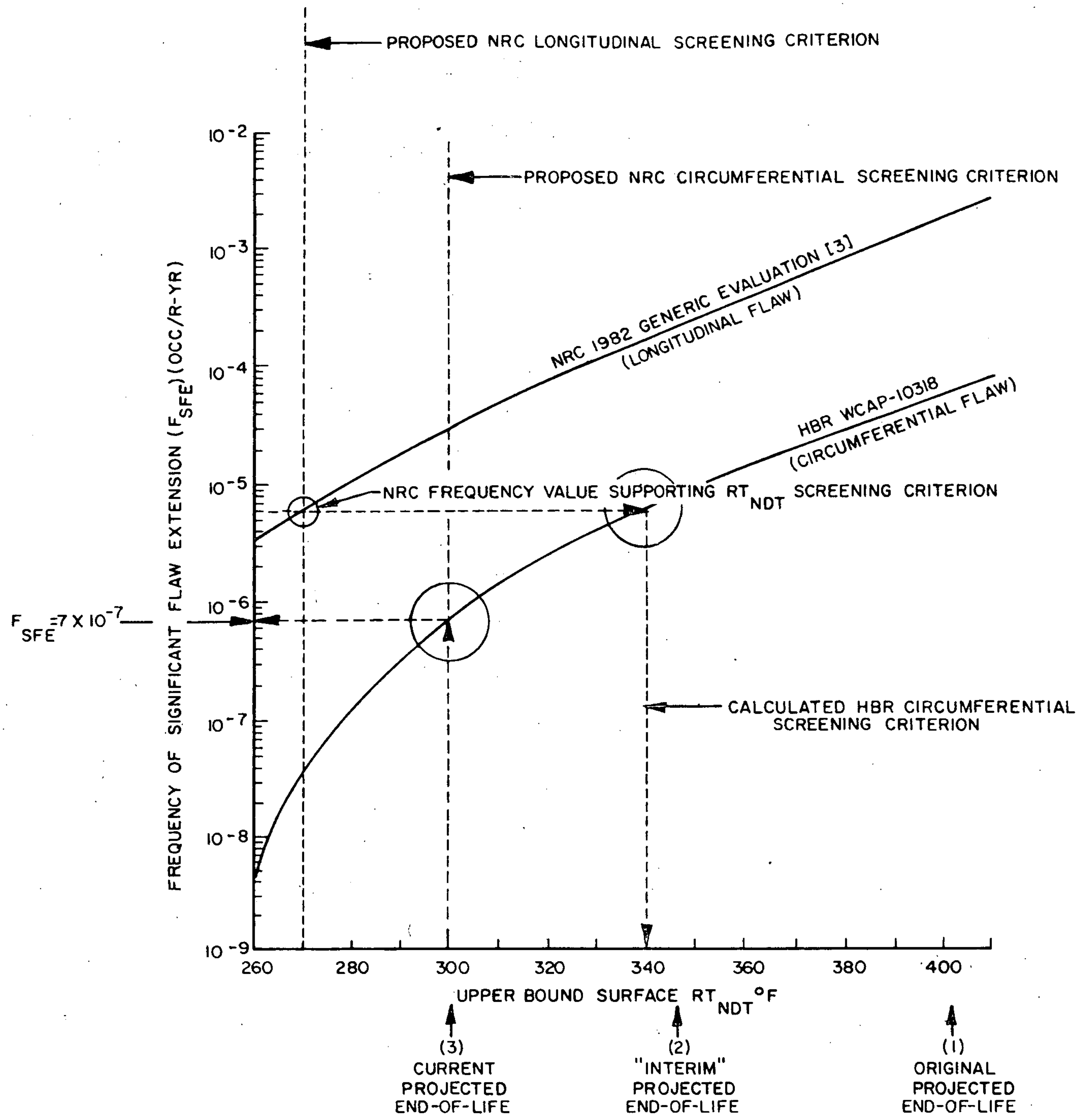
TABLE 5.3.1-1

IDENTIFICATION OF H. B. ROBINSON UNIT 2 VESSEL WELD MATERIALS

Weld Location[a]	Seam No.[a]	Weld Process	Weld Wire Type/Heat No.	Flux Type/Lot	Cu Content %	Ni Content %
Upper Shell Longitudinal Seams	1-273A 1-273B 1-273C	Note B	RACO 3/86054B	ARCOSB5/ 4D5F	0.22	0.054
Intermediate Shell Longitudinal Seams	2-273A 2-273B 2-273C	Note B	RACO 3/86054B	ARCOSB5 4E5F	0.22	0.054
Lower Shell Longitudinal Seams	3-273A 3-273B 3-273C	Note B	RACO 3/86054B	ARCOSB5	0.22	0.054
Upper Circumferential Weld	10-273	Note C	RACO 3/W5214 Ni-200/N7753A	Linde 1092/ 3617	0.34 Note E	0.66 Note E
Lower Circumferential Weld	11-273	Note D	RACO 3/34B009 Ni-200/N9879A	Linde 1092/ 3724	Note E	Note E
Surveillance Weld		Note C	RACO 3/W5214 Ni-200/N7753A	Linde 1092/ 3617	0.34	0.66

Note A - See Figure 5.3.1-1 for seam locations.
Note B - Submerged arc; no Ni wire added.
Note C - Submerged arc; tandem arc process; Ni wire added.
Note D - Submerged arc; single arc process; Ni wire added.
Note E - See Reference 5.3.1-15.

6



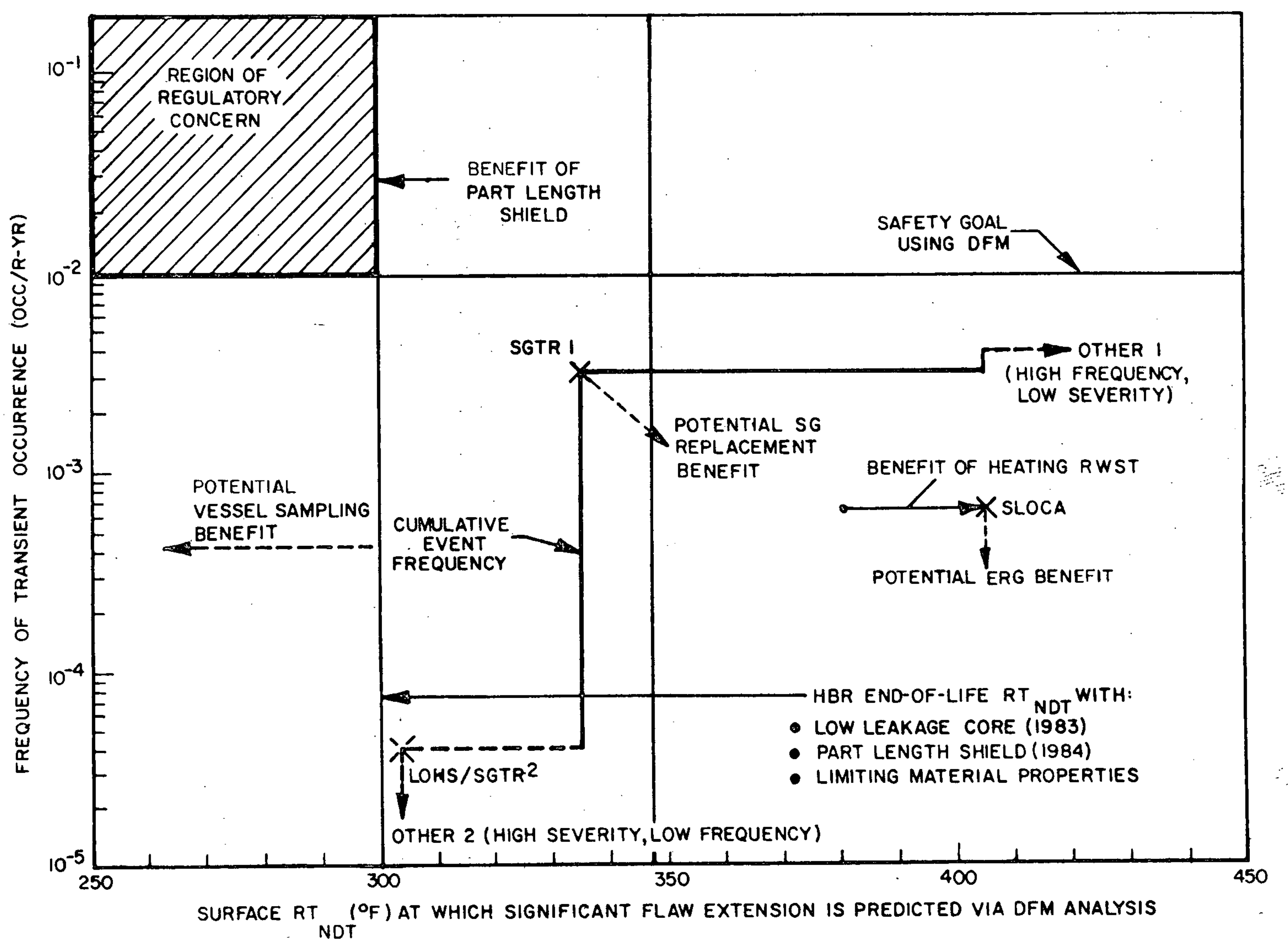
(1) BASED ON ORIGINAL CORE CONFIGURATION WITH "UPPER BOUND" COPPER AND NICKEL.

(2) BASED ON CURRENTLY INSTALLED "LOW LEAKAGE CORE" WITH "UPPER BOUND" COPPER AND NICKEL, NOT INCLUDING ADDITIONAL PLANNED REDUCTION.

(3) BASED ON CURRENTLY INSTALLED "LOW LEAKAGE CORE" AND PLANNED FLUX REDUCTION USING "PART LENGTH SHIELDING" WITH ASSUMED "UPPER BOUND" COPPER AND NICKEL.

AMENDMENT 2

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	DETERMINATION OF TOTAL RISK OF FLAW EXTENSION FROM PRESSURIZED THERMAL SHOCK OF THE REACTOR VESSEL	FIGURE 5.3.1 - 6

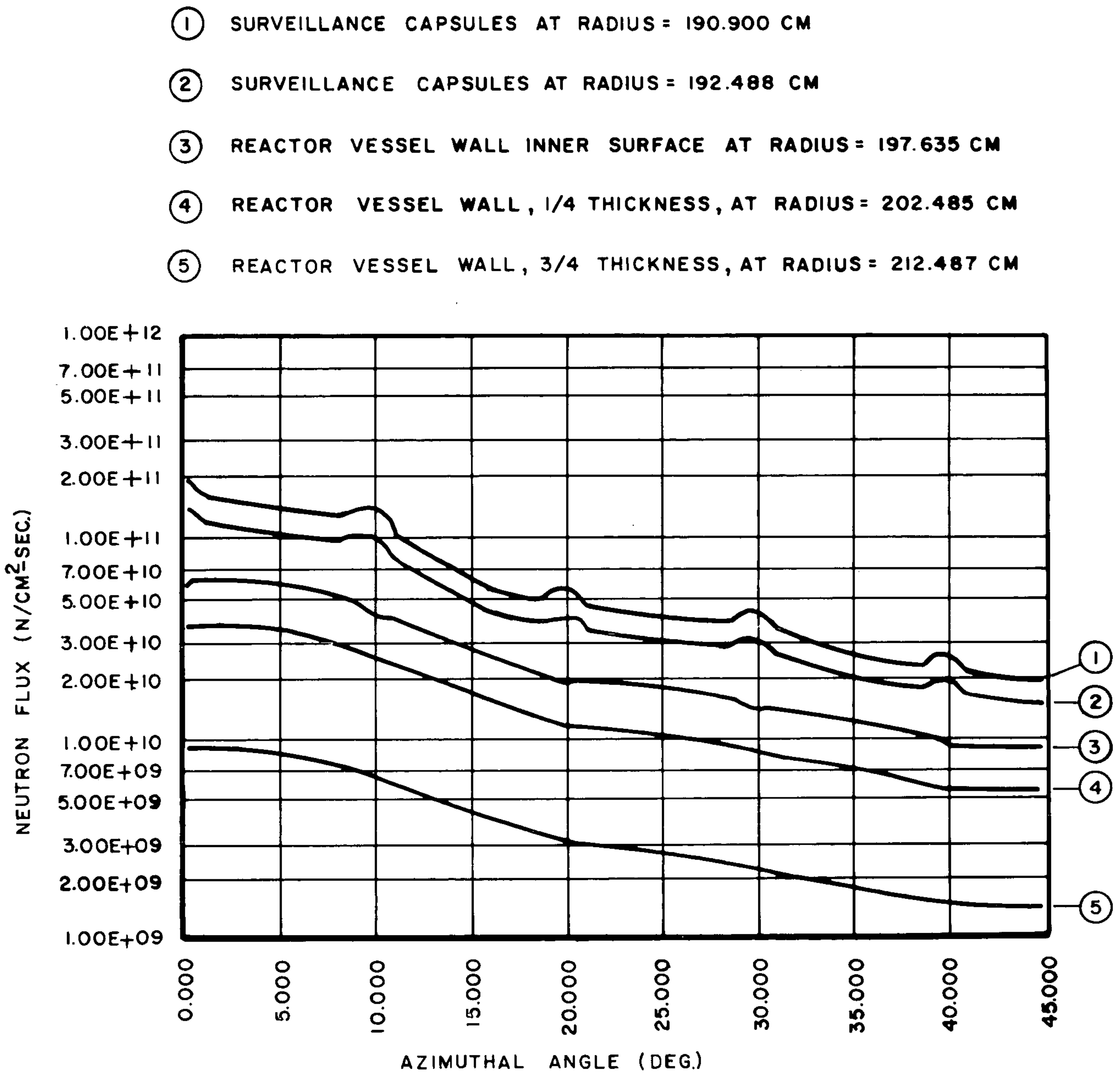


AMENDMENT 2

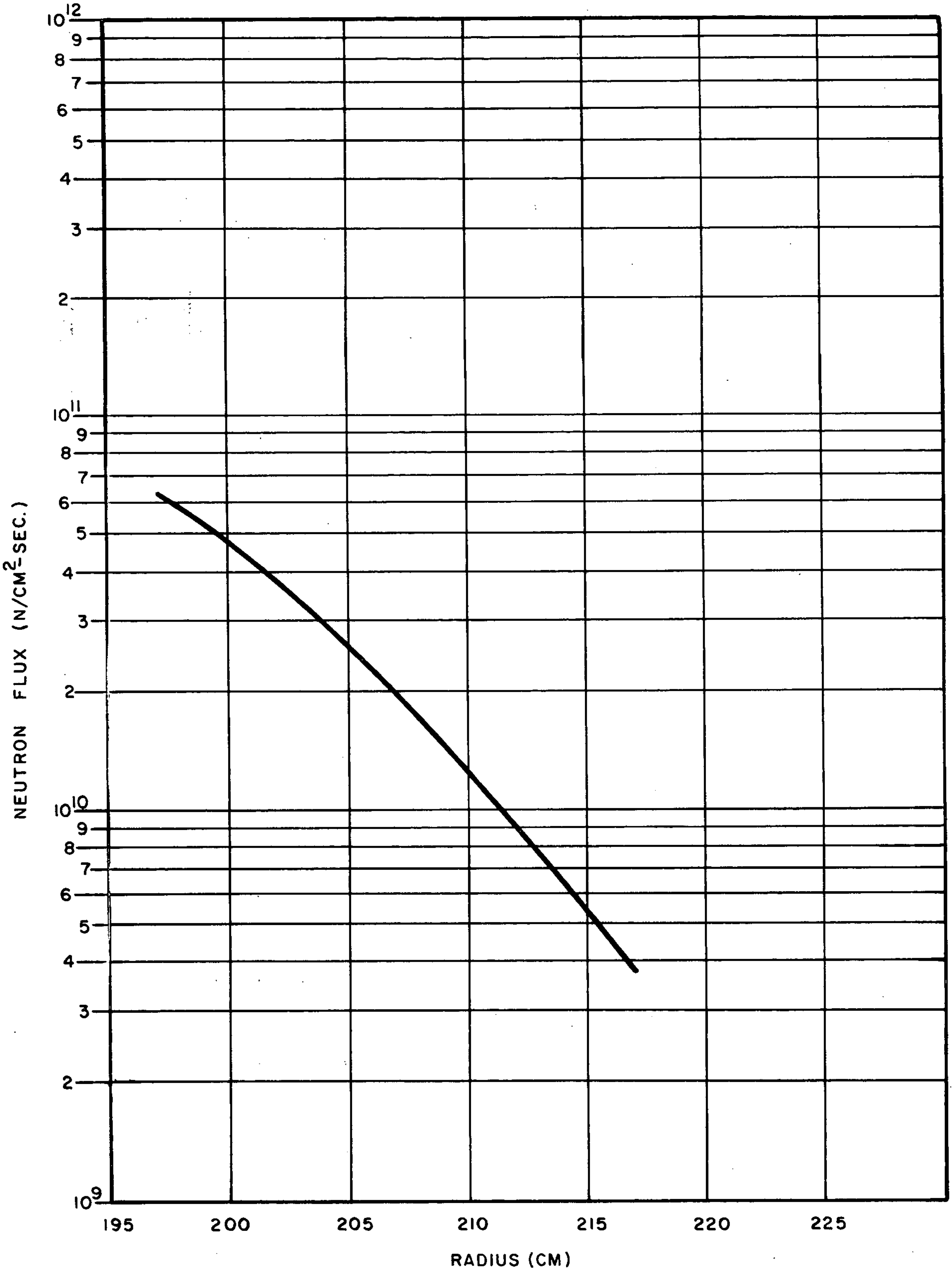
H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

FREQUENCY OF TRANSIENT OCCURENCE
LEADING TO SIGNIFICANT FLAW EXTENSION
USING DETERMINISTIC FRACTURE MECHANICS
ANALYSIS WITH CP&L INITATIVES

FIGURE
5.3.1 - 7

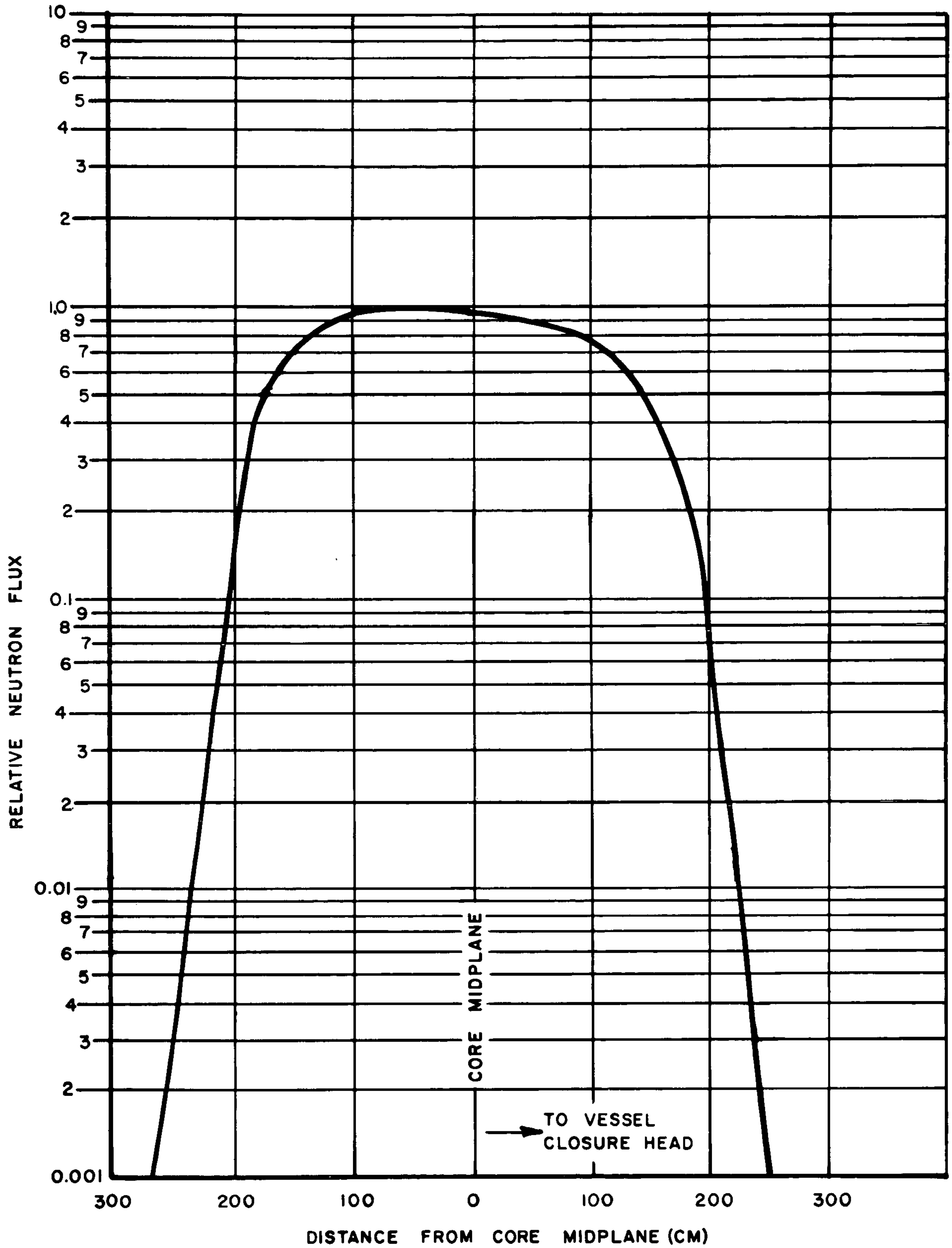


H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	AZIMUTHAL DISTRIBUTION OF NEUTRON FLUX (N/CM^2 - SEC) WITHIN PV	FIGURE 5.3.1 - 8



AMENDMENT 3

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	RADIAL DISTRIBUTION OF FAST NEUTRON FLUX (E>1.0 Mev) WITHIN THE PRESSURE VESSEL WALL	FIGURE 5.3.1 - 9

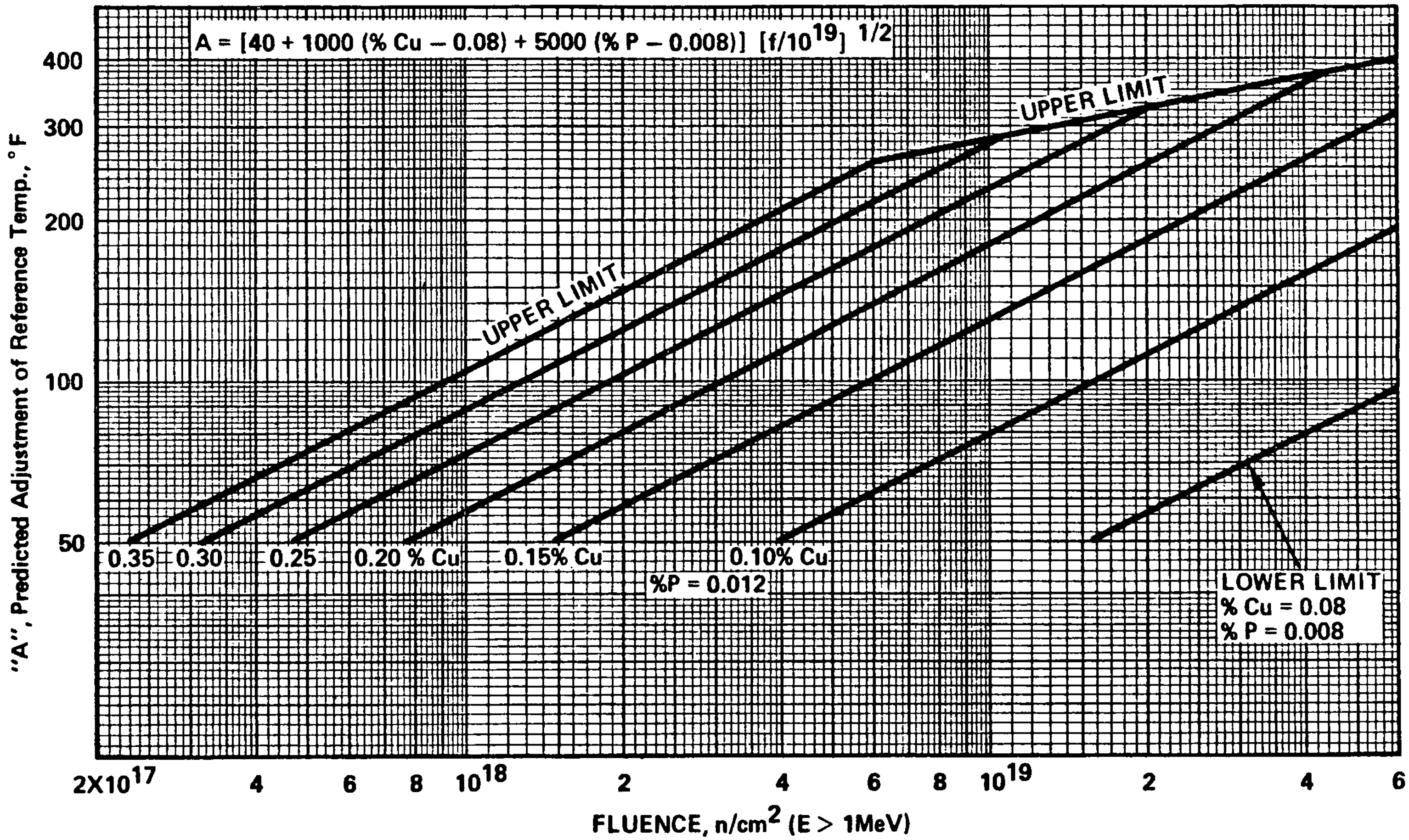


H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	RELATIVE AXIAL VARIATION OF FAST NEUTRON FLUX (E>1.05 Mev) WITHIN THE PRESSURE VESSEL	FIGURE 5.3.1 - 10

H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

PREDICTED ADJUSTMENT OF REFERENCE TEMPERATURE, "A", AS A FUNCTION OF FLUENCE AND COPPER CONTENT

FIGURE 5.3.1 - 11



For Copper and Phosphorus Contents Other Than Those Plotted, Use the Expression for "A" Given on the Figure.

TABLE 5.4.2-1

STEAM GENERATOR DESIGN DATA (2300 MWt)* 3

Number of Steam Generators	3	
Design Pressure, Reactor Coolant/Steam, psig	2485/1085	
Reactor Coolant Hydrostatic Test pressure (tube side-cold), psig (original)	3106	3
Design Temperature, Reactor Coolant/Steam, °F	650/556	
Reactor Coolant Flow, lb/hr	33.8×10^6	
Total Heat Transfer Surface Area per S/G, ft^2	43,467	3
Steam Conditions at Full Load, Outlet Nozzle:		
Steam Flow, lb/hr	3.37×10^6	
Steam Temperature, °F	518.2	3
Steam Pressure, psig	800	
Feedwater Temperature, °F	441.5	
Overall Height, ft-in.	63-1.6	
Shell OD, upper/lower, in.	166/127	
Shell Thickness, upper/lower, in.	3.5/2.62	
Number of U-tubes	3214	3
U-tube Diameter, in.	0.875	
Tube Wall Thickness, (average), in.	0.050	
Number of Manways/ID, in.	3/16	
Number of handholes/ID, in.	6/6	3

* Steam Generator Lower Assembly Replacement 1984
All parameters are for nominal operation conditions at 100% load. 3

5.4.4 RESIDUAL HEAT REMOVAL SYSTEM

The Residual Heat Removal (RHR) system is one of three loops of the Auxiliary Coolant System. The other two loops are the Component Coolant system (Section 9.2.2) and the Spent Fuel Pool Coolant System (Section 9.1.3).

The residual heat removal loop removes residual and sensible heat from the core and reduces the temperature of the Reactor Coolant System during the second phase of plant cooldown.

5.4.4.1 Design Basis

The residual heat removal loop is designed to remove residual and sensible heat from the core and reduce the temperature of the Reactor Coolant System during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the Reactor Coolant System is reduced by transferring heat from the Reactor Coolant System to the Steam and Power Conversion System.

All piping and components of the RHR are designed to the applicable codes and standards listed in Section 3.2. Austenitic stainless steel piping is used in the residual heat removal loop, which contains reactor coolant.

All active loop components which are relied upon to perform their function are redundant.

The loop design precludes any significant reduction in the overall design reactor shutdown margin when the loop is brought into operation for residual heat removal or for emergency core cooling by recirculation.

The loop design includes provisions to enable hydrostatic testing to applicable code test pressures during shutdown.

Loop components, whose design pressure and temperature are less than the Reactor Coolant System design limits, are provided with overpressure protective devices and redundant isolation means.

5.4.4.2 System Design

Figure 5.4.4-1 shows the residual heat removal system.

5.4.4.2.1 Residual Heat Exchangers

The two residual heat exchangers, located within the auxiliary building, are of the shell and U-tube type with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

5.4.4.2.2 Residual Heat Removal Pumps

The two residual heat removal pumps are in-line, centrifugal units with special seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

5.4.4.2.3 Residual Heat Removal Valves

The valves used in the residual heat removal loop are constructed of austenitic stainless steel or equivalent corrosion resistant material.

Manual motor operated stop valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote and manual control of the residual heat exchanger tube side flow. Check valves prevent reverse flow through the residual heat removal pumps.

Double, remotely operated series stop valves are provided at the inlet to isolate the residual heat removal loop from the Reactor Coolant System.

When Reactor Coolant System pressure exceeds the design pressure of the residual heat removal loop, an interlock between the Reactor Coolant System wide range pressure channel and the first inlet valve prevents the valve from opening. A remotely operated stop valve and two series check valves isolate each line to the Reactor Coolant System cold legs from the residual heat removal loop. Overpressure in the residual heat removal loop is prevented by a relief valve which discharges to the pressurizer relief tank.

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System.

Manually operated valves have backseats to facilitate repacking and to limit the stem leakage when the valves are open.

5.4.4.2.4 Residual Heat Removal Piping

All residual heat removal loop piping is austenitic stainless steel. The piping is welded except for flanged connections at the control valves.

5.4.4.3 <u>System Performance</u>

Two pumps and two residual heat exchangers perform the decay heat cooling functions for the reactor unit. After the Reactor Coolant System temperature and pressure have been reduced to less than 350°F and 375 psig respectively, decay heat cooling is initiated by aligning the pumps to take suction from the reactor outlet line and discharge through the heat exchangers into the reactor inlet line. If only one pump and one heat exchanger are available reduction of reactor coolant temperature is accomplished at a lower rate.

An additional function of the residual heat removal pumps is to assist in the mitigation of the LOCA in the refill of the vessel and to ultimately return the core to a subcooled state. A complete discussion of this function is provided in Section 6.3.

5.4.6 PRESSURIZER

The general arrangement of the pressurizer is shown in Figure 5.4.6-1 and the design data are listed in Table 5.4.6-1.

The pressurizer maintains the required reactor coolant pressure during steady-state operation, limits the pressure changes caused by coolant thermal expansion and contraction during normal load transients, and prevents the pressure in the Reactor Coolant System from exceeding the design pressure.

The pressurizer contains replaceable direct immersion heaters, multiple safety and relief valves, a spray nozzle and interconnecting piping, valves and instrumentation. The electric heaters located in the lower section of the vessel maintain the pressure of the Reactor Coolant System by keeping the water and steam in the pressurizer at saturation temperature corresponding to the system pressure. A pressurizer heater bank rated at 150 kW is available, powered from redundant sources in the event of a loss of offsite power to aid natural circulation. This is automatically tripped off from the emergency bus in the event of a safety injection signal to prevent overloading of the diesel generators.

The pressurizer is designed to accommodate positive and negative surges caused by load transients. The surge line which is attached to the bottom of the pressurizer connects it to the hot leg of a reactor coolant loop. During a positive surge, caused by a decrease in plant load, the spray system, which is fed from the cold leg of a coolant loop, condenses steam in the pressurizer to prevent the pressurizer pressure from reaching the set point of the power operated relief valves. Power operated spray valves on the pressurizer limit the pressure during load transients. In addition, the spray valves can be operated manually by a switch in the control room. A small continuous spray flow is provided to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excess cooling of the spray and surge line piping.

During a negative pressure surge, caused by an increase in plant load, flashing of water to steam and generation of steam by automatic actuation of the heaters keeps the pressure above the minimum allowable limit. Heaters are also energized on high water level during positive surges to heat the subcooled surge water entering the pressurizer from the reactor coolant loop.

The pressurizer is constructed of carbon steel with internal surfaces clad with austenitic stainless steel. The heaters are sheathed in austenitic stainless steel.

The pressurizer vessel surge nozzle is protected from thermal shock by a thermal sleeve. A thermal sleeve also protects the pressurizer spray nozzle connection.

TABLE 5.4.6-1

PRESSURIZER AND PRESSURIZER RELIEF TANK DESIGN DATA

Pressurizer

Design/Operating Pressure, psig	2485/2235
Hydrostatic Test Pressure (cold), psig	3110
Design/Operating Temperature, °F	680/653
Water Volume, Full Power, ft^{3*}	780
Steam Volume, Full Power, ft^3	520
Surge Line Nozzle Diameter, in./Pipe Schedule	14/Sch 140
Shell ID, in./Minimum Shell Thickness, in.	84/4.1
Minimum Clad Thickness, in.	0.188
Electric Heaters Capacity, kW (total available)	1066
Heatup Rate of Pressurizer Using Heaters Only, °F/hr	55 (approximately)
Power Relief Valves	
Number	2
Set Pressure, psig	2335
Capacity, lb/hr Saturated Steam/Valve	210,000
Safety Valves	
Number	3
Set Pressure, psig	2485
Capacity, lb/hr Saturated Steam Valve	288,000

* 60 percent of net internal volume (maximum calculated power)

CHAPTER 6
ENGINEERED SAFETY FEATURES

TABLE OF CONTENTS (Cont'd)

CHAPTER 6
ENGINEERED SAFETY FEATURES

TABLE OF CONTENTS (Cont'd)

6.0 ENGINEERED SAFETY FEATURES

Seven types of engineered safety features are included in the design of the HBR 2 facility to mitigate the consequences of a postulated accident in spite of the fact that these accidents are very unlikely. These safety features are:

1. The Safety Injection (SI) System accumulators and pumps, which inject borated water into each coolant loop of the Reactor Coolant System (RCS). This system limits damage to the core and limits the energy released into the containment following a loss-of-coolant accident (LOCA).

2. The Containment Spray System, which is used to reduce containment pressure and to wash down iodine into the containment sump.

3. The air recirculation coolers, which reduce containment pressure following a LOCA.

4. A steel-lined concrete containment structure described herein, with testable penetrations and liner welds, which form a virtually leaktight barrier to the escape of fission products should a LOCA occur.

5. An Isolation Valve Seal Water System, which creates a leak tight seal in all pipes which could communicate with the atmosphere inside the containment following a LOCA.

6. A reactor coolant gas vent system which vents non-condensible gases from the reactor vessel head and the pressurizer steam space during post-accident situations.

6.1 ENGINEERED SAFETY FEATURES MATERIALS

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Emergency Core Cooling System Components

Emergency core cooling system (ECCS) components are constructed of austenitic stainless steel or an equivalent corrosion resistant material, and hence are quite compatible with the spray solution over the full range of exposure in the post-accident regime. While this material is subject to crevice corrosion by hot concentrated caustic solution, the NaOH additive cannot enter the containment or the ECCS without first being diluted and partially neutralized with boric acid to a mild solution. Corrosion tests performed with simulated spray showed negligible attack, both generally and locally, in stressed and unstressed stainless steel at containment and ECCS conditions. These tests are discussed in Reference 6.1.1-1.

6.1.1.1.1.1 Pumps

The pressure-containing parts of the pumps were constructed of castings which conformed to American Society for Testing and Materials (ASTM) A-351 Grade CF8 or CF8M specifications. Stainless steel forgings were procured per ASTM A-182 Grade F304 or F316 or ASTM A-336, Class F8 or F8M, and stainless plate was constructed to ASTM A-240 Type 304 or 316 specifications. All bolting material conformed to ASTM A-193. Materials such as weld-deposited Stellite or Colmonoy were used at points of close running clearances in the pumps to prevent galling and to assure continued performance capability in high velocity areas subject to erosion.

All pressure-containing parts of the pumps were chemically and physically analyzed and the results checked to ensure conformance with the applicable ASTM specification. In addition, all pressure-containing parts of the pump were liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Boiler and Pressure Vessel (B&PV) Code. The acceptance standard for the liquid penetrant test was USAS B31.1, Code for Pressure Piping, Case N-10.

Where welding of pressure containing parts was necessary, a welding procedure including joint detail was submitted for review and approval by Westinghouse. The procedure included evidence of qualification necessary for compliance with Section IX of the ASME Code, Welding Qualifications. This requirement also applied to any repair welding performed on pressure containing parts.

6.1.1.1.1.2 Heat Exchangers

The two residual heat exchangers of the Auxiliary Coolant System conform to the strict rules of the ASME Code regarding the wall thicknesses of all pressure containing parts, material quality assurance provisions, weld joint design, radiographic and liquid penetrant examination of materials and joints, and hydrostatic testing of the unit as well as final inspection and stamping of the vessel by an ASME Code inspector. Each unit has an SA-285 Grade C Carbon Steel shell, an SA-234 Carbon Steel shell end cap, SA-213 Type-304 Stainless Steel tubes, an SA-240 Type 304 Stainless Steel channel, an SA-240 Type 304 Stainless Steel channel cover and an SA-240 Type 304 Stainless Steel tube sheet.

6.1.1.1.1.3 Valves. All material in accumulator check valves, motor-operated valves, and all other ECCS valves in contact with radioactive fluid were constructed (except the packing) of austenitic stainless steel or materials of equivalent corrosion resistance. Carbon steel was used for manual globe, gate and check valves which pass only non-radioactive fluids.

6.1.1.1.1.3.1 Stainless steel valves (except accumulator check valves). The pressure-containing parts (body, bonnet and discs) of the valves employed in the Safety Injection (SI) System were designed per criteria established by the USAS B16.5 or MSS SP66 specifications. The materials of construction for these parts were procured to applicable ASME or ASTM specifications for austenitic stainless steel materials.

The pressure containing cast components were radiographically inspected as outlined in ASTM E-71 Class 1 or Class 2. The body, bonnet and discs were liquid penetrant inspected in accordance with the ASME Code Section VIII, Appendix VIII or ASME Code Section III. The liquid penetrant acceptance standard was as outlined in USAS B31.1 Case N-10 or ASME Code Section III.

When a gasket was employed, the body-to-bonnet joint was designed per the ASME Code, Section VIII, or USAS B16.5 with a fully trapped, controlled compression, spiral wound gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials were procured per ASTM A193 and A194, respectively.

The seating surfaces chosen are hard faced (Stellite No. 6, nickel-chrome-boron, or equivalent) to prevent galling and reduce wear.

The stem material chosen was ASTM A276 Type 316 condition B or precipitation hardened 17-4 PH stainless procured and heat treated to Westinghouse Specifications. These materials were selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. With the exception of valves which have been live loaded and had leakoff lines capped, the valve stuffing box is designed with a lantern ring leak-off connection with a minimum of a full set of packing below the lantern ring and a maximum of one-half of a set of packing above the lantern ring; a full set of packing is defined as a depth of packing equal to 1-1/2 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials has been very favorable in both conventional and nuclear power plants.

6.1.1.1.1.3.2 Accumulator check valves. The pressure-containing parts of this valve assembly were designed in accordance with MSS SP-66. All parts in contact with the operating fluid were procured to applicable ASTM or WAPD specifications. The cast pressure containing parts were radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The cast pressure containing parts, machined surfaces, finished hard facings, and gasket bearing surfaces were liquid penetrant inspected per the ASME Code, Section VIII, and the acceptance standard was as outlined in USAS B31.1, Code Case N-10.

The valve was designed with a low pressure drop configuration, with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The clapper arm shaft was manufactured from 17-4 PH Stainless Steel heat treated to Westinghouse Specifications. The disc and seat ring mating surface and the clapper arm shaft bushings were manufactured from Stellite No. 6 material. The various working parts were selected for their corrosion resistant, tensile, and bearing properties. Nickel-chrome-boron may be used as an alternate hard-surfacing material.

6.1.1.1.1.3.3 Carbon steel valves. The carbon steel valves pass only nonradioactive fluids. Since the fluid controlled by the carbon steel valves is not radioactive, the double packing included in the stainless steel valve design described in Section 6.1.1.1.1.3.1 and seal weld provisions were not provided.

The carbon steel valves were built to conform with USAS B16.5. The materials of construction of the body, bonnet and disc conformed to the requirements of ASTM A105 Grade II, A181 Grade II, or A216 Grade WCB or WCC.

6.1.1.1.1.4 Piping. All SI System piping in contact with borated water is austenitic stainless steel. Piping joints are welded except for the flanged connections at the SI and containment spray pumps.

The piping was designed to meet the minimum requirements set forth in:

1. The USAS B31.1 Code for Pressure Piping

2. Nuclear Code Case N-7

3. USAS Standards B36.10 and B36.19

4. ASTM Standards, and

5. Supplementary standards plus additional quality control measures.

Minimum wall thicknesses were determined by the USAS Code formula in Section 1, Piping of the USAS Code for Pressure Piping. This minimum thickness was increased to account for the manufacturer's permissible tolerance of minus 12 1/2 percent on the nominal wall. Purchased pipe and fittings had a specified nominal wall/thickness that was no less than the sum of that required for pressure containment, mechanical strength, and manufacturing tolerance.

Pipe and fitting materials were procured in conformance with all requirements of the ASTM and USAS specifications. All materials were verified for conformance to specification and documented by certification of compliance to ASTM material requirements. Specifications imposed additional quality control upon suppliers of pipes and fittings as listed below.

1. Check analyses were performed on both the purchased pipe and fittings.

2. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conform to ASTM A376 and meet the supplementary requirement S6 ultrasonic testing.

3. Fittings conform to the requirements of ASTM A403. Fittings 3 in. and above have requirements for UT inspection similar to S6 of ASTM A376, except the 6" diameter end caps used in fabricating strainers for the 3/4" diameter piping branching off of the 3" discharge lines of the safety injection pumps.

Welds for pipes sized 2 1/2 in. and larger are butt welded. Reducing tees were used where the branch size exceeds 1/2 of the header size. Branch connections of sizes that are equal to or less than 1/2 of the header size are of a design that conformed to the USAS rules for reinforcement set forth in the USAS B31.1 Code for Pressure Piping. Bosses for branch connections are attached to the header by means of full penetration welds.

All welding was performed by welders and welding procedures qualified in accordance with the ASME Code, Section IX, Welding Qualifications. The Shop Fabricator was required to submit all welding procedures and evidence of qualification for review and approval prior to release for fabrication. All welding materials used by the Shop Fabricator had prior approval.

All high pressure piping butt welds containing radioactive fluid, at greater than 600°F temperature and 600 psig pressure or equivalent, were radiographed. The remaining piping butt welds were randomly radiographed. The technique and acceptance standards were those outlined in UW-51 of the ASME Code, Section VIII, except for the end cap weld joints used in fabricating the strainers for the 3/4" diameter piping branching off of the 3" discharge lines of the safety injection pumps, in which case USAS B31.1 was used as applicable. In addition, butt welds were either liquid penetrant examined in accordance with the procedure of the ASME Code, Section VIII, Appendix VIII (acceptance standard as defined in USAS Nuclear Code Case N-10) or liquid penetrant examined to the requirements and acceptance criteria of ASME Code Section III. Finished branch welds were liquid penetrant examined on the outside and where size permitted, on the inside root surfaces.

A post-bending solution anneal heat treatment was performed on hot-formed stainless steel pipe bends. Completed bends were then completely cleaned of oxidation from all affected surfaces. The shop fabricator was required to submit the bending, heat treatment, and cleanup procedures for review and approval prior to release for fabrication.

6.1.1.1.1.5 Accumulators. The accumulators are carbon steel, clad with stainless steel, and were designed to ASME Section VIII, Division 2 requirements.

6.1.1.1.1.6 Boron injection tank. The boron injection tank was constructed of solid austenitic stainless steel and was designed to ASME Section VIII, Division 2 requirements.

6.1.1.1.1.7 Refueling water storage tank. The refueling water storage tank was constructed of austenitic stainless steel, and conformed to the requirements of American Water Works Association (AWWA) D100-65. The roof of the tank is carbon steel lined with Amercoat.

6.1.1.1.2 Containment Spray System Components

Containment Spray System components in contact with borated water, the sodium hydroxide spray additive, or mixtures of the two, are stainless steel or an equivalent corrosion-resistant material.

The principal components of the Containment Spray System consist of two pumps, one spray additive tank, spray ring headers and nozzles, and the necessary piping and valves. The containment spray pumps and the spray additive tank are located in the Auxiliary Building and the spray pumps take suction directly from the refueling water storage tank. As all of the active components of the Containment Spray System are located outside the containment, they are not required to operate in the steam-air environment produced by a hypothetical accident.

The Containment Spray System also utilizes the two residual heat removal pumps, two residual heat exchangers and associated valves and piping of the SI System for the long-term recirculation phase of containment cooling and iodine removal (refer to Section 6.1.1.1.1).

The containment spray pumps were designed in accordance with the specifications discussed in Section 6.1.1.1.1 for the pumps in the SI System. The materials of construction are stainless steel or equivalent corrosion-resistant material.

The piping for the Containment Spray System was designed in accordance with the specifications discussed for the piping in the SI System (Section 6.1.1.1.4).

Spray nozzles and piping were built to conform to USAS B31.1. Nozzles are constructed of stainless steel.

The valves for the Containment Spray System were designed in accordance with the specifications discussed for the valves in the SI System, and conformed to the criteria of USAS B16.5. Valving descriptions and valve details are shown in Section 6.5.2.

The spray additive tank was constructed of austenitic stainless steel, and conformed to the requirements of the ASME code, Section III, Class C.

The Containment Spray System shares the refueling water storage tank liquid capacity with the SI System. Refer to Section 6.1.1.1.1.7 for a description of this tank.

6.1.1.1.3 Containment Air Recirculating System Components

All fan parts, damper shaft, and blade seating surfaces and ducts in contact with the containment fluid are protected against corrosion. The fan motor enclosures, electrical insulation and bearings were designed for operation during accident conditions.

The coils are fabricated of copper plate fins vertically oriented on stainless steel tubes. 3

Ducts are constructed of corrosion-resistant material. Where flanged joints are used, joints are provided with gaskets suitable for temperatures to 300°F.

6.1.1.1.4 Post-Accident Containment Venting System Components

The Post-Accident Containment Venting System consists of two full capacity supply lines through which hydrogen-free air can be admitted to the containment; two full capacity exhaust lines through which hydrogen bearing gases may be vented from the containment; and, associated valving and instrumentation. The supply lines use equipment and piping which provide instrument air and service air during normal operation. One of the exhaust lines uses equipment and piping which normally provides pressure relief for the containment. The second exhaust line does not use existing equipment. Equipment added to permit the post-accident venting process was constructed of stainless steel. Details of the Post-Accident Containment Venting System are
1 provided in Section 6.2.5.

6.1.1.1.5 Containment Structural Components

As discussed in Section 3.8.1.6, basically eight materials, of which six are metallic, have been used for construction of the containment structure. Metallic materials and components of the containment are as follows:

a) Reinforcing steel

b) Prestressed Steel System

c) Plate steel penetration frame

d) Liner

e) Equipment hatch and personnel lock, and

f) Pipe piles.

Metallic materials used for pipe piles are discussed in Section 3.8.5.

Metallic materials used for reinforcing steel, the prestressed steel system, the plate steel penetration frames, the liner, the equipment hatch, and personnel lock are discussed in Section 3.8.1.6.

6.1.1.1.6 Isolation Valve Seal Water System Components

The Isolation Valve Seal Water System provides a simple and reliable means for injecting seal water between the seats and stem packing of the globe and double disc types of isolation valves, and into the piping between closed diaphram-type isolated valves (refer to Section 6.8 for the system design description).

The piping and valves for the system, including the air-operated valves, were designed in accordance with the USAS Code for Pressure Piping (Power Piping System), B31.1.

The isolation valve seal water tank was constructed of ASTM A-240, in accordance with the criteria of the ASME Code, Section VIII. The design data for the tank are given in Table 6.1.1-1.

There are no components of this system located inside containment.

6.1.1.1.7 Containment penetration pressurization system components. The Containment Penetration Pressurization System provides continuous or intermittent positive pressure gradient into the mechanical and cartridge type electrical containment penetrations and the sealing head assembly of CAPSULE type electrical penetrations (refer to Section 6.9.1 for the System Design Description).

The pressurization air receivers are constructed of ASTM A-285-C in accordance with ASME UPV (Section VIII).

The piping and valves for the system were designed in accordance with the USAS Code for Pressure Piping (Power Piping Systems), B31.1.

For a description of the air compressors, refer to Service Air System, Section 9.3.1.

The nitrogen cylinders used were designed in accordance with Section VIII (Unfired Pressure Vessels) of the ASME Code, for 2000 psig maximum pressure, and contain a total of 17,350 scf of nitrogen.

6.1.1.1.8 Nonmetallic thermal insulation.

6.1.1.1.8.1 Piping and equipment insulation. Heat insulation specifications for piping and equipment require the use of low leachable chloride insulation, which has been silicate-inhibited against chloride stress corrosion cracking of austenitic stainless steel.

During the construction phase, the insulation material selected for use in containment was Unibestos block and pipe covering. The insulation was weatherproofed with white duck canvas (instead of an aluminum jacket) to minimize the use of aluminum inside containment.

Each lot and batch of insulation was required to pass a stress corrosion test devised by Knolls Atomic Power Laboratory (Reference 6.1.1-2).

An estimated 6400 ft^3 of Unibestos was originally installed inside containment during construction. Approximately 15 percent of this material has since been replaced by Thermon-12 insulation or equivalent, which was the standard for new or replacement Q-List components and piping.

As a result of the 1984 steam generator replacement project, the steam generators were completely reinsulated with new insulation. This new insulation was a combination of both a metallic reflective and a calcium silicate product consisting of approximately 2600 ft^3.

Removable insulation was installed on areas requiring in-service inspection and access openings such as manways and handholes. Metallic reflective insulation was installed on the lower portion of the steam generators from the channel head to just above the upper set of secondary side handholes.

6.1.1.1.8.2 Containment Liner Insulation

The cylindrical portion of the containment liner was insulated to reduce the design temperature to which it would be exposed.

Containment liner insulation consists of 44 in. x 84 in. x 1 1/4 in. thick, 4 lb/ft^3 density cross-linked polyvinyl chloride (PVC) foam with an outer covering of 24 gauge stainless steel.

The liner plate was protected against corrosion as follows: The entire inside surface of the dome and walls was sandblasted. Above operating deck level the plate received one shop coat of alkyd-based metal primer and two field coats of alkyd-based finish. Below operating deck level the liner and penetrations received one shop coat of zinc-filled inorganic primer, such as Carbo Zinc II, and one field coat of phenolic type paint, such as Phenoline 305. All painted surfaces were inspected after erection and any damaged areas reprimed before finishing. The face of the liner plate in contact with the concrete had no primer or paint applied: the intimate contact with the concrete provides corrosion protection.

6.1.1.2 Composition, Compatibility and Stability of Containment and Core Spray Coolants

An evaluation program led to the selection of sodium hydroxide (NaOH), as the iodine removal additive to the boric acid containment spray. The results of the evaluation program are detailed in Reference 6.1.1-1. NaOH was found to be chemically stable at post-accident containment temperatures, and resistant to oxidation. The NaOH solution was found to be radiolytically stable, with a relatively low net hydrogen liberation rate.

Corrosion rates of copper and copper-alloy heat exchanger tubing were acceptably low (<0.01 mil/month at 200°F) for the application. These tests showed that pitting or local corrosion did not occur.

The means of adding NaOH to the spray liquid is provided by a liquid jet eductor, a device which uses the kinetic energy of a pressure liquid to entrain another liquid, mixes the two, and discharges the mixture against a counter pressure. The pressure liquid, in this case, is the spray pump discharge which is used to entrain the NaOH solution and discharge the mixture into the suction of the spray pumps. The two eductors were designed to provide enough NaOH in the mixture so as not to exceed a pH of 10 during the injection phase. The design parameters are presented in Table 6.1.1-2.

Analysis has shown that the worst case containment sump pH is slightly above 8.0. This was consistent with the Westinghouse recommendation to maintain sump pH between 8.0 and 10.5 for material compatibility. The worst case containment spray pH for the plant is 8.8 which is greater than the Westinghouse minimum acceptance criterion of 8.5 and consistent with the current Nuclear Regulatory Commission (NRC) acceptance criteria, Standard Review Plan 6.5.2, which states that the spray solution must have a pH between 8.5 and 11.0.

Engineered Safety Feature (ESF) coolants are stored in the refueling water storage tank, the boron injection tank, the safety injection accumulators and the containment spray additive tank. The materials selection and fabrication requirements for these vessels are described in Section 6.1.1.1.1.

The refueling water storage tank contains a minimum of 300,000 gal of 1950 ppm borated water available for delivery. The maximum boric acid concentration is approximately 1.4 weight percent boric acid. This concentration of boric acid in the refueling water storage tank is well below the solubility limit at 32°F (2.2 percent).

The boron injection tank contains 900 gal of weak boric acid solution (zero to 2500 ppm) at an operating pressure between 0 and 1500 psig. Design parameters are 2735 psig and 300°F. (See FSAR Section 6.3.2.2.7 and Table 6.3.2-3.)

The tank is vertical with the outlet nozzle on top. A level alarm is provided from a stand pipe/vent arrangement on the outlet pipe at an elevation higher than the top of the tank. This alarm assures that the tank is maintained full of solution at all times.

The three SI accumulators contain 2000 ppm boric acid and are pressurized with nitrogen gas to between 600 and 660 psig, at 70 to 120°F. Design parameters are 700 psig and 300°F.

The spray additive tank contains a minimum of 2505 gal of 30 weight percent sodium hydroxide solution which, upon mixing with the refueling water from the refueling water storage tank, the boric acid from the boric acid tank, the borated water contained within the accumulators, and the primary coolant, will bring the concentration of sodium hydroxide in the containment to approximately 0.6 weight percent solution caustic, and 1.7 weight percent boric acid. This maintains a pH of at least 9.3 and assures the continued iodine removal effectiveness of the containment spray during the recirculation phase of operation after the supply of borated water in the refueling water storage tank has been exhausted. The 300 psig design pressure of the tank is the sum of the refueling water storage tank head and the total developed head of the containment spray pumps at shutoff. Vacuum breaker relief valves on the spray additive tank are designed to actuate prior to achieving a 1.5 psid vacuum to insure adequate system performance. A level indicating alarm is provided to alarm in the Control Room if, at any time, the solution tank contains less than the required amount of sodium hydroxide solution. Periodic sampling confirms that proper sodium hydroxide concentration exists in the tank.

The tank design parameters are given in Table 6.1.1-3.

TABLE 6.1.1-1

ISOLATION VALVE SEAL WATER TANK

Material	ASTM A-240
Design Pressure, psig	150
Design Temperature, ^{o}F	200
Operating Pressure, psig	50-100
Operating Temperature, ^{o}F	Ambient
Code	ASME Code, Section VIII

TABLE 6.1.1-2

CONTAINMENT SPRAY EDUCTORS DESIGN PARAMETERS

Quantity	2
Eductor Inlet (motive)	Injection Phase
Operating Fluid	Water (with 2000 ppm boron)
Operating Pressure, psig	200
Operating Temperature	Ambient
Flow Rate, gpm, max.	80
Discharge Head (including static pressure, friction loss, and discharge elevation) psig	0 - 7
Eductor Suction	
Fluid	30 percent NaOH (solution)
Specific Gravity	1.3
Viscosity (design), cp	10
Suction Pressure, psig	1 to 10
Operating Temperature	Ambient
Suction Capacity (required), gpm	12

TABLE 6.1.1-3

SPRAY ADDITIVE TANK DESIGN PARAMETERS

Number	1
Total Volume (empty), gal	5100
Minimum Volume at Operating Conditions (solution), gal	2505
NaOH Concentration, percent	30
Design Temperature, °F	300
Design Pressure, psig	300
Design Vacuum, psi	2
Material	Austenitic Stainless Steel

4

6.1.2 ORGANIC MATERIALS

Significant quantities of organic material within the Containment Building include containment liner insulation, piping, and equipment insulation, electrical insulation, lubricants, and protective coatings.

The quantity and identity of materials selected for containment liner insulation are described in Section 6.1.1.1.7.2. Materials selected for use as piping and equipment insulation are described in Section 6.1.1.1.7.1.

The ability of electrical equipment in the ESF Systems to withstand radiation exposure would be limited by radiation effects on electrical insulation materials and motor bearing lubrication.

The electrical equipment for the ECCS located in the containment utilizes only inorganic, silicone, and epoxy plastic insulating materials. These materials have a threshold for radiation damage which provides considerable margin above the maximum post-accident radiation dose that would result from the exposure levels and times described in Section 3.11.

The fan cooler motors of the Containment Air Recirculation System contain Class F Thermalastic insulation (NEMA rated total temperature 155°C). The insulation was impregnated and coated to give a homogeneous insulation system which is highly impervious to moisture.

Where required, because of location in possible high radiation areas, ECCS motor bearings will be lubricated with radiation-rated lubricants. 6

The investigation of materials compatibility in the post-accident design basis environment also included an evaluation of protective coatings for use in containment.

The results of the protective coatings evaluation (Reference 6.1.2-1) showed that several inorganic zincs, modified phenolics and epoxy coatings are resistant to an environment of high temperature (320°F maximum test temperature) and alkaline sodium borate. Long-term tests included exposure to spray solution at 150 - 175°F for 60 days, after initially being subjected to the design basis accident (DBA) cycle. Similar tests were conducted at the National Reactor Testing Station at Idaho Falls, Idaho (Reference 6.1.2-2).

The protective coatings, which were found to be resistant to the test conditions, that is, exhibited no significant loss of adhesion to the substrate nor formation of deterioration products, comprise virtually all of the protective coatings exposed in the Carolina Power & Light (CP&L) containment. Hence, the protective coatings will not add deleterious products to the core cooling solution. Essentially all carbon steel surfaces are either coated with Carbozinc-11, an inorganic zinc primer, and Phenoline 305, a modified phenolic top coat, or are protected from direct impingement of the spray. For example, the containment vessel liner surface is protected by the liner insulation and is not exposed to the DBA spray. The coating in this

area is the Keeler & Long 7230 System. It should be noted further, however, that this coating system, while exhibiting blisters in the conservative test environment (Reference 6.1.2-1) did not fail to the extent that significant deterioration products were released from the surface.

The concrete surfaces which have been coated are coated with Phenoline 305 or Carboline 195 Surfacer and Phenoline 305. Carboline 195 Surfacer is a product generally identical (modified epoxy-polyomide) with protective coating which has been shown to be completely resistant to the DBA environment.

It should be pointed out that several test panels of the types of protective coatings used at HBR 2 were exposed for two DBA cycles and showed no deterioration or loss of adhesion with the substrate.

All the power generated by the core during blowdown is transferred to the coolant, and reaches the containment. The initial core stored and metal sensible energy is transferred to the coolant by a time dependent temperature difference calculation. It should be emphasized that the energy transferred from the core to the coolant for the containment evaluation far exceeded that transferred for the core thermal evaluation. That is to say, a conservatively high core heat transfer coefficient was used for the containment evaluation, while a conservatively low coefficient was used during the core thermal evaluation. Between the end of blowdown and the beginning of core reflooding there is no energy entering the containment. While the core is being reflooded the remaining stored energy in the core and internals causes a portion of the accumulator water to be boiled, and this energy is transferred to the containment.

Any energy addition resulting from a $Zr-H_2O$ reaction was also considered. The reaction energy reaches the containment by transfer to coolant, while the recombination energy of the H_2 generated in the reaction was added directly to the steam-air mixture in the containment. The hydrogen was assumed to burn as it is produced.

Finally, hot metal surfaces not cooled by safety injection (SI) water (reactor vessel above nozzles and steam generator tubes) were simulated as hot walls in contact with the containment steam-air mixture. A small heat transfer coefficient is employed to reflect actual conditions since these surfaces are covered by stagnant steam inside the RCS.

The actual values for energy release used are presented in Table 6.2.1-1. The computer codes and assumptions used in deriving the mass and energy release rates are also discussed in Section 6.2.1.3.

6.2.1.1.1.3 ESF Systems Impact on Energy Removal and Pressure Reduction

Provision was made in the computer analysis for the effects of several engineered safeguards, including internal spray, fan coolers, and recirculation of sump water. The heat removal from containment steam-air phase by internal spray is determined by allowing the spray water temperature to rise to the steam-air temperature.

In the transients one spray pump and two fans starting at 60 sec were assumed. These acted to quickly reduce the pressure after the peak pressures were reached. This is the minimum equipment available considering the single failure criterion in the emergency power system, the spray system, and the fan cooler system.

The ability of the fan coolers to limit containment pressure following loss of the component cooling system was examined. If the component cooling loop were lost for any reason during long-term recirculation, core subcooling could be lost and boiling in the core would begin. Since the fan cooling units are cooled by service water, the energy from the core would be removed from the containment via the fans. The following table summarizes the maximum pressure the containment could reach for assumed times of component cooling system failure.

	3 FANS	2 FANS
C.C. Failure at 12 hr	9.5	27
C.C. Failure at 1 day	7.0	16
C.C. Failure at 1 week	2.0	4.5

The containment heat removal capability started at 60 sec exceeds the energy addition rate and the pressure does not exceed the initial blowdown value. An extended depressurization time results due to the increased heat load on the containment coolers.

The time dependent behavior of containment internal pressure resulting from a LOCA is shown in Figure 3.8.1-29. The loads resulting from the design pressure are shown in Figure 3.8.1-30.

The containment structure is designed to contain the radioactive material which might be released from the core following a LOCA at a leak rate no greater than 0.1 percent of the containment free volume per day at design pressure.

The maximum allowable differential pressure loading from an internal negative pressure is 3.0 psig.

The inadvertent initiation of containment spray flow with refueling borated water at 45^{o}F temperature would reduce the environment temperature by 50^{o}F (120^{o}F to 70^{o}F) within ten minutes. A negative pressure of 1.25 psi is calculated for a 50^{o}F temperature reduction in the containment, based on a free volume of 2.10 x 10^{6} cu ft and an initial relative humidity of 20 percent.

The maximum differential which could occur with 100 percent humidity would be approximately 2.45 psig which is less than the maximum allowable of 3.0 psig. An alarm set at 1 psi negative pressure will inform the Control Room operator of the containment pressure. Upon receipt of an alarm the Control Room operator will actuate remote power operated valves to relieve the negative pressure condition and provide vacuum relief. The cause of the negative pressure within the containment will then be determined and corrected.

6.2.1.1.2 Design Features

The design features of the containment and internal structure are described in Sections 3.8.1 and 3.8.3, respectively.

The containment structure, subcompartments, and ESF systems are protected from loss of safety function due to dynamic effects that could occur following postulated accidents. The detailed criteria, locations, and description of protective devices are presented in Sections 3.5 and 3.6.

Codes and standards applied to the design, fabrication, and construction of the containment and internal structure are given in Section 3.8.1.2.

No special design features to mitigate the effects of external pressure loads are required. A Control Room low pressure alarm at 1 psi negative pressure has been incorporated in the containment functional design. However, inadvertent operation of the Containment Heat Removal Systems (CHRS) cannot possibly exceed the negative loading maximum allowable pressure differential. Refer to Section 6.2.1.1.1.3 for details.

The equipment and floor drainage system inside containment is described in Section 9.3.3.

Containment cooling and ventilation systems which maintain the containment and subcompartment atmospheres within prescribed pressure, temperature, and humidity during normal operation are described fully in Section 9.4.3.

6.2.1.1.3 Design Evaluation

Calculation of containment pressure and temperature transients was accomplished by use of the digital computer code, COCO. The analytical model was restricted to the containment volume and structure. Transient phenomena within the RCS affect containment conditions by means of convective mass and energy transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture was separated into two systems. The first system consists of the air-steam phase, while the second is the water phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each system, together with appropriate boundary conditions. As thermodynamic equations of state and conditions may vary during the transient, the equations have been derived for all possible cases of superheated or saturated steam, and subcooled or saturated water. Switching between states is handled automatically by the code. The following were the major assumptions made in the analysis:

a) Discharge mass and energy flow rates through the RCS break were established from the coolant blowdown and core thermal transient analysis (described in Section 6.2.1.3).

b) At the break point, the discharge flow separates into steam and water phases. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment.

c) Homogeneous mixing was assumed. The steam-air mix and the water phase have uniform properties. More specifically, thermal equilibrium between the air and steam was assumed. This does not imply thermal equilibrium between the steam-air mixture and the water phase.

d) Air is taken as an ideal gas, while compressed water and steam tables are employed for water and steam thermodynamic properties. During the transient, there is energy transfer from the steam-air and water systems to the internal structures and equipment within the shell.

Provision is made in the containment pressure transient analysis for heat transfer through, and heat storage in, both interior and exterior walls. Every wall is divided into a large number of nodes. For each node, a conservation of energy equation was expressed in finite difference from accounts for transient conduction into and out of the node and temperature rise of the node. Table 6.2.1-2 is a summary of the containment structural heat sinks used in the analysis.

The heat transfer coefficient to the containment surface was calculated by the code based primarily on the work of Tagami (Reference 6.2.2-1). From this work it was determined that the value of the heat transfer coefficient increases parabolically to peak value at the end of blowdown and then decreased exponentially to a stagnant heat transfer coefficient which is a function of steam to air weight ratio.

Tagami presents a plot of the maximum value h as a function of "coolant energy transfer speed," defined as:

$$\frac{\text{total coolant energy transferred into containment}}{\text{(containment vessel volume) (time interval to peak pressure)}}$$

From this the maximum of h for steel was calculated:

$$h_{max} = 75 \left(\frac{E}{t_p V}\right)^{0.60} \qquad (1)$$

h_{max} = maximum value of h (Btu/hr ft^2 ^{o}F)

t_p = time from start of accident to end of blowdown

V = containment volume (ft^3)

E = initial cooling energy (Btu)

The parabolic increase to the peak value was given by:

$$h_s = h_{max}\sqrt{\frac{t}{t_p}} \qquad 0 \leq t \leq t_p \qquad (2)$$

h_s = heat transfer coefficient for steel (Btu/hr ft^2 ^{o}F)

t = time from start of accident (sec)

the exponential decrease of the heat transfer coefficient was given by:

$$h_s = h_{stag} + (h_{max} - h_{stag})\, e^{-.05\,(t-t_p)} \qquad t > t_p \qquad (3)$$

6.2.1.4.2 Analysis assumptions. All cases were run with offsite power available. Loss of offsite power causes the reactor coolant pumps to trip, which decreases the primary - to - secondary heat transfer rate. Auxiliary feedwater was assumed to deliver at a maximum flowrate of 1325 gpm beginning at the start of the event. The omission of the AFW delay time maximizes the integrated mass release from the faulted steam generator. The break flow area was limited to 1.4 ft2 by the flow restrictor in the exit nozzle of the steam generators. The break flow is assumed to be manually terminated at 10 minutes when AFW flow to the faulted generator is isolated. Safety related equipment inside containment was conservatively represented using the heat absorbing components in CONTEMPT. A typical cable outside of conduit and a thin walled steel cylinder were modeled. Initial conditions used for the RCS and containment are provided in Table 6.2.1-4.

6.2.1.4.3 Analysis results. The most limiting containment pressure response, shown in Figure 6.2.1-14, resulted from the HZP, check valve failure case - with entrainment. This case released the largest integrated mass into containment. The pressure rise is very steep initially, then moderates as the break flowrate decreases. A peak pressure of 40.5 psig is reached at 172 seconds, which corresponds to the time that the initial steam generator inventory is depleted. The break flow beyond this time becomes equal to the AFW addition rate. The maximum MSLB containment pressure does not exceed the 42 psig design limit.

The most limiting temperature response results from the 102% power, check valve failure case - without entrainment. This case maximized the integrated energy deposited into the containment during the early portion of the event. The containment temperature, shown in Figure 6.2.1-15, also rises sharply early in the event. Blowdown fluid enthalpies of 1200 BTU/lbm allow the steam entering the containment to remain superheated. Cooling by the heat structures holds the atmosphere temperature to around 350°F. When the containment sprays actuate, the superheated steam is rapidly condensed, and the temperature quickly falls to the saturation temperature at the partial pressure of the steam. The equipment temperature, however, heats up more slowly than the atmosphere. Condensing steam on the equipment surface further hampers the temperature rise. After condensation ends, the temperature difference between the atmosphere and the surface of the equipment controls the heat up rate. Following spray actuation, the equipment equilibrates with the atmosphere temperature, which remains relatively constant for the remainder of the event. The maximum equipment temperature of 252.8°F remains below the equipment qualification limit of 264.7°F shown in Figure 3.11.1-1.

<u>6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of ECCS</u>. Section 6.2.1.1.3, Design Evaluation, presents the results of perturbations in mass and energy release to determine the effectiveness of ECCS for HBR 2.

<u>6.2.1.6 Testing and Inspection</u>. Tests performed on materials and special construction techniques are described in Section 3.8.1.6. Structural integrity tests of the completed Containment Building are described in Section 3.8.1.7. The in-service inspection program for associated ESF components is discussed in Section 3.9.

6.2.1.7 Instrumentation

Instrumentation has been provided to monitor containment atmospheric conditions:

Pressure	-5 to 126 psig
Radiation	10^{-3} - 10^{-9} μCi/cc
Hydrogen Concentration	0 to 10 percent
Water Level	Up to 600,000 gallons

Containment pressure indication will be used to distinguish between various incidents. Pressure taps reflect the effectiveness of the containment and cooling systems and other ESF. High pressure indicates high temperatures and reduced pressure indicates reduced temperatures. Indicators and alarms are provided in the Control Room to inform the operator of system status and to guide actions taken during recovery operations.

Detailed descriptions for all containment instrumentation, including diversity and redundancy considerations, are provided in Section 7.3.

TABLE 6.2.1-2

STRUCTURAL HEAT SINKS

HEAT SINK	MATERIAL	AREA (ft^2)	THICKNESS (ft)	DENSITY (lb/ft^3)	HEAT CAPACITY (Btu/lb ^oF)	CONDUCTIVITY (Btu/hr ft ^oF)
Containment cylinder	steel lined concrete	47,500	0.03	486	0.11	29.5
Containment dome	steel lined concrete	26,600	0.04	486	0.11	29.5
Containment floor	unlined concrete	29,500	1.,0.4,0.3	144	0.186	1.05
Refueling canal	lined concrete	4,140	0.02	486	0.11	29.5
Misc. concrete structure	unlined concrete	29,100	1.	144	0.186	1.05
Misc. steel structure	steel	48,300	0.05	486	0.11	29.5
Insulation	vinylcol	57,000	0.104	4.	0.75	0.037

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEMS

6.2.2.1 Design Basis 3

Adequate heat removal capability for the containment is provided by two separate, full capacity, ESF systems. These are the Containment Spray System (CSS), described in Section 6.2.2.2.1 and the Containment Air Recirculation Cooling System whose components operate as described in Section 6.2.2.2.2. These systems are of different engineering principles and serve as independent backups for each other.

These two ESF systems were designed to remove sufficient heat from the reactor containment, following the initial LOCA containment pressure transient, to keep the containment pressure from exceeding the design pressure.

Any of the following combinations of equipment will provide sufficient heat removal capability to maintain the post-accident containment pressure below the design value, assuming that the core residual heat is released to the containment as steam.

a) All four containment cooling units

b) Both containment spray pumps, and

c) Two of the four containment cooling units and one containment spray pump.

Details of the normal and emergency power sources for these ESF systems are presented in the discussion of the Electrical System, Section 8.

6.2.2.1.1 Containment Spray System

The primary purpose of the CSS is to spray cool water into the containment atmosphere when appropriate in the event of a LOCA and thereby ensure that containment pressure does not exceed its design value which is 42 psig at 263°F (100 percent RH). This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Pressure and temperature transients for LOCA are presented in Section 6.2.1.1.1.1. Although the water in the core after a LOCA is quickly subcooled by the SIS, the CSS design is based on the conservative assumption that the core residual heat is released to the containment as steam.

The CSS was designed to spray at least 2322 gpm of borated water into the Containment Building whenever the coincidence of two sets of two out of three (Hi-Hi) containment pressure signals occurs or a manual signal is given. Either of two subsystems containing a pump and associated valving and spray headers is independently capable of delivering one-half of this flow, or, 1161 gpm.

The design basis was to provide sufficient heat removal capability to maintain the post-accident containment pressure below the design pressure, assuming that the core residual heat is released to the containment as steam. This requires a heat removal capacity of the subsystem, with either pump operating, at least equivalent to two fan-coolers heat removal capability at the containment design conditions.

A second purpose served by the CSS is to remove elemental iodine from the containment atmosphere should it be released in the event of a LOCA (refer to Section 6.5.2). The analysis showing the systems ability to limit offsite thyroid dose to within 10CFR100 limits after a hypothetical LOCA is presented in Section 15.

The spray system was designed to operate over an extended time period, following a primary coolant system failure as required to restore and maintain containment conditions at near atmospheric pressure. It has the capability of reducing the containment post-accident pressure and consequent containment leakage taking into account any reduction due to single failures of active components.

Portions of other systems which share functions and become part of the containment cooling system when required are designed to meet the criteria of this section. Any single failure of active components in such systems does not degrade the heat removal capability of containment cooling.

Those portions of the spray system located outside of the containment which are designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment meet the following requirements:

a) Adequate shielding to maintain radiation levels within the guidelines of 10CFR100 (Section 11.2)

b) Collection of discharges from pressure relieving devices into closed systems, and

c) Means to limit radioactivity leakage to the environs, consistent with guidelines set forth in 10CFR100.

System active components are redundant. System piping located within the containment is redundant and separable in arrangement unless fully protected from damage which may follow any primary coolant system failure.

System isolation valves relied upon to operate for containment cooling are redundant, with automatic actuation or manual actuation.

All portions of the system located within containment were designed to withstand, without loss of functional performance, the post-accident containment environment and operate without benefit of maintenance for the duration of time to restore and maintain containment conditions at near atmospheric pressure.

6.2.2.1.2 Containment Air Recirculation Cooling System

The Containment Air Recirculation Cooling System was designed to recirculate and cool the containment atmosphere in the event of a LOCA and thereby ensure that the containment pressure cannot exceed its design value of 42 psig at 263°F (100 percent relative humidity). Although the water in the core after a LOCA is quickly subcooled by the SIS, the Containment Air Recirculation Cooling System was designed on the conservative assumption that the core residual heat is released to the containment as steam. The fans and cooling coils continue to remove heat after the LOCA and reduce the containment pressure close to atmospheric within the first 24 hr. | 8

The following objectives are met to provide the ESF functions:

a) Each of the four fan-cooler units is capable of transferring heat at the rate of 11,100 Btu/sec from the containment atmosphere at the post-accident design conditions, i.e., a saturated air-steam mixture at 42 psig and 263°F. This heat transfer rate was that assigned to the fan-cooler units in the analysis of containment and related heat removal system capability in Section 6.2.2.3.2. | 8

The establishment of basic heat transfer design parameters for the cooling coils of the fan-cooler units, and the calculation by computer of the overall heat transfer capacity are discussed in Section 6.2.2.3.2. Among the topics covered are selection of the tube side fouling factor, effect of air side pressure drop, effect of moisture entrainment in the air-steam mixture entering the fan-coolers, and calculation of the various air side to water side heat transfer resistances.

b) In removing heat at the design basis rate, the coils are capable of discharging the resulting condensate without impairing the flow capacity of the unit and without raising the exit temperature of the service water to the boiling point. Since condensation of water from the air-steam mixture is the principal mechanism for removal of heat from the post-accident containment atmosphere by the cooling coils, the coil fins will operate as wetted surfaces under these conditions. Entrained water droplets added to the air-steam mixture, such as by operation of the containment spray system, will therefore have essentially no effect on the heat removal capability of the coils.

In addition to the above design bases, the Containment Air Recirculation Cooling System was designed to possess sufficient margin to withstand an over-rated condition of 60 psig and 286°F for one hour without loss of operability. No specific criteria for heat removal capability are applied at the over-rated condition. The equipment was designed to operate at the post-accident conditions at 42 psig and 263°F for three hours, followed by operation in an air-steam atmosphere at 20 psig, 219°F for an additional 21 hr. The equipment design will permit subsequent operation in an air-steam atmosphere at 5 psig, 152°F for an indefinite period. | 8

All components are capable of withstanding or are protected from differential pressures which may occur during the rapid pressure rise to 42 psig in ten seconds.

Portions of other systems which share functions and become part of this containment cooling system when required were designed to meet the criteria of this section. Neither a single active component failure in such systems during the injection phase nor an active or passive failure during the recirculation phase will degrade the heat removal capability of containment cooling.

Where portions of these systems are located outside of containment, the following features were incorporated in the design for operation under post-accident conditions:

a) Means for isolation of any section, and

b) Means to detect and control radioactivity leakage into the environs, to the limits consistent with guidelines set forth in 10CFR100.

Design provisions were made to the extent practical to facilitate access for periodic visual inspection of all important components of the Containment Air Recirculation Cooling System.

The Containment Air Recirculation Cooling System was designed to the extent practical so that the components can be tested periodically, and after any component maintenance, for operability and functional performance.

6.2.2.2 System Design

6.2.2.2.1 Containment Spray System

Adequate containment cooling and iodine removal are provided by the CSS shown in Figure 6.2.2-1 whose components operate in sequential modes. These modes are:

a) Spray from the refueling water storage tank into the entire containment atmosphere using the containment spray pumps. During this mode, the contents of the spray additive tank (sodium hydroxide) are mixed into the spray stream to provide adequate iodine removal from the containment atmosphere by a washing action.

b) Recirculation of water from the containment sump is provided by the diversion of a portion of the recirculation flow from the discharge of the residual heat removal (RHR) heat exchangers to the suction of the spray pumps after injection from the refueling water storage tank has been terminated.

The principal components of the CSS which provides containment cooling and iodine removal following a LOCA consist of two pumps, one spray additive tank, spray ring headers and nozzles, and the necessary piping and valves. The containment spray pumps and the spray additive tank are located in the Auxiliary Building and the spray pumps take suction directly from the refueling water storage tank.

The CSS also utilizes the two RHR pumps, two residual heat exchangers, and associated valves and piping of the SIS for the long term recirculation phase of containment cooling and iodine removal.

The spray system will be actuated by the coincidence of two sets of two out of three (Hi-Hi) containment pressure signals. This starting signal will start the pumps and open the discharge valves to the spray header and the valves associated with the spray additive tank. If required, the operator can manually actuate the entire system from the Control Room and, periodically, the operator will actuate system components to demonstrate operability.

The system design conditions were selected to be compatible with the design conditions for the low pressure injection system since both of these systems share the same suction line.

Recirculation Phase - After the injection operation it is expected that spray flow could be discontinued while maintaining containment pressure reduction with the containment fan cooler units, and returning all of the recirculated water to the core. In this mode the bulk of the core residual heat is transferred directly to the sump by the spilled coolant to be eventually dissipated through the residual heat exchanger once the sump water becomes heated. The heat removal capacity of two of the four fan coolers is sufficient to remove the corresponding energy addition to the vapor space resulting from steam boil off from the core assuming flow into the core from one RHR pump at the beginning of recirculation without exceeding containment design pressure; hence, it is not expected that continued spray operation would be required for containment cooling. If, for any reason, the containment pressure should be observed to increase recirculation spray flow may be initiated. The operator can direct part of the discharge flow from the residual heat exchangers to the suction of the spray pumps. With this mode of operation, core cooling can be maintained and containment pressure maintained below design even with no fan coolers operating.

There are two sump return lines which lead from the containment to the RHR pumps. Each line is located inside of a larger diameter guard pipe. The lines are separated by approximately 18 ft. The lines are designed to allow for 2 in. differential movement between the containment and pump chamber and are designed as Class I equipment.

The design of the ECCS Sumps are discussed in Section 6.3.2.2.2.

Recirculation may start with a water depth of 1.5 ft on the containment floor. This is equivalent to the amount of water in the primary systems plus 60 percent of the refueling water storage tank, or approximately 215,000 gallons of water at 263°F. The maximum inlet velocity between the upper baffle and the container floor, which is the smallest flow area in this design, is approximately 1 ft per sec.

Cooling Water

Component Cooling System - During the recirculation mode, the Component Cooling System is used to cool the recirculation fluid as it passes through the residual heat exchanger. This system is described in detail in Section 9.2.2.

One of the three component cooling pumps and one of the two component cooling heat exchangers provide the core and containment cooling function during recirculation.

Service Water System - The service water system is provided with redundant and independent loop headers and valves such that the two component cooling heat exchangers which are supplied with service water for cooling can have flow directed to them from the two independent headers. Two of the four service water pumps are required to operate during the recirculation phase. This system is described in detail in Section 9.2.1.

Change-Over from Injection Phase to Recirculation Phase - The sequence, from the time of the SI signal, for the change-over from the injection to the recirculation is as follows:

a) First, sufficient water is delivered to provide the required net positive suction head (NPSH) of the RHR pumps to change to recirculation.

b) Second, the first low level alarm on the refueling water storage tank sounds. The operator, at this point, takes appropriate action to assure that sufficient NPSH exists for the operating pumps to run until the refueling water storage tank is nearly empty. This alarm also serves to alert the operator to prepare for switchover to the recirculation mode.

c) Finally the second low level alarm on the refueling water storage tank sounds. At this time, the operator performs the switchover operation.

The changeover from injection to recirculation is effected by the operator in the Control Room via a series of manual switching operations.

Components - Materials, code requirements, and construction techniques for associated components, piping, and structures of the CSS are described in Section 6.1.1.1.2.

6.2.2.2.2 Containment Air Recirculation Cooling System. A schematic arrangement of a Containment Air Recirculation Cooling System is shown in Figure 6.2.2-2.

The air recirculation system consists of four air handling units, each including rack for roughing filters, air operated inlet louvers, cooling coils, fan and drive motor, duct distribution system, instrumentation, and controls. The units are located on the operating floor adjacent to the containment wall. The roughing filters are removed during reactor operation. The filter pads should be replaced during outage conditions when activities within the containment may stir up dust which might deposit on the coils.

Each fan is designed to supply at least 65,000 cfm at design basis accident (DBA) conditions at approximately 20 in. s.p., 263°F, 0.162 lb/ft^3 density. The fans are direct driven centrifugal type. Cooling coils are plate fin-tube type. Each air handling unit is capable of removing 40 x 10^6 Btu/hr from the containment atmosphere under DBA conditions. 750 gpm of service (cooling) water is supplied to each unit. The design maximum cooling water inlet temperature is 95°F which results in a maximum outlet temperature of 195°F under DBA conditions.

A gravity operated damper in the fan discharge isolates any inactive air handling unit from the duct distribution system. The damper opens automatically when the fan is started. Duct work distributes the cooled air to the various containment compartments and areas. The flow sequence through each air handling unit is as follows: roughing filter, inlet damper, cooling coils, fan, outlet louver, and discharge header for normal flow. For accident flow path, the inlet damper is closed and the flow enters the unit through a butterfly valve to the cooling coils.

Individual system components and their supports meet the requirement for Class I (Seismic) structures (Section 3.7) and each component is mounted to isolate it from fan vibration.

<u>Actuation Provisions</u> - The inlet dampers used to route air flow through the operating units have only two positions, full open or full closed. These louvers are air operated and spring loaded. Upon loss of control signal or control air, the spring actuates the louver to the closed position (fail-safe operation). The inlet butterfly valves used to route air flow through the operating units for accident conditions have only two positions, full close or full open. These valves are air operated and spring loaded. Upon loss of control signal or control air, the spring actuates the valve in the open position (fail-safe operation).

Redundant electrically operated three-way solenoid valves are used at each damper and butterfly valve to control the instrument air supply (control air). These valves are arranged so that failure of a single solenoid valve to respond to the accident signal will not prevent actuation of the louver or valve to the accident position (fail-safe operation). A high containment pressure signal automatically actuates the SI safety feature sequence which trips any closed inlet butterfly valves to the open position, trips any open inlet dampers to the closed position, and starts any stopped fan cooler unit.

The fans are part of the ESF and either all four, or at least two of four fans will start after an accident, depending on the availability of emergency power (refer to Section 8.3).

Overload protection for the fan motors is provided at the switchgear by overcurrent trip devices in the motor feeder breakers. The breakers can be operated from the Control Room and can be reclosed from the Control Room following a motor overload trip.

Flow switches in the system, operating both normally and post-accident, indicate whether air is circulating in accordance with the design arrangement. Low flow alarms are provided in the Control Room.

Temperature elements (RTD's) are installed on the inlet and outlet (air side) of each fan cooler unit to provide data for monitoring cooling performance.

<u>Flow Distribution and Flow Characteristics</u> - The location of the distribution ductwork outlets, with reference to the location of the air handling unit returns inlets, ensures that the air will be directed to all areas requiring ventilation before returning to the units. The distribution system is represented schematically by the Ventilation Systems Flow Diagram, Figure 9.4.1-2.

The air discharged inside the reactor coolant loop shield walls will circulate and rise above the operating floor through openings around the SG and return to the air handling unit inlets. The temperature of this air will be essentially the ambient existing in the containment vessel.

The steam-air mixture from the containment entering the fan-cooler units during the accident will be at approximately 263°F and have a density of 0.162 lb per cubic foot. Part of the water vapor will condense on the cooling coils, and the air leaving the coils will be saturated at a temperature slightly below 263°F.

The fluid will remain in this condition as it flows into the fan, but will pick up some sensible heat from the fan and fan motor before flowing into the distribution header. This sensible heat will increase the dry-bulb temperature slightly above 263°F and will decrease the relative humidity slightly below 100 percent.

<u>Cooling Water for the Fan Cooler Units</u> - The cooling water requirements for all four fan cooling units during a major loss of primary coolant accident and recovery are supplied by two of the four service water pumps and one of the two service water booster pumps. The service water system is described in Section 9.2.1.

The cooling water discharges from the cooling coils to the discharge canal and is monitored for radioactivity by routing a small bypass flow from each unit through a common radiation monitor. Upon indication of radioactivity in the effluent, each cooler discharge line is monitored individually to locate the defective cooling coil. The service water system is pressurized inside the containment, but the pressure in certain portions will be below the containment design pressure of 42 psig. However, since the cooling coils and service water lines form a closed system inside the containment, no contaminated leakage is expected into these units. Isolation valves on the inlet and discharge of each fan cooler are located outside the containment and may be used to isolate individual fan cooler units in the event that radioactivity is detected by the radiation monitor.

Local flow and temperature indication is provided outside containment for service water flow from each cooling unit.

Local temperature elements (RTD's) on the water inlets and outlets and a local pressure differential indicator and pressure gauges are installed on each fan cooler unit to provide data for monitoring cooling coil performance.

Environmental Protection - All system control and instrumentation devices required for containment accident conditions are located to minimize the danger of control loss due to missile damage. Differential pressure switches across the fans indicate whether air is circulating in accordance with the design arrangement. Abnormal flow alarms are provided in the Control Room.

All fan parts, damper shaft and blade seating surfaces, and ducts in contact with the containment fluid are protected against corrosion. The fan motor enclosures, electrical insulation, and bearings are designed for operation during accident conditions.

All of the air handling units are located outside the shield wall (which serves as a missile barrier) on the operating floor adjacent to the containment wall. The distribution header and service water cooling piping are also located outside the shield. This arrangement provides missile protection for all components.

Components

Roughing Filters - During reactor operation, the roughing filters are removed to reduce the amount of fibrous material in the containment. During outage conditions where activities in the containment may stir-up dust, the filter pads are installed, as required.

The roughing filter bank was designed for horizontal air flow, and can contain 54 individual filters, each of which is 2 ft sq by 2 in. thick. The filters are of fire resistance construction, with the media composed of a glass fiber mat reinforced with stainless steel wire cloth.

These filters when installed are in series with the inlet damper in the air inlet path.

Fan-Motor Units - The four containment cooling fans are of centrifugal, non-overloading, direct drive type.

Each fan was designed for a minimum flow rate of 65,000 cfm when operating against the system resistance of approximately 20 in. s.p. existing during the DBA conditions (0.162 lb/ft^3 density, a containment pressure of 42 psig, and temperature of 263°F). Each fan is also capable of circulating a minimum of 65,000 cfm at the containment over-rated condition.

The reactor containment fan cooler (RCFC) motors are Westinghouse, totally enclosed water cooled, 350 horsepower, induction type, 3 phase, 60 cycle, 720 rpm, Westinghouse, Thermalastic 440 volt with ample insulation margin. Significant motor details are as follows:

a) Insulation - Class F (NEMA rated total temperature 155°C) Thermalastic. Basic structure high turn to turn and coil to ground insulation. It was impregnated and coated to give a homogeneous insulation system which is highly impervious to moisture. Internal leads and the terminal box-motor interconnection are given special design consideration to assure that the level of insulation matches or exceeds that of the basic motor system. At incident ambient and load conditions (263°F and 305 HP) the motor insulation hot spot temperature is not expected to exceed 107°C.

b) Heat Exchanger - An air to water heat exchanger is connected to the motor to form an entirely enclosed cooling system. Air movement is through the heat exchanger and back to the motor. Two vent valves permit incident ambient (increasing containment pressure) to enter the motor air system so the bearings will not be subjected to differential pressure. It also assures pressure equalization as the containment pressure is reduced by the containment cooling systems. Water connections are welded throughout, and supply and discharge are common with the containment cooling water system, i.e., supplied from the service water header. The drain will be piped to the containment fan cooler drain system.

c) Bearings - The motors are equipped with high temperature grease lubricated ball bearings as would be required if the bearings were subjected to incident ambient temperatures.

d) Conduit (Connection) Box - The motor leads are brought out of the frame through a seal and into a cast iron, sealed explosion proof type of conduit box.

Cooling Coils - The coils are fabricated of copper plate fins vertically oriented on stainless steel tubes. The heat removal capability of the cooling coils is 40 x 10^6 Btu/hr per air handling unit at saturation conditions (263°F, 42 psig).

The design internal pressure of the coil is 150 psig at 300°F and the coils can withstand an external pressure of 60 psig at a temperature of 298°F without damage.

Local flow and temperature indication of service water are provided at each air handling unit. Alarms indicating abnormal service water flow and radioactivity are provided in the Control Room.

The coils are provided with drain pans and drain piping to prevent flooding during accident conditions. This condensate is drained to the containment sump.

Ducting - The ducts are designed to withstand the sudden release of RCS energy and energy from associated chemical reactions without failure due to shock or pressure waves by incorporation of pressure-relieving devices along the ducts which open at slight overpressure, approximately 1.0 psi. The ducts are designed and supported to withstand thermal expansion during an accident.

The structural capability of the ductwork was analyzed to determine the maximum pressure differential that can be maintained across the ductwork without exceeding the maximum allowable stress of the containment air recirculation ductwork. In performing this analysis, the sheet metal duct walls were considered as membranes and the reinforcing members were considered as frame structures receiving its load from the sheet metal duct walls.

The results of the analysis of the reinforcing members and the duct walls indicate that the maximum allowable stress of 15,000 psi would be reached when the pressure differential across the containment air recirculation ductwork is 0.40 psi. The maximum allowable stress is well below the yield stress of 36,000 psi.

In order to ensure that the rapid pressurization of the containment following a LOCA would not interfere with the proper operation of the containment air recirculation system, pressure equalizing devices have been installed.

A computer program has been developed to calculate the pressure differential as a function of time across the walls of the duct and to determine the required relief panel areas and separation distances. The program assumes:

a) The ideal gas law for an isothermal process is used to calculate the pressure within the duct at any time

b) Air flows from the containment into the duct at a rate dependent upon the pressure differential, area of the panel and discharge coefficient of the panel

c) The panel area opens linearly with time after its set differential opening pressure is reached, and

d) The containment pressure transient can be approximated by several straight lines of different slope.

The duct was conservatively considered to be made up of several independent compartments whereby interflow between adjacent compartments of the duct is prohibited. The length of each compartment is the distance between adjacent panels. The differential pressures across the walls of the duct for different compartmental volumes and relief panel areas are calculated for the following conditions:

a) The relief panels will not open until a set pressure differential of 0.01 psig is reached.

b) A containment pressurization rate of 17.3 psi/sec exists up until 0.05 sec after the LOCA, and 15 psi/sec thereafter. The initial pressurization rate of 17.3 psi/sec is approximately 20 percent higher than the greatest pressurization rate occurring as a result of the double-ended pipe rupture. The 0.05 sec time duration of the initial pressurization rate is 100 percent higher than the actual duration in the double-ended pipe rupture. The conservative representation of the containment pressure transient assures conservatism of the calculated pressure differential across the duct walls.

The results of the analysis indicate that the greatest differential pressure exists across the duct walls of the compartment with the largest ratio of compartment volume to relief panel area servicing that compartment. The pressure differential across the duct walls have been calculated as a function of time for several panel areas, separation distances, and panel opening times and the design case is shown on Figures 6.2.2-3 through 6.2.2-5.

The results of the analysis were used to determine the number, separation distance, and size of the pressure relief panels to be installed. The separation distance between panels has been chosen to be 10 ft for the 72 in. x 72 in. duct.

The smaller ducts have pressure relief panels of either 24 in. x 24 in. or 24 in. x 12 in. size and are separated by distances of either 10 or 16 ft. The analysis has shown that these ducts would be subjected to lower pressure differentials than the 72 in. x 72 in. duct serviced by the 24 in. x 24 in. relief panel.

Each pressure relief panel has four louver blades interconnected by a linkage which is connected to an adjustable counterweight mechanism. The counterweight has been set in such a position that the panels open at a pressure differential of 0.01 psi.

The differential pressure produced across the ductwork within the crane wall has been analyzed by the same method used for the ductwork within the containment. The duct, which is 25 ft long and open at its end, has a cross sectional area of 5.5 sq ft. For purposes of this analysis this area served as the relief panel area. The pressurization rate within the compartments of the crane wall is considerably higher than the containment pressurization rate because of the much smaller free volume of the crane wall compartments. The maximum differential pressure calculated for this ductwork is 2.0 psi. This is based on a conservatively high value of crane wall pressurization rate. This segment of the duct will be reinforced so that the air recirculation capability within the crane wall will not be impaired.

When flanged joints are used, joints are provided with gaskets suitable for temperatures to 300°F.

Ducts are constructed of corrosion resistant material.

Air Operated Dampers - Air operator multi-bladed dampers are installed in the air inlet to each air handling unit. These dampers are used to route air flow through units that are operating, and also to help isolate idle units from the main distribution header. They have only two positions, fully open or fully closed; the damper operation is spring loaded to fail to the closed position required for post-accident operation. Their design permits only nominal air leakage when closed.

Further information on the components of the Containment Air Recirculation Cooling System is given in Section 6.1.1.1.3.

6.2.2.3 Design Evaluation

6.2.2.3.1 Containment Spray System

During the injection phase following the maximum LOCA (i.e., during the time that the containment spray pumps take their suction from the refueling water storage tank) this system provides the design heat removal capacity for the containment. After the injection phase, each train of the recirculation system provides sufficient cooled recirculated water to keep the core flooded as well as providing, if required, sufficient flow to the suction of the containment spray pumps to maintain the containment pressure below the design value. This applies for all reactor coolant pipe sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Only one pumping train and one heat exchanger are required to operate

V = velocity

ρ = droplet density

ρ_m = steam-air mixture density

System Response - The starting sequence of the containment spray pumps and their related emergency power equipment was designed so that delivery of the minimum required flow is reached within 60 sec (see Section 8.3) which is the delay assumed for the starting of containment cooling (Section 6.2.1.1).

Single Failure Analysis - A failure analysis has been made on all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2.2-1.

The analysis of the LOCA presented in Section 6.2.1.1.3 reflects the single failure analysis.

Reliance on Interconnected Systems - The CSS initially operates independently of other ESF following a LOCA. It provides backup cooling to the Containment Air Recirculation Cooling. For extended operation in the recirculation mode, water is supplied through the RHR pumps. Spray pump cooling is supplied from the component cooling loop.

During the recirculation phase some of the flow leaving the residual heat exchangers may be bled off and sent to the suction of either the containment spray pumps or the high head SI pumps. Sufficient flow instrumentation is provided so that the operator can perform appropriate flow adjustments with the remote throttle valves in the flow path, as shown in Figure 6.2.2-1.

Shared Function Evaluation - Table 6.2.2-2 is an evaluation of the main components which have been discussed previously and a brief description of how each component functions during normal operation and during the accident.

6.2.2.3.2 Containment Air Recirculation Cooling System

The Containment Air Recirculation Cooling System provides the design heat removal capacity for the containment following a LOCA assuming that the core residual heat is released to the containment as steam. The system accomplishes this by continuously recirculating the air-steam mixture through coiling coils to transfer heat from containment to service water.

The performance of the Containment Recirculation Cooling System in pressure reduction is discussed below.

Air-Recirculation Fan-Coolers Heat Removal Capability Model - The ability of the containment air recirculation coolers to function properly in the accident environment was demonstrated by the Westinghouse computer code "HECO." The code determined the plate-fin cooling coil heat removal rate when operating in a saturated steam-air mixture.

In the code, a mass flow rate of cooling water was first established.

This determines the tube inside film coefficient. Next, the resistance to heat transfer between the cooling water and the outside of the fin collars was computed; including inside film coefficient, fouling factor, tube radial conduction, fin-collar interface resistance, and conduction across the fin collars.

A fouling factor of .001 hr-ft^2-^{o}F/Btu, under both normal and DBA conditions, was assumed for cooling coil design purposes. This value was conventionally used in sizing heat exchangers cooled by lake water at 125^{o}F or less (Reference 6.2.2-8), and is considered conservative for this application. Computer analysis of the coils selected shows that the required post-accident heat removal rate can be achieved with a fouling factor approaching .002 hr-ft^2-^{o}F/Btu.

The analysis becomes iterative. Assuming an overall heat transfer rate Q_{tot}, the temperature at the outside of the fin collars was determined from Q_{tot} and the sum of the resistances cited above.

A second iterative procedure was then established. The variable whose value was assumed is the effective film coefficient between the fins and the gas stream, which involves the effect of convective heat transfer and mass transfer. With this value of $h_{effective}$, fin efficiency and the fin temperature distribution were determined. It was assumed that a condensate film exists on the vertical fins. An analysis was performed which relates this film thickness to the rate of removal due to gravity and shear, and the rate of addition of condensate by mass transfer from the bulk gas. In the process, from an energy balance, the temperature of the interface between the bulk gas and the condensate was determined; this was necessary for determining the mass transfer rate from the gas. When the thickness of the condensate film was known, the value of the assumed $h_{effective}$ was checked from the relation h_{eff} = K water/ δ_{film}. If the assumed and computed values were not the same, a new guess was made and calculations repeated until the assumed and computed values were equal.

When this occurred, the heat transfer rate from the fins and fin collar was computed, using the standard equations for fin and fin collar heat transfer and the values of $h_{effective}$ and film-bulk gas interface temperature. If this value was not the same as Q_{tot}, initially assumed in order to determine fin collar temperature, the whole analysis was repeated with a new estimate of Q_{tot}. When, finally, the heat transfer rate to the cooling water from the fin collar equaled the resulting computed rate to the fin collar and fins from the gas, the effect of this heat transfer rate on the cooling water was computed. The water exit temperature was established and this value was used as the inlet temperature for the next heat exchanger pass. Also, the effect of convective heat transfer and condensate mass transfer were determined relative to the gas composition and thermodynamic state. The updated gas state was used as inlet conditions for the next pass. The process was now repeated for the second, third etc., passes until the gas exits the heat exchanger.

The mass transfer coefficients used in the "HECO" code were derived from analyses and reports of experimental data contained in References 6.2.2-6, 6.2.2-7, and 6.2.2-8. From Reference 6.2.2-6, the mass flow rate of condensate is defined by:

$$\dot{m} = \bar{h}_D (\rho_{sg} - \rho_{sw}) \qquad (8)$$

Nomenclature is defined at the end of the section.

From Reference 6.2.2-6, pp. 471-473, experimental data for mass and heat transfer are correlated by the expression.

$$\frac{\bar{h}_D}{u_s} (Sc)^{-2/3} = \bar{S}t \ (Pr)^{-2/3} \tag{9}$$

as shown in Figure 16-10 of Reference 6.2.2-1. Thus

$$\bar{h}_D = u_s \cdot St\left(\frac{Sc}{Pr}\right)^{2/3} \tag{10}$$

$$\bar{h}_D = \frac{u_s \cdot h}{\rho C \ u_s}\left(\frac{Sc}{Pr}\right)^{2/3}$$

As Reference 6.2.2-6 points out, for large partial pressures of the condensing components, Equation (10) must be corrected by a factor P_t/P_{am}. Thus h_D is defined by

$$\bar{h}_D = \frac{h}{\rho C} \ \frac{P_t}{P_{am}}\left(\frac{Sc}{Pr}\right)^{2/3} \tag{11}$$

This is essentially the same result as reported by Reference 6.2.2-7, pg. 343 and Reference 6.2.2-9.

Reference 6.2.2-6 states that experiments show Equation (9) to be valid when the Schmidt number does not differ greatly from 1.0. Equations (9) and (11) are combined to give the mass transfer rate, which is

$$\dot{m} = \frac{h}{\rho C} \ \frac{P_t}{P_{am}}\left(\frac{Sc}{Pr}\right)^{2/3} (\rho_{sg} - \rho_{sw}) \tag{12}$$

An approximation was made in assuming that $(\frac{Sc}{Pr})^{2/3} \cong 1.0$ thus the local mass transfer rate was computed from

$$\dot{m} = \frac{h}{\rho C} \ \frac{P_t}{P_{am}} (\rho_{sg} - \rho_{sw}) \tag{13}$$

The heat transfer rate due to condensation was computed from

$$q_1 = \frac{\dot{m} \ \lambda h P}{\rho C P_{am} \ t} \ (\rho_{sg} - \rho_{sw}) \tag{14}$$

where: ρ_{sg} is evaluated at the local bulk gas temperature

ρ_{sw} is evaluated at the local gas-condensate interface temperature

λ is evaluated at the local gas-condensate interface temperature

P and C are evaluated at the local bulk gas temperature

The heat transfer coefficient, h, was determined from experiments on W plate-fin coils which are the same geometry as are used in this application.

The heat transfer rate, locally, was computed from

$$q_2 = h\ (T_g - T_i) \tag{15}$$

The basis for selecting these values was that the authorities cited as references have shown, through analyses and through cited experiments, that the methods used are accurate.

The air ride pressure drop across the cooling coils under DBA condition was estimated to be approximately 1.9 in. of water or .07 psi. This will have negligible effect on the heat removal capability of the cooling coils.

The pressure of noncondensible gases were taken into consideration by virtue of the fact that the theory behind the analyses assumed that the condensible vapor must diffuse through a noncondensible gas.

Application of this method resulted in the fan-cooler heat removal rate per fan presented in Figure 6.2.2-6.

Nomenclature

$\dot{m}$ = mass flow rate of condensate, lbm/hr-ft^2

$\bar{h}_D$ = mass transfer coefficient, ft/hr

ρ_{sg} = density of saturated steam at local bulk gas temperature, lbm/ft^3

ρ_{sw} = density of saturated steam at local condensate-gas interface temperature, lbm/ft^3

u_s = free steam gas velocity, ft/min

Sc = Schmidt number, M/pD, dimensionless

μ = viscosity of bulk gas, lbm/ft-hr

ρ = bulk gas density, lbm/ft^3

D = gas-air diffusion coefficient, $\frac{ft^2}{hr}$

St = Stanton number, h/pcu_s, dimensionless

h = convective heat transfer coefficient, Btu/hr-ft^2-^{o}F

C = specific heat of bulk gas, Btu/lbm-°F

P_r = Prandtl number, $\mu c/k$, dimensionless

k = thermal conductivity of bulk gas, Btu/hr-ft-°F

P_t = total gas pressure, lbf/ft^2

P_{am} = air log-mean $\dfrac{P_{aw} - P_{ag}}{\text{lm} \dfrac{P_{aw}}{P_{ag}}}$, lbf/ft^2

P_{aw} = partial pressure of air at the local gas-condensate interface, lbf/ft^2

P_{ag} = partial pressure of air at the local bulk gas temperature, lbf/ft^2

λ = latent heat of vaporization (or condensation) at the local gas-condensate interface temperature, Btu/lbm

q_1 = local heat transfer rate due to condensation, Btu/hr-ft^2

q_2 = local heat transfer rate due to convection, Btu/hr-ft^2

T_g = local bulk gas temperature, °F

T_i = local gas-condensate interface temperature, °F

<u>System Response</u> - The starting sequence of the containment cooling fans and the related emergency power equipment is designed so that delivery of the minimum required air flow and cooling water flow is reached in 46 sec as shown in Section 8.3. In the analysis of the containment pressure transient, Section 6.2.1.1.3, a delay time of 60 sec was assumed for the initiation of containment cooling.

<u>Single Failure Analysis</u> - A failure analysis has been made on all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.2.2-3.

<u>Reliance on Interconnected Systems</u> - The Containment Air Recirculation Cooling System is dependent on the operation of the electrical and service water systems. Cooling water to the coils is supplied from the service water system. Four service water pumps and two service water booster pumps are provided, only two and one of which respectively are required to operate during the post-accident period.

<u>Shared Function Evaluation</u> - Table 6.2.2-4 is an evaluation of the main components which have been discussed previously and a brief description of how each component functions during normal operation and during the accident.

Reliability Evaluation of the Fan Cooler Motor - The basic design of the motor and heat exchanger as described herein is such that the incident environment is prevented, in any major sense, from entering the motor winding or when entering in a very limited amount (equalizing motor interior pressure) the incoming atmosphere is directed to the heat exchanger coils where moisture is condensed out. If some quantity of moisture should pass through the coil, the changed motor interior environment would "clean up" in that interior air continually recirculates through the heat exchanger.

It should be noted that the motor insulation hot spot temperature is not expected to exceed 107°C even under incident conditions. Considering that rated life could be expected with a continuous hot spot of 155°C, using the industry accepted 10 degree rule (life is doubled for every 10°C drop in temperature), the life expectancy would exceed by many times the expected life of motors applied elsewhere in the plant, even if the incident temperatures were experienced on a continuous basis.

During the lifetime of the plant, these motors perform the normal heat removal service and, as such, are only loaded to approximately 120-150 HP.

Motor insulation hot spot is expected to be from 15 to 20°C below design level or approximately 90°C with cooling water at maximum summer temperature. In summary, practically none of the insulation life due to thermal aging is used up in normal service and, at incident loading, the motor insulation should have greater than normal life. Incident high temperature, moisture, and load conditions last only a few hours.

The bearings are designed to perform in the incident ambient temperature conditions. However, it should be noted that the interior bearing housing details are cooled by the heat exchanger. It is expected that bearing temperatures would not exceed 125°C by any significant amount, even under incident conditions.

The insulation has high resistance to moisture, and tests performed indicate the insulation system would survive the incident ambient moisture condition without failure. The heat exchanger system for preventing moisture from reaching the winding therefore provides a design margin. In addition, it should be noted that at the time of the postulated incident, the load on the fan motor would increase, internal motor temperature would increase, and would, therefore, tend to drive any moisture present out of the windings. Additionally, the motors are furnished with insulation margin beyond the operating voltage of 440 V.

Following the incident rise in pressure, a rather slow rise as far as equalizing pressure in the small volumes of the motor-heat exchanger is concerned, it is not expected that there will be significant mixing of the motor (closed system) environment and the containment ambient.

Also all hardware used in connection with the motor and heat exchanger is corrosion resistant.

The heat exchanger has been designed using a very conservative fouling factor. However, if surface fouling reduces the capability of the heat exchanger by one-half, the motor would still have a normal life expectancy, even under incident conditions.

6.2.2.4 <u>Tests and Inspection</u>.

6.2.2.4.1 Containment Spray System. All components of the CSS can be inspected periodically to demonstrate system readiness.

The pressure containing systems are inspected for leaks from pumps seals, valves packing, flanged joints, and safety valves during system testing. During the operational testing of the containment spray pumps, the portions of the system subjected to pump pressure are inspected for leaks. The inservice inspection program for HBR 2, is discussed in Section 3.9.

<u>Component Testing</u>. - All active components in the CSS were tested both in pre-operational performance test in the manufacturer's shop and in-place testing after installation.

The containment spray pumps can be tested singly by opening the valves in the miniflow line. Each pump in turn can be started by operator action and checked for flow establishment. The spray injection valves can be tested with the pumps shut down.

The spray additive tank valves can be opened periodically for testing. The contents of the tank will be periodically sampled to determine that the proper solution is present.

Initially, the containment spray nozzle availability was tested by blowing smoke through the nozzles and observing the flow through the various nozzles in the containment.

During these tests the equipment was visually inspected for leaks. Leaking seals, packing, or flanges were tightened to eliminate the leak. Valves and pumps have been operated and inspected after any maintenance to ensure proper operation.

<u>System Testing</u>. - Permanent test lines for all containment spray loops were located so that the system, up to the isolation valves at the spray header, can be tested. These isolation valves can be checked separately.

The air test lines, for checking initially the spray nozzles, connect downstream of the isolation valves. Air flow through the nozzles is monitored by the use of hot air and infrared thermography.

During the initial pre-operational tests of the spray system, the flow bypass through the spray eductors was checked. This initial and all subsequent system tests were made with the spray additive tank isolation valves closed.

<u>Operational Sequence Testing</u>. - The functional test of the SIS described in Section 6.3.4 demonstrated proper transfer to the emergency DG power source in the event of loss of power. A test signal simulating the containment spray signal has been used to demonstrate operation of the spray system up to the isolation valves on the pump discharge.

6.2.2.4.2 Containment air recirculation cooling system. Access is available for visual inspection of the containment air recirculation system components including fans, cooling coils, louvers, and ductwork.

The service water pumps and booster pumps which supply the cooling units, are in operation on an essentially continuous schedule during plant operation, and no additional periodic tests are required. The roughing filters are removed from the air recirculation cooling units during reactor operation.

Component Testing - The roughing filters used in the containment fan cooler system will be installed only during outage conditions. The filters are subjected to standard manufacturer's efficiency and production tests prior to shipment.

Reactor Containment Fan Cooler Motor Unit Tests - The testing program has been completed on the effects of radiation on the WF-8AC "Thermalastic" (Westinghouse Electric Corporation Trademark) epoxy insulation system used in the reactor containment fan cooler motor. Tests description and results are presented in Reference 6.2.2-10.

Fan Cooler Motor Insulation Irradiation Testing - This testing program is an extension of the work reported in Reference 6.2.2-11.

Irradiation of form wound motor coil sections was accomplished up to exposure levels exceeding that calculated for the design basis LOCA. Three coil samples received the following treatment sequence: Irradiation, high-potential test, vibration test, high-potential test, and breakdown voltage test. Nine coil samples received an alternate treatment sequence: Thermal aging, high-potential test, irradiation, high-potential test, vibration test. (Six of nine coil samples), high-potential test and breakdown voltage test.

All coil samples passed the high potential tests. The breakdown voltage levels of all coils were well in excess of those required by the design, and clearly indicate that the reactor containment fan cooler motor insulation system will perform satisfactorily following exposure to the radiation levels calculated for the DBA.

Reactor Containment Fan Cooler Motor Lubricant Irradiation Testing - The lubricant used in the containment fan cooler motors is qualified for its applicable service. Testing documentation is located in the EQ Central File.

6

RCFC Cooling Coil Test Summary - In the event of a LOCA of a pressurized water reactor system, compressed water at thermodynamic conditions of approximately 600°F and 2250 psig would flash into the Containment Building. This condition causes the containment atmosphere to become a high pressure steam saturated environment, limited to a maximum pressure of 40 to 60 psig in most dry Containment Buildings. One of the active containment cooling systems employed

to remove energy from the atmosphere and reduce the containment pressure is the RCFC System. An integral part of this system are plate-finned cooling coils. These heat exchangers remove sensible heat during normal operation, but become condensers in the post-accident environment. Because there was limited experimental information available concerning the performance of plate-finned cooling coils operating in a condensing environment in the presence of a noncondensible (air), Westinghouse undertook a demonstration test to establish the validity of its selection procedure (Reference 6.2.2-12).

The test method was to subject a scaled coil to a parametric test. These parameters were: containment pressure (with corresponding steam density and temperature), air flow rate, cooling water flow rate, cooling water temperature, and entrained water content. Each parametric test condition was then used as input to the computer program used in coil selections. The results of the test and the computer program predictions were compared to establish the applicability.

In all cases considered, the measured heat transfer rate is greater than that predicted by the computer code predictions. The range of parameters variations was selected to be consistent with the design points of the RCFC coils contained in actual plants. It is apparent that for this specific type of heat exchanger, functioning in the range of environments tested, no moisture separator is needed to protect the coils from excessive waterlogging due to entrained spray droplets.

The extension of the test to full size units is merely an increase in component size and total flow quantities, but not a change in controlling parameters. It is concluded that the test demonstrates that the computer code used to select cooling coil design is valid in defining the heat removal rates of plate-finned tube cooling coil assemblies of RCFC Systems. Therefore, these test demonstrate that Westinghouse fan cooler designs which are selected by this computer program will perform as required in the post-accident containment environment.

The air operated louvers on each air handling unit can be operated periodically to assure continued operability. The degree of leak tightness of the assemblies will be established by test at the time of installation.

System Testing - Each fan cooling unit was tested after installation for proper flow and distribution through the duct distribution system. Three of the fan cooling units are used during normal operation. The fan not in use can be started from the Control Room to verify readiness.

Operational Sequence Testing - Periodic tests can be conducted to demonstrate proper transfer and sequencing of the fan motor supplies from the emergency DG in the event of loss of outside power as described in Section 6.3.4. These tests can be conducted at the same time as the DG are tested, as described in Section 8.3.

6.2.2.5 Instrumentation

The ESF Instrumentation System actuates (depending on the severity of the condition) the SIS, Containment Isolation, the Containment Air Recirculation Cooling System, and the CSS.

The ESF systems are actuated by the ESF actuation channels. Each coincidence network energizes an ESF actuation device that operates the associated ESF equipment, motor starters, and valve operators. The channels are designed to combine redundant sensors, and independent channel circuitry, coincident trip logic, and different parameter measurements so that a safe and reliable system is provided in which a single failure will not defeat the channel function. The action initiating sensors, bistables, and logic are shown in the figures included in the detailed ESF Instrumentation Description given in Section 7.3.

The ESF actuation circuits are designed on the same "de-energize to operate" principle as the reactor trip circuits with the exception of the containment spray actuation circuit which is energized to operate in order to avoid spray operation on inadvertent power failure.

The spray system will be actuated by the coincidence of two sets of two out of three (Hi-Hi) containment pressure signals. This starting signal will start the pumps and open the discharge valves to the spray header. The valves associated with the spray additive tank will be opened automatically.

The operator can manually actuate the entire system from the Control Room, and periodically, the operator will actuate system components to demonstrate operability.

The containment air recirculation coolers are normally in use during plant operation. These units are in the automatic sequence which actuates the ESF upon receiving the necessary signals indicating an accident condition, e.g., a high containment pressure signal automatically actuates the SI safety feature sequence which trips any closed inlet butterfly valves to the open position, trips any open inlet dampers to the closed position and starts any stopped fan cooler unit.

ESF Instrumentation Equipment - The following instrumentation ensures monitoring of the effective operation of the ESF.

Containment Pressure - Eight channels, monitoring containment pressure, and derived from three pressure taps, reflect the effectiveness of the containment and cooling systems and other ESF. High pressure indicates high temperatures and reduced pressure indicates reduced temperatures. Indicators and alarms are provided in the Control Room to inform the operator of system status and to guide actions taken during recovery operations. Containment pressure indication will be used to distinguish between various incidents. 1

Redundant containment pressure signals are provided to isolate the containment. The containment pressure is sensed by eight separate pressure transmitters located outside the containment. Containment pressure is communicated to the transmitters through three 1 in. stainless steel lines penetrating the containment vessel. 1

Each of the three pairs of differential pressure transmitters external to the containment in the Auxiliary Building have their own connection to the containment. Remote indicating facilities, and alarm and control signals are provided from each transmitter.

Remote indicating facilities have been provided which afford the operator the opportunity to read containment pressure.

Refueling Water Storage Tank Level - Level instrumentation on the refueling water storage tank consists of three channels. One channel provides a local indication and low level alarm function. The second channel provides remote indication (on the control board) and two low level alarms. One of these is a normal operating low level and the other is a low-low level alarm. The third channel provides remote indication on the control board.

Containment Spray Flow - Instrumentation monitoring containment spray and additive flow is described in Section 6.5.2.5.

Pump Energization - All pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board.

Valve Position - All ESF remote-operated valves have position indication on the control board to show proper positioning of the valves. Air-operated and solenoid-operated valves are selected to move in a preferred direction with the loss of air or power. After a loss of power to the motors, motor-operated valves remain in the same position as they were prior to the loss of power.

Air Coolers - The cooling water discharge flow of each of the coolers is alarmed in the Control Room if the flow is low. The transmitters are outside the reactor containment. In addition, the exit flow is monitored for radiation and alarmed in the Control Room if high radiation should occur. This is a common monitor and the faulty cooler can be located locally by manually valving each one out in turn. Local water differential pressure and outlet water pressure indications are provided, in addition to, local temperature (RTD) indications on the water and air side inlets and outlets of each unit to provide data monitoring.

Containment Atmospheric Hydrogen - Two hydrogen concentration monitors are provided, with readout in the Control Room.

Sump Instrumentation - The containment sump instrumentation consists of two analog instrument channels and two channels of eight-point level switches with gasketed junction boxes designed to operate in a post-accident environment. The indicators and alarm system are located in the Control Room.

Alarms - Visual and audible alarms are provided to call attention to abnormal conditions. The alarms are of the individual acknowledgement type; that is, the operator must recognize and silence the audible alarm for each alarm point.

TABLE 6.2.2-2

SHARED FUNCTIONS EVALUATION CONTAINMENT SPRAY SYSTEM

COMPONENT	NORMAL OPERATING FUNCTION	NORMAL OPERATING ARRANGEMENT	ACCIDENT FUNCTION	ACCIDENT ARRANGEMENT
Spray Additive Tank	None	Lined up for spray water diversion	Source of sodium hydroxide for spray water	Lined up for spray water diversion
Containment Spray Pumps (2)	None	Lined up to spray headers	Supply spray water to containment atmosphere	Lined up to spray headers

NOTE: Refer to Section 6.2 for a brief description of the refueling water storage tank, residual heat removal pumps, conventional service water pumps, component cooling pump, residual heat exchangers, and component cooling heat exchangers which are also associated either directly or indirectly with the Containment Spray System.

TABLE 6.2.2-3

SINGLE FAILURE ANALYSIS - CONTAINMENT AIR RECIRCULATION COOLING SYSTEM

	COMPONENT	MALFUNCTION	COMMENTS AND CONSEQUENCES
A.	Containment Cooling Fan	Fails to start	Four provided. Evaluation based on two fans and one containment spray pump operating during the injection phase.
B.	Service Water Pumps	Fails to start	Four provided. Two required for operation.
	Service Water Booster Pumps	Fails to start	Two provided. One required for operation.
C.	Automatically Operated Valves: (Open on automatic safeguards sequence signal)		
	Nuclear service water discharge from fan cooler units.	Fails to open	One valve per fan cooler unit. Operation of two units required.
D.	Automatically Operated Louvers: (Inlet damper closes and butterfly valve opens on automatic safeguards sequence signal)	Fails to open	Four fan-cooler units provided. Evaluation based on two units and one containment spray pump in operation during the injection phase.

TABLE 6.2.2-4

SHARED FUNCTION EVALUATION CONTAINMENT AIR RECIRCULATION COOLING SYSTEM

COMPONENT	NORMAL OPERATING FUNCTION	NORMAL OPERATING ARRANGEMENT	ACCIDENT FUNCTION	ACCIDENT ARRANGEMENT
Containment Fan Cooling Units (4)	Circulate and cool containment atmosphere	Three fan units in service	Circulate and cool containment atmosphere	Two fan units in service is required
Service Water Pumps (4)	Supply lake cooling water to fan units	Three pumps in service	Supply lake cooling water to fan units	Two pumps in service
Service Water Booster Pumps (2)	Supply lake cooling water to fan unit	One pump in service	Supply lake cooling water to fan units	One pump in service

6.2.4 CONTAINMENT ISOLATION SYSTEM (CIS)

6.2.4.1 Design Basis

Each system whose piping penetrates the containment leakage limiting boundary was designed to maintain or establish isolation of the containment from the outside environment under the following postulated conditions:

a) Any accident for which isolation was required (severely faulted conditions), and

b) A coincident independent single failure or malfunction (expected fault condition) occurring in any active system component within the isolated bounds.

Piping penetrating the containment was designed for pressures at least equal to the containment design pressure. Isolation valves were provided as necessary for all fluid system lines penetrating the containment to assure at least two barriers for redundance against leakage of radioactive fluids to the environment. Such releases might be due to rupture of a line within the containment concurrent with a LOCA, or due to rupture of a line outside the containment which connects to a source of radioactive fluid within the containment.

These barriers, in the form of isolation valves or closed systems, were defined on an individual line basis. In addition to satisfying containment isolation criteria, the valving was designed to facilitate normal operation and maintenance of the systems and to ensure reliable operation of other engineered safeguards systems. With respect to numbers and locations of isolation valves, the criteria applied were generally those outlined by the six classes described in Section 6.2.4.2 below.

In general, isolation of a line outside the containment protects against rupture of the line inside concurrent with a LOCA, or closes off a line which communicates with the containment atmosphere in the event of a LOCA.

Isolation of a line inside the containment prevents flow from the RCS or any other large source of radioactive fluid in the event that a piping rupture outside the containment occurs. A piping rupture outside the containment at the same time as a LOCA was not considered credible, as the penetrating lines are seismic Class I design at least up to and including the second isolation barrier and were assumed to be an extension of containment.

The system was designed such that failure of one valve to close will not prevent isolation, and no manual operation is required for immediate isolation. Automatic isolation is initiated by a containment isolation signal, Section 7.3, derived either from any automatic safety injection (SI) signal ("T" signal) or from a high containment pressure signal ("P" signal).

The containment isolation valves have been examined to assure that they are capable of withstanding the maximum potential seismic loads. To assure their adequacy in this respect:

1. Valves were located in a manner to reduce the accelerations on the valves. Valves suspended on piping spans were reviewed for adequacy for the loads to which the span would be subjected. Valves were mounted in the position recommended by the manufacturer.

2. Valve yokes were reviewed for adequacy and strengthened as required for the response of the valve operator to seismic loads.

3. Where valves are required to operate during seismic loading, the operate forces were reviewed to assure that system function is preserved. Seismic forces on the operating parts of the valve are small compared to the other forces present.

4. Control wires and piping to the valve operators were designed and installed to assure that the flexure of the line does not endanger the control system. Appendages to the valve, such as position indicators and operators, were checked for structural adequacy.

<u>6.2.4.2 System Design</u>. The six classes listed below are general categories into which lines penetrating containment may be classified. The seal water referred to in the listing of categories is provided by the Isolation Valve Seal Water (IVSW) System described in Section 6.8. The following notes apply to these classifications.

1. The "not missile protected" designation refers to lines that are not protected throughout their length inside containment against missiles generated as the result of a LOCA. These lines, therefore, were not assumed invulnerable to rupture as a result of a loss of coolant.

2. In order to qualify for containment isolation, valves inside the containment must be located outside the missile barrier for protection against loss of function following an accident.

3. Manual isolation valves that are locked closed or otherwise closed and under administrative control during power operation qualify as automatic trip valves.

4. A check valve qualifies as an automatic trip valve in certain incoming lines not requiring seal water injection.

5. The double disk type of gate valve was used to isolate certain lines. When sealed by water injection, this valve provides both barriers against leakage of radioactive liquids or containment atmosphere.

6. In lines isolated by globe valves and provided with seal water injection, the valves were installed so that the seal water wets the stem packing.

7. Excessive loss of seal water through an isolation valve that fails to close on signal, is prevented by the high resistance of the seal water injection line. A water seal at the failed valve is assured by proper slope of the protected line, or a loop seal, or by additional valves on the side of the isolation valves away from the containment.

8. Isolated lines between the containment and the second outside isolation barrier (valve or closed system) were designed to the same seismic criteria as the containment vessel, and were assumed to be an extension of containment.

9. The first outside isolation valve is located as close to the containment as possible unless a more remote location was dictated by equipment isolation requirements.

The six classes of piping penetrations are:

Class 1 (Outgoing Lines, Reactor Coolant System) - Normally operating outgoing lines connected to the Reactor Coolant System are provided with at least two automatic trip valves in series located outside the containment. Automatic seal water injection is provided for lines in this classification.

Exceptions to the general classification are the residual heat removal loop outlet line (P-16) and the reactor coolant pump seal water return line (P-28). The two barriers for P-16 are a normally closed missile protected valve inside containment, and the closed residual heat removal loop outside containment. The two barriers for P-28 are an automatic trip valve (double disc gate valve with automatic IVSW) and the closed chemical and volume control system, both outside containment.

Class 2 (Outgoing Lines) - Normally operating outgoing lines not connected to the Reactor Coolant System, and not missile protected or which can otherwise communicate with the containment atmosphere following an accident, are provided at a minimum with two automatic trip valves in series outside containment. Automatic seal water injection is provided for lines in this classification. Most of these lines are not vital to plant operation following an accident.

Class 3 (Incoming Lines) - Incoming lines connected to open systems outside containment, and not missile protected or which can otherwise communicate with the containment atmosphere following an accident are provided with one of the following arrangements outside containment:

1. Two automatic trip valves in series, with automatic seal water injection. This arrangement is provided for lines which are not necessary to plant operation after an accident. Containment fire water penetrations (P-73 and P-74) do not have seal water injection.

2. Two manual isolation valves in series, with manual seal water injection. This arrangement is provided for lines which remain in service for a time, or are used periodically, subsequent to an accident.

Incoming lines not missile protected or which can otherwise communicate with the containment atmosphere are provided, at a minimum, with one check valve or normally closed isolation valve located either inside or outside containment and a closed system or automatic trip valve outside containment. Most lines in this category are provided with additional isolation valves which satisfy particular systems or safeguards requirements. Seal water injection is not required for lines in this category.

Class 4 (Missile Protected) - Normally operated incoming and outgoing lines which penetrate the containment and are connected to closed systems inside the containment and protected from missiles throughout their length and are provided with at least one manual isolation valve located outside the containment. Seal water injection is not required for this class of penetration.

Class 5 (Normally Closed Lines Penetrating the Containment) - Lines which penetrate the containment and which can be opened to the containment atmosphere but which are normally closed during reactor operation are provided with two isolation valves in series or one isolation valve and one blind flange/mechanical connection. One valve or flange is located inside and the second valve or flange located outside the containment. Both isolation valves are located outside containment on the sump recirculation lines (P-46 and P-47).

Class 6 (Special Service) - There are a number of special groups of penetrating lines and containment access openings. These are discussed below.

Each ventilation purge duct penetration (P-37 and P-38) is provided with two tight-closing butterfly valves, which are closed during reactor power operation and are actuated to the closed position automatically upon a containment isolation or a containment high radiation signal. One valve is located inside and one valve is located outside the containment at each penetration.

The containment pressure and vacuum relief lines (P-41 and P-42) are similarly protected with two tight closing butterfly valves in series, one inside and one outside the containment. These valves also are actuated to the closed position upon a containment isolation or containment high radiation signal.

The equipment access hatch is a bolted, gasketed closure which is sealed during reactor operation. The personnel air locks consist of two doors in series with mechanical interlocks to assure that one door is closed at all times. Each air lock door and the equipment closure are provided with double gaskets to permit pressurization between the gaskets.

The fuel transfer tube penetration (P-32) inside the containment, Figure 3.8.1-16, is designed to present a missile protected and double barrier between the containment atmosphere and the atmosphere outside the containment. The penetration closure is treated in a manner similar to the equipment access hatch. The inside closure is a blind flange which contains two gaskets to complete the double barrier between the containment atmosphere and the inside of the fuel transfer tube. The interior of the fuel transfer tube is not pressurized. Seal water injection is not required for this penetration.

The containment radiation monitor inlet and outlet lines (P-35 and P-36) communicate with the containment atmosphere at all times (normally filled with air or vapor). In an accident condition the two containment isolation valves close.

The Reactor Vessel Level Instrumentation System (RVLIS) sensing lines (P-75 through P-80) are utilized post accident. Each line is isolated by a hydraulic isolator outside containment.

The containment pressure sensing lines (P-68, P-69 and P-70) are open to containment atmosphere and remain open to pressure transmitters post accident. Redundant, closed globe valves isolate the attached Post Accident Sampling System.

Figures 6.2.4-1 through 6.2.4-19 show the containment isolation provisions credited for each containment penetration. Figure 6.2.4-21 defines the nomenclature and symbols used on the aforementioned figures.

A summary of the fluid systems lines penetrating containment and the valves and closed systems employed for containment isolation is presented in Table 6.2.4-1. Each valve is described as to type, operator, position indication and open or closed status during normal operation, shutdown, and accident conditions. Information is also presented on valve preferential failure mode, automatic trip by containment isolation signal, and the fluid carried by the line.

Containment isolation valves were provided with actuation and control equipment appropriate to the valve type. For example, air-operated globe and diaphragm (Saunders Patent) valves are generally equipped with air diaphragm operators, with fail-safe operation assured by the control devices in the instrument air supply to the valve. Motor-operated gate valves are capable of being supplied from reliable onsite emergency power as well as from their normal power source.

Automatically operated containment isolation valves are actuated to the closed position by one of two separate containment isolation signals. The first of these signals is derived in conjunction with automatic safety injection actuation, and trips the majority of the automatic isolation valves. These are valves in the so-called "non-essential" process lines penetrating the containment. This was defined as "Phase A" isolation, and the trip valves were designated by the letter "T" in the isolation diagrams (Figures 6.2.4-1 through 6.2.4-20). This signal also initiates automatic seal water injection. The second, or "Phase B", containment isolation signal was derived upon actuation of the containment spray system, and trips the automatic isolation valves in the so-called "essential" process lines penetrating the containment. "Essential" process lines are those providing cooling and seal water flow through the reactor coolant pumps. These services should not be interrupted unless absolutely necessary while the reactor coolant pumps are operating. These trip valves were designated by the letter "P" in the isolation diagrams.

Some automatically tripped isolation valves are actuated to the closed position by the containment ventilation isolation signal. These valves were designated by the letter "V" in the isolation diagrams. The "V" signal is derived from Safety Injection, Containment High Radiation, or manually.

A manual containment isolation signal can be generated from the Control Room. This signal performs the same functions as the automatically derived "T" signal, i.e. "Phase A" isolation and automatic seal water injection.

Non-automatic isolation valves, i.e., remote stop valves and manual valves, were used in lines which must remain in service, at least for a time, following an accident. These are closed manually if and when the lines are taken out of service.

"Non-essential" lines are defined as lines which are not required to mitigate or limit an accident and which, if required at all, would be required for long term recovery only. "Essential" lines are defined as lines required to mitigate an accident or which, if unavailable, could increase the magnitude of the event.

Standard closing times available with commercial valve modes were adequate for the sizes of containment isolation valves used. Valves equipped with air-diaphragm operators generally close in approximately two seconds. The typical closing time available for large motor-operated gate valves was ten seconds.

The large butterfly valves used to isolate the containment ventilation purge ducts were equipped with air-cylinder operators, with spring returns capable of closing the valves in two seconds. These valves fail to the closed position on loss of control signal or instrument air.

The following types of isolation valves were generally employed outside the containment:

1. Diaphragm valves (Saunders Patent)
2. Globe valves
3. Double disk gate valves
4. Regular gate valves, and
5. Butterfly valves.

Isolation valves with packed stems were provided with steam leakoffs if all of the following operating conditions were satisfied with the exception of those valves which have been live loaded and have had leakoff lines capped:

1. Line size is 2 in. or larger
2. Operating temperature can exceed 212°F, and
3. The fluid is radioactive.

All air and motor operated containment isolation valves can be remotely operated from the Control Room. The open or closed conditions of these valves are displayed visually in the Control Room at all times. Post Accident Venting valves associated with penetrations P-40 and P-41 are exceptions to this criteria.

Only the valves located inside the containment which were missile protected can be considered as available for containment isolation. These valves were located outside the missile barrier.

All lines penetrating the containment which normally carry radioactive fluids or that can communicate with the containment atmosphere following an accident were provided with radiation shielding in all areas where personnel access is possible. Manual valves in the lines, including containment isolation valves, were equipped with extension handles for operation from outside the shielding. Manually operated valves in the non-radioactive seal water injection lines were located outside the shielding.

Valves that are normally open during power operation and which must be closed for containment isolation are actuated to the closed position on receipt of a containment isolation signal.

Redundant electrical control circuits were provided for all remotely operated containment isolation valves. If the normal power supply for the control circuits fails, they may be energized by an emergency power supply. Duplicate cabling to the valve operators was not provided.

All air operated isolation valves fail closed on loss of control signal or control air. This is not detrimental to power operation. If one of the isolation valves should fail closed, operation of the connected systems either is not affected or can be modified until repairs are made.

It was necessary to demonstrate that containment isolation barriers were leak-tight. The closed systems that back up the containment isolation valves have adequate capability for flow toward the containment or adequate design to contain any radioactivity introduced into the system as the result of an accident. The water seal maintained between certain closed isolation valves by seal water injection was designed to prevent leakage of containment atmosphere to the environment by ensuring that any leakage through the valve seats or past stem packing is seal water, not containment atmosphere.

In general, vertical water legs were not used to seal the closed isolation valves. However, on lines isolated by two remotely operated valves in series, a loop seal or vertical water leg was installed between the isolation valves and the containment. This prevents loss of the water seal provided by seal water injection if the first outside isolation valve fails to close and the line is exposed to the containment atmosphere. Presence of water in the loop seal or vertical leg is assured by the inflow of seal water.

Penetrating lines other than those associated with the engineered safety features (ESF) which continue to be used, at least for a time, after containment isolation include:

1. Main steam headers
2. Auxiliary feedwater headers
3. Reactor coolant pump cooling water supply lines
4. Reactor coolant pump cooling water return lines
5. Reactor coolant pump seal water supply lines
6. Containment air sample in if containment pressure <5 psig,
7. Containment air sample out if containment pressure <5 psig, and
8. Reactor vessel level instrumentation system lines.

Automatic isolation valve sizes are listed in Table 6.2.4-2.

<u>6.2.4.3 Tests and Inspections</u>. The HBR 2 containment structure was designed such that the maximum allowable containment vessel leakage rate shall not exceed 0.1 percent per day of the containment atmosphere at 42 psig and 263°F which are the maximum conditions of the DBA.

Leakage from the containment to the outside could occur in the following locations:

1. Containment Penetrations (L_{pen})
2. Containment Liner Welds (L_c)
3. Containment Liner Plates (L_L), and
4. Containment Isolation Valves (L_{iso}).

The leakage from the penetrations (L_{pen}) may be continuously or intermittently monitored by the PPS as described in Section 6.9. The PPS can provide pressurization to several volumes formed by double containment isolation valves or by double gasketed seals. These include the spaces between butterfly type isolation valves in the purge supply and exhaust lines, containment pressure and vacuum relief lines, the double isolation valves in the containment radiation monitor inlet and outlet lines, the plant air supply header and the post accident venting line, and into the spaces formed by double gaskets in the fuel transfer tube and on the equipment hatch and personnel lock doors. Leakage designated by L_{pen} was defined to

include leakage from these volumes as well as from the penetration sleeves. In this context the word "penetration" also includes these volumes. The PPS is used to perform a sensitive leak rate test of these volumes to verify that leakage to the outside does not exceed the design limits at accident pressure (i.e., 42 psig).

Containment liner weld channels were installed on all liner welds to provide the means for a sensitive leak rate test to determine liner weld leakage (L_c). However, the liner weld leakage is no longer determined and the integrity of the containment welds was verified by periodic integrated leakage rate testing.

Containment isolation valves were individually tested prior to the preoperational leak rate tests to assure proper seating. The design of the lines which penetrate the containment boundary provide isolation valves and additional positive means for limiting the leakage (L_{iso}) which can occur from the containment atmosphere through these lines in the post-accident condition. Table 6.2.4-1 lists each fluid line which penetrates the containment wall and indicates the additional positive barriers which will minimize leakage through these lines from the containment following an accident. These positive barriers include injection of IVSW System water at a pressure greater than accident pressure between the seats and stem packing of the globe and double disc types of isolation valves and into piping between closed diaphragm type isolation valves.

Other lines are all located outside the missile barrier and are connected to closed systems within the containment, or are part of a system with design pressure greater than the design pressure of the containment. Therefore, the isolation valve arrangement and these positive barriers will assure minimal leakage after a DBA through these potential leak paths.

No leakage was expected through the liner plates (L_L). However, any liner plate leakage will be measured as part of the preoperational integrated leakage rate test. The containment liner has insulation from the area of the "spring line" to the base mat. This polyvinyl chloride (PVC) foam insulation has a sheet stainless steel outer covering. Any physical damage to this insulation and thus to the underneath liner would be readily observable.

Following the preoperational tests, periodic inspection of the containment wall was conducted to ensure that no physical damage to the liner has occurred. Evidence of damage would be examined to determine the necessary methods for assuring that the liner plate(s) in the affected area will not leak at containment design conditions. Therefore, no periodic leak rate testing of the liner plates is required unless physical damage was evident.

The preoperational integrated leak rate test was conducted with containment atmosphere at 42 psig and 90°F. The corresponding test leakage

TABLE 6.2.4-1 (Continued)

PENE. NO.	PENETRATION AND SYSTEM	FIG. 6.2.4-	VALVE OR BARRIER (SEE FIGURE)	VALVE TYPE	OPER. TYPE	POSIT. INDIC. IN CONT. ROOM	NORMAL POSIT.	POSIT. DURING SHUTDOWN	POSIT. AFTER ACCIDENT	POSIT. ON POWER FAIL.	CONT. ISOL. TRIP	SEAL WATER INJ.	USED AFTER ACCID.	FLUID G-GAS W-WATER	NOTES
8	Main Stream Header	-3	MS-V1-3B	SDSV	Air	Yes	Open	Closed	Open*	FC	No*	-	Yes*	G	*Automatic isolation for MSLB,E
			MS-353B	DDV	Mot.	Yes	Closed	Closed	Closed	As is	No	-	No	G	
			MS-11A	Globe	Man.	No	Closed	Closed	Closed	-	No	-	No	G	
			MS-28	Globe	Man.	No	L.C.	Closed**	Closed	-	No	-	No	G	**May be opened for RCS temperature control
			MS-30	Globe	Man.	No	L.C.	Closed**	Closed	-	No	-	No	G	
			RV1-2	PORV	Air	Yes	Closed	Closed	Closed	FC	No	-	Maybe	G	
			MS-262B	Gate	Man.	No	L.O.	Open	Open	-	No	-	Yes	G	
			C.S.	-	-	-	-	-	-	-	-	-	-	-	
9	Main Stream Header	-3	MS-V1-3C	SDSV	Air	Yes	Open	Closed	Open*	FC	No*	-	Yes*	G	*Automatic isolation for MSLB,E
			MS-353C	DDV	Mot.	Yes	Closed	Closed	Closed	As is	No	-	No	G	
			MS-12A	Globe	Man.	No	Closed	Closed	Closed	-	No	-	No	G	
			MS-37	Globe	Man.	No	L.C.	Closed**	Closed	-	No	-	No	G	**May be opened for RCS temperature control
			MS-39	Globe	Man.	No	L.C.	Closed**	Closed	-	No	-	No	G	
			RV1-3	PORV	Air	Yes	Closed	Closed	Closed	FC	No	-	Maybe	G	
			MS-262C	Gate	Man.	No	L.O.	Open	Open	-	No	-	No	G	
			C.S.	-	-	-	-	-	-	-	-	-	-	-	
10	Feedwater	-4	FW-8A	Check	-	No	L.O.	Open	Open*	-	No	-	Yes*	W	*Isolated for MSLB
			FW-201	Gate	Man.	No	Closed	Closed**	Closed	-	No	-	Yes*	W	**Open during wet layup activities,NE
			C.S.	-	-	-	-	-	-	-	-	-	-	-	
11	Feedwater	-4	FW-8B	Check	-	No	L.O.	Open	Open*	-	No	-	Yes*	W	*Isolated for MSLB
			FW-203	Gate	Man.	No	Closed	Closed**	Closed	-	No	-	Yes*	W	**Open during wet layup activities,NE
			C.S.	-	-	-	-	-	-	-	-	-	-	-	
12	Feedwater	-4	FW-8C	Check	-	No	L.O.	Open	Open*	-	No	-	Yes*	W	*Isolated for MSLB
			FW-205	Gate	Man.	No	Closed	Closed**	Closed	-	No	-	Yes*	W	**Open during wet layup activities, NE
			C.S.	-	-	-	-	-	-	-	-	-	-	-	

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

6.2.5.1 Design Basis

Following a design basis accident (DBA), hydrogen gas may be generated inside the containment by reactions such as radiolysis of aqueous solutions in the sump and core, zirconium metal with water, and corrosion of materials of construction.

An evaluation has been made to determine the amounts of hydrogen that could exist in the containment following a loss-of-coolant accident (LOCA) and to develop a method of controlling the hydrogen concentration by a controlled containment venting procedure.

On the basis of the magnitude of the doses determined below and the results of the sensitivity analysis presented in Reference 6.2.5-1, it was concluded that controlled venting is an adequate method to maintain a limit on the hydrogen concentration following a LOCA.

The Post-Accident Containment Venting System was therefore provided to permit controlled venting of the containment atmosphere to prevent the accumulation of hydrogen gas from ever reaching a potentially hazardous concentration.

The capability to hook up an external hydrogen recombiner is also provided in accordance with the requirements of 10 CFR 50.44. The hydrogen recombiner and control panel are shared with another utility; they will be transported on site, and hooked up at the direction of the emergency response organization as conditions dictate. 3

6.2.5.2 System Design

6.2.5.2.1 Post-Accident Venting System

The Post-Accident Containment Venting System consists of two full capacity supply lines through which hydrogen-free air can be admitted to the containment, two full capacity exhaust lines through which hydrogen bearing gases may be vented from the containment, and associated valving and instrumentation. The supply lines use equipment and piping which provide instrument air and service air during normal operation. One of the exhaust lines uses equipment and piping which normally provide pressure relief for the containment. The second exhaust line does not use existing equipment. The Post-Accident Venting System Flow Diagram is shown in Figure 6.2.5-1. Piping and valving in the supply lines and in the exhaust lines are Seismic Class I starting inside the containment proceeding up to and including the isolation valve more remote from the containment. Equipment and piping beyond the more remote containment isolation valve is not Seismic Class I because the rate of hydrogen accumulation in the containment is slow enough to permit repair of equipment that might fail either before or during operation of the venting system.

Design data for components and equipment descriptions are presented in Table 6.2.5-1. Materials and code requirements for the Post-Accident Venting System components are discussed in Section 6.1.1.1.4.

Protection against dynamic effects, and the capability to remain operable in the post-accident environment, are discussed below.

6.2.5.2.1.1 Air Supply

Supply lines in the containment are located in missile protected areas over the total length of the piping run, and are terminated so as to prevent either spray or sump water from entering the pipe. The supply line motor operated valves in the containment are located above the flood line in missile protected areas.

6.2.5.2.1.2 Air Exhaust

Exhaust lines in the containment are located in missile protected areas over the total length of the piping run and are terminated in well ventilated areas in a manner which prevents either spray or sump water from entering the pipe. The exhaust line motor operated valves are located above the flood line in missile protected areas.

Control valves, instruments and filters in the exhaust lines are separated so that there is no direct line of sight between equipment in one line and equipment in the other.

6.2.5.2.1.3 Electrical

Electrical cable runs and instrument lines are separated so that no single accident would render more than one of the four lines (two supply, two exhaust) inoperable.

6.2.5.2.1.4 Operation

Operation of the Post-Accident Venting System does not require the use of any fans during venting.

Based on the containment hydrogen concentration and on the hydrogen generation rate, the operator will determine the flow rate required to maintain the hydrogen concentration at 3 percent by volume by venting the containment for one hour daily. From Figure 6.2.5-2, System Resistance Curve, the operator will then determine the containment pressure necessary to obtain the required vent flow. The pressure determined is not to exceed 3.0 psig, to preclude damaging the system piping or filters. (To obtain the nominal 240 scfm design flow, the containment must be pressurized to 2.4 psig.) Hydrogen-free air will be pumped into the containment, using either the station air compressor or one of the two instrument air compressors, until the required containment pressure is reached. The air supply will then be stopped and the supply line isolated by valves outside the containment. The motor operated valve inside the containment will remain open.

Because the addition of air to pressurize the containment will also dilute the hydrogen, the containment will remain isolated until analysis of samples indicates that the concentration is again approaching 3 percent by volume. Venting will then be started by opening either the containment exhaust line or the bypass in the containment pressure relief line to the plant vent, and adjusting the hand-controlled throttling valve to obtain the required flow. Operation will continue under these conditions for one hour, and then the system will be shut down. The vent line will be isolated by valves outside the containment. The motor operated valve inside the containment will remain open.

TABLE 6.2.5-1

POST-ACCIDENT VENTING SYSTEM COMPONENTS

ABSOLUTE FILTER

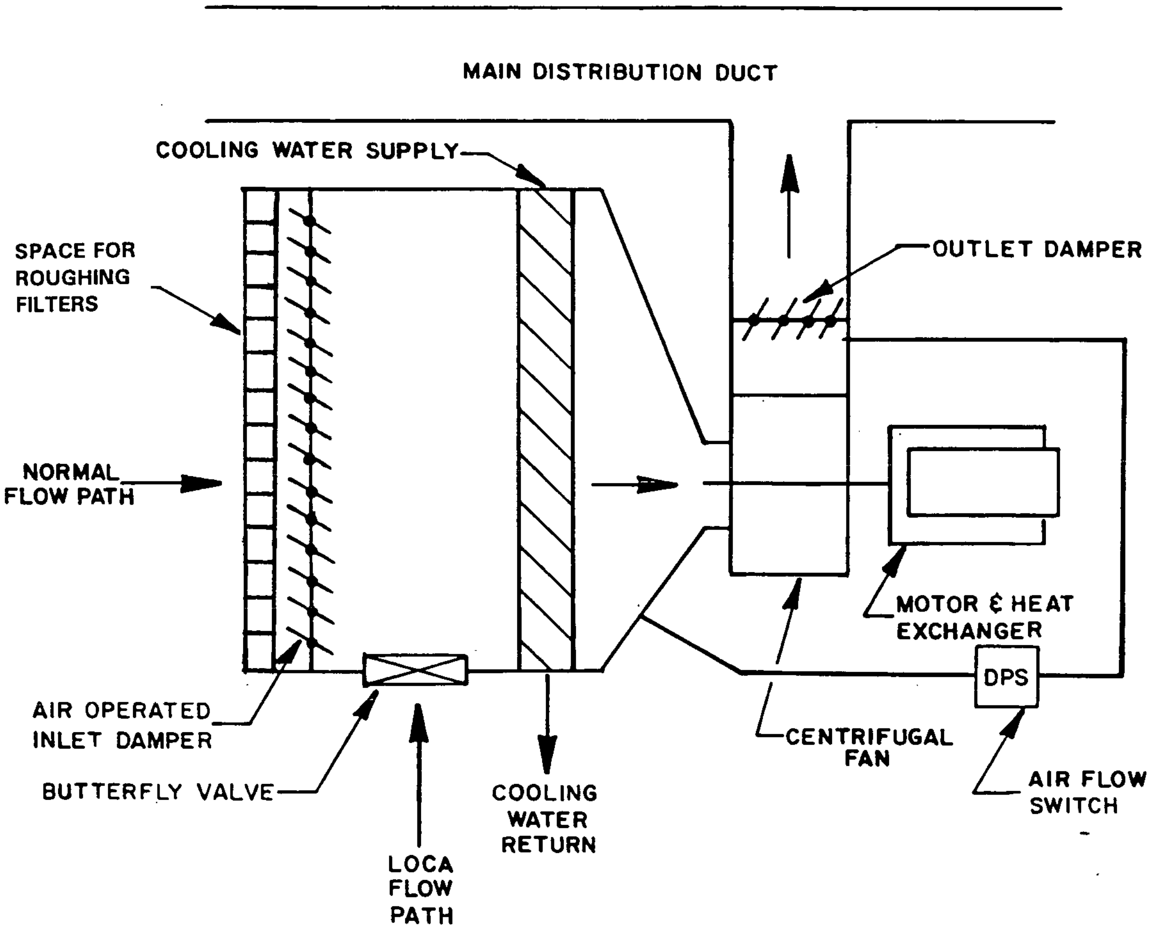
Number required	1
Air flow, scfm	1000
Maximum differential pressure (clean), in. wg	1.0
Maximum differential pressure (loaded) in. wg	2.0
Design temperature, ^{o}F	180
Filtering Efficiency--with 0.3 micron dia. DOP	99.97%

CHARCOAL FILTER

Number required	1
Air flow, scfm	1000
Maximum differential pressure (clean), in. wg	1.0
Maximum differential pressure (loaded), in. wg	2.0
Design temperature, ^{o}F	180
Charcoal type	iodine impregnated
Iodine Removal Efficiency	99.9%

PRESSURE REGULATING VALVES

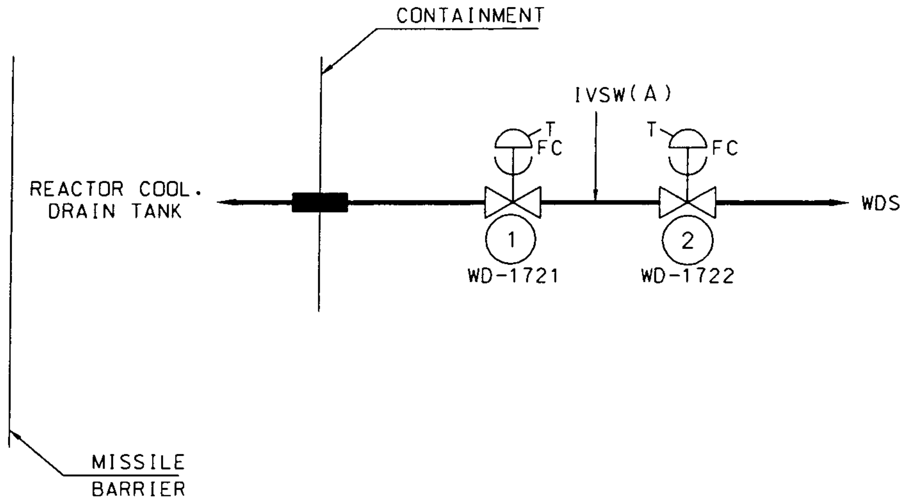
Number required	2
Design pressure, psig	150
Design temperature, ^{o}F	200
Maximum flow (sp. gr. 1.0 rel to air), scfm	500
Maximum differential pressure at max. flow, psi	1.3
Minimum flow (sp. gr. 0.92 rel. to air), scfm	100
Maximum differential pressure at min. flow, psi	5.0
Calculated Cv range required	10-110
Discharge set pressure, psi	0-1.0



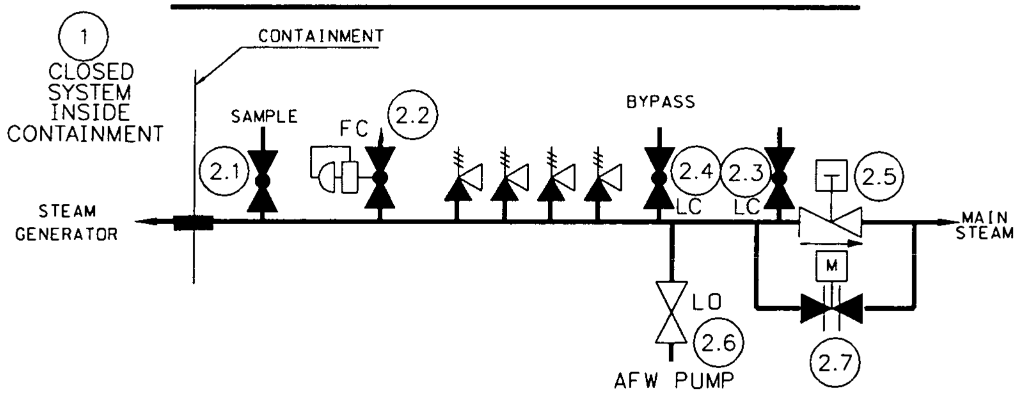
Amendment No. 12

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT AIR RECIRCULATION COOLING SYSTEM	FIGURE 6.2.2 - 2

PENETRATION NO. 6 - REACTOR COOLANT DRAIN TANK PUMP DISCHARGE LINE



PENETRATIONS NO. 7, 8, 9 - MAIN STEAM HEADER

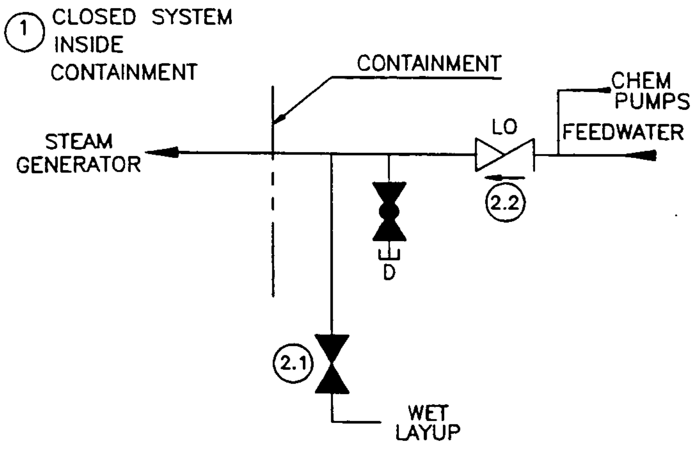


BARRIER	P-7	P-8	P-9
2.1	MS-10A	MS-11A	MS-12A
2.2	RV1-1	RV1-2	RV1-3
2.3	MS-21	MS-30	MS-39
2.4	MS-19	MS-28	MS-37
2.5	MS-V1-3A	MS-V1-3B	MS-V1-3C
2.6	MS-262A	MS-262B	MS-262C
2.7	MS-353A	MS-353B	MS-353C

Revision No. 14

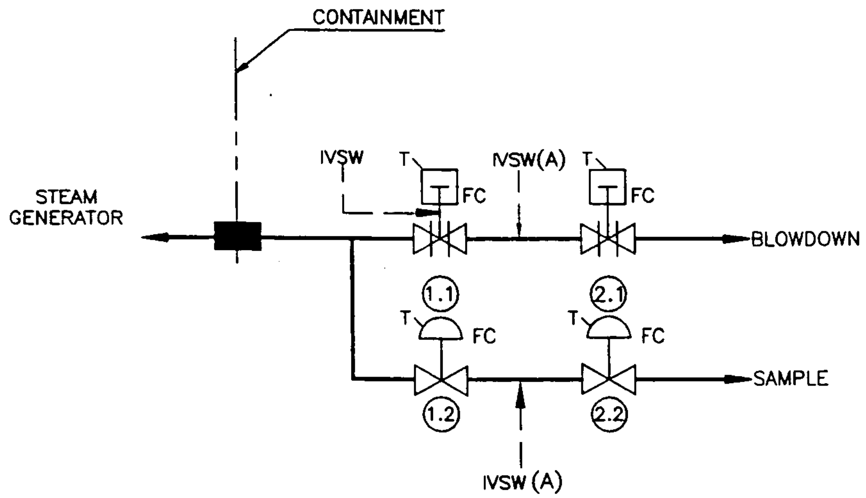
H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT ISOLATION VALVES PENETRATIONS P-6, P-7, P-8, P-9	FIGURE 6.2.4-3

PENETRATIONS NO. 10, 11, 12 – FEEDWATER



BARRIER	P–10	P–11	P–12
2.1	FW–201	FW–203	FW–205
2.2	FW–8A	FW–8B	FW–8C

PENETRATIONS NO. 13, 14, 15 – STEAM GENERATOR BLOWDOWN

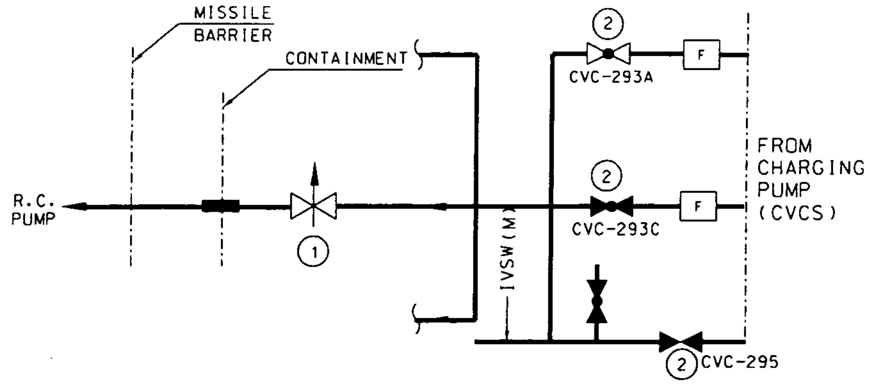


BARRIER	P–13	P–14	P–15
1.1	FCV–1931A	FCV–1932A	FCV–1930A
2.1	FCV–1931B	FCV–1932B	FCV–1930B
1.2	FCV–1934A	FCV–1935A	FCV–1933A
2.2	FCV–1934B	FCV–1935B	FCV–1933B

Amendment No. 12

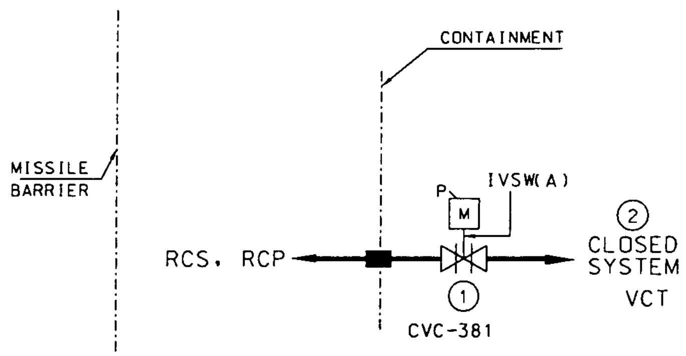
H.B.ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT ISOLATION VALVES PENETRATIONS P-10, P-11, P-12, P-13, P-14, P-15	FIGURE 6.2.4-4

PENETRATIONS NO. 25, 26, 27 - REACTOR COOLANT PUMP SEAL WATER SUPPLY LINE

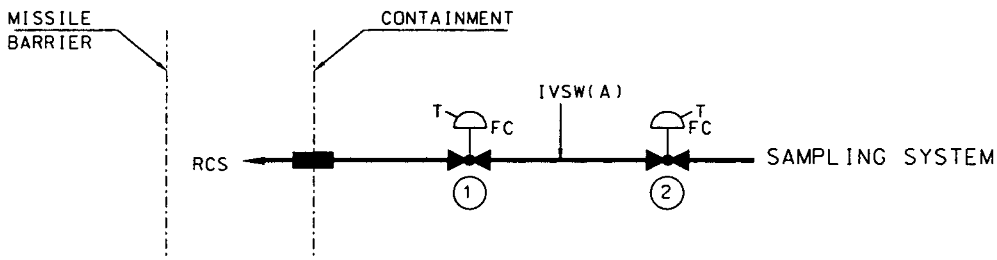


BARRIER	P-25	P-26	P-27
1	CVC-297C	CVC-297B	CVC-297A

PENETRATION NO. 28 - REACTOR COOLANT PUMP SEAL WATER RETURN LINE



PENETRATIONS NO. 29, 30, 31 - REACTOR COOLANT SYSTEM SAMPLE LINE

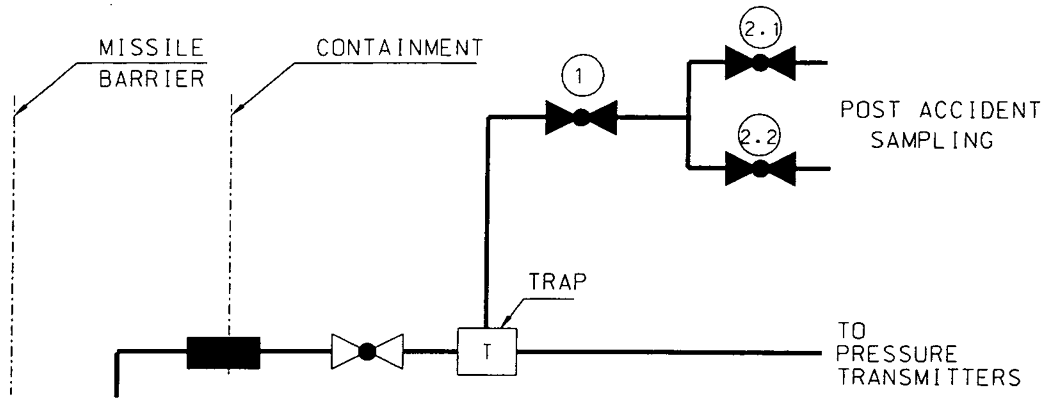


BARRIER	P-29	P-30	P-31
1	PS-956A	PS-956C	PS-956E
2	PS-956B	PS-956D	PS-956F

Revision No. 14

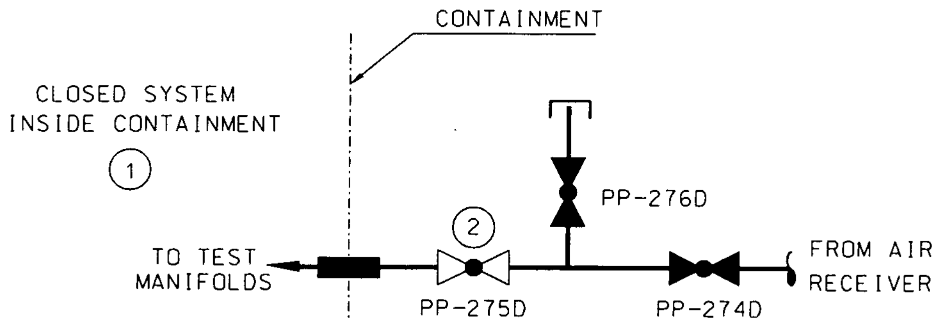
H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT ISOLATION VALVES PENETRATIONS P-25, P-26, P-27, P-28, P-29, P-30, P-31	FIGURE 6.2.4-8

PENETRATIONS NO. 68, 69, 70 - CONTAINMENT PRESSURE SENSING LINES

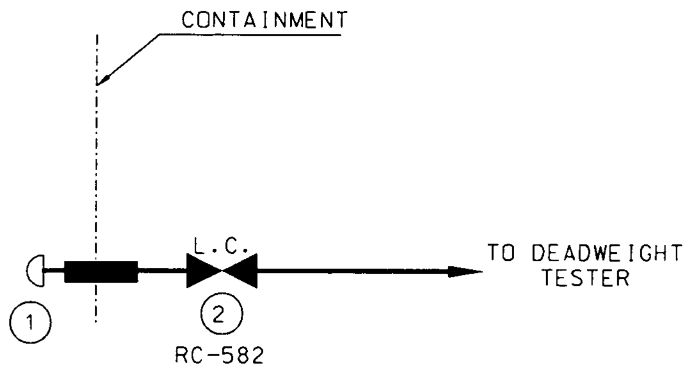


BARRIER	P-68	P-69	P-70
1	VCT-20	VCT-19	VCT-18
2.1	PAS-5	PAS-3	PAS-1
2.2	PAS-6	PAS-4	PAS-2

PENETRATION NO. 71 - PENETRATION PRESSURIZATION SYSTEM AIR SUPPLY



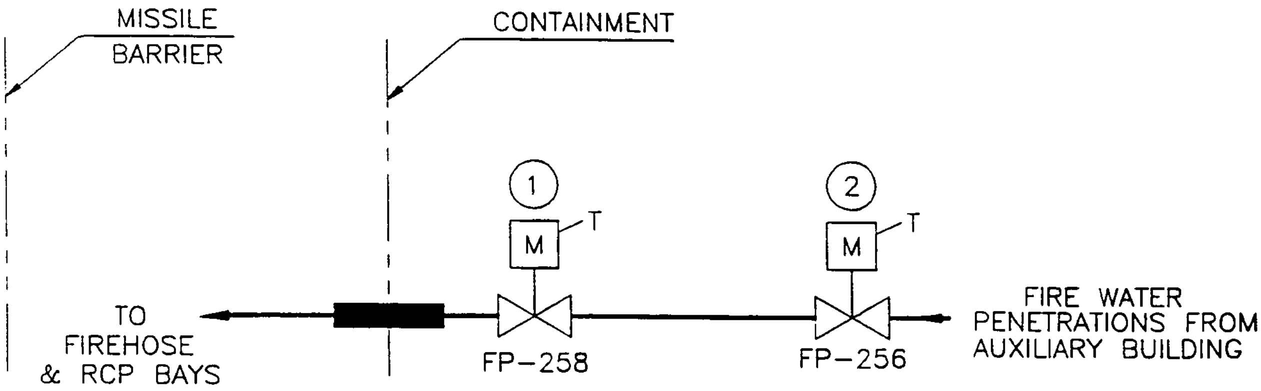
PENETRATION NO. 72 - DEADWEIGHT TESTER LINE



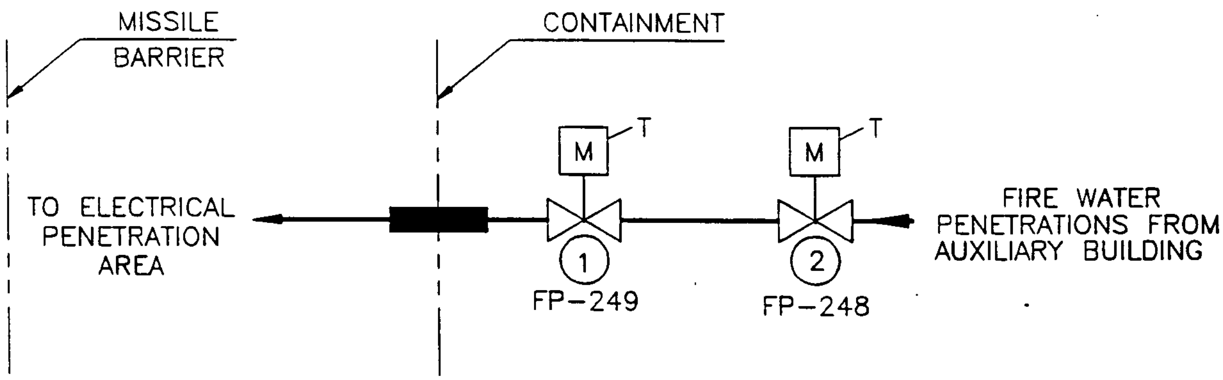
Revision No. 14

H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT ISOLATION VALVES PENETRATIONS P-68, P-69, P-7Ø, P-71, P-72	FIGURE 6.2.4-18

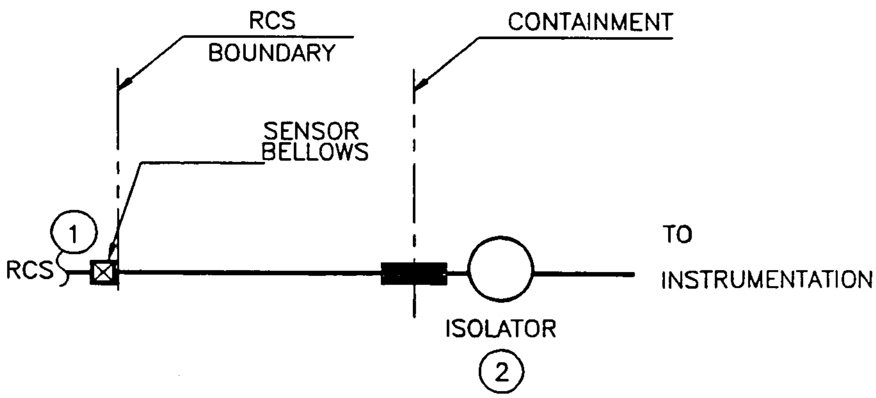
PENETRATION NO. 73 – FIRE WATER



PENETRATION NO. 74 – FIRE WATER



PENETRATIONS NO. 75, 76, 77, 78, 79, 80 – RVLIS SENSING LINE



BARRIER	P–75	P–76	P–77	P–78	P–79	P–80
1	LX511AB	LX511AA	LX511AC	LX511BB	LX511BA	LX511BC
2	LIS511AB	LIS511AA	LIS511AC	LIS511BB	LIS511BA	LIS511BC

Amendment No. 12

H.B.ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CONTAINMENT ISOLATION VALVES PENETRATIONS P-73, P-74, P-75, P-76, P-77. P-78, P-79, P-80	FIGURE 6.2.4-19

6.3 EMERGENCY CORE COOLING SYSTEM

6.3.1 DESIGN BASIS

6.3.1.1 Summary Description

Adequate emergency core cooling is provided by the Safety Injection System (SIS) [which constitutes the Emergency Core Cooling System (ECCS)], whose components operate in three modes. These modes are delineated as passive accumulator injection, active safety injection (SI), and residual heat removal recirculation.

The primary purpose of the SIS is to automatically deliver cooling water to the reactor core in the event of a loss-of-coolant accident (LOCA). This limits the fuel cladding temperature and thereby ensures that the core will remain intact and in place, with its heat transfer geometry preserved. This protection is afforded for:

a) All pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant loop, assuming unobstructed discharge from both ends.

b) A loss of coolant associated with the rod ejection accident.

c) A steam generator (SG) tube rupture.

The principal components of the SIS which provide emergency core cooling immediately following a loss of coolant are the accumulators (one for each loop), the two SI (high head) pumps with Pump B to act as a maintenance replacement for Pumps A and C, and the two residual heat removal (low head) pumps. 7

The SIS operates in the following possible modes:

a) Injection of borated water by the passive accumulators.

b) Injection of borated water from the refueling water storage tank by the SI pumps.

c) Injection by the residual heat removal pumps, which also draw borated water from the refueling water storage tank.

d) Recirculation of spilled coolant, injected water, and Containment Spray System (CSS) drainage back to the reactor from the containment sump by the residual heat removal pumps.

The initiation signal for core cooling by the SI pumps and the residual heat removal pumps in the SIS is actuated by any of the following:

a) Low pressurizer pressure (2/3)

b) High containment pressure (2/3, Hi level-approximately 10 percent of containment design pressure)

c) High steam line differential pressure (2/3 per line in 1/3 lines)

d) High steam flow (1/2 per line in 2/3 lines) with low T_{avg} (2/3 loops) or low steam line pressure (2/3 lines), and

e) Manual-Actuation (1/2 pushbuttons).

Automatic initiation of SI due to pressurizer low pressure and high steam line differential pressure may be manually blocked when the plant is below 2000 psi. Initiation due to high steam line flow coincident with low steam line pressure
6 | or low T_{avg} can be blocked when T_{avg} is below 543°F.

6.3.1.2 Design Basis for Functional Requirements

The ECCS complies with the functional criteria for ECCS derived from 10CFR50, Appendix K, as delineated in 10CFR50.46. The conditions relating to peak cladding temperature, maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long-term cooling are all met with adequate margin relative to the specified limits.

6.3.1.3 Design Basis for Reliability

For any rupture of a steam pipe and the associated uncontrolled heat removal from the core, the SIS adds shutdown reactivity so that, with a stuck rod, no offsite power, and minimum engineered safety features, there is no consequential damage to the Reactor Coolant System (RCS) and the core remains in place and intact.

Redundancy and segregation of instrumentation and components are incorporated in the design to assure that postulated malfunctions will not impair the ability of the system to meet the design objectives. The system is effective in the event of loss of normal plant auxiliary power coincident with the loss of coolant, and can accommodate the failure of any single component or instrument channel to respond actively in the system. During the recirculation phase of a LOCA, the system can accommodate a loss of any part of the flow path, since backup alternative flow path, capability is provided.

6.3.1.4 ECCS Protection from Physical Damage

Pipe whip protection for ECCS components is provided in accordance with General Design Criteria 40 and 42 (Section 3.6).

Protection of ECCS components against seismic loads is discussed in Section 3.7.

Protection of ECCS components against missiles is discussed in Section 3.5.

Protection is provided for ECCS components against loads which may result from the effects of a LOCA.

The accumulators, which are passive components, discharge into the cold legs of the reactor coolant piping when RCS pressure decreases to 660 psig, thus assuring rapid core cooling for large pipe breaks. They are located inside the containment, but outside the crane wall. Therefore each accumulator is protected against possible missiles.

When the break is large, RCS depressurization occurs due to the large rate of mass and energy loss through the break to the containment. The system is arranged so that the RHR pumps take suction from the sump in the containment floor and deliver spilled reactor coolant and borated refueling water back to the core through the residual heat exchangers. The system is arranged to allow either of the RHR pumps to take over the recirculation function.

There are two sump return lines which lead from the containment to the RHR pumps. Each line is located inside of a larger diameter guard pipe. The lines are separated by approximately 18 ft. The lines are designed to allow for 2 in. differential movement between the containment and pump chamber and are designed as Seismic Class I equipment.

Staged debris removal of the water entering the RHR Pump suction piping during the recirculation mode is accomplished as follows: (Refer to Figure 6.3.2-3 and Containment Spray Flow Diagram)

1. Debris approximately 1" and above is stopped by the coarse screens located at the base of the shield wall inside the Reactor Coolant Pump Bays. These screens have openings approximately 1".

2. Submerged debris is stopped from entering the sump by the outer 9" baffle wall.

3. Floating debris is stopped from entering the sump screens by having the water level above the sump screens. The inner 4'6" baffle wall assures the water is above the screens before floating material is allowed to approach them.

4. Neutral and near neutral bouyant debris greater than 7/32" diameter are stopped by the sump screens. The screens consist of a prescreen with a 1/2" square mesh opening in series with a 7/32" square mesh opening screen. This prescreen reduces the debris loading on the final screen.

5. Debris smaller than 7/32" may pass through the screens and enter the pump suction without detrimental effect to the Containment Spray Nozzles.

Recirculation may start with a water depth of 1.5 ft on the containment floor. This is equivalent to the amount of water in the primary systems plus 60 percent of the RWST contents, or approximately 215,000 gal of water at 263°F. The maximum inlet velocity between the upper baffle and the container floor, which is the smallest flow area in this design, is approximately 1 ft/sec.

6.3.2.2.3 Net Positive Suction Head (NPSH) Requirements. The number of pumps operating, and the worst case flows for determining NPSH requirements are:

1. 3 high head pumps at 600 gpm each, or 1800 gpm total

2. 2 low head pumps at 3750 gpm each, or 7500 gpm total, and

3. 2 containment spray pumps at 1300 gpm each, or 2600 gpm total.

A quantitative analysis of the available and required NPSH for the SI, RHR and containment spray pumps for both the initial injection phase (with suction from the RWST) and the recirculation phase (suction from the containment sump) shows:

1. During the initial injection phase from RWST, (at initiation of this phase), the following applies:

Pump	NPSH, ft Required	Available
High head	25	51.1
Low head (RHR)	12	63.5
Containment spray	20	51.8

From this it can be seen that the high head pump is the controlling component for NPSH. The injection phase will be terminated just before the RWST level decreases to the point at which the available NPSH is reduced to the required NPSH of 25 ft at the runout flow of 600 gpm. Transition to recirculation from the containment sump will commence prior to this point.

2. During the recirculation phase (from containment sump) the following applies:

a. High head SI pumps - During recirculation via the high head pump, this pump and the RHR pump would be aligned in series, with the RHR pump (which has a head of 240 ft) boosting the suction of the high head pump. Thus, no NPSH problems would be experienced.

b. Containment spray pump - Same as high head SI pump.

c. RHR (low head) pump - During recirculation from the containment sump at 3750 gpm, the available NPSH with 1.5 ft of water on the containment floor is 19 ft. This takes credit for elevation head only. The required NPSH at 3750 gpm is 12 ft.

The high head recirculation flow path via the high head SI pumps is only required for the range of small break sizes for which the RCS pressure remains in excess of the shut-off head of the RHR pumps at the end of the injection phase.

Those portions of the SIS located outside of the containment which are designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment, meet the following requirements:

1. Shielding to maintain radiation levels within the guidelines set forth in 10CFR100

2. Collection of discharges from pressure relieving devices into closed systems, and

3. Means to limit radioactivity leakage to the environs, within guidelines set forth in 10CFR100.

Recirculation loop leakage is discussed in Section 6.3.2.5.5.

For the recirculation phase of the accident, the reactor coolant water which eventually is located on the containment floor is recirculated through the sump line from the containment to the suction of the RHR pump. Two independent and redundant recirculation lines are provided. Each line has two motor-operated valves. Both valves are located adjacent to the containment penetration in the RHR pit such that the line outside the containment can be isolated in the event of a passive failure. During recirculation, one recirculation train, which includes either of the two RHR pumps and either of the two residual heat exchangers, will be in service. The flow will go from the discharge of the RHR pump through the residual heat exchanger and then into the reactor via either the low head injection path or the high head injection path via the SI pumps. The high head injection path is provided in the event of a small break in which the pressure in the RCS is higher than the shut-off head of the RHR pumps.

In the event of a failure in the operating train during recirculation, the capability exists to switch to the other independent recirculation flow path; i.e., through the high head SI pumps to provide core cooling.

In the long term (post-accident) phase, injection through a separate header into the hot legs is possible by manual remote Control Room switch operation.

6.3.2.2.4 Cooling water

6.3.2.2.4.1 Component cooling system. During the recirculation mode, the Component Cooling System is used to cool the recirculation fluid as it passes through the residual heat exchanger. One of the three component cooling pumps and one of the two component cooling heat exchangers provide the cooling function during recirculation.

6.3.2.2.4.2 Service water system. The service water system is provided with redundant and independent loop headers and valves such that the two component cooling heat exchangers which are supplied with service water for cooling can have flow directed to them from the two independent headers. Two of the four service water pumps are required to operate during the recirculation phase.

6.3.2.2.5 Changeover from injection phase to recirculation phase. The sequence, from the time of the SI signal, for the changeover from the injection to the recirculation is as follows:

1. First, sufficient water is delivered into the containment during the injection phase to provide the required NPSH of the RHR pumps to allow the change to recirculation.

2. Second, the first low level alarm on the RWST sounds. At this point, the operator takes appropriate action to assure that sufficient NPSH exists for the operating pumps to run until the RWST is nearly empty. This alarm also serves to alert the operator to prepare for switchover to the recirculation mode.

3. Finally the second low level alarm on the RWST sounds. At this time, the operator performs the switchover operation.

The changeover from injection to recirculation is effected by the operator in the Control Room via a series of manual switching operations according to written procedures. Valves SI-856A and B are manually closed at the valves.

Remotely operated valves for the injection phase of the SIS (Figures 6.3.1-1 and 6.3.1-2) which are under manual control, (this is, valves which normally are in their ready position and do not receive a SI signal) have their positions indicated on a common portion of the control board. At any time during operation, when one of these valves is not in the ready position for injection, it is shown visually on the board. Table 6.3.2-1 is a listing of the instrumentation readouts on the control board which the operator can monitor during recirculation. In addition, an audible annunciation alerts the operator to the condition.

6.3.2.2.5.1 Location of the major components required for recirculation. The RHR pumps are located in the RHR pump pit (Elevation 203 ft 0 in.) which is below the basement floor of the Auxiliary Building (Elevation 226 ft 0 in). The RHR pump pit is located between the Containment Building and the Auxiliary Building. The residual heat exchangers are located on the first floor of the Auxiliary Building.

The high head SI pumps, component cooling pumps and component cooling heat exchangers are located in the Auxiliary Building (Elevation 226 ft 0 in).

The service water pumps are located in the intake structure, and the redundant piping to the component cooling heat exchangers is run underground.

6.3.2.2.6 Accumulators. The accumulators are pressure vessels filled with borated water and pressurized with nitrogen gas. During normal plant operation, each accumulator is isolated from the RCS by two check valves in series.

Should the RCS pressure fall below the accumulator pressure, the check valves open and borated water is forced into the RCS. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

The accumulators are passive engineered safety features (ESF) because the gas forces injection; no external source of power or signal transmission is needed to obtain fast-acting, high-flow capability when the need arises. One accumulator is attached to each of the cold legs of the RCS.

The design capacity of the accumulators is based on the assumption that flow from one of the accumulators spills onto the containment floor through the ruptured loop. The flow from the remaining accumulators provides sufficient water to fill the volume outside of the core barrel below the nozzles, the bottom plenum, and one-half the core.

The accumulators are carbon steel, clad with stainless steel and designed to American Society of Mechanical Engineers (ASME) Section III, Class C. Connections are provided for remotely draining or filling the fluid space during normal plant operation.

The minimum boron concentration of 1950 ppm during refueling, together with the control rods, maintains $\geq$ 6% $\Delta k/k$ shutdown margin in the core for these operations. The boron concentration is also sufficient to maintain the core in a shutdown condition without any rod cluster control (RCC) rods during refueling. For cold shutdown, at the beginning of core life, a lower concentration is sufficient for one percent shutdown with all but one stuck rod inserted. The boron concentration for refueling is well within solubility limits at ambient temperature.

The minimum boron concentration required in the accumulators is 1950 ppm as specified in the HBR 2 Technical Specifications, Section 3.3. Thus the boron concentration in the accumulators is more than adequate to maintain the core subcritical following a LOCA.

The level of borated water in each accumulator tank is adjusted remotely as required during normal plant operations. Refueling water is added using a SI pump. Water level is reduced by draining to the reactor coolant drain tank. Samples of the solution in the tanks are taken at the sampling station for periodic checks of boron concentration. Redundant level and pressure indicators are provided with readouts on the control board. Each indicator is equipped with high and low level alarms.

The accumulator design parameters are given in Table 6.3.2-2.

6.3.2.2.7 Boron Injection Tank (BIT). The tank is vertical with the outlet nozzle on top. A level alarm is provided from a stand pipe/vent arrangement on the outlet pipe at an elevation higher than the top of the tank. This alarm assures that the tank is maintained full of solution at all times.

Design parameters are given in Table 6.3.2-3.

6.3.2.2.8 Refueling water storage tank. In addition to its usual duty of supplying borated water to the refueling canal for refueling operations, this tank provides borated water to the SI pumps, the RHR pumps, and the containment spray pumps for mitigation of a LOCA. During plant operation, it is aligned to the suction of the pumps. It is constructed of stainless steel.

The capacity of the RWST is based on the requirement for filling the refueling canal, with a minimum of 300,000 gal being available for delivery. This capacity provides an amount of borated water to assure:

1. A volume sufficient to refill the reactor vessel above the nozzles.

2. The volume of borated refueling water needed to increase the concentration of initially spilled reactor coolant to a point that assures no return to criticality with the reactor at cold shutdown and all control rods except the most reactive RCC assembly inserted into the core.

3. A sufficient volume of water on the containment floor to permit the initiation of recirculation during a LOCA.

The water in the tank is borated to a concentration which assures reactor shutdown margin of $\geq$ 6% $\Delta k/k$ when all RCC assemblies are inserted and when the reactor is cooled down for refueling. The maximum boric acid concentration in the tank is approximately 1.4 weight percent boric acid. At 32°F, the solubility limit of boric acid is 2.2 percent. Therefore, the concentration of boric acid in the RWST is well below the solubility limit at 32°F.

The RWST is thermally insulated and provided with an electrical heating and control system capable of maintaining the water temperature at 90°F, however, this system will not normally be used.

Two level indications with low level alarms are provided.

A dynamic response analysis similar to that performed for the Containment Structure has been performed to determine the horizontal loads to be applied to the RWST for the hypothetical earthquake. Vertical seismic loads equal to 0.133g have been applied simultaneously. Wave generation in the tank has been taken into account. A membrane stress analysis of the vertical cylindrical tank was performed considering the discontinuities at the base and top.

The allowable stress criteria are 95 percent of yield for tension, 90 percent for compression and shear.

The RWST design parameters are given in Table 6.3.2-4.

6.3.2.2.9 Safety injection pumps. The three high head SI pumps for supplying borated water to the RCS are horizontal, centrifugal pumps driven by electric motors. Parts of the pumps in contact with borated water are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on each pump discharge to recirculate flow to the

RWST in the event the pumps are started with the normal flow paths blocked. The design parameters are presented in Table 6.3.2-5, and Figure 6.3.2-4 gives the performance characteristics of the high head SI pumps.

The two RHR (low head) pumps of the Auxiliary Coolant System are used to inject borated water at low pressure into the RCS. They are also used to recirculate fluid from the containment sump back to the RCS, to the suction of the spray pumps, or to the suction of the high head SI pumps. These pumps are of the in-line, centrifugal type, driven by electric motors. Parts of the pumps which contact the borated water and sodium hydroxide solution during recirculation are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on the discharge of each residual heat exchanger to recirculate cooled fluid to the suction of its RHR pump, should these pumps be started with their normal flow paths blocked. The design parameters for the RHR pumps are presented in Table 6.3.2-5, and the characteristics are shown in Figure 6.3.2-5.

The pressure-containing parts of the pumps are castings conforming to American Society for Testing and Materials (ASTM) A-351 Grade CF8 or CF8M. Stainless steel forgings were procured per ASTM A-182 Grade F304 or F316 or ASTM A-336, Class F8 or F8M, and stainless plate was constructed to ASTM A-240, Type 304 or 316. All bolting material conforms to ASTM A-193. Materials such as weld-deposited Stellite or Colmonoy are used at points of close running clearances in the pumps to prevent galling and to assure continued performance ability in high velocity areas subject to erosion.

All pressure-containing parts of the pumps were chemically and physically analyzed, and the results checked to ensure conformance with the applicable ASTM specification. In addition, all pressure-containing parts of the pump were liquid penetrant inspected in accordance with Appendix VIII of Section VIII of the ASME Boiler and Pressure Vessel (B&PV) Code. The acceptance standard for the liquid penetrant test was USAS B31.1, Code for Pressure Piping, Case N-10.

The pump design was reviewed with special attention to the reliability and maintenance aspects of the working components. Specific areas included evaluation of the shaft seal and bearing design to determine that adequate allowances were made for shaft deflection and clearances between stationary parts.

Where welding of pressure containing parts was necessary, a welding procedure including joint detail was submitted for review and approval by Westinghouse. The procedure included evidence of qualification necessary for compliance with Section IX of the ASME Code, Welding Qualifications. This requirement also applies to any repair welding performed on pressure containing parts.

The pressure-containing parts of the pump were assembled and hydrostatically tested to 1.5 times the design pressure for 30 minutes.

Each pump was given a complete shop performance test in accordance with Hydraulic Institute Standards. The pumps were run at design flow and head, shut-off head, and three additional points to verify performance characteristics. Where NPSH is critical, this value was established at design flow by means of adjusting suction pressure.

Details of the component cooling and service water pumps which serve the SIS are presented in Section 9.2.

6.3.2.2.10 Heat Exchangers. The two residual heat exchangers of the Auxiliary Coolant System cool the recirculated sump water. These heat exchangers are sized for the cooldown of the RCS. Table 6.3.2-6 gives the design parameters of the heat exchangers.

The ASME Code has strict rules regarding the wall thicknesses of all pressure-containing parts, material quality assurance provisions, weld joint design, radiographic and liquid penetrant examination of materials and joints, and hydrostatic testing of the unit, as well as requiring final inspection and stamping of the vessel by an ASME Code inspector.

The design of the heat exchangers also conforms to the requirements of Tubular Exchanger Manufacturer's Association (TEMA) for Class R heat exchangers. Class R is the most rugged class of TEMA heat exchangers and is intended for units where safety and durability are required under severe service conditions. Items such as tube spacing, flange design, nozzle location, baffle thickness and spacing, and impingement plate requirements are set forth by TEMA Standards.

In addition to the above, additional design and inspection requirements were imposed to ensure rugged, high quality heat exchangers such as: confined-type gaskets, main flange studs with two nuts on each end to ensure permanent leak tightness, general construction and mounting brackets suitable for the plant seismic design requirements, tubes and tube sheet capable of withstanding full shell side pressure and temperature with atmospheric pressure on the tube side, ultrasonic inspection in accordance with Paragraph N-324.3 of Section III of the ASME Code of all tubes before bending, penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts, a hydrostatic test duration of not less than thirty minutes, the witnessing of hydro and penetrant tests by a qualified inspector, a thorough, final inspection of the unit for good workmanship of any gouge marks or other scars that could act as stress concentration points, a review of the radiographs and of the certified chemical and physical test reports for all materials used in the unit.

The residual heat exchangers are conventional vertical shell and U-tube type units. The tubes are seal welded to the tube sheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube handle. Each unit has an SA-285 Grade C carbon steel shell, an SA-234 carbon steel shell end cap, SA-213 TP-304 stainless steel tubes, an SA-240 Type 304 stainless steel channel, an SA-240 Type 304 stainless steel channel cover and an SA-240 Type 304 stainless steel tube sheet.

6.3.2.2.11 Valves. All parts of valves used in the SIS in contact with borated water are austenitic stainless steel or equivalent corrosion-resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of SI or isolation of the system have remote position indication in the Control Room.

Valving is specified for exceptional tightness and, where possible, such as instrument valves, packless diaphragm valves are used. All valves except those which perform a control function are provided with backseats which are capable of limiting leakage to less than 1.0 cc/hr/in. of stem diameter, assuming no credit taken for valve packing. ECCS external system leakage is maintained within 2 gallons per hour as verified periodically by plant surveillance testing. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves are totally enclosed. Control and motor-operated valves, 2 1/2 in. and above, which are exposed to recirculation flow, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the Waste Disposal System or have had stuffing boxes live loaded and leakoff lines removed.

The check valves which isolate the SIS from the RCS are installed immediately adjacent to the reactor coolant piping to reduce the probability of an injection line rupture causing a LOCA.

Two relief valves are associated with the post loss-of-coolant recirculation. One is located outside the containment at the BIT discharge to prevent overpressure in the header and in the BIT. The high head SI piping leading to the hot legs is protected by a relief valve inside the containment in the test line.

The relieving capacity of these valves is based on a flow several times greater than the expected leakage rate through the check and isolation valves. They will also prevent overpressurization due to thermal expansion.

The SI Cold Leg Injection Lines between the SI-870 and SI-868 valves are protected from overpressurization by a relief valve (SI-857B) located downstream of SI-868B. The relieving capacity of this valve is greater than the expected check valve leakage from the RCS. The relief valve discharges to the pressurizer relief tank.

The RHR loop is protected by a relief valve in the common header leading to the accumulator pipes. The valve is located inside the containment and is relieved to the pressurizer relief tank. Apart from relieving possible leakage from the RCS, the valve is sized to relieve flow from one charging pump.

The gas relief valves on the accumulator protect them from pressures in excess of the design value.

6.3.2.2.12 Motor-operated valves. The pressure-containing parts (body, bonnet, and discs) of the valves employed in the SIS are designed per criteria established by the USAS B16.5 or MSS SP66 specifications. The materials of construction for these parts are procured to applicable ASME or ASTM specifications for austenitic stainless steel materials. All material in contact with the primary fluid, except the packing, is austenitic stainless steel or equivalent corrosion resisting material. The pressure-containing cast components were radiographically inspected as outlined in ASTM E-71, Class 1 or Class 2. The body, bonnet, and discs were liquid penetrant inspected in accordance with the ASME Code, Section VIII, Appendix VIII. The liquid penetrant acceptable standard was as outlined in USAS B31.1 Case N-10.

When a gasket is employed, the body-to-bonnet joint was designed per ASME B&PV Code Section VIII or USAS B16.5 with a fully trapped, controlled compression, spiral wound, asbestos or graphite-filled gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A194, respectively.

The entire assembled unit was hydrotested as outlined in MSS SP-61, with the exception that the test was maintained for a minimum period of 30 minutes per inch of wall thickness. Any leakage was cause for rejection. The seating design is of the Darling parallel disc design, the Crane flexible wedge design, or the equivalent. These designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, the motor operator has to work only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and provide ease of gate movement. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear. Nickel-chrome-boron may be used as an alternate hard-surfacing material.

The stem material is ASTM A276 Type 316 condition B, or precipitation hardened 17-4 PH stainless procured and heat treated to Westinghouse Specifications. These materials were selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. With the exception of valves which have been live loaded and have had leakoff lines capped, the valve stuffing box is designed with a lantern ring leak-off connection with a minimum of a full set of packing below the lantern ring and a maximum of one-half of a set of packing above the lantern ring; a full set of packing is defined as a depth of packing equal to 1 1/2 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials has been very favorable in both conventional and nuclear power plants.

The motor operator is extremely rugged and is noted throughout the power industry for its reliability. The unit incorporates a "hammer blow" feature that allows the motor to impact the discs away from the fore or backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed.

The valve was assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned, and packaged per specifications. All manufacturing procedures employed by the valve supplier such as hard facing, welding, repair welding and testing were submitted to Westinghouse for approval.

For those valves which must function on the SI signal, 10 sec operators are provided. For all other valves in the system, the valve operator completes its cycle from one position to the other within 120 sec.

Valves which must function against system pressure were designed such that they function with a pressure drop equal to full system pressure across the valve disc.

6.3.2.2.13 Manual valves. The stainless steel manual globe, gate, and check valves were designed and built in accordance with the requirements outlined in the motor-operated valve description above.

The carbon steel valves were built to conform with USAS B16.5. The materials of construction of the body, bonnet, and disc conformed to the requirements of ASTM A105 Grade II, A181 Grade II, or A216 Grade WCB or WCC. The carbon steel valves pass only non-radioactive fluids and were subjected to hydrostatic test as outlined in MSS SP-61, except that the test pressure was

maintained for at least 30 minutes per inch of wall thickness. Since the fluid controlled by the carbon steel valves is not radioactive, the double packing and seal weld provisions included in the stainless steel valve design were not provided.

6.3.2.2.14 Accumulator check valves. The pressure-containing parts of this valve assembly were designed in accordance with MSS SP-66. All parts in contact with the operating fluid are of austenitic stainless steel or of equivalent corrosion resistant materials procured to applicable ASTM or Westinghouse Atomic Power Division (WAPD) specifications. The cast pressure-containing parts were radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The cast pressure-containing parts, machined surfaces, finished hard facings, and gasket bearing surfaces were liquid penetrant inspected per the ASME Code, Section VIII, and the acceptance standard was as outlined in USAS B31.1 Code Case N-10. The final valve was hydrotested per MSS SP-66, except that the test pressure was maintained for at least 30 minutes. The seat leakage test was conducted in accordance with the manner prescribed in MSS SP-61, except that the acceptable leakage was 2 cc/hr/in. nominal pipe diameter.

The valve was designed with a low presure drop configuration with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The Clapper arm shaft was manufactured from 17-4 PH stainless steel heat treated to Westinghouse Specifications. The clapper arm shaft bushings were manufactured from Stellite No. 6 or nickel-chrome-boron materials. The various working parts were selected for their corrosion resistant, tensile, and bearing properties.

The disc and seat rings are manufactured from a forging. The mating surfaces are hard faced with Stellite No. 6 or nickel-chrome-boron to improve the valve seating life. The disc is permitted to rotate, providing a new seating surface after each valve opening.

The valves are intended to be operated in the closed position, with a normal differential pressure across the disc of approximately 1550 psi. The valves remain in this position except for testing and SI. Since the valve is not required to normally operate in the open condition, it will not be subjected to impact loads caused by sudden flow reversal, and it is expected that this equipment will not have difficulties performing its required functions.

When the valve is required to function, a differential pressure of less than 25 psig will shear any particles that may attempt to prevent the valve from functioning. Although the working parts are exposed to the boric acid solution contained within the reactor coolant system, a boric acid "freeze up" is not expected with this low a concentration.

The experience derived from the check valves employed in the Emergency Injection System of the Carolina - Virginia Tube Reactor (CVTR) in a similar system indicates that the system is reliable and workable. The CVTR Emergency Injection System, normally maintained at containment ambient conditions, was separated from the main coolant piping by a single six inch check valve. A leak detector was provided at a proper elevation to accumulate any leakage coming back through the check valve. A level alarm provided a signal on excessive leakage. The pressure differential was 1500 psi and the system was

stagnant. The valve was located 2 to 3 ft from the main coolant piping, which resulted in some heatup and cooldown cycling. The CVTR went critical late in 1963 and operated until 1967. During that time, the level sensor in the detection never alarmed due to check valve leakage.

6.3.2.2.15 Relief Valves

The accumulator relief valves are sized to pass nitrogen gas at a rate in excess of the accumulator gas fill line delivery rate. The relief valves will also pass water in excess of the expected leak rate, but this is not necessary because the time required to fill the gas space gives the operator ample opportunity to correct the situation. For an inleakage rate 15 times the manufacturing test rate, there will be about 1000 days before water will reach the relief valves. Prior to this, level and pressure alarms would have been actuated.

The SI test line relief valve is provided to relieve any pressure above design that might build up in the high head SI piping. The valve will pass a nominal 60 gpm, which is far in excess of the manufacturing design leak rate of 24 cc/hr.

6.3.2.2.16 Leakage Limitations

Valving was specified for exceptional tightness. Small, normally open valves have backseats which limit leakage to less than one cubic centimeter per hour per inch of stem diameter, assuming no credit for packing in the valve. Normally closed globe valves are installed with recirculation flow under the seat to prevent stem leakage from the more radioactive fluid side of the seat.

Motor-operated valves, with the exception of those which have been live loaded and had leakoff lines capped, which are exposed to recirculation flow, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the WDS.

The specified leakage across the valve disc required to meet the equipment specification and hydrotest requirements is as follows:

a) Conventional globe - 3 cc/hr/in. of nominal pipe size

b) Gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb USA Standard

c) Motor-operated gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb USA Standard

d) Check valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in. for 300 and 150 lb USA Standard, and

e) Accumulator check valves - 2 cc/hr/in. of nominal pipe size.

Relief valves are totally enclosed. Leakage from components of the recirculation loop, including valves, is tabulated in Table 6.3.2-7.

6.3.2.2.17 Piping. All SIS piping in contact with borated water is austenitic stainless steel. Piping joints are welded, except for the flanged connections at the SI and containment spray pumps.

The piping beyond the accumulator stop valves was designed for RCS conditions (2485 psig, 650°F). All other piping connected to the accumulator tanks was designed for 900 psig and 650°F.

The SI pump suction piping (210 psig at 300°F) from the RWST was designed for low pressure losses to meet NPSH requirements of the pumps.

The SI high pressure branch lines (1500 psig at 300°F) to the hot legs were designed for high pressure losses to limit the flow rate out of a potential rupture of a branch line at the connection to the reactor coolant loop.

The piping was designed to meet the minimum requirements set forth in the USAS B31.1 Code for Pressure Piping, Nuclear Code Case N-7, USAS B36.10 and B36.19, ASTM Standards, and supplementary standards plus additional quality control measures.

Minimum wall thicknesses were determined by the USAS Code formula in Power Piping, Section 1, USAS Code for Pressure Piping. This minimum thickness was increased to account for the manufacturer's permissible tolerance of minus 12-1/2 percent on the nominal wall. Purchased pipe and fittings have a specified nominal wall thickness that is no less than the sum of that required for pressure containment, mechanical strength, and manufacturing tolerance.

Thermal and seismic piping flexibility analyses were performed. Special attention was directed to the piping configuration at the pumps with the objective of minimizing pipe-imposed loads at the suction and discharge nozzles. Piping is supported to accommodate expansion due to temperature changes during the accident.

Pipe and fitting materials were procured in conformance with all requirements of the applicable ASTM and USAS specifications. All materials were verified for conformance to specification and documented by certification of compliance to ASTM material requirements. Specifications imposed additional quality control upon the suppliers of pipes and fittings as listed below.

1. Check analyses were performed on both the purchased pipe and fittings.

2. Pipe branch lines between the reactor coolant pipes and the isolation stop valves conformed to ASTM A376 and met the supplementary requirements S6 ultrasonic testing (UT).

3. Fittings 2 1/2 inches and above conformed to the requirements of ASTM A403. Fittings 3 inches and above had requirements for UT inspections similar to S6 of ASTM A376. The 6 inch diameter end caps used in fabricating strainers for the 3/4 inches diameter piping branching off of the 3 inch discharge lines of the safety injection pumps are an exception.

Shop fabrication of piping subassemblies was performed by reputable suppliers in accordance with specifications which defined and governed material procurement, detailed design, shop fabrication, cleaning, inspection, identification, packaging and shipment.

Welds for pipes sized 2-1/2 in. and larger are butt welded. Reducing tees are used where the branch size exceeds 1/2 of the header size. Branch connections of sizes that are equal to or less than 1/2 of the header size are of a design that conforms to the USAS rules for reinforcement set forth in the USAS B31.1 Code for Pressure Piping. Bosses for branch connections are attached to the header by means of full penetration welds.

All welding was performed by welders and welding procedures qualified in accordance with the ASME Code, Section IX, Welding Qualifications. The Shop Fabricator was required to submit all welding procedures and evidence of qualifications for review and approval prior to release for fabrication. All welding materials used by the Shop Fabricator were required to have prior approval.

All high pressure piping butt welds containing radioactive fluid at greater than 600°F temperature and 600 psig pressure or equivalent were radiographed. The remaining piping butt welds were randomly radiographed. The technique and acceptance standards were those outlined in UW-51 of the ASME Code, Section VIII. In addition, butt welds were liquid penetrant examined in accordance with the procedure of the ASME Code, Section VIII, Appendix VIII, and the acceptance standard as defined in the USAS Nuclear Code Case N-10. Finished branch welds were liquid penetrant examined on the outside and, where size permits, on the inside root surfaces.

A post-bending solution anneal heat treatment was performed on hot-formed stainless steel pipe bends. Completed bends were then completely cleaned of oxidation from all affected surfaces. The shop fabricator was required to submit the bending, heat treatment and clean-up procedures for review and approval prior to release for fabrication.

General cleaning of completed piping subassemblies (inside and outside surfaces) was governed by basic ground rules set forth in the specifications. For example, these specifications prohibit the use of hydrochloric acid and limit the chloride content of service water and demineralized water.

Packaging of the piping subassemblies for shipment was done so as to preclude damage during transit and storage. Openings were closed and sealed with tight-fitting covers to prevent entry of moisture and foreign material. Flange facings and weld end preparations were protected from damage by means of wooden cover plates securely fastened in position. The packing arrangement proposed by the shop fabricator was subject to approval.

6.3.2.2.18 Pump and Valve Motors

6.3.2.2.18.1 Motors Outside the Containment. Motor electrical insulation systems were supplied in accordance with USAS, IEEE, and NEMA standards and were tested as required by such standards. Temperature rise design selection was such that normal long life is achieved even under accident loading conditions.

Although the motors which were provided only to drive ESF equipment are normally run only for test, the design loading and temperature rise limits were based on accident conditions. Normal design margins were specified for these motors to make sure the expected lifetime included allowance for the occurrence of accident conditions.

Criteria for motors of the SIS required that under any anticipated mode of operation, the motor name plate rating not be exceeded. The motors have a 1.15 service factor for normal operation. Design and test criteria ensured that motor loading does not exceed the application criteria.

6.3.2.2.18.2 Motors Inside the Containment

The motor operators for the valves inside containment were designed to withstand containment environmental conditions following a LOCA so that the valves can perform their required function during the recovery period.

Periodic operation of the motors and testing of the insulation ensure that the motors remain in a reliable condition.

6.3.2.3 Applicable Code and Classifications

The ECCS has been designed to conform with the codes and classifications applicable at the time of construction. These are discussed in Section 3.2.

6.3.2.4 Material Specifications and Compatibility

Material specifications for each component are given in the component discriptions in Subsection 6.3.2.2.

Emergency core cooling system components are austenitic stainless steel, and hence are quite compatible with the spray solution over the full range of exposure in the post-accident regime. While this material is subject to crevice corrosion by hot concentrated caustic solution, the NaOH additive cannot enter the containment or ECCS without first being diluted and partially neutralized with boric acid to a mild solution. Corrosion tests performed with simulated spray showed negligible attack, both generally and locally, in stressed and unstressed stainless steel at containment and ECCS conditions. These tests are discussed in Reference 6.3.2-1.

6.3.2.5 System Reliability

To provide protection for large area ruptures in the RCS, the SIS must respond to rapidly reflood the core following the depressurization and core voiding that is characteristic of large area ruptures. The accumulators act passively to perform the rapid reflooding function with no dependence on the normal or emergency power sources.

Operation of this system with two of the three available accumulators delivering their contents to the reactor vessel (one accumulator spilling through the break) prevents fuel cladding melting and limits the metal-water reaction to an insignificant amount (<1 percent).

The function of the SI or RHR pumps is to complete the refill of the reactor vessel and ultimately return the core to a subcooled state. As discussed in Section 15.6.5, the flow from one SI pump and one RHR pump is sufficient to complete this refill function. Moreover, there is sufficient excess water delivered by the accumulators to tolerate a delay in starting the pumps.

Initial response of the injection systems is automatic, with appropriate allowances for delays in actuation of circuitry and active components. The active portions of the injection systems are automatically actuated by the SI signal (Section 7.3). In addition, manual actuation of the entire injection system and individual components can be accomplished from the Control Room. In analysis of system performance, delays in reaching the programmed trip points and in actuating components are conservatively established on the basis that only onsite emergency power is available.

The starting sequence of the SI, RHR pumps and the related emergency power equipment is designed so that delivery of the full rated flow is reached within 26 sec after the process parameters reach the setpoints for the injection signal.

Since the 26 sec delay includes an allowance for pump runup to full rated delivery, some credit is taken for the partial flow which occurs before the full rated flow is reached. An analysis of the partial flow which occurs during the pump runup period shows that it is conservative to assume full rated flow at 25 sec. 25 sec is the delay which is assumed in the analysis of a postulated LOCA.

For the small break LOCA analysis, an additional delay time is allowed to account for the receipt of SIS, either from low pressurizer pressure or from high containment pressure.

6.3.2.5.1 Single Failure Analysis

A single active failure analysis is presented in Table 6.3.2-8. All credible active system failures are considered. The analysis of the LOCA is consistent with the single failure analysis. It is based on the worst single failure (generally a pump failure) in both the SI and RHR pumping systems. The analysis shows that the failure of any single active component will not prevent fulfilling the design function. In addition, an alternative flow path is available to maintain core cooling if any part of the recirculation flow path becomes unavailable. This is evaluated in Table 6.3.2-9.

6.3.2.5.2 Service Life

All portions of the system located within the containment are designed to operate without benefit of maintenance and without loss of functional performance for the duration of time the component is required.

6.3.2.5.3 Passive Systems

The accumulators are a passive safety feature in that they can perform their design function in the total absence of an actuation signal or power source. The only moving parts in the accumulator injection train are the two check valves.

The working parts of the check valves are exposed to fluid of relatively low boric acid concentration contained within the reactor coolant loop. Even if some unforeseen deposition accumulated, calculations have shown that a differential pressure of about 25 psi will shear any particles in the bearing that may attempt to prevent the valve from functioning.

The isolation valve at each accumulator is only closed momentarily for testing, or when the reactor is intentionally depressurized. The isolation valve is normally opened, and an alarm in the Control Room sounds if the valve is inadvertently closed. It receives a signal to open when SIS is initiated.

The check valves operate in the closed position with a nominal differential pressure across the disc of approximately 1550 psi. They remain in this position except for testing or when called upon to function. Since the valves operate normally in the closed position, and are therefore not subject to the abuse of flowing operation or impact loads caused by sudden flow reversal and seating, they do not experience any wear of the moving parts.

When the RCS is being pressurized during the normal plant heatup operation, the check valves are tested for leakage as soon as there is about 100 psi differential across the valve. This test confirms the seating of the disc and whether or not there has been an increase in the leakage since the last test. When this test is completed, the discharge line test valves are opened and the RCS pressure increase continues. There should be no increase in leakage from this point on, since increasing reactor coolant pressure increases the seating force and decreases the probability of leakage.

The accumulators can accept leakage back from the RCS without effect on their availability. Table 6.3.2-10 indicates that inleakage rates, over a given time period, require readjusting the level at the end of the time period. In addition, these rates are compared to the maximum allowed leak rates for manufacturing acceptance tests (20 cc/hr; i.e, 2 cc/hr/in.).

In-leakage at a rate of 5 cc/hr/in., 2-1/2 times test, would require that the accumulator water volume be adjusted approximately once every 30 months. This would indicate that level adjustments can be scheduled for normal refueling shutdowns and that this work can be done at the operator's convenience. At a leakrate of 30 cc/hr/in. (15 times the acceptance leak rate), the water level will have to be readjusted approximately once every 5 or 6 months. This readjustment will take about 2 hr maximum.

The accumulators are located inside the reactor containment and are protected from the RCS piping and components by a missile barrier. Accidental release of the gas charge in the three accumulators would cause an increase in the containment pressure of approximately 0.1 psi. This release of gas has been included in the containment pressure analysis for the LOCA.

During normal operation, the flow rate through the reactor coolant piping is approximately five times the maximum flow rate from the accumulator during injection. Therefore fluid impingement on reactor vessel components during operation of the accumulator is not restricting.

6.3.2.5.4 Emergency Flow to the Core. Special attention is given in the analysis to factors that could adversely affect the accumulator and SI flow to the core. These factors are as follows:

a) Steam binding in the core, including flow blockage due to loop sealing

b) Carryover of accumulator water during blowdown

c) Short circuiting of the accumulator from the core to another part of the RCS, and

d) Loss of accumulator water through the break.

6.3.2.5.5 Recirculation Loop Leakage. Table 6.3.2-7 summarizes the maximum potential leakage from the leak sources of the recirculation loop which goes through the RHR pumps, a residual heat exchanger, and the high head SI pumps. In the analysis, a maximum leakage is assumed from each leak source. For conservatism, a leakage of 10 drops per minute was assumed from each flange, although each flange would be adjusted to essentially zero leakage. The total maximum potential leakage resulting from all sources is 9400 cc/hr to the Auxiliary Building atmosphere and 12 cc/hr to the drain tank.

During external recirculation, significant margin exists between the design and operating conditions of the RHR system components, as shown in Table 6.3.2-11. In addition, during normal plant cooldown, operation of the RHR system is initiated when the primary system pressure and temperature have been reduced to 350 psig and 350°F, respectively. Since the maximum operating pressure and temperature during recirculation are 150 psig and 213°F, significant margin also exists between normal operating and accident conditions. In view of the above margins, it is considered that the leakage rates tabulated in Table 6.3.2-7 are conservative.

Leakage detection exterior to containment is achieved through use of sump level detection. The Auxiliary Building sump pumps start automatically in the event that liquid accumulates in the sump, and an alarm in the Control Room indicates that water has accumulated in the sump. Valving is provided to permit the operator to individually isolate each RHR pump.

6.3.2.5.6 Guard Pipe Protection for Sump Suction Line.

In the unlikely event that the sump suction line should fail, the guard pipe and bellows are capable of containing fluid at 60 psig at 365°F, which is in excess of the required 42 psig at 263°F. This failure would be identified during the performance of 10 CFR 50 Appendix J testing.

The containment pipe penetration assemblies consist of an expansion joint element welded to a pipe and sleeve going through the containment wall. The expansion joint elements were hydraulically formed from a stainless steel cylinder having a single longitudinal weld. Each longitudinal weld was radiographed. One end of the element is welded to a closure plate of the same material as the corresponding process line and the other end of the element is welded to a carbon steel closure plate. The latter plate is welded to a sleeve.

TABLE 6.3.2-4

REFUELING WATER STORAGE TANK DESIGN PARAMETERS

Number	1
Material	Stainless Steel
Total volume, gal	350,000
Minimum volume, (solution) gal	300,000
Normal pressure, psig	Atmospheric
Operating temperature, °F	Ambient
Design pressure, psig	Head Height
Design temperature, °F	95
Minimum Boron concentration (as boric acid), ppm	1950

TABLE 6.3.2-5

PUMP PARAMETERS

Safety Injection Pump Design Parameters

Number	3
Design pressure, discharge, psig	1,750
Design temperature, °F	300
Design flow rate, gpm	375
Max. flow rate, gpm	550
Design head, ft	2,500
Shutoff head, ft	3,500
Material	11 - 14 Chrome
Motor H.P.	350
Type	Horizontal centrifugal

Residual Heat Removal Pump Design Parameters

Number of pumps	2
Type	Inline centrifugal
Design pressure, discharge, psig	600
Design temperature, °F	400
Design flow, gpm	3,750
Design head, ft	225
Material	Austenitic stainless steel
Motor H.P	300

TABLE 6.3.2-6

RESIDUAL HEAT EXCHANGERS DESIGN PARAMETERS

Number	2
Design heat duty, Btu/hr (normal)	29.4×10^6
Design UA, Btu/hr/°F	1.41×10^6
Design cycles (85°F - 350°F)	Vertical shell and
Type	U-tube

	Tube-Side	Shell-side
Design pressure, psig	600	150
Design flow, lb/hr	1.88×10^6	4.29×10^6
Inlet temperature, °F	140	108
Outlet temperature, °F	124	115
Design temperature, °F	400	200
Material	Stainless steel	Carbon steel

TABLE 6.3.2-9

LOSS OF RECIRCULATION FLOW PATH

FLOW PATH	INDICATION OF LOSS OF FLOW PATH	ALTERNATIVE FLOW PATH
Low head recirculation		
From containment sump to low head injection header via the residual heat removal pumps and the residual heat exchangers	1. No flow in low head injection header. (flow monitor in main header)	From containment sump to high head injection header via the residual heat removal pumps, the residual heat exchangers, and the safety injection pumps
High head recirculation		
From containment sump to high head injection header via the residual heat removal pumps, the residual heat exchangers, the high head injection pumps suction header, and the high head injection pumps	1. No flow in high head injection headers (four flow monitors and two pressure monitors)	From containment sump to high head injection header via the residual heat removal pumps, the residual heat exchangers, the redundant high head recirculation suction header, and either or both of two of the three high head injection pumps
	2. Flow in only one of the two high head injection branch headers	As 1 except that flow from the safety injection pump(s) is only supplied to the unbroken branch header.

NOTE: As shown on Figure 6.2-1, there are valves at all locations where alternative flow paths are provided.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 ECCS Performance Tests

The Preoperational Test Program, including ECCS performance tests, is described in Chapter 14.

6.3.4.2 Reliability Tests and Inspections

6.3.4.2.1 Inspection Capability

All components of the SIS can be inspected periodically to demonstrate system readiness.

The pressure containing systems can be inspected for leaks from pump seals, valve packing, flanged joints, and safety valves during system testing.

In addition, to the extent practical, the critical parts of the reactor vessel internals, injection nozzles, pipes, valves, and SI pumps can be inspected visually or by boroscopic examination for erosion, corrosion, and vibration wear evidence, and for nondestructive test inspection where such techniques are desirable and appropriate.

6.3.4.2.2 System Testing

Surveillance requirements are specified in the Technical Specifications.

Testing can be conducted during plant shutdown to demonstrate proper automatic operation of the SIS. A test signal is applied to initiate automatic action and verification made that the SI pumps attain required discharge heads. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

The test is considered satisfactory if control board indication and visual observations indicate all components have operated and sequenced properly.

The accumulator pressure and level are continuously monitored during plant operation and flow from the tanks can be checked at any time using test lines.

The accumulators and the injection piping up to the final isolation valve are maintained full of borated water while the plant is in operation. The accumulators and injection lines are refilled with borated water as required by using the SI pumps to recirculate refueling water through the injection lines. A small test line is provided for this purpose in each injection header.

Flow in each of the hot leg injection lines and in the main flow line for the RHR pumps is monitored by flow indicators. Pressure instrumentation is also provided for the main flow paths of the SI and RHR pumps.

6.3.4.2.3 Components Testing

Preoperational performance tests of the components were performed in the manufacturer's shop. An initial system flow test demonstrated proper functioning of the system. Thereafter, periodic tests demonstrate that components are functioning properly.

Each active component of the SIS can be individually actuated on the normal power source at any time during plant operation to demonstrate operability. The test of the SI pumps employs the minimum flow recirculation test line which connects back to the refueling water storage tank. Remote operated valves are exercised and actuation circuits tested. The automatic actuation circuitry, valves and pump breakers also may be checked during integrated system tests performed during a planned cooldown of the RCS.

The operation of the remote stop valves in the accumulator discharge line can be tested by opening the remote test valves in the test line connected just downstream of the stop valves. Flow through the test line is measured, and the opening and closing of the discharge line stop valves are verified by the flow instrumentation. Test circuits are provided to periodically examine the leakage back through the check valves and to ascertain that these valves seat whenever the reactor system is raised.

The isolation valves are closed at any time that the RCS is depressurized. The SI actuation signal will cause this valve to open should it be in the closed position at the time of a LOCA.

The entire recirculation loop is pressurized during periodic testing of the ESF components. The recirculation piping is also leak tested at the time of the periodic re-tests of the containment.

Since the recirculation flow path is operated at a pressure in excess of the containment pressure, it is hydrotested during periodic re-tests at the recirculation operating pressures. This is accomplished by running each pump utilized during recirculation (safety injection, spray, and RHR pumps) in turn at near shut off head conditions and checking the discharge and recirculation test lines. The suction lines are tested by running the RHR pumps and opening the flow path to containment spray and SI pumps in the same manner as described above.

During the above test, system joints, valve packings, pump seals, leakoff connection, or other potential points of leakage are visually examined. Valve gland packing, pump seals, and flanges are adjusted or replaced as required to reduce the leakage to acceptable proportions. For power operated valves, final packing adjustments are made, and the valves are put through an operating cycle before a final leakage examination is made.

ASME Section XI requires that pressure tests be performed on ECCS each 40 month period of the ISI 10 year interval. ECCS is designated as Class 2 and as such the following criteria has been applied:

The Class 2 40 Month Pressure Testing procedures were written to meet the testing requirements of Table IWA-5210-1. This table specifies only functional and hydrostatic testing required per IWA-5211(b) and IWA-5211(d) but refers to IWC-5210 which had since been revised to include IWC-5210(1), "a system pressure test conducted during a system functional test of those [IWA-5211(b)] systems (or components) not required to operate during normal plant operation but for which periodic system (or component) functional tests are performed to meet the owners requirements," and IWC-5210(2), "a system pressure test conducted during a system inservice test [IWA-5211(c)] for those systems required to operate during normal plant operation." The test requirements, method, and frequency for Class 2 Pressure Retaining Components

6.4.5 TESTING AND INSPECTION

The tests to verify that the Control Room filter system will adequately remove radioactivity from the incoming ambient air, should there be an accidental radiation release to the atmosphere, are specified in the HBR 2 Technical Specifications, Appendix A to Facility Operating License No. DPR-23.

The inspection of the charcoal bed and charcoal filter housings of the filter system is performed each refueling outage as part of a refueling periodic test. This inspection includes a visual check of each system's filter bank and a check of individual cells when they are removed to obtain charcoal samples and to change the charcoal. The inspection also includes a freon leak check which would immediately detect a system leak caused by insufficient charcoal in the cells and by deformation of the housing.

Testing and inspection is also conducted to demonstrate Control Room envelope leak tightness and satisfactory operation of air cleaning unit fans, air handling unit fans, and the refrigeration equipment.

6.5.2 CONTAINMENT SPRAY SYSTEMS

6.5.2.1 Design Basis 3

In addition to its heat removal function, the Containment Spray System was designed to add sodium hydroxide (NaOH) to scrub elemental iodine from the containment atmosphere. The heat removal capability of the spray system is discussed in Section 6.2.2 (Containment Heat Removal).

The Containment Spray System iodine removal function was designed to limit the offsite thyroid dose to within 10CFR100 limits after a postulated LOCA.

Those portions of the spray systems located outside of the containment which were designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment were provided with closed systems for collection of discharges from pressure-relieving devices and adequate shielding to maintain radiation levels within the guidelines of 10CFR100.

The spray system was designed to operate over an extended period of time and to withstand, without loss of functional performance, the post-accident containment environment.

All associated components, piping, structures, and power supplies of the Containment Spray System were designed to Seismic Class I criteria.

Redundant active components were provided. System piping located within the containment was designed to be redundant with the redundant components separated in arrangement, unless it is fully protected by other means from damage which may follow any primary coolant system failure.

The starting sequence of the containment spray pumps and their related emergency power equipment was designed so that delivery of the minimum required flow is reached within 60 sec from receipt of the initiating signal, which is the delay assumed for the starting of containment cooling. The initiation of the addition of sodium hydroxide to the spray flow is automatic with no additional time delay.

The design bases for sizing of spray system components are discussed in Section 6.2.2 for spray pumps and piping, and in Section 6.1.1.2 for the spray additive eductor and spray additive tank. The pH characteristics, materials compatibility, and core spray stability are also discussed in Section 6.1.1.2.

Design basis, postulated accident conditions, and fission product releases are discussed in Section 15 for the LOCA and the fuel handling accident.

It should be noted that, in the analyses of postulated accidents (Chapter 15), quantitative credit was taken only for the spray system effectiveness in removing reacting and/or soluble forms of iodine. Sprays are effective in removing particulate iodine as well. However, experimental work done prior to the original Final Safety Analysis Report (FSAR) submittal was not considered extensive enough to assess accurately the effect of the spray on particulates and non-reactive iodine under the conditions which would exist in the containment after such an accident.

6.5.2.2 System Design

Adequate containment iodine removal capability is provided by the Containment Spray System shown in Figure 6.2.2-1. The components of this system are aligned into two subsystems. Each subsystem contains a pump, associated valving, and spray headers independently capable of delivering one-half of the total required flow of 2322 gpm. If one train is inoperable, the minimum delivered flow is, therefore, 1161 gpm. This system operates in two sequential modes:

a) Spray from the refueling water storage tank into the entire containment atmosphere using the containment spray pumps. During this mode, the contents of the spray additive tank (sodium hydroxide) are mixed into the spray stream to provide adequate iodine removal from the containment atmosphere by a washing action.

b) Recirculation of water from the containment sump is provided by the diversion of a portion of the recirculation flow from the discharge of the residual heat removal heat exchangers to the suction of the spray pumps after injection from the refueling water storage tank has been terminated.

The principal components of the Containment Spray System are two pumps, one spray additive tank, spray ring headers and nozzles, and the necessary piping and valves. The containment spray pumps and the spray additive tank are located in the Auxiliary Building. The spray pumps take suction directly from the refueling water storage tank.

The Containment Spray System also utilizes the two residual heat removal pumps, two residual heat exchangers, and associated valves and piping of the Safety Injection System (SIS) for the long-term recirculation phase of containment cooling and iodine removal.

During spray injection, approximately 80 gpm of pump discharge flow is diverted from the spray pump discharge through the spray eductors. The liquid from the tank then mixes with the liquid entering the suction of the pumps via the eductors. The pH of the resulting solution is suitable for the removal of iodine from the containment atmosphere (refer to Section 6.1.1.2).

During spray recirculation operation, the water is screened through a 7/32 in. mesh before leaving the containment sump.

The spray nozzles are stainless steel and have a 3/8 in. diameter orifice. The spray nozzles, of the ramp bottom design, are not subject to clogging by particles less than 1/4 in. in maximum dimension. Since particles larger than 7/32 in. in dimension are screened out of the spray recirculation flow, as indicated above, the spray nozzles are effectively protected against clogging and are capable of producing a mean drop size of approximately 1000 microns in diameter with the spray pump operating at design conditions and the containment at design pressure. The nozzles are connected to six ring headers located within the dome of the Containment Building. The lowest ring header is located at Elevation 372.3 ft and the highest ring header is located at Elevation 412.1 ft. There are 116 Spraco Model 1713 nozzles distributed on the six headers.

The containment spray pumps can be tested singly by opening the valves in the miniflow line. Each pump in turn can be started by operator action and checked for flow establishment. The spray injection valves can be tested with the pumps shut down.

The spray additive tank valves can be opened periodically for testing. The contents of the tank are periodically sampled to determine that the proper solution is present.

Initially the containment spray nozzle availability was tested by blowing smoke through the nozzles and observing the flow through the various nozzles in the containment.

During these tests the equipment was visually inspected for leaks. Leaking seals, packing, or flanges were tightened to eliminate the leak. Valves and pumps are operated and inspected after any maintenance to ensure proper operation.

6.5.2.4.3 System Testing

Permanent test lines for all containment spray loops are located so that the system, up to the isolation valves at the spray header, can be tested. These isolation valves can be checked separately.

The air test lines, for checking initially the spray nozzles, connect downstream of the isolation valves. Air flow through the nozzles is monitored by the use of hot air and infrared thermography.

During the initial preoperational tests of the spray system, the flow bypass through the spray eductors was checked. This initial test and all subsequent system tests are made with the spray additive tank isolation valves closed.

6.5.2.4.4 Operational Sequence Testing

The functional test of the SIS described in Section 6.2.2 demonstrates proper transfer to the emergency diesel generator power source in the event of loss of power. A test signal simulating the containment spray signal will be used to demonstrate operation of the spray system up to the isolation valves on the pump discharge.

6.5.2.5 Instrumentation Requirements

The spray system is actuated by the coincidence of two sets of two out of three (high-high) containment pressure signals. This starting signal starts the pumps and opens the discharge valves to the spray header. The valves associated with the spray additive tank open automatically upon receipt of the containment spray signal. After the containment spray signal is actuated, the system has the capability to allow the operator to stop the sodium hydroxide addition and reset the initiating signal if he determines that the actuation was not warranted, provided proper conditions are met. The system also has the capability to allow the operator to manually reinitiate the sodium hydroxide addition if required. Emergency procedures set forth guidelines for these actions. If required, the operator can manually actuate the entire system from the Control Room.

Remotely operated valves of the Containment Spray System, which are under manual control (that is, valves which normally are in their ready position and do not receive a containment spray signal), have their positions indicated on a common portion of the control board. At any time during operation when one of these valves is not in the ready position for injection, it is shown visually on the board.

5| Containment spray additive tank level is indicated in the Control Room. A level indicating alarm is provided in the Control Room to alarm if, at any time, the spray additive tank contains less than the required amount of sodium hydroxide solution. Periodic sampling confirms that proper sodium hydroxide concentration exists in the tank.

During the recirculation phase, some of the flow leaving the residual heat exchangers may be bled off and sent to the suction of either the containment spray pumps or the high head safety injection pumps. Minimum flow requirements have been set for the flow being sent to the core and for the flow being sent to the containment spray pump suction. Sufficient flow instrumentation is provided so that the operator can perform appropriate flow adjustments with the remote throttle valves in the flow path as shown in Figure 6.2.2-1.

6.5.2.6 Materials

A complete discussion of materials utilized in the Containment Spray System is presented in Section 6.1.1.1. The chemical composition and stability of spray additives in storage, in the spray solution, and in the sump are presented in Section 6.1.1.2.

6.8.2 System Design

6.8.2.1 System Description. The IVSW system flow diagram is shown in Figure 6.8.2-1.

System operation is initiated either manually or by any automatic safety injection (SI) signal. When actuated, the IVSW System interposes water inside the penetrating line between two isolation points located outside the containment. The resulting water seal blocks leakage of the containment through valve seats and stem packing. The water is introduced at a pressure slightly higher (approximately 47 psig) than the containment design pressure of 42 psig. The possibility of leakage from the containment or the RCS past the first isolation point is thus prevented by assuring that if leakage does exist, it will be from the seal water system into the containment. Service is discontinued after the manual reset buttons for PCV-1922 A and B are reset after a containment isolation Phase A reset.

The system includes one seal water tank capable of supplying the total requirements of the system. The tank is pressurized with a nitrogen blanket supplied from two independent sources. Primary supply is from the plant nitrogen supply header through a pressure regulating control valve. Automatic backup supply is provided from two high pressure nitrogen bottles through separate high and low pressure regulating valves. Design pressure of the tank and piping is 150 psig. The injection piping runs and the piping from the nitrogen supply bottles are fabricated using 3/8 in. OD stainless steel tubing, which is capable of 2500 psig service. Relief valves are provided to prevent over-pressurization of the system if a pressure control valve fails, or if a seal water injection line communicates with a high pressure line due to a check valve failure in the seal water line. The seal water tank requires no external power source to maintain the required driving pressure.

Local instrumentation is also provided, as shown in Figure 6.8.2-1. The primary source of N_2 from the plant N_2 supply header is backed up by two, independent, high pressure N_2 bottles. If there should be a break or failure of the N_2 header, the N_2 blanket pressure is maintained by the tanks and blowdown through the N_2 header is prevented by check valves.

The tank supplies pressurized water to four distribution headers. Header "A" is the manual header, meaning an isolation valve on this header must be pressurized by opening a manual valve supplying the individual isolation valve. Headers "B", "C", and "D" are automatic headers that are pressurized through one or both of two redundant, fail-open, air-operated valves in parallel. These valves open on receipt of an SI signal. A loss of power will cause the automatic valves to open, since automatic initiation is a de-energized signal to vent air from the valve operators. System operation is initiated by a Phase A containment isolation signal which accompanies any SI signal. System operation is discontinued after the manual reset buttons for valves PCV-1922 A and B are reset after the Phase A reset.

Liquid carrying piping two inches and larger with design pressure or temperature exceeding 200 psig or 200°F is typically isolated by one manual or remote-operated, double disc gate valve. A drawing of this valve is presented in Figure 6.8.2-2. Redundant isolation barriers are provided when the valve is closed. The upstream and downstream discs are forced against their respective seats by the closing action of the valve. Seal water is injected through thevalve bonnet or body and pressurizes the space between the two valve discs.

The seal water pressure in excess of the potential accident pressure eliminates any outleakage past the first isolation point.

For smaller lines, isolation is typically provided by two globe valves in series with the seal water injected into the pipe between the valves. The valves are oriented such that the seal water wets the stem packing. When the valves are closed for containment isolation, the first isolation point is the valve plug in the valve closest to containment, and the water seal is applied between the valve plug and stem packing. In a number of the smaller lines, isolation is provided by two diaphragm (Saunders Patent) valves in series, with the seal water injected into the pipe between the valves.

The design of the IVSW System is based on the conservative assumption that all containment isolation valves serviced by the IVSW System are leaking at 50 cc/hr/inch of nominal pipe diameter.

Acceptable leakage criteria is based on a total allowable leakage value calculation for each of the four (4) IVSW System headers, using the IVSW System design leakage.

In addition, should one of the isolation valves fail to close, flow through the failed valve will be limited by a restricting orifice to a maximum leakage value of 63,200 cc/hr. A water seal at the failed valve is assured by proper slope of the protected line, or a loop seal, or by additional valves on the side of the isolation valves away from the containment.

The seal water tank is sized to provide at least a 24 hr supply of seal water under the following adverse circumstances: isolation valves leaking at the design rate of 50 cc/hr/in. plus the failure of the largest containment isolation valve to seat, resulting in leakage at the maximum rate of 1000 cc/hr/in. The seal water tank is sized to satisfy these conditions. Two separate, independent, seismically qualified sources of makeup water (primary water and service water) are provided to ensure that an adequate supply of seal water is available for long-term operation. Service water makeup is from two sources - the service water header, and from each of the service water booster pumps. This assures a redundant long-term supply of water from a source at greater than the 1.1 times the design pressure (approximately 46 psig). Based on maximum leakage and flows into the tank from makeup sources, use of the makeup source would be required for only minimal amounts of time each day at very low flows which will not affect other functions of the makeup system.

6.8.2.2 Isolation Valve Seal Water Actuation Criteria. Containment isolation and seal water injection are accomplished automatically for certain penetrating lines requiring early isolation, and manually for others, depending on the status of the system being isolated and the potential for leakage in each case.

The automatically operated containment isolation valves are actuated to the closed position by one of two separate containment isolation signals. The first of these signals is derived in conjunction with automatic SI actuation, and trips the majority of the remotely operated isolation valves. These valves are in the so-called "non-essential" process lines penetrating the containment. This is defined as "Phase A" isolation, and the remotely operated valves are designated by the letter "T".

This signal also initiates automatic seal water injection. The second, or "Phase B" containment isolation signal, is derived upon actuation of the Containment Spray System, and actuates the remotely operated containment isolation valves in the so-called "essential" process lines penetrating the containment. These remotely operated valves are designated by the letter "P".

A manual containment isolation signal or SI signal can be generated from the Control Room. This signal performs the same functions as the automatically derived "T" signal, i.e., "Phase A" isolation and automatic seal water injection.

Generally, the following criterion determines whether the isolation and seal water injection is automatic or manual. Automatic containment isolation and automatic seal water injection are required for lines that could communicate with the containment atmosphere and be void of water following a LOCA.

These lines include:

1. Reactor coolant pump seal water return line (Phase B isolation)

2. Letdown line

3. RCS sample lines

4. Reactor coolant vent line

5. Reactor coolant drain tank gas analyzer line.

Automatic containment isolation and automatic seal water injection are also provided for the following lines, which are not connected directly to the RCS, but terminate inside the containment at certain components. These components can be exposed to the reactor coolant or to the containment atmosphere as the result of leakage or failure of a related line or component. The isolation lines are not required for post-accident service.

These lines include:

1. Pressurizer relief tank gas analyzer line

2. Pressurizer relief tank makeup line

3. SI System test line

4. Reactor coolant drain tank pump discharge line

5. Steam generator blowdown lines

6. Steam generator blowdown sample lines

7. Accumulator sample line, and

8. Containment sump pump discharge.

Manual containment isolation and manual seal water injection are provided for lines that are normally filled with water and will remain filled following the LOCA, and for lines that must remain in service for a time following the accident. The manual seal water injection assures a long-term seal. These lines include:

1. Reactor coolant pump seal water supply lines

2. Charging line

3. SI headers

4. Boron injection lines, and

5. Containment spray headers.

Seal water injection is not necessary to ensure the integrity of isolated lines in the following categories:

1. Lines that are connected to non-radioactive systems outside the containment, and in which a pressure gradient exists that opposes leakage from the containment. These include nitrogen supply lines to the pressurizer relief tank, accumulators, the reactor coolant drain tank, the instrument air header, the pressurizer deadweight tester line, and the plant air header.

2. Lines that do not communicate with the containment atmosphere or RCS and are missile-protected throughout their length inside containment. These lines are not postulated to be severed or otherwise opened to the containment atmosphere as a result of a LOCA. These include the steam and feedwater headers, the containment ventilation system cooling water supply and return lines, and the excess letdown heat exchanger cooling water supply and return lines. The reactor coolant pump cooling water supply and return lines are also included in this category; however, seal water injection is provided. Reference 6.2.4-1 provides additional details.

3. Lines that are designed for long-term, post-accident service as part of the engineered safety features. The only lines in this category are the containment sump recirculation lines. These lines are connected to a closed system outside containment.

4. Special lines such as the fuel transfer tube, containment purge ducts, and the containment pressure and vacuum relief lines. These lines are tested as per 10 CFR 50 Appendix J.

TABLE 6.8.2-1

ISOLATION VALVE SEAL WATER TANK

Material	ASTM A-240
Design Pressure, psig	150
Design Temperature, ^{o}F	200
Operating Pressure, psig	50-100
Operating Temperature, ^{o}F	Ambient
Code	ASME Code, Section VIII

6.8.3 DESIGN EVALUATION

The IVSW System provides an extremely prompt and reliable method of limiting the fission product release from the containment isolation valves in the event of a LOCA.

The employment of the system during a LOCA, while not considered for analysis of the consequences of the accident, provides an additional means of conservatism in ensuring that leakage is minimized. No detrimental effect on any other safeguards system will occur should the seal water system fail to operate.

The IVSW System can operate and meet its design function without reliance on any other system. Electric power is not required for system operation, although instrument power is required to provide indication in the Control Room of seal water tank pressure and level.

6.8.3.1 System Response

Automatic containment isolation will be completed within approximately two seconds following generation of the phase A containment isolation signal. This is the estimated closing time of the air operated containment isolation valves. Since the IVSW System is actuated by this signal, automatic seal water injection will be in effect within this time period.

Subsequent generation of the phase B isolation signal on containment high pressure (spray actuation signal) will close a number of motor operated isolation valves with an estimated closing time of 10 sec. Automatic seal water injection flow will have been initiated in advance of this signal by the phase A signal.

The operator has the ability to override containment isolation valves as necessary; for example, the isolation valves in the steam generator blowdown lines and valves in those systems required for post-accident operation. (Refer to Section 6.3).

6.8.3.2 Single Failure Analysis

A single failure analysis is presented in Table 6.8.3-1. The analysis shows that the failure of any single active component will not prevent fulfilling the design function of the system.

6.8.5 Instrumentation Requirements

The sections below provide information regarding instrumentation indicators, setpoints, and operation.

6.8.5.1 Instrumentation Indicators and Setpoints. Remote indications are:

1. IVSW tank level indicated on RTGB from LT-1912
2. IVSW tank pressure indicated on RTGB from PT-1911
3. IVSW valves PCV-1922A and B indication on RTGB containment isolation Phase "A" Panel open or closed.

Local indications are:

1. IVSW tank level LT-1912
2. IVSW tank pressure PI-1910
3. IVSW tank sight glass
4. IVSW header "A" pressure PI-1915
5. IVSW header "B" pressure PI-1916
6. IVSW header "C" pressure PI-1917
7. IVSW header "D" pressure PI-1918
8. IVSW header "A" flow indicator FI-1914
9. IVSW header "B" flow indicator FI-1919
10. IVSW header "C" flow indicator FI-1920, and
11. IVSW header "D" flow indicator FI-1921

The following is a list of instrumentation that supply alarms; their setpoints will be found in the annunciator procedure.

CONTROLLER NO.	WINDOW NAME	WINDOW NO.
LT-1912	Seal Water Injection Tank Low Level	7-E6
PT-1911	Seal Water Injection Tank Low Pressure	7-D6
PC-1059/PC-1060	N_2 Header Pressure	36-C8

6.8.5.2 Instrumentation Operation. IVSW System operation modes are:

1. Automatic Operation - The isolation valve seal water system is normally in a static condition, with the seal water injection tank pressurized to 46 psig. A low pressure alarm at 42 psig and a low level alarm at 70 percent full are provided in the Control Room on the RTGB.

A SI or containment phase "A" signal will de-energize EV-1922 A and B which opens PCV-1922 A and B and injects seal water at 46 psig to distribution manifolds 1919, 1920, and 1921. For the list of systems and piping supplied by each manifold, refer to System Description SD-038.

2. Manual Operation - The isolation valve seal water system may be initiated manually by pushing the SI or containment isolation buttons on the RTGB. This action will put manifolds 1919, 1920, and 1921 in service. Manifold 1914 may be put in service anytime the seal water injection tank is pressurized. To inject seal water via manifold 1914, the isolation valves must be opened manually. Normally the only time manifold 1914 would be used is when post-accident equipment is secured.

3. Terminating System Operation - If the isolation valve seal water system was actuated by SI or containment isolation phase "A" signals, its operation may be terminated at the discretion of the operator by pressing the reset buttons for valves PCV-1922 A and B after a containment isolation Phase "A" signal reset.

To terminate service from Manifold 1914, the isolation valves must be closed locally at the manifold.

6.9.2 System Design

6.9.2.1 <u>System Description</u>. The Containment Penetration Pressurization system utilizes a regulated supply of clean and dry compressed air from the instrument air system, which is backed up by the service air system, to test all containment penetrations (only the sealing head assembly is pressurized in the CAPSULE type electrical penetrations). The system is capable of demonstrating compliance with Technical Specifications Local Leak Rate Surveillance testing requirements in accordance with 10CFR50, Appendix J. Typical piping and electrical penetrations are described in Section 3.8.1.

The primary source of air for this system is the 100 psig instrument air system (Section 9.3). Two instrument air compressors are used, although only one is required to maintain pressurization at the maximum allowable leakage rate of the pressurization system. The service air compressor acts as a backup to the instrument air compressors (Section 9.3).

A standby source of gas pressure for the system is provided by a bank of nitrogen cylinders. These will deliver nitrogen at a slightly lower pressure (approximately 44 psi) than the normal regulated air supply pressure of approximately 46 psig.

Leakage from the system and potential leakage from penetrations are determined by measurement of the air flow.

During Appendix J Testing pressurization of each penetration can be verified by closing off its air supply line, and opening a test connection at the penetration to observe the escape of the pressurizing medium.

6.9.2.2 <u>Containment Inleakage</u>. Assuming a continuous inleakage to the containment from the penetration pressurization system of 0.02 percent of the containment free volume per day, the calculated time for the containment pressure to rise by 0.3 psig is approximately 25 days. Therefore inleakage is not considered to be an operating or safety problem. From the standpoint of allowable pressure, a much greater inleakage would be permitted. The activity of the air in the containment is limited during normal operation through the use of two containment charcoal auxiliary filter units. Each unit contains high efficiency particulate air (HEPA) and charcoal filters, and permits containment overpressure relief, as required, through the pressure relief line to the plant vent. The containment pressure relief line is also equipped with HEPA and charcoal filters.

6.9.2.3 <u>Components</u>. All associated components, piping, and structures, of the Containment Penetration Pressurization System were designed to Seismic Class I criteria. Refer to Section 6.1.1.1.7.

For a description of the instrument air compressors and the service air compressors, refer to Service Air System, Section 9.

The nitrogen cylinders used are designed in accordance with the requirements of Section VIII (Unfired Pressure Vessels) of the ASME Boiler and Pressure Vessel Code. The cylinders are designed for 2200 psig maximum pressure and contain a total of 17,350 scf of nitrogen.

CHAPTER 7
INSTRUMENTATION AND CONTROLS

TABLE OF CONTENTS (Cont'd)

CHAPTER 7
INSTRUMENTATION AND CONTROLS

TABLE OF CONTENTS (Cont'd)

CHAPTER 7
INSTRUMENTATION AND CONTROLS

TABLE OF CONTENTS (Cont'd)

CHAPTER 7
INSTRUMENTATION AND CONTROL

LIST OF FIGURES

CHAPTER 7
INSTRUMENTATION AND CONTROLS

LIST OF FIGURES (Cont'd)

6. Low Pressurizer Pressure Trip - The purpose for this circuit is to protect against excessive core steam voids which could lead to DNB. A lead-lag filter is applied to the pressure signal to compensate for transient pressure overshoot. The circuit trips the reactor on coincidence of two out of the three low pressurizer pressure signals. This trip is blocked when either three of the four power range channels or one of two turbine first stage pressure channels read below approximately 10 percent power (P7).

7. High Pressurizer Pressure Trip - The purpose of this circuit is to limit the range of required protection from the overtemperature ΔT trip and to protect against RCS overpressure. The reactor is tripped on coincidence of two out of the three high pressurizer pressure signals.

8. High Pressurizer Water Level Trip - This trip is provided as a backup to the high pressurizer pressure trip. The coincidence of two out of the three high pressurizer water level signals trips the reactor. This trip is bypassed when either three of the four power range channels or one of two turbine first stage pressure channels read below approximately 10 percent power (P7).

9. Low Reactor Coolant Flow Trip - This trip protects the core from DNB following a low flow or loss of coolant flow accident. The means of sensing low flow and a loss of coolant flow accident are as follows:

a. Measured low flow or loss of coolant in the reactor coolant piping

The low reactor flow signal is actuated by the coincidence of 2/3 signals for any reactor coolant loop. The loss of flow in any two loops causes a reactor trip in the power range above approximately 10 percent (P7). Above 45 percent power (P8), the loss of flow in any loop causes a reactor trip.

b. Monitored electrical supply to the RCP

The power, voltage, and frequency to each RCP is monitored and the reactor is tripped on a loss of electrical power to the pump by undervoltage signal when (2/3) above approximately 10 percent power (P7). Underfrequency trips RCP breakers, consequently tripping the reactor.

10. Safety Injection System (SIS) Actuation Trip - A reactor trip occurs when the SIS is actuated. The means of actuating the SIS trips are discussed in Section 7.3.

11. Turbine Generator Trip - A turbine trip is sensed by two out of three signals from autostop oil pressure. A turbine trip causes a direct reactor trip above approximately 10 percent power (P7) and a controlled short term release of steam to the condenser which removes sensible heat from the RCS and thereby avoids SG safety valve actuation.

The turbine control system automatically trips the turbine generator under any of the following conditions:

a. Turbine overspeed

b. Generator electrical faults

c. Low condenser vacuum

d. Thrust bearing failure

e. Low lube oil pressure

f. Low control oil pressure

g. Reactor trip

h. Manual trip

12. Steam/Feedwater Flow Mismatch Trip - This trip protects the reactor from a sudden loss of its heat sink. The trip is actuated by a steam/feedwater flow mismatch (1/2) in coincidence with low water level (1/2) in any SG.

13. Low-Low Steam Generator Water Level Trip - The purpose of this trip is to protect the SG in the case of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a flow mismatch reactor trip. The trip is actuated on two out of the three low-low water level signals in any SG.

14. Manual Trip - The manual actuating devices are independent of the automatic trip circuitry, and are not subject to failures which make the automatic circuitry inoperable. Either of two manual trip devices located in the Control Room can initiate a reactor trip.

7.2.1.1.3 Reactor trip system interlocks. Interlocking functions of the RPS prevent control rod withdrawal when a specified parameter reaches a value less than the value at which reactor trip is initiated. These interlocks are:

1. Rod Stops - Rod stops are added to prevent a reactor trip or prevent an abnormal condition from increasing in magnitude.

A list of rod stops is given in Table 7.2.1-3. Some of these have been previously noted under permissive circuits, but are listed again for completeness.

2. Rod Drop Protection - Two independent systems are provided to sense a dropped rod, a rod bottom position detection system, and a system which senses sudden reduction in out-of-core neutron flux. Both protection systems initiate protective action in the form of a turbine load cutback and blocking of automatic rod withdrawal. This action compensates for possible adverse core power distributions and permits an orderly retrieval of the dropped RCCA.

The primary protection for the dropped RCCA accident is the rod bottom signal derived for each rod from its individual position indication system. With the position indication system, initiation of protection is not dependent on location, reactivity worth, or power distribution changes.

Backup protection is provided by use of the out-of-core power range nuclear detectors and is particularly effective for larger nuclear flux reductions occurring in the region of the core adjacent to the detectors. The rod drop detection circuit from nuclear flux consists basically of a comparison of each of the four ion chamber signals with the same signal taken through a first order lag network. Since a dropped RCCA will rapidly depress the local neutron flux, the decrease in flux will be detected by one or more of these circuits. Such a sudden decrease in ion chamber current will be seen as a difference signal. A negative signal output greater than a preset value (approximately 10 percent) from any one of the four power range channels will actuate the rod drop protection.

The Nuclear Instrumentation System (NIS), including the dropped RCCA alarm, is described later in this chapter.

3. Automatic Turbine Load Cutback - Automatic turbine load cutback is initiated by a signal from a dropped RCCA as indicated by either a rapid decrease in nuclear flux or by the rod bottom on-off controllers. Load cutback is also initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation which might lead to minimum DNB ratio less than the safety limit specified in Section 4.4.

Both the rod stop and the turbine runback are redundant. Rod stop contacts are located in the rod control logic cabinet and in the rod speed control analog rack. The turbine runback acts by both of the following:

a. Reduction of the load reference setpoint of the turbine E-H controller by a preset amount. This is accomplished by reducing the setpoint at a constant rate for a preset time.

b. Reduction of the turbine load limit to a preset value. The load limit (a clamp on the voltage signal controlling the turbine control valve position) is reduced until turbine thermal load as sensed by either of two turbine impulse pressure channels is below a preset value.

The amount of the runback was determined by physics tests of dropped rod worths and hot channel factors during plant startup tests. The safety requirement of the runback is to preclude return to a power level that might result in a core damage because of adverse hot channel factors.

7.2.1.1.4 Reactor trip indication. Any of the following conditions actuate an alarm:

1. Reactor trip (first-out annunciator)

2. Trip of any reactor trip channel

3. Actuation of any override

4. Significant deviation of any major control variable (pressure, T_{avg}, pressurizer water level, and SG water level)

5. Test initiation in any reactor trip channel (and control channel where feasible)

7.2.1.1.5 Analog Channels

The basic elements comprising an analog protection channel, shown in Figure 7.2.1-2, are a transmitter, power supply, bistable, bistable trip switch and proving lamp, test signal injection switch, test signal injection jack, and test point.

The RPS is designed to achieve isolation between redundant protection channels. The channel design is applied to the analog and the logic portions of the protection system, and is illustrated by Figure 7.2.1-3. Although shown for four channel redundancy, the design is applicable to two and three channel redundancy.

Isolation of redundant analog channels originates at the process sensors and continues along the field wiring and through containment penetrations to the analog protection racks. Isolation of field wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Analog equipment is isolated by locating redundant components in different protection racks. Each channel is energized from a separate AC power feed. Logic equipment separation is achieved by providing separate racks, each associated with individual trip breakers. Physical separation is provided between these racks.

Provisions are made to manually place the output of the bistable in a tripped condition for "at power" testing of all portions of each trip circuit including the reactor trip breakers. Administrative procedure requires that the final element in a trip channel (required during power operation) is placed in the trip mode before that channel is taken out of service for repair or testing so that the single failure criterion is met by the remaining channels.

Provision is made for the insertion of test signals in each analog loop. Verification of the test signal is made by plant instruments at test points specifically provided for this purpose. This enables testing and calibration of meters and bistables. Transmitters and sensors are checked against each other and against precision read-out equipment during normal power operation.

Each protection rack includes a test panel containing those switches, test jacks, and related equipment needed to test the channels contained in the rack. A hinged cover encloses the test panel. Opening the cover or placing the test-operate switch in the "TEST" position initiates an alarm. These alarms are arranged on a rack basis to preclude entry to more than one redundant protection rack (or channel) at any time. The test panel cover is designed such that it cannot be closed (and the alarm cleared) unless the test signal plugs (described below) are removed. Closing the test panel cover will mechanically return the test switches to the "OPERATE" position.

Administrative procedures require that the bistable in the channel under test be placed in the tripped mode prior to test. This places a proving lamp across the bistable output so that the bistable trip point can be checked during channel calibration. The bistable trip switches must be manually reset after completion of a test. Closing the test panel cover will not restore these switches to the untripped mode. However, the annunciator on the control board cannot be reset until these switches are returned to the untripped mode.

Channel calibration consists of inserting a test signal from an external calibration signal source into the test signal injection jack. Where applicable, the channel power supply serves as a power source for the calibration source and permits verifying the output load capacity of the power supply. Test points are located in the analog channel and provide an independent means of measuring the calibration signal level.

7.2.1.1.6 Logic Channels. The general design features of the logic system are described below. The trip logic channels for a typical two-out-of-three and a two-out-of-four trip function are shown in Figure 7.2.1-4. The analog portions of these channels are shown in Figure 7.2.1-5. Each bistable drives two relays ("A" and "B" for level and "C" and "D" for pressure). Contacts from the "A" and "C" relays are arranged in a 2/3 and 2/4 trip matrix for Trip Breaker 1. The above configuration is duplicated for Trip Breaker 2 using contacts from the "B" and "D" relays. A series configuration is used for the trip breakers. The logic system testing includes exercising the reactor trip breakers to demonstrate system integrity. Bypass breakers are provided for this purpose. During normal operation, these bypass breakers are open. Administrative controls are used to minimize the amount of time these breakers are closed and to prevent simultaneous closure of both bypass breakers. Indication of a closed condition of either bypass breaker is provided locally on the test panel and on the main control board (RTGB).

As shown in Figure 7.2.1-4, the trip signal from the logic network is simultaneously applied to the main trip breaker associated with the specific logic chain as well as the bypass breaker associated with the alternate trip breaker. Should a valid trip signal occur while AB-1 is bypassing TB-1, TB-2 will be opened through its associated logic train. The trip signal applied to TB-2 is simultaneously applied to AB-1 thereby opening the bypass around TB-1. TB-1 would either have been opened manually as part of the test or would be opened through its associated logic train which would be operational or tripped during a test.

An auxiliary relay is located in parallel with the undervoltage coils of the trip breakers. This relay is connected to a white test light which is used to indicate transmission of a trip signal through the logic network during testing. Lights are also provided to indicate the status of the individual logic relays.

The following procedure illustrates the method used for testing Trip Breaker Number 1 and its associated logic network:

a) With the bypass breaker (AB-1) racked-out, manually close and trip AB-1 to verify operation

b) Rack-in AB-1. Verify that the bypass breaker position is "tripped". Close AB-1. Verify that the bypass breaker position status lights indicates that the breaker is closed. Trip TB-1.

c) Sequentially de-energize the trip relays (A1, A2, A3) for each logic combination (1-2, 1-3, 2-3). Verify that the logic network de-energizes the undervoltage coil on TB-1 for each logic combination. Since the white test light monitors the signal applied to the undervoltage coil, operation of the undervoltage coil can be determined from the white test light.

d) Repeat c) above for every logic combination in each matrix

e) Reset TB-1

f) Trip TB-1 to validate prior test results as evidence by the white test light, and

g) Reset TB-1. Trip and rack-out AB-1.

In order to minimize the possibility of operational errors (such as tripping the reactor inadvertently or only partially checking all logic combinations), each logic network includes a logic channel test panel. This panel includes those switches, indicators, and white test light needed to perform the logic system test. The arrangement is shown in Figure 7.2.1-6. The test switches used to de-energize the trip bistable relays operate through interposing relays as shown in Figures 7.2.1-2 and 7.2.1-5. This approach avoids violating the separation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical isolation of redundant protection channels is maintained by the inclusion of the interposing relay which is actuated by the logic test switches.

The reactor trip bistables are mounted in the analog protection racks and are the final operational component in an analog protection channel. Each bistable drives two logic relays ("C" and "D"). The contacts from the "C" relays are interconnected to form the required actuation logic for Trip Breaker Number 1. The transition from channel identity to logic identity is made at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the analog and the logic portions of the protection system. The above logic network is duplicated for Trip Breaker Number 2 using the contacts from the "D" relays. Therefore, the two redundant reactor trip logic channels are physically separated and electrically isolated from one another. Overall, the RPS is comprised of identifiable channels which are physically, electrically, and functionally separated and isolated from one another.

7.2.1.1.7 Nuclear Instrumentation System. The NIS (Figure 7.2.1-7) consists of eight independent channels: two of these being the source range, two the intermediate range, and four the power range channels. In addition, there are three auxiliary channels, the visual-audio count rate channel, the comparator channel, and the startup rate channel. The various detectors associated with the eight primary channels are shown in relative position with respect to the core configuration on Figure 7.2.1-8. Figure 7.2.1-9 shows the range of operation of each channel.

Nuclear plant protection assurance is obtained from the three ranges of out-of-core nuclear instrumentation. Separation of redundant protective channels is maintained from the neutron sensor with its associated cables to the signal conditioning equipment in the Control Room with its associated output wiring, indicating or recording devices and protective devices. Where redundant protective channels are combined to provide nonprotective functions, the required signals are derived through isolation amplifiers. These devices are designed so that open or short circuit conditions as well as the

application of 120 V AC or 140 V DC to the isolated side of the circuit will have no effect on the input or protection side of the circuit. As such, failures on the nonprotective side of the system will not affect the individual protection channels. Redundant channels are powered from independent power sources, each channel being provided with the necessary power supplies for its detectors, signal conditioning equipment, trip bistables, and associated trip relays. The nuclear instrumentation channels are mounted in four separate racks to provide the necessary physical separation between redundant channels.

The overpower protection provided by the out-of-core nuclear instrumentation consists of three discrete levels. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A one-of-two intermediate range permissive signal (P6) is required prior to source range level trip blocking and detector high voltage cutoff. Source range level trips are automatically reactivated and high voltage restored when both intermediate range channels are below the permissive (P6) level. There are provisions for administratively reactivating the source range level trip and detector high voltage, if required. Source range level trip block and high voltage cutoff are automatically maintained by the same power range permissive (P10) which permits blocking of the intermediate range and low-range, power-range flux level trips.

The intermediate range level trip and low-range, power-range level trip can only be blocked after satisfactory operation and permissive information are obtained from two-of-four power range channels. Individual blocking switches are provided so that the low-range, power-range trip, and the intermediate range trip can be independently blocked. These trips are automatically reactivated when any three of the four power range channels are below the permissive (P10) level, thus ensuring automatic activation of more restrictive trip protection.

Blocking of any reactor trip function is indicated by the control board status lights. Channels which provide reactor plant protection through one-of-two or one-of-four logic matrices are equipped with positive detent type trip-bypass switches to enable channel testing. The trip-bypass condition for individual channels is indicated at the control board and at the nuclear instrumentation racks. The reactor plant protection afforded by the high-range, power-range trip is never blocked or bypassed.

The out-of-core NIS consists of various plug-in type modules which perform the functions indicated on Figure 7.2.1-7 for the source, intermediate, and power ranges. Components designed to military specifications are used, where possible, in conjunction with a conservative design stressing reliability, derating of components and circuits, and the use of field-proven circuits.

On-line testing and calibration features are provided for each channel. The test signals are superimposed on the normal sensor signal during plant operation. This permits valid trip conditions to over-ride the test signal since the sensing elements are never removed from the circuit.

7.2.1.1.7.1 Source Range Instrumentation - General Description

Two independent source range channels are provided. Each receives pulse-type signals from a proportional counter. The preamplified detector signal is received by the source range instrumentation conditioning equipment located in the Control Room racks. The detector signal, which is a random count rate proportional to leakage neutron flux, is conditioned for conversion to an analog signal proportional to the logarithm of the neutron flux count rate.

The isolated analog signals from each channel are sent to various recording and indicating devices to provide the operator with necessary startup information. Bistable units also located in the racks are used to generate alarms and reactor trip signals. Trip signals from the bistables are transmitted to relays in the protection relay racks where the necessary logic involved in generating reactor trip signals is performed.

An isolated count rate signal derived from either channel is connected to a scaler-timer. This same signal also feeds the audio count rate channel which provides an audible count rate signal, proportional to the neutron flux. Speakers are provided both in the containment and in the Control Room. Startup rate indication is also provided for each source range channel, and a startup rate meter is installed on the reactor and turbine-generator board to give the operation more accurate information on the core flux during startup. These signals are generated from the isolation amplifier output since there is no protection function involved.

7.2.1.1.7.2 Intermediate Range Instrumentation - General Description

Two independent compensated ionization chambers provide extended flux coverage from the upper end of the source range to approximately 100 percent power. The equipment for each channel, including the high voltage and compensating voltage power supplies, are located in separate drawers. To maintain separation between these redundant channels, the drawers are mounted in separate racks. The signal conditioning equipment furnishes an analog output voltage proportional to the logarithm of the neutron flux spectrum. Each channel covers approximately eight decades of leakage flux. Isolation amplifiers (for startup-rate circuits, remote recording, remote indication, etc.) and bistable amplifiers (for permissives, rod stop and reactor trip) use this analog voltage to indicate plant status and provide the necessary plant protection functions. All relays associated with plant control or protection are located in the logic or auxiliary relay racks.

7.2.1.1.7.3 Power Range Instrumentation - General Description

Four dual section, uncompensated ionization chambers are used for power range flux detection. Each chamber provides two current signal outputs (one from each section) to signal conditioning equipment in the Control Room racks. Each chamber has an independent high voltage power supply. The individual current signals obtained from each section of the detector are proportional to upper core and lower core neutron flux, respectively. These provide core flux status information at the instrument racks and, through isolation amplifiers, the same information at the control console. A separate output furnishes bias signals used in the overpower and overtemperature ΔT reactor trip functions. The individual current signals are combined to provide an average signal proportional to average core flux in the associated core quadrant. This

average signal is conditioned to provide an analog voltage signal for use in permissive control and protection bistable amplifiers.

Isolation amplifiers, which provide remote control signals and core power status information to the operator and computer, also utilize the average power analog signal. The four power range channels are operated from separate AC sources and are housed in separate racks so that a single failure will not cause loss of protection functions. Redundant relays for the protection functions are located in the logic portion of the protection system.

Isolated analog outputs from the power range channels are compared in a separate auxiliary channel drawer. This comparator provides the operator with annunciation of deviations in average power between the four power range channels. Switches are provided to defeat this comparison for a failed channel so that subsequent deviations or failures among the three remaining channels are annunciated.

7.2.1.1.7.4 Detectors

The NIS employs six detector radial locations containing a total of eight detectors (two proportional counters, two compensated ionization chambers and four dual section uncompensated ionization chamber assemblies) installed around the reactor in the primary shield. Windows in the primary shield minimize leakage flux attenuation and distortion.

BF_3 gas filled proportional counters having a nominal thermal neutron 4
sensitivity of ten counts per neutron per square centimeter per second, provide pulse signals to the source range channels. These detectors are installed on opposite "flat" portions of the core containing the primary startup sources, at an elevation approximating the quarter core height.

Compensated ionization chambers serve as neutron sensors for the intermediate range channels and are located in the same instrument wells and detector assemblies as the source range detectors. These detectors have a nominal thermal neutron sensitivity of 4×10^{-14} amperes per neutron per square centimeter per second. Gamma sensitivity is less than 3×10^{-11} amperes per Roentgen per hour when operated uncompensated, and is reduced to approximately 3×10^{-13} amperes/R/hr in compensated operation. The detectors are positioned at an elevation corresponding to the center of the quarter core height.

The detector assemblies containing one each of the above-mentioned detectors use watertight, corrosion-resistant steel enclosures. High density polyethylene, used as a moderator-insulator within the detector assemblies, will be confined at temperatures associated with a loss-of-coolant accident (LOCA). The detectors are connected to the junction box at the top of the detector well by special high temperature, radiation-resistant cables.

The remaining four detector assemblies contain the power range ionization chambers. Each provides two current signals corresponding to the neutron flux in the upper and lower sections of a core quadrant. These detectors have a total neutron-sensitive length of ten feet and a nominal thermal neutron sensitivity for each section of 1.7×10^{-13} amperes per neutron per square centimeter per second. Gamma sensitivity of each section is approximately 10^{-10} amperes per Roentgen per hour.

The detector assemblies for power range operation are installed vertically and located equidistant from the reactor vessel at all points, and, to minimize neutron flux pattern distortions, within one foot of the reactor vessel. Cabling from individual detector wells to the containment penetrations and to the instrument racks in the Control Room are routed in individual conduits, with physical separation between the penetrations and conduits associated with redundant protective channels.

7.2.1.1.7.5 Detailed description. The source range output information is tabulated in Table 7.2.1-4. The detector for each source range channel is a BF_3 gas filled proportional counter. The signal received from the counter has a range of 1 to 10^6 pulses per second randomly generated and is received through a low noise variable gain preamplifier located outside the containment. After the initial gain setting, the variable gain preamplifier is operated as a fixed gain preamplifier.

The preamp has internal provisions for generating self-test frequencies. These test oscillator circuits are energized by a switch located on the associated source range drawer. The source range channel power supplies furnish low voltage for preamp operation as well as low voltage for the drawer-mounted modules. The preamp is solid state in design with discrete components and includes an impedance matching network between the preamp output and the 75-ohm triaxial cable.

The preamp output is received at the post-amplifier located on the source range drawer. This module provides amplification and discrimination, both of which are adjustable. Discrimination is provided between neutron flux pulses and combined noise and gamma-generated pulses. The discriminator supplies two outputs: one output (isolated) to a scaler-timer unit on the visual-audio channel drawer (see source range auxiliary equipment); and the other to a pulse shaper (transistorized flip-flop circuit) which supplies a constant amplitude pulse to the log integrator module within the source range drawer.

Logarithmic integration of the pulse signal is performed in another modular unit to obtain an analog DC signal. The log signal is then amplified for local indication on the front panel of the source range drawer, and is also delivered through a parallel run to the source range level bistables and isolation amplifier. The analog output signal is proportional to the count rate being received from the sensor and is displayed by the front panel meter on a scale calibrated logarithmically from 10^0 to 10^6 cps. The solid state isolation amplifier provides five analog outputs, all of which are adjustable through attenuator controls. Three outputs are used as follows: as remote indication (0-1 ma); as remote recording (0-37.5 mv DC); and as an input to the computer (0-5 V DC). A 0-10 V DC output is used by the startup-rate amplifier to produce a startup-rate indication at the main control board. The remaining output (0-5 V DC) is a spare.

All bistables will employ a basic plug-in module with the external wiring determining the mode of operation (latching or non-latching and direction of output change with rising power). Bistables will have two adjustments: "Trip Level" and "Differential." The first adjustment determines the trip point of the bistable, while the second determines the "dead zone" difference between the trip and release points of the bistable. The bistable module card will include a relay driver circuit made up of an silicon control rectifier (SCR) and full-wave bridge configuration. The bistable output will control the SCR gate which, in turn, controls conduction of the full-wave bridge supplying the power to drive up to four 115 V AC WBF relays. All relays are located remote from the NIS racks.

Of the three bistables monitoring the source range level amplifier signal, one is a spare, one is used to monitor shutdown flux level only, and the third monitors source range operation during shutdown and startup operation and provides a reactor trip on high flux level. The reactivity of the core during shutdown is monitored by a bistable to ensure protection of plant personnel working in the containment. Bistable tripping will initiate local visual and audible annunciation and remote audible annunciation of any abnormal increase in core activity. Visual annunciation occurs at the NIS rack and on the main control board. Audible annunciation is handled by the annunciator located in the Control Room, and the evacuation horn located in the containment.

These annunciators ensure that plant personnel will be alerted to any potentially hazardous condition. This bistable action will be manually blocked by deliberate operator action during plant startup. Blocking is continuously annunciated at the control board during source range operation and is automatically blocked by permissive P6. The bistable trip point is approximately one-half decade above the flux level recorded during full shutdown.

The source range level bistable monitors the core activity during the full span of source range operation until such time as the intermediate range channels assume control of that portion of the reactor protection which is being supplied by nuclear instrumentation. At that time, when the intermediate range permissive P6 is available, the source range reactor trip bistable may be manually blocked and high voltage removed from the B10 detector by the operator actuating two momentary-contact switches located on the main control board.

A fourth bistable-relay driver unit is used as a high voltage failure monitor. Loss of this voltage actuates the bistable, the relay driver and then the associated relay. The relay provides control board annunciation through a one of two matrix formed with a similar relay controlled by the other source range. Failure of either source range high voltage actuates this common annunciator on the main control board. During normal operation the source range high voltage will be cut off (mentioned above) when manual block of the source range trips is initiated. In this instance, loss of high voltage annunciation will be intentionally defeated to prevent the alarming of a condition which is not abnormal.

A test-calibrate module is also included in each source range drawer for self check of that particular channel. A multi-position switch on the source range front panel controls this module and also the operation of the built-in oscillator circuits in the preamp. The module is capable of injecting test signals of 60, 10^3, 10^5, and 10^6 cps at the input to the post-amplifier, or a variable DC voltage corresponding to 1 to 10^6 cps at the input to the log amplifier. An interlock between the trip bypass switch and the test-calibrate switch will prevent inadvertent actuation of the reactor trip circuits, (i.e., the channel cannot be put in the test mode unless the trip is defeated). Trip bypass will be annunciated on the source range drawer and on the main control board per the proposed IEEE 279 Standard, Section 4.13. Operation of the test-calibrate module will be annunciated on the control board as "NIS Channel Test." This common annunciator for all NIS channels will be alarmed when any channel is placed in the test position and will alert the operator that a test is being performed at the NIS racks.

a) Visual-Audio Count Rate - The visual-audio count rate receives a signal from each of the source range channels. This isolated signal originates at the discriminator output in each source range. A switch on the audio count rate drawer selects either source range channel for monitoring. The selected signal is fed to a scaler-timer unit which permits count accumulation in the preset time or preset count mode. A visual display to five decimal places is presented through counting strips located on the front of the audio count rate drawer.

A "Scale Factor" switch permits division of the scaler output signal by 10, 100, or 1000. This signal, derived from the printer output of the scaler, is conditioned and sent to two of the audio amplifiers which power two speakers: one speaker located in the Control Room, and the other in the containment. These speakers give plant personnel an audible indication of the count rate. Since the audio signal is taken from the coded scaler output, adjustment of the scale factor switch will alter only the audible count rate. This enables the operator to maintain the audible count rate at a distinguishable level.

b) Remote Count Rate Meter - The remote meter indication is an analog signal proportional to the count rate being received, and is obtained from the 0-1 ma isolation amplifier output.

The meter is mounted on the main control board and calibrated logarithmically from 10^0 to 10^6 cps. This meter gives the same indication at the control board as is displayed by the local meter on the corresponding source range drawer.

c) Remote Recorder - This two-pen recorder is capable of continuously recording any two NIS channels at a time. Each pen receives its signal through a multi-position switch which can select any one of the eight nuclear channels. In the case of the source ranges, a 0-37.5 mvDC signal, proportional to the count rate range of 10^0 to 10^6 cps, is supplied for recording during source range operation.

d) Startup-Rate Circuitry - The startup-rate drawer receives four input signals (0-10V DC) one from each of the source and intermediate range channels. Four rate amplifier modules condition these signals and output four rate signals to the respective Control Room startup-rate (SUR) meters. A test module is provided which can inject a test signal into any one of the rate circuits and can be monitored on a test meter mounted on the front panel of this drawer. Two power supplies are provided to assure rate indication from this drawer. Two power supplies are provided to assure rate indication from at least one Source and Intermediate Range channel pair.

7.2.1.1.7.6 Intermediate Range Detailed Description

Intermediate Range output information is tabulated in Table 7.2.1-5. Each intermediate range channel receives a direct current signal from a compensated ion chamber and supplies positive high voltage and compensating (negative) high voltage to its respective detector. The compensating high voltage is used to cancel the effects of gamma radiation on the signal current being delivered to the intermediate range channel. Both high voltage supplies will be adjustable through controls located inside the channel drawer. The detector signal is received by the intermediate range logarithmic amplifier. The modular unit, comprised of several operational amplifiers and associated discrete solid state components, produces an analog voltage output signal which is proportional to the logarithm of the input current. This signal is used for local indication and it is monitored by the isolation amplifier and the various bistable relay-driver modules within the intermediate range drawer. A 10^{-11} ampere signal is continuously inserted and serves as a reference during gamma compensation. Local indication is provided by a meter mounted on the front panel of the drawer which has a logarithmic scale calibration of 10^{-11} to 10^{-3} amperes. The isolation amplifier is the same solid state module that is used in the source range; it supplies the same five outputs and for the same usage. Six bistable relay-driver units are used in the intermediate range drawer to provide the following functions:

a) One monitors the positive high voltage

b) One monitors the compensating high voltage

c) One provides the permissive P6

d) One provides rod stop (blocks automatic and manual rod withdrawal)

e) One provides reactor trip

f) One serves as a spare

The intermediate range permissive P6 bistable drives two WBF relays (for redundancy) and the relays from each channel are combined in 1 of 2 matrices to provide the permissive function and control board annunciation of permissive availability. Permissive P6 permits simultaneous manual blocking of the source range trips and removal of the source range detector high voltage. Once source range blocking has been performed, the operator may, through administrative action, defeat permissive P6 and reactivate the source range high voltage and trip functions if required. This defeat is accomplished by the coincident operation of two control board mounted,

momentary-contact switches. This provision, however, is only operational below permissive P10 which is supplied by the power range channels. Above P10, the defeat circuit is automatically bypassed and permissive P6 is maintained which, in effect, maintains source range cutoff. The level bistable relay-driver unit which provides the intermediate range rod stop function also drives two WBF relays. Again, one-of-two matrices formed by the relays from the two intermediate range channels supplies the rod stop function and control board annunciation. Blocking of the outputs of these matrices is administratively performed when nuclear power is above permissive P10 and can only be accomplished by deliberate operator action on two control board mounted switches.

The intermediate range reactor trip function is provided by a similar circuit arrangement, the only difference being the trip point of the bistable units. The same control board switches which control blocking of the rod stop matrices also provide blocking action for the reactor trip matrices. These blocks are manually inserted when the power range of instrumentation indicates proper operation through activation of the P10 permissive function. On decreasing power, however, the more restrictive intermediate range trip functions are automatically reinserted in the protective system. While these trips are blocked, there will be continuous illumination on the main control board of "Intermediate Range Trip Blocked." The high voltage failure monitors provide both local and remote annunciation upon failure of the respective high voltage supplies. A common "Intermediate Range Loss of Detector Voltage" and separate "N-35 Loss of Comp Volt" and "N-36 Loss of Comp Volt" are provided as control board annunciators for the intermediate ranges.

Administrative testing of each intermediate range channel is provided by a built-in test-calibrate module which injects a test signal at the input to the log amplifier. The signal is controlled by a multi-position switch on the front of each intermediate range drawer. A fixed 10^{-11} ampere signal is available along with a variable 10^{-10} through 10^{-3} signal, selectable in decade increments.

As in source range testing, the test switch on the intermediate range must be operated in coincidence with a trip bypass on the drawer. An interlock between these switches prevents injection of a test signal until the trip bypass is in operation. Removal of the trip bypass also removes the test signal.

1. Remote Meter - The remote meter indication is in the form of an analog signal (0-1 ma) proportional to the ion chamber current. The isolation amplifier in each channel supplies this output to a separate meter. Meter calibration is 10^{-11} to 10^{-3} amperes.

2. Remote Recorder - This is the same recorder described above for the source range. A 0-50 mv DC signal from the isolation amplifier is supplied to the recorder and is proportional to the ion chamber current range of 10^{-11} to 10^{-3} amperes. The signal from I.R. Number 1 is available in position 3 of the recorder selector switches, and I.R. Number 2 in position 4. In switch positions 9 and 10, the signals from I.R. Number 1 and I.R. Number 2, respectively, are applied to the inputs of two adjustable span and zero units. These units are then connected to the recorder in place of the fixed span and zero "built-in" units. The adjustable span and zero units are mounted on the control board and are used during physics testing.

c) Startup-Rate Circuitry - The SUR drawer receives four input signals (0-10V DC) one from each of the source and intermediate range channels. Four rate amplifier modules condition these signals and output four rate signals to the respective Control Room SUR meters. A test module is provided which can inject a test signal into any one of the rate circuits and can be monitored on a test meter mounted on the front panel of this drawer. Two power supplies are provided to assure rate indication from at least one Source and Intermediate Range channel pair.

7.2.1.1.7.7 Power Range Detailed Description

The power range output information is tabulated in Table 7.2.1-6. The power range detector is a long uncompensated ion chamber assembly which is comprised of two separate neutron sensitive sections. Each section supplies a current signal to the associated power range. There is one high voltage power supply per channel and it supplies voltage to both sections of the associated detector. The two signals are received at the channel input and handled through separate ammeter-shunt assemblies. Four full-scale ranges can be selected for each ammeter through switches located on the front panel of the power range drawer, 100 ua, 500 ua, 1 ma, and 5 ma DC. The switch selects shunt resistors for the meter but never interrupts the ion chamber signal to the power range channel. The circuit is so designed that a failure of the meter or switch will not interrupt the signal to the average power circuitry.

The individual currents are displayed on the two front panel ion chamber current meters and are then sent to separate isolation amplifiers. There are two isolation amplifiers monitoring each of the two individual current signals. The unit feeding the ΔT function is being used for its impedance matching characteristics rather than for isolation. All of the isolation amplifiers are capable of providing the same five output ranges as the isolation amplifiers previously described in relation to the source and intermediate ranges. Two of the isolation amplifiers (used as impedance matching networks), one monitoring each of the currents, supply signals to the ΔT reset. The other two isolation amplifiers provide output for the remote recorder, remote meter, and computer. The individual current signals are then sent to a summing amplifier module which outputs a linear 0-10 V DC signal proportional to their average. The output of this unit will feed a linear amplifier with two controls: one a "Zero" adjust located on the module itself, while the other is a "Gain" adjust with a calibrated dial located on the drawer's front panel. The output signal from this unit corresponds to 0 to 120 percent of full power and is displayed on a percent full power meter on the front panel of the power range drawer. This same signal is delivered directly to three isolation amplifiers, a dropped rod sensing assembly, and six bistable relay-driver modules. These isolation amplifiers are identical to those previously described and the outputs are the same in number and range but are used in different functions. (Specific outputs from the amplifiers are discussed in the auxiliary equipment section which follows.)

The dropped-rod sensor assembly is an operational amplifier unit which incorporates an adjustable lag network at one input and a non-delayed signal on the other. The unit compares the actual power signal with the delayed power signal received through the lag network and amplifies the difference. This amplified differential signal is delivered to a bistable relay-driver unit which trips when the level of this signal exceeds a preset amount.

Tripping of this unit indicates a power level change over the lag period which would be indicative of a dropped rod. This bistable unit is a latching type, ensuring that the necessary action will be initiated and carried to completion. Specifically, the unit controls dual WBF relays which, in one-of-four logic matrices, provide a rod stop and turbine load cut-back signal, a control board annunication signal, and a computer input signal. A reset switch on the associated power range drawer must be operated manually to remove the trip functions and reset the bistable.

The bistable units which sense the power level signal as derived by the linear amplifier are non-latching and perform the following functions:

a) Overpower rod stop (blocks automatic and manual rod withdrawal)

b) Permissive functions (provisions for three are incorporated in the design but are not required on all plants)

c) Low-range reactor trip

d) High-range reactor trip

The overpower rod stop and permissive bistables are units which trip on high power level and control WBF relays in the remote relay racks. The rod stop relay matrices (one-of-four) provide a rod stop function to the rod control system and a main control board annunciation. Two-of-four logic, developed by relays controlled through the respective power range bistables, provide the signals required for the permissive functions. One set of relays provides permissive P10, as was previously discussed with regard to its use in the source range and intermediate range. Two other groups of relays are available to provide inputs to two additional permissive functions when required. These bistable functions, when used, provide permissive P8 and contribute to the overall logic for P9.

Permissive P8 and P10 are supplied solely by nuclear instrumentation.

For this reason, the nuclear instrumentation design provides for main control board annunciation of P8 and P10 availability. Permissive P10 is used in all three ranges of nuclear instrumentation while P8 is provided by nuclear instrumentation for use in the RPS.

The low range trip bistable actuates two WBF relays in the logic system. The two relays provide redundancy within the logic portion of the protection system. Each relay is used in a separate matrix with the relays from the other power range channels to continue the redundancy. The logic circuitry formed by the contacts on these relays provide for one-of-four and two-of-four logic outputs. The low range trip relays provide the following functions:

a) Computer input (single channel)

b) Low range trip annunciation (two-of-four coincidence)

c) Reactor-trip signal to RPS (two-of-four coincidence)

d) Annunciation of "Single Channel Low Range Trip" (one-of-four)

Provisions for manually blocking these functions become available when 2 of 4 power ranges exceed the permissive P10 level. Operator action on two control board mounted momentary-contact switches then initiates the blocking action. A control board permissive status light, "Power Range Low Range Trip Blocked," will be illuminated continuously when the trip function is blocked. On decreasing power, three-of-four power ranges below the P10 power level will automatically reactivate the low range trip.

The high range reactor trip logic circuitry is developed identically to the low range reactor trip circuitry, but no provision for blocking is included.

The high range trip remains active at all times to prevent any continuation of an overpower condition.

An additional bistable unit monitors the high voltage power supply in the power range. Operation of this unit is identical to that for the source and intermediate ranges. The bistable provides relay actuation in the remote relay racks on failure of power range high voltage. While there is a separate relay for each power range, they control a common "Power Range Loss of Detector Voltage" annunciator on the main control board. Separate local indication of high voltage failure is provided on the power range drawers.

The test-calibrate module which is provided on each power range is capable of injecting test signals at several points in the channel. In all cases, the test signals are superimposed on the normal signal. A bypass of the dropped rod-rod stop circuit will be required during channel test. Since this circuit produces a load cutback through a one-of-four logic matrix for a sudden power change, it must be bypassed to prevent an inadvertent dropped rod indication. An interlock between the bypass switch and channel test switch is provided as was done in the source and intermediate ranges. The bypass switch from each power range will activate a common annunciator, "NIS Trip/Rod Drop Bypass," but individual bypass status lights will identify the particular channel. The remaining bistables which will be affected during channel test do not require bypasses since they operate in two-of-four logic. Test signals can be injected independently or simultaneously at the input of either ammeter-shunt assembly to appear as the individual ion chamber currents. Operation of the test-calibrate switch on any power range will cause the "Channel Test" annunciator to be alarmed on the main control board.

1. Comparator - The comparator receives an isolated signal from each of the four power ranges. These signals are conditioned in separate operational amplifier circuits and then compared with one another to determine if a preset deviation of power levels has occurred between any two power ranges. Should such a deviation occur, the comparator output will operate a remote relay to actuate the control board annunciator, "Power Range Channel Deviation." This alarm will alert the operator to either a power unbalance being monitored by the power ranges or to a channel failure. Through other indicators, the operator can then determine the deviating channel(s) and take corrective action. Should correction of the situation not be immediately possible (e.g., a channel failure, rather than reactor condition), provisions are available to eliminate the failed channel from the comparison function. The comparator can then continue to monitor the active channels.

b) Remote Recorder - Each power range supplies a 0-50 mv DC signal proportional to 0-120 percent power to the selector switches for the two pens on the main nuclear recorder. The signals from Power Ranges Number 1, Number 2, Number 3, and Number 4 are available in positions 5, 6, 7, and 8, respectively, on either channel selector switch. Any two of the ranges can be monitored continually during power range operation. All four signals are continually indicated on control board meters.

c) Remote Meter - The remote meters receive the 0-1 ma isolated output that is available from each power range. This indication corresponds to that shown on the power range drawer. The signal is displayed on a meter scale calibrated from 0 to 120 percent of full power.

d) Overpower Recorder - A pair of two-pen recorders are used to monitor the individual average power indications from the four power ranges. Each recorder provides continuous monitoring of two power range channels and has a full-scale deflection time of 0.25 sec. The recorders are capable of displaying overpower excursions up to 200 percent of full power. A power range isolated output of 0-50 mv DC will correspond to the range of zero percent to 200 percent full power for these recorders.

e) Ion Chamber Current Recorders - Four two-pen recorders are provided to record the upper and lower ion chamber currents for each power range detector. Two isolated outputs (0-5 V DC), one from each of the ion chamber isolation amplifiers, are provided for each recorder. Comparison of the two traces will be an indication of the flux difference between the upper and lower sections of a given detector.

f) Remote Meter (Delta Flux) - Four control board mounted meters display the flux difference between the upper and lower ion chambers directly for each of the power range detectors.

7.2.1.1.7.8 Miscellaneous Control and Indication Panel

Indicating lights (one per power range channel) are provided on this panel to be used during test of the dropped rod-rod stop function. Illumination of one of the lights indicates completion of the relay tripping function, concerned with turbine load cutback and rod stop, for the channel under test.

Switches are also provided on this panel to permit a failed power range channel's overpower-rod stop function to be bypassed, and its average power signal to the RCS to be replaced by a signal derived from an active channel. This will allow normal power operation to continue while the failed channel is repaired.

7.2.1.1.7.9 Output Information

Tables 7.2.1-4, 7.2.1-5, and 7.2.1-6 provide the NIS control and indication output information for the source, intermediate and power ranges, respectively.

7.2.1.1.7.10 Testing Nuclear Instrument Channels

In the source and intermediate ranges where the trip logic is one-out-of-two for each range, bypasses are provided for the testing procedure.

Administrative controls prevent the nuclear instrumentation source range and intermediate range protection channels from being disabled during periodic testing.

Nuclear instrument power range channels are tested by superimposing a test signal on the normal sensor signal so that the reactor trip protection is not bypassed. Based upon coincident logic (2/4) this will not trip the reactor; however, a trip will occur if a reactor trip is required. Power range overpower protection cannot be disabled since this function is not affected by the testing of circuits. Administrative controls also prevent the power range dropped-rod protection from being disabled by testing. In addition, the rod position system would provide indication and associated corrective actions for a dropped rod condition.

7.2.1.1.7.11 Energy Supply

A loss of power in the RPS causes the affected channel to trip. All bistables operate in a normally energized state and go to a de-energized state to initiate action.

Current to the mechanisms is interrupted by opening either of the reactor trip breakers. The 70 volt DC maintenance supply will also be interrupted since this supply receives its input power through the reactor trip breakers as described in Section 7.6 and Chapter 8.0.

7.2.1.1.8 Rod Drive Power

Power to the full length CRDM is supplied through duplicate series-connected circuit breakers. Upon proper coincidence of trip signals, as described above, the undervoltage coils and the auto shunt trip relays (part of these circuit breakers) are de-energized, opening both breakers and interrupting power to the full length CRDM. Rapid reactivity insertion is provided by the insertion of the RCCA by gravity fall on loss of power. |3

The solid state rod control system is operated from two parallel connected 400 kVa generators which provide 260 volt line-to-line, three phase, four wire power to the rod control circuit through two series connected reactor trip breakers. This AC power is distributed from the trip breakers to a line-up of identical solid state power cabinets using a single overhead run of enclosed bus duct which is bolted to, and therefore comprises, part of the power cabinet arrangement. Alternating current from the motor-generator sets is converted to a profiled direct current by the power cabinet and is then distributed to the mechanism coils (Figure 7.2.1-10). Each complete rod control system includes a single 70 volt DC power supply which is used for holding the mechanisms in position during maintenance of normal power supply.

This 70 volt supply, which receives its input from the AC power source downstream of the reactor trip breakers, is distributed to each power cabinet and permits holding mechanisms in groups of four by manually positioning switches located in the power cabinets. The 30 ampere output capacity limits the holding capability to eight rods.

7.2.1.1.8.1 Reactor Trip

Current to the mechanisms is interrupted by opening either of the reactor trip breakers. The 70 volt DC maintenance supply will also be interrupted since this supply receives its input power through the reactor trip breakers.

7.2.1.1.8.2 Trip Breaker Arrangement

The trip breakers are arranged in the reactor trip switchgear in individual metal-enclosed compartments. The 1000 ampere bus work making up the connections between trip breakers will be separated by metal barriers to prevent the possibility that any conducting object could short circuit or bypass trip breaker contacts.

7.2.1.1.8.3 Maintenance Holding Supply

The 70 V DC holding supply and associated switches have been provided to avoid the need for bringing a separate DC power source to the rod control system during maintenance on the power cabinet circuits. This source is adequate for holding a maximum of eight mechanisms and satisfies all maintenance holding requirements.

7.2.1.1.8.4 Control System Construction

The rod control system equipment is assembled in enclosed steel cabinets. Three phase power is distributed to the equipment through a steel enclosed bus duct, bolted to the cabinets. DC power connections to the individual mechanisms are routed to the reactor head area from the solid state cabinets through insulated cables, enclosed junction boxes, enclosed reactor containment penetrations, and sealed connectors. In view of this type of construction, any accidental connection of either an AC or DC power source, either internal or external to the cabinets, is not considered credible.

7.2.1.1.9 Primary Power Source

The primary power sources for the RPS are the instrument buses described in Chapter 8.0. The source of electrical power for the measuring elements and the actuation of circuits in the engineered safety features (ESF) instrumentation is also from these buses.

7.2.1.2 Design Basis Information

7.2.1.2.1 Reactor Protection System and DNB

The following is a description of how the RPS prevents DNB.

The plant variables affecting the DNB ratio are:

a) Thermal power

The analog portion of a protective channel (e.g., sensor and amplifier) provides an analog signal of the reactor or plant parameter. The following methods for checking the analog portion of a protective channel during reactor operation are provided:

1) Varying the monitored parameter

2) Introducing and varying a substitute transmitter signal

3) Cross checking between identical channels or between channels which bear a known relationship to each other and which have readouts available.

The design provides for administrative control for the purpose of manually bypassing channels for test and calibration purposes.

The design provides for administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

e) Information Readout and Indication of Bypass - The protective system provides the operator with complete information pertinent to system status and plant safety.

Indication is provided on the reactor and turbine-generator board if some part of the system has been administratively bypassed or taken out of service.

Trips are indicated and identified down to the channel level.

f) Vital Protective Functions and Functional Requirements - The RPS monitors all parameters related to safe operation of the reactor. The system is designed to trip the reactor so as to protect the core against fuel rod cladding damage causes by departure from DNB, and to protect the RCS against damage caused by overpressure. The ESF Instrumentation System monitors parameters to detect failure of the RCS, and initiates containment isolation and ESF operation.

g) Completion of Protective Action - Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are part of the protective system and are designed in accordance with the criteria of this section.

The protective systems are so designed that, once initiated, a protective action goes to completion. Return to normal operation requires administrative action by the operator.

h) Multiple Trip Settings - For monitoring nuclear flux, multiple trip settings are used. When it is necessary to change to a more restrictive trip setting to provide adequate protection for a particular mode of operation or set of operating conditions, the design provides positive means of assuring that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protective system and are designed in accordance with the other provisions of these criteria.

i) Interlocks and Administrative Procedures - Interlocks and administrative procedures required to limit the consequences of fault conditions other than those specified as limits for the protective function comply with the protective system criteria.

j) Protective Actions - The RPS automatically trips the reactor to protect the reactor core when the following conditions exist:

1) The reactor power, as measured by neutron flux, reaches a preset limit

2) The temperature rise across the core as determined from loop ΔT reaches a limit; both from a fixed ΔT setpoint (function of T_{avg} and neutron flux distribution) or a variable ΔT setpoint (function of T_{avg}, pressurizer pressure and neutron flux distribution).

3) The pressurizer pressure reaches a minimum limit

4) Loss of reactor coolant flow as sensed by low flow, loss of pump power or pump breakers opening

The RPS automatically trips the reactor to protect the RCS when the pressurizer pressure reaches a maximum limit.

Interlocking functions of the RPS prevent control rod withdrawal when a specified parameter reaches a value less than the value at which reactor trip is initiated.

For anticipated abnormal conditions, protective systems in conjunction with inherent plant characteristics and ESF are designed to assure that limits for energy release to the containment and for radiation exposure (as in 10CFR100) are not exceeded.

k) Indication - All transmitted signals (flow, pressure, temperature, etc.) which can lead to a reactor trip are either indicated or recorded for every channel.

All nuclear flux power range currents (top detector, bottom detector, and algebraic difference and average of bottom and top detector currents) are indicated and/or recorded.

l) Alarms - Alarms are also used to alert the operator of deviation from normal operating conditions so that he may take corrective action to avoid a reactor trip. Further, actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

m) Operating Environment - The protective channels are designed to perform their function when subjected to the most adverse environmental conditions and to prevent loss of function resulting from the most adverse environmental conditions anticipated during their lifetime.

TABLE 7.2.1-6

POWER RANGE

SIGNAL AND SOURCE	DESTINATION AND/OR FUNCTION
1. Isolation Amplifier (Ion Chamber A)	
a. 0-10 V DC	Spare
b. 0-5 V DC	Computer
c. 0-1 ma DC	Remote Meter (Delta Flux)
d. 0-5 V DC	Remote Recorder
e. 0-50 mv DC	Spare
2. Isolation Amplifier (Ion Chamber A)	
a. 0-10 V DC	ΔT Overpower-Overtemperature Compensation
3. Isolation Amplifier (Ion Chamber B)	
a. 0-10 V DC	Spare
b. 0-5 V DC	Computer
c. 0-1 ma DC	Remote Meter (Delta Flux)
d. 0-5 V DC	Remote Recorder
e. 0-50 mv DC	Spare
4. Isolation Amplifier (Ion Chamber B)	
a. 0-10 V DC	ΔT Overpower-Overtemperature Compensation
5. Isolation Amplifier (Average Power)	
a. 0-10 V DC	Spare
b. 0-5 V DC	Computer

TABLE 7.2.1-6 (Cont'd)

SIGNAL AND SOURCE	DESTINATION AND/OR FUNCTION
c. 0-1 ma DC	Remote Meter (Percent FP)
d. 0-50 mv DC	Remote Recorder
e. 0-5 V DC	Spare
6. Isolation Amplifier (Average Power)	
a. 0-10 V DC	Power Mismatch
b. 0-5 V DC	Spare
c. 0-1 ma DC	Spare
d. 0-50 ma DC	Spare
e. 0-5 V DC	Spare
7. Isolation Amplifier (Average Power)	
a. 0-10 V DC	Comparator
b. 0-5 V DC	Spare
c. 0-1 ma DC	Spare
d. 0-50 mv DC	Overpower Recorder
e. 0-5 V DC	Spare
8. Bistable Amplifiers	
a. 115 V AC	Reac. Prot. Relay Rack (Dropped Rod-Rod Stop)
b. 115 V AC	Misc. Proc. Relay Rack (Overpower Rod Stop)
c. 115 V AC	Reac. Prot. Relay Rack (Spare Permissive)
d. 115 V AC	Reac. Prot. Relay Rack (Permissive P-10)

TABLE 7.2.1-6 (Cont'd)

SIGNAL AND SOURCE	DESTINATION AND/OR FUNCTION
e. 115 V AC	Reac. Prot. Relay Rack (Spare Permissive)
f. 115 V AC	Reac. Prot. Relay Rack (Low Range Reactor Trip)
g. 115 V AC	Reac. Prot. Relay Rack (High Range Reactor Trip)
h. 115 V AC	Misc. Proc. Relay Rack (Annunciate "Power Range Loss of Detector Voltage")
9. Test-Calibrate (115 V AC)	Misc. Proc. Relay Rack (NIS Channel Test-MCB)
10. Trip Bypass (115 V AC)	Reac. Prot. Relay Rack (Block of Rod-Drop Circuit)

7.2.2 ANALYSIS

7.2.2.1 General Design Criteria and IEEE 279

Information on how the design basis requirements of IEEE-279 are met is presented above. The applicable General Design Criteria are discussed in Section 3.1. Additional analysis are presented below.

7.2.2.2 Control and Protection Interaction

7.2.2.2.1 Nuclear Power

Four power-range nuclear flux channels are provided for overpower protection. Isolated outputs from all four channels are averaged for automatic control rod regulation of power. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection. In principle, the same failure may cause rod withdrawal and, hence, overpower. Two-out-of-four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, the control system will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are compensated by the temperature control signals. Also, a rapid decrease of any nuclear flux signal will block automatic rod withdrawal as part of the rod drop protection circuitry and initiate a load cutback. Finally, an overpower signal from any nuclear channel will block automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.2.2 Coolant Temperature

The three T_{avg} channels (one per loop) are used in the overtemperature and overpower protection system logic. A reactor trip signal is generated if two out of the three signals exceed the calculated ΔT setpoint where overtemperature and overpower setpoint equations are given in Section 7.2.1.1.2.

The input signals to the Reactor Control System are obtained from electronically isolated protection T_{avg} and ΔT signals (one per loop). A Median Signal Selector (MSS) is implemented in the Reactor Control System, one for T_{avg} and one for ΔT. The MSS receives three channels as input and selects the median signal for input to the appropriate control systems. Any single failure (high or low) in a calculated temperature will not result in adverse control system behavior since the failed high or low temperature signal will be rejected by the MSS. 7

Hence, the implementation of a MSS in the Reactor Coolant System in conjunction with the two out of three protection logic satisfies the requirements of IEEE 279-1971, Section 4.7, "Control and Protection System Interaction."

The response time allocated for measuring RCS hot and cold leg temperature using thermowell mounted fast response RTDs is four seconds. This response time does not include the process electronics.

In addition, channel deviation alarms in the control system will block automatic rod motion (insertion or withdrawal) if any temperature channel deviates significantly from the others. Automatic rod withdrawal blocks will also occur if any two of four nuclear channels indicates an overpower condition or if any two of three temperature channels indicates an overtemperature condition. Two-out-of-three trip logic is used to ensure that an overtemperature trip will occur if needed even with an independent failure in another channel. Finally, as shown in Chapter 15.0, the combination of trips on nuclear overpower, high pressurizer water level, and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion.

7.2.2.2.3 Pressurizer Pressure

Three pressure channels are used for high and low pressure protection and as part of overpower-overtemperature protection. Two pressure channels are used for pressure control and compensation signals for rod control. These are discussed below:

a) Control of rod motion: one of the pressure control channels is used for rod control with a low pressure signal acting to withdraw rods. The discussion for coolant temperature is applicable, i.e., two-out-of-three logic for overpower-overtemperature protection as the primary protection, with backup from multiple rod stops and "backup" trip circuits. In addition, the pressure compensation signal is limited in the control system such that failure of the pressure signal cannot cause more than about 10°F change in T_{avg}. This change can be accommodated at full power without a DNBR less than the safety limit specified in Section 4.4. Finally, the pressurizer safety valves are adequately sized to prevent system overpressure.

b) Pressure Control: Spray, power-operated relief valves, and heaters, are controlled by isolated output signals from the pressure control channels.

1) Low Pressure - A spurious high pressure signal from one control channel can cause low pressure by spurious actuation of spray and/or a relief valve. Additional redundancy is provided in the protection system to ensure underpressure protection, i.e., two-out-of-three low pressure reactor trip logic and two-out-of-three logic for safety injection.

2) High Pressure - The pressurizer heaters are incapable of overpressurizing the reactor coolant system. Maximum steam generation rate with heaters is about 11,000 lb/hr, compared with a total capacity of 864,000 lb/hr for the three safety valves and a total capacity of 420,000 lb/hr for the two power-operated relief valves. Therefore, overpressure protection is not required for a pressure control failure. Two-out-of-three high pressure trip logic is therefore used.

In addition, either of the two relief valves can easily maintain pressure below the high pressure trip point. The two relief valves are controlled by independent pressure control channels, one of which is independent of the pressure channel used for heater control. Finally, the rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available for operator action.

7.2.2.2.4 Pressurizer Level

Three pressurizer level channels are used for reactor trip. Isolated output signals from these channels are used for volume control, increasing or decreasing water level. A level control failure could fill or empty the pressurizer at a slow rate (on the order of half an hour or more).

A reactor trip on pressurizer high level is provided to prevent rapid thermal expansions of reactor coolant fluid from filling the pressurizer: the rapid change from high rates of steam relief to water relief can be damaging to the safety valves and the relief piping and pressurizer relief tank. However, a level control failure cannot actuate the safety valves because the high

pressure reactor trip is set below the safety valve set pressure. With the slow rate of charging available, overshoot in pressure before the trip is effective is much less than the difference between reactor trip and safety value set pressures. Therefore, a control failure does not require protection system action.

In addition, ample time and alarms are available for operator action.

7.2.2.2.5 Steam generator water level; feedwater flow. Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation. (See Figure 7.2.1-16.)

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long-term residual heat. Should a complete loss of feedwater occur with no protective action, the steam generators would boil dry and cause an overtemperature-overpressure excursion in the reactor coolant. Reactor trips on temperature, pressure, and pressurizer water level will trip the plant before there is any damage to the core or reactor coolant system. However, residual heat after trip would cause thermal expansion and discharge of the reactor coolant to containment through the pressurizer relief valves. Redundant emergency feedwater pumps are provided to prevent this. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

1. Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam generator water inventory.

2. It is desirable to minimize the thermal transient on a steam generator for credible loss of feedwater accidents.

It should be noted that controller malfunctions caused by a protection system failure affect only one steam generator. Also, they do not impair the capability of the main feedwater system under either manual control or automatic control. Hence, these failures are far from being the worst cases with respect to decay heat removal with the steam generators.

a. Feedwater Flow - A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, will ensure a reactor trip if needed.

In addition, the three-element feedwater controller incorporates reset on level, such that with expected controller settings a rapid increase in the flow signal would cause only a 12 in. decrease in level before the controller re-opened the feedwater valve. A slow increase in the feedwater signal would have no effect at all.

b. Steam Flow - A spurious low steam flow signal would have the same effect as a high feedwater signal, discussed above.

c. Steam Generator Level - A spurious high water level signal from the protection channel used for control will tend to close the feedwater valve. This level channel is independent of the level and flow channels used for reactor trip on low flow coincident with low level.

1) A rapid increase in the level signal will completely stop feedwater flow and lead to an actuation of a reactor trip on low feedwater flow coincident with low level.

2) A slow drift in the level signal may not actuate a low feedwater signal. Since the level decrease is slow, the operator has time to respond to low level alarms. Since only one steam generator is affected, automatic protection is not mandatory and reactor trip on two-out-of-three low-level is acceptable.

7.2.2.2.6 Steam line pressure. Three pressure channels per steam line are used for steam break protection (two-out-of-three low pressure signals for any steam line actuates safety injection). An additional channel is used to control the power-operated relief valve on that steam line. These valves are typically rated at 10 percent of the safety valve capacity. A spurious high pressure signal from the channel used for control will open the relief valve and cause low pressure. This is a slow rate of steam release, classified as a credible steam (line) break in Chapter 15.0. In that the consequences of a more severe steam line break are acceptable, analysis for this event is not necessary. Therefore, control failure does not create a need for the protection, and two-out-of-three logic is acceptable.

7.2.2.3 Nuclear Instrumentation. During plant shutdown and operation, three discrete independent levels of nuclear protection are provided from the three ranges of out-of-core nuclear instrumentation. The basic protection philosophy is that the level protection is present in all three ranges to provide a reliable, rapid and restrictive protection system which is not dependent upon operation of higher range instrumentation.

Reliability is obtained by providing redundant channels which are physically and electrically separated. Fast trip response is an inherent advantage of using level trip protection in lieu of startup rate protection (with a long time constant) during plant startup. More restrictive operation is an inherent feature since an increase in plant power cannot be performed until satisfactory operation is obtained from higher range instrumentation which permits administrative bypass of the lower range instrumentation. On

decreasing power level, protection is automatically made more restrictive. Startup accidents while in the source range are rapidly terminated without significant increases in nuclear flux and with essentially no power generation or reactor coolant temperature increase.

The indications and administrative actions required by this protection system are readily available to the operator and should result in a safe, uncomplicated increase of power.

7.2.2.3.1 Reactor trip protection. During reactor startup, the operator will be made aware of satisfactory operation of one or more intermediate range channels by annunciation (audible and visual) at the control board. The source and intermediate range flux level information is also readily available on recorders and indicators at the control console. At this time, if both intermediate range channels are functioning properly, the operator would depress the two manual block switches associated with the source range logic circuitry, thus causing cutoff of source range detector voltages and blocking the trip logic outputs. The manual block should not be initiated, however, until at least one decade of satisfactory intermediate range operation is obtained. If one intermediate range channel is not functioning, normal power increase could be performed if desired. The permissive P6 annunciation is continuously displayed by the control board status lights.

Continuation of the startup procedure in the intermediate range would result in a normal power increase, and the receipt of a permissive signal from the power range channels when two-of-four channels exceed 10 percent of full power. The operator would be alerted to this condition by a control board permissive status light. Indicators (one per channel) and a recorder also indicate plant status in terms of percent full power. If the operator does not block the intermediate range trip and continues the power increase, a rod stop will automatically occur from either of the intermediate range channels. The operator should then depress the momentary "Manual Block" pushbuttons associated with the intermediate range rod stop and reactor trip logic. This would transfer protection to the low-range trips for the four power range channels. The permissive P10 status light would be continuously displayed as was P6. The low-range manual block switches (two) must be depressed to initiate blocking prior to continuation of the power increase. The permissive functions associated with administrative trip blocking and automatic reactivation are provided with the same separation and redundancy as the trip functions.

When decreasing power operation to lower levels, more restrictive trip protection is automatically afforded when three-of-four power range channels are below P10 permissive and when two-of-two intermediate ranges are below the permissive P6.

7.2.2.3.2 Rod-Drop Protection

An additional protection function provided by the power range instrumentation is backup to the rod-drop protection of the rod bottom bistables on the Rod Position System. The nuclear instrumentation rod-drop protection is provided by comparison of the average nuclear power signal with the same signal which is conditioned by an adjustable lag network. This method provides a response to dynamic signal changes associated with a dropped rod condition, but does not respond to the slower signal changes associated with normal plant operation. Rod-stop actuation from at least one of the four power range channels will occur for any dropped rod condition.

Each rod-drop sensing circuit has associated with it a bistable amplifier driving two relays in separate logic relay racks. The logic relay matrices are connected in a one-of-four, "OR", configuration to block rod withdrawal and initiate a load cutback.

7.2.2.3.3 Control and Alarm Functions

Various control and alarm functions are obtained from the three ranges of out-of-core nuclear instrumentation during shutdown, startup and power operation. These functions are used to alert the operator of conditions which require administrative action and alert personnel of unsafe reactor conditions. They also provide signals to the rod control system for automatic blocking of rod withdrawal during plant operation to avoid unnecessary reactor trips.

a) Source Range - No control functions are obtained from the source range channels. Alarm functions are provided, however, to alert the operator of any inadvertent changes in shutdown reactivity. Visual annunciation of this condition is at the control board, with audible annunciation performed in the containment and Control Room. This alarm can either be blocked prior to startup or can serve as the startup alarm in conjunction with administrative procedures.

b) Intermediate Range - Both alarm and control functions are supplied by the intermediate range channels. Blocking of rod withdrawal is initiated by either intermediate range on high flux level. This condition is alarmed at the control board to alert the operator that rod-stop has been initiated. In addition, the intermediate ranges provide an alarm when either channel exceeds the P6 permissive level. This alerts the operator to the fact that he must take administrative action to manually block the source range trips to prevent an inadvertent trip during normal power increase.

c) Power Range - The power ranges provide alarm and control functions similar to those in the intermediate ranges. An overpower rod-stop function from any of the four power range channels inhibits rod withdrawal and is alarmed at the control board. The power ranges also provide an alarm function when two-of-four channels exceed permissive P10 level. As in the case of P6 in the intermediate range, this alerts the operating personnel that administrative action (namely, blocking of intermediate and low range trips) is required before any further power increase may take place.

The power ranges also have provisions for two additional permissive functions. When P8 and P9 are used, the power ranges through two-of-four matrices provide P8 and contribute to the overall logic for permissive P9. A permissive status light is provided for P8, "Nuclear Power Below P8." The extinguishing of the P8 permissive status light alerts the operator that the flow trips and "pump breaker open" trips are now active. These trips are blocked while the status light is alarmed. Additional functions are provided in the power range of operation. A dropped control rod will be sensed by one or more of the power range channels, and this condition will initiate a block rod withdrawal signal and a turbine load cutback signal to the reactor control and protection system.

Another function is a power range channel deviation alarm. This alarm is furnished by the comparator channel through a comparison of the average power level signals being supplied by the power ranges. Actuation of this alarm alerts the operator to a power unbalance between the channels so that corrective action can be taken. Finally, three signals are supplied by each power range to the reactor control and protection system; one signal from each ion chamber isolation amplifier, and one from the average isolation amplifier. The isolated average power signal is transmitted through the miscellaneous control and indication panel switches.

In the case of a failed channel, this permits the removal of the failed channel's average power signal and the insertion of an active channel's signal in the RPS function.

7.2.2.3.4 Loss of Power

The nuclear instrumentation draws its primary power from the vital instrument buses whose reliability is discussed in Section 8. Redundant NIS channels are powered from separate buses. Loss of a single vital instrument bus would result in the initiation of all reactor trips associated with the channels deriving power from that source. During power operation, the loss of a single bus would not result in a reactor trip since the power range reactor trip function operates from a two-of-four logic. If the bus failure occurred during source or intermediate range operation (one-of-two logic), a reactor trip condition would result.

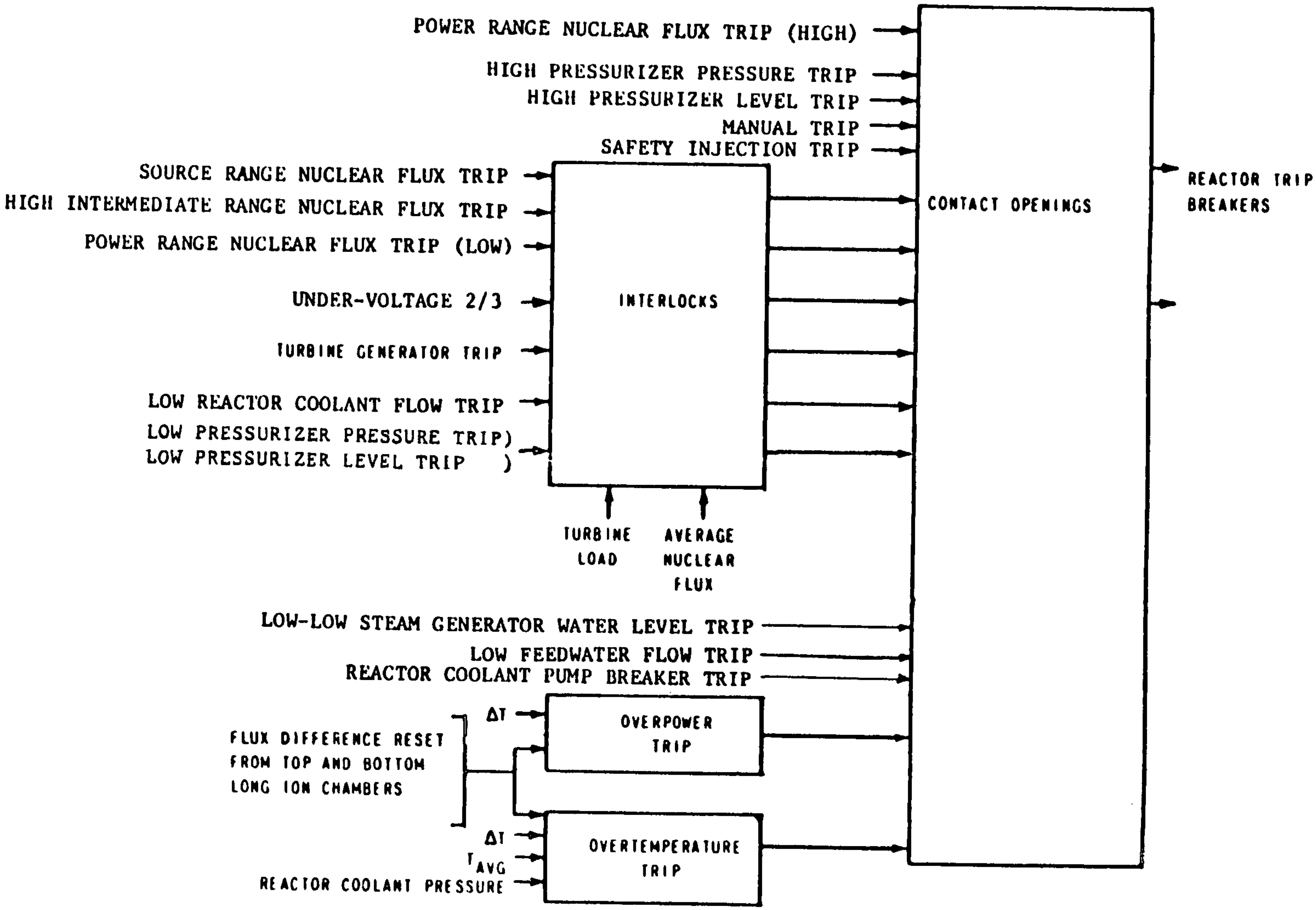
7.2.2.3.5 Safety Factors

The relation of the power range channels to the Reactor Protective System has been described. To maintain the desired accuracy in trip action, the total error from drift in the power range channels will be held to ±1.0 percent at full power. Routine tests and recalibration will ensure that this degree of deviation is not exceeded. Bistable trip set points of the power range channels will also be held to an accuracy of ±1.0 percent of full power.

7.2.2.4 <u>Full Length Rod Drive Power Supply</u>

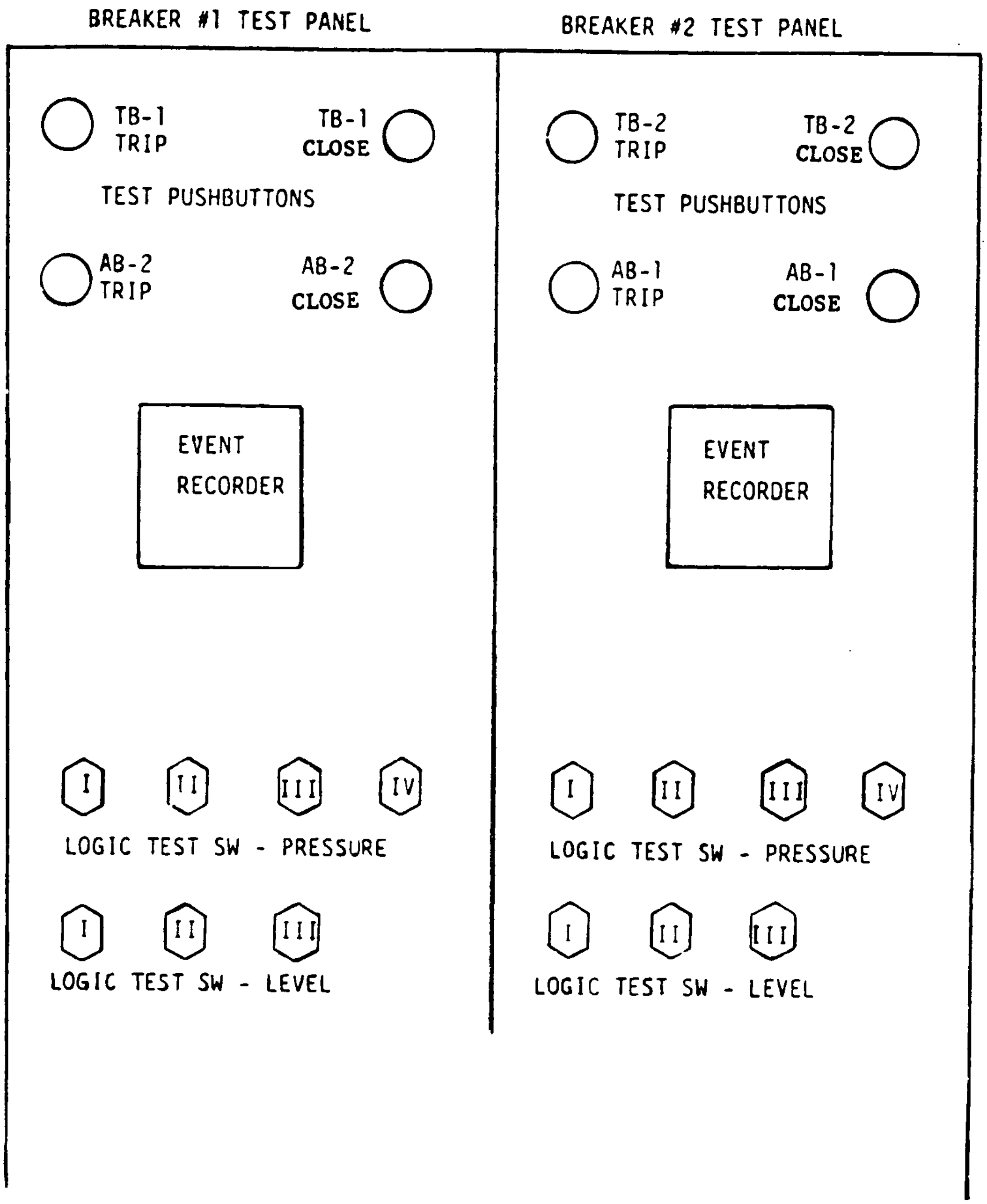
The full length control rod drive power supply concept using a single scram bus system has been successfully employed on all Westinghouse plants. Potential fault conditions with a single scram bus system are discussed in this section. The unique characteristics of the latch type mechanisms with its relatively large power requirements make this system with the redundant series trip breakers particularly desirable.

H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

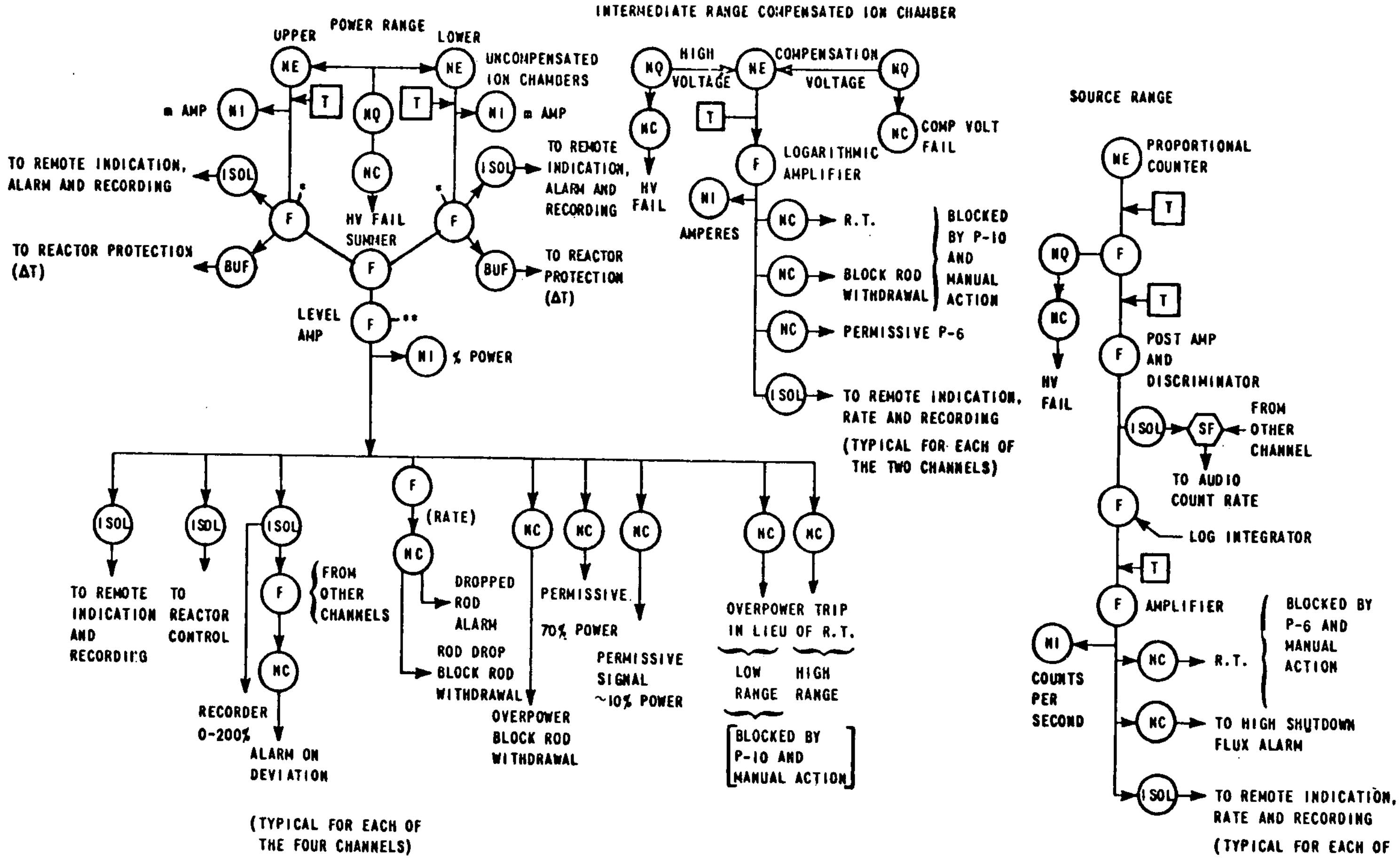


REACTOR PROTECTION SYSTEMS

FIGURE 7.2.1 - 1



H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	LOGIC CHANNEL TEST PANELS	FIGURE 7.2.1 - 6



* QUADRANT POWER TILT MONITORING ADJUSTED ON BASIS OF IN-CORE DATA

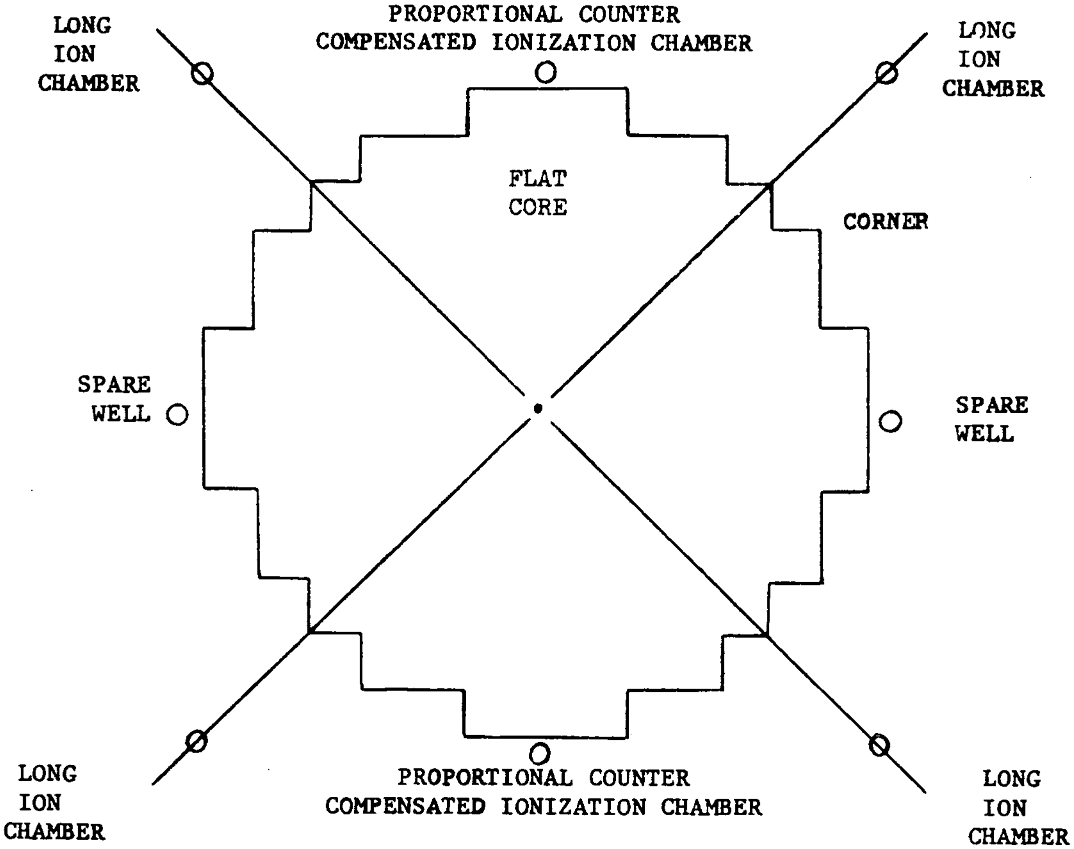
** AVERAGE POWER ADJUSTED ON BASIS OF CALORIMETRIC DATA

NOTE: SEE FIGURE 7.2.1-12 FOR DEFINITION OF SYMBOLS

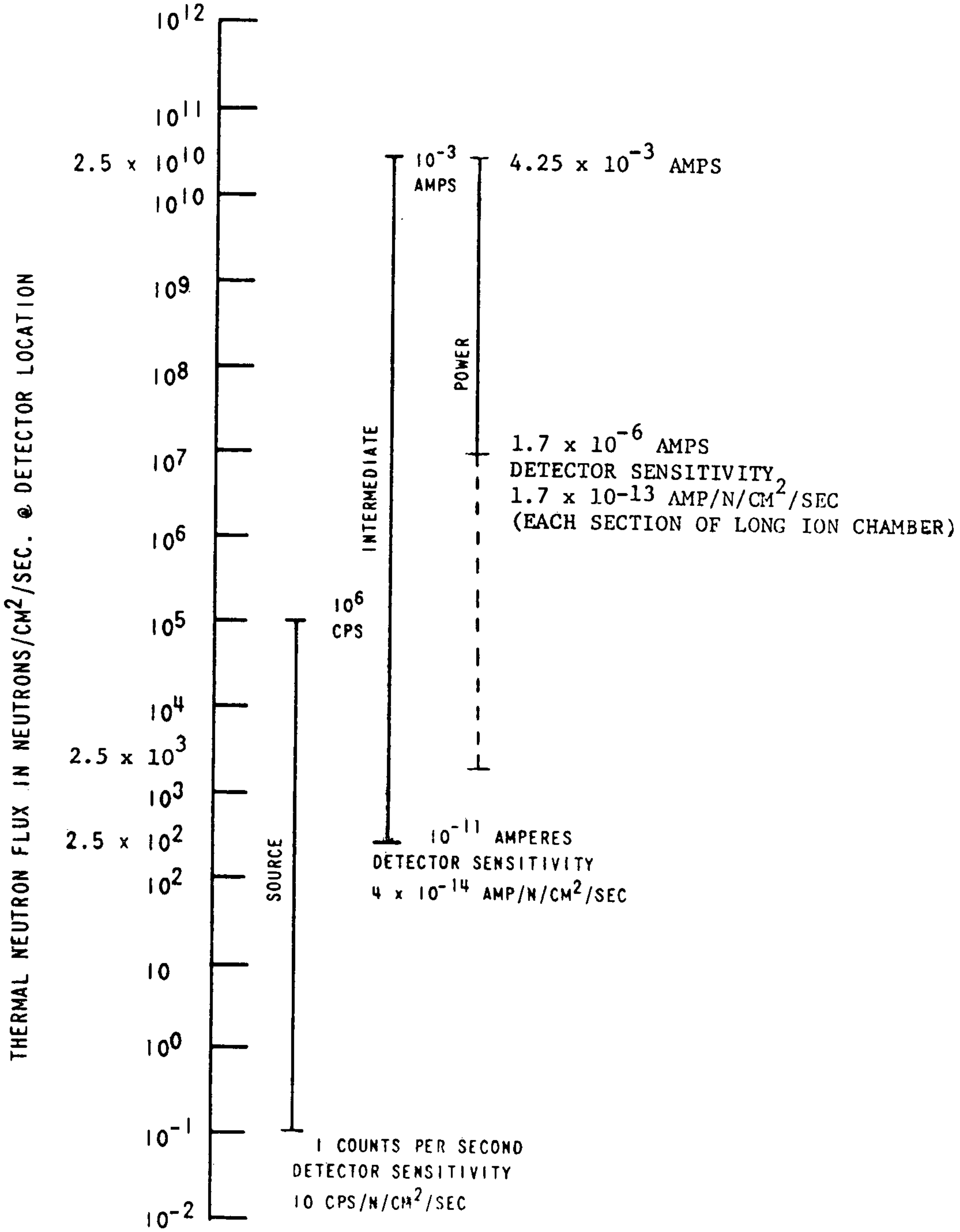
H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

NUCLEAR PROTECTION SYSTEM

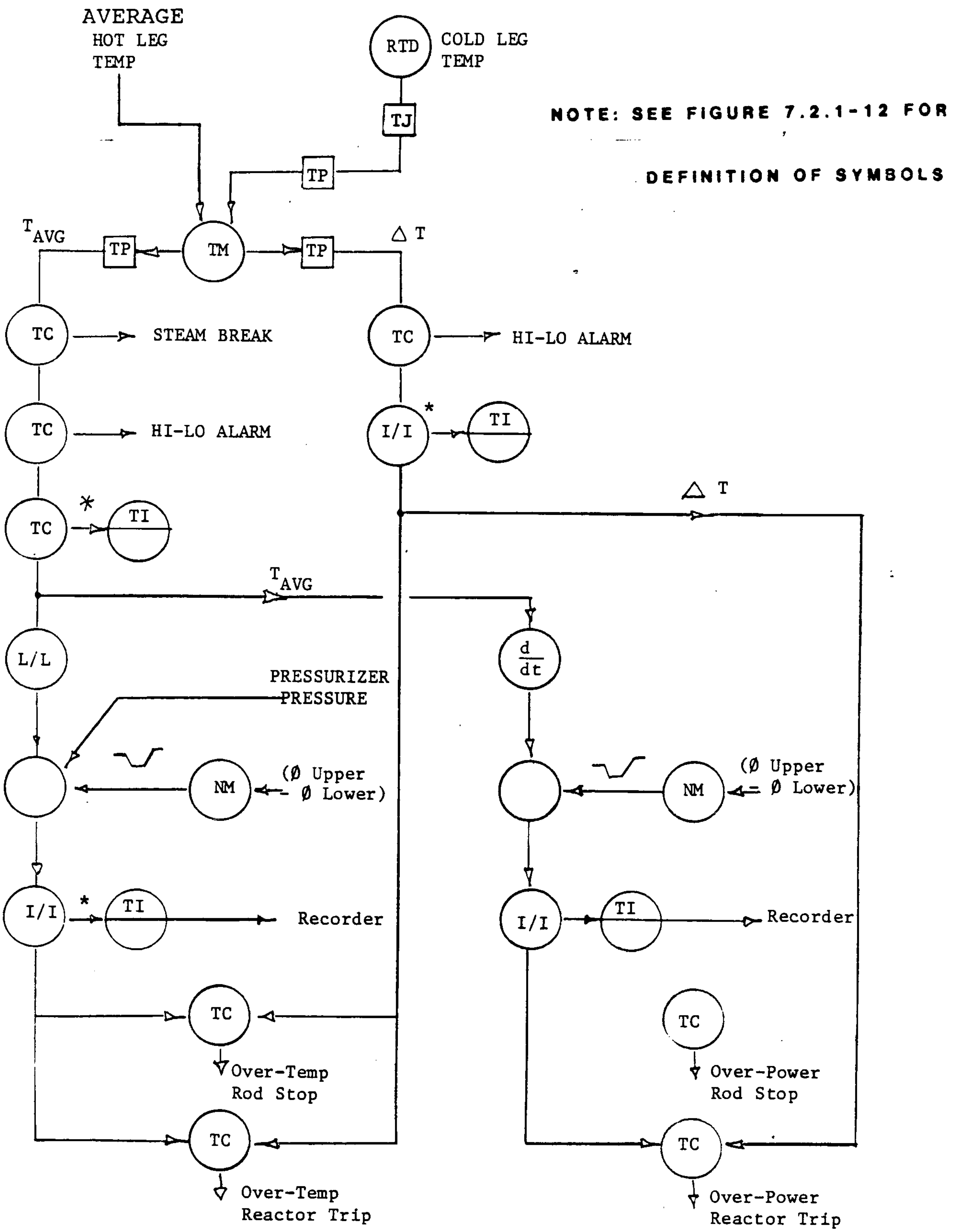
FIGURE
7.2.1-7



H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	PLAN VIEW INDICATING DETECTOR LOCATION RELATIVE TO CORE	FIGURE 7.2.1 - 8

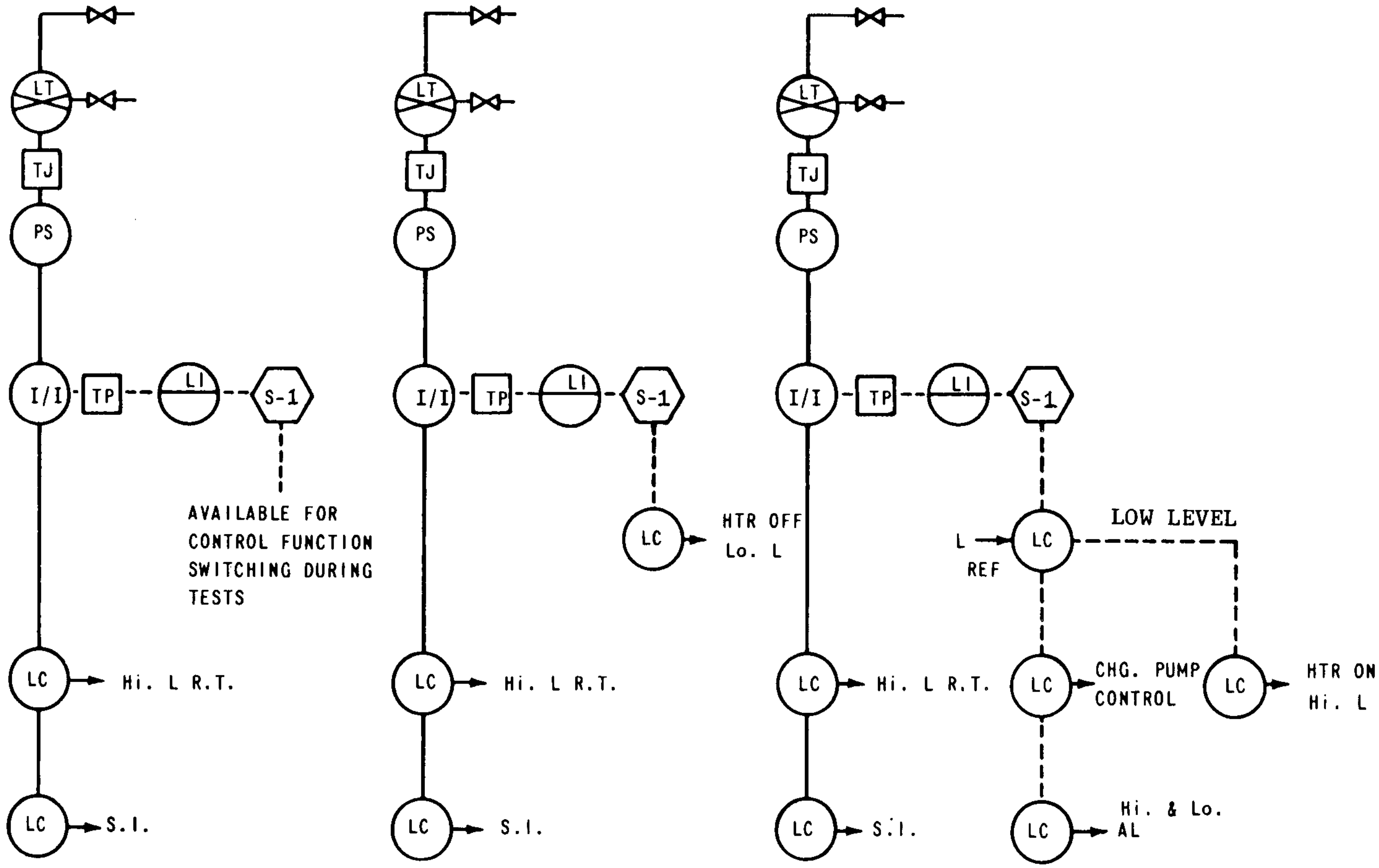


H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	RANGE OF OPERATION OF NUCLEAR INSTRUMENT CHANNELS	FIGURE 7.2.1 - 9



AMENDMENT NO. 7

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	T_{AVG} - △T PROTECTION SYSTEM	FIGURE 7.2.1 - 13

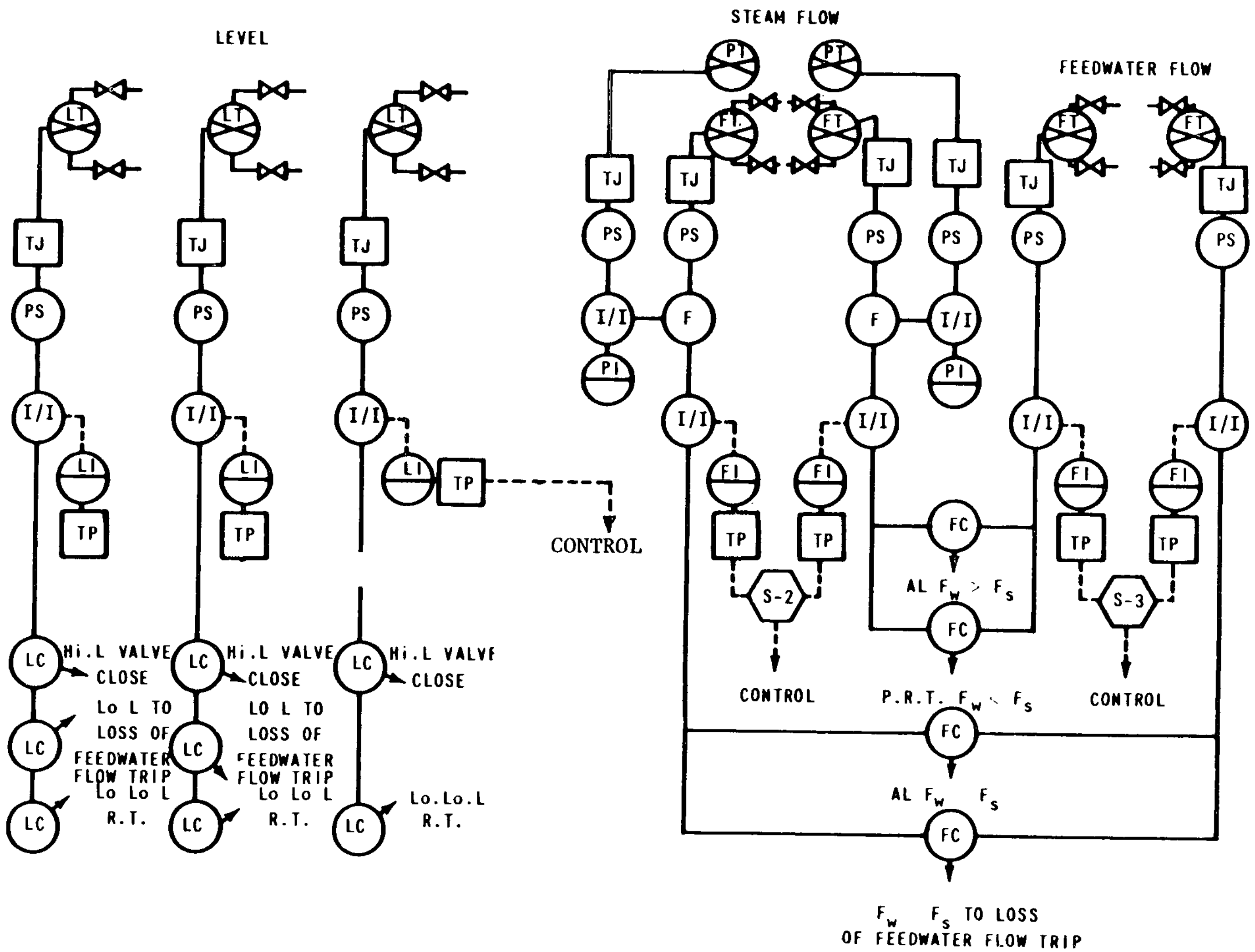


NOTE: SEE FIGURE 7.2.1-12 FOR DEFINITION OF SYMBOLS

H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

PRESSURIZER LEVEL CONTROL
AND PROTECTION SYSTEM

FIGURE
7.2.1 - 15



NOTE: SEE FIGURE 7.2.1-12 FOR DEFINITION OF SYMBOLS

H. B. ROBINSON
UNIT 2
Carolina Power & Light Company
UPDATED FINAL
SAFETY ANALYSIS REPORT

STEAM GENERATOR LEVEL CONTROL
AND PROTECTION SYSTEM

FIGURE
7.2.1 - 16

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

The Engineered Safety Feature (ESF) Instrumentation measures temperatures, pressures, flows, and levels in the Reactor Coolant System (RCS), Reactor Containment, and Auxiliary Systems, activates the ESF, Containment Isolation, Steam Line Isolation, and Emergency Feedwater, and monitors their operation.

7.3.1 DESCRIPTION

7.3.1.1 System Description The ESF actuation instrumentation performs the functions shown in Table 7.3.1-1. These functions are summarized below.

a) Operation of the Safety Injection System (SIS) is initiated upon occurrence of any of the following events: low pressurizer pressure; high containment pressure; high differential pressure between any steam line and the steam line header; or high steam flow in any 2 steam lines, coincident with low steam pressure or low reactor coolant average temperature.

b) Operation of the containment isolation valves in nonessential process lines (phase A) is initiated upon automatic actuation of safety injection.

c) Operation of the Containment Spray System and remaining containment isolation valves (phase B) is initiated upon detection of a high-high containment pressure signal.

d) Operation of the Containment Air Recirculation Cooling System is started after initiation of the SIS.

e) The following signals will close all steam isolation valves:

1) High steam flow coincident with low reactor coolant average temperature or low steam pressure

2) High-high containment pressure signals

Steam line isolation is required to prevent the blowdown of more than one steam generator (SG) in the unlikely event of a steam line fracture.

f) Any safety injection signal will isolate the main feedwater lines by closing all control valves (main and bypass valves), tripping the main feedwater pumps and closing the pump discharge valves. Key switches on the RTGB will allow the operator to override/block the Feedwater Isolation signal to the Feedwater Control Bypass valves and to the Main Feedwater pumps. The isolation signal to the Main Feedwater Control valves is not blocked or overridden by these switches. Placing of these key switches in the override/reset position will give an alarm on the RTGB and the keys cannot be removed when the switches are in the override/reset position. The auxiliary feedwater system is actuated by the safety injection signal.

g) Although the emergency feedwater system is not considered to be an engineered safeguard, its actuation is described below.

7.3.1.1.1 Auxiliary feedwater system initiation. The controls used to automatically start the auxiliary feedwater pumps are designed to meet the single failure criterion, with the exception of the opening of both feedwater pump circuit breakers and AMSAC. The following pump starting logic is used:

1. The two motor driven auxiliary feedwater pumps are started automatically on:

   a. 2/3 low low level in any SG

   b. Opening of both feedwater pump circuit breakers (one contact per pump breaker is used)

   c. Any Safety Injection Signal

   d. Loss of offsite power (i.e., the blackout sequence)

   e. Manually

   f. AMSAC trip (two of three SG below low-low setpoint at ≥ 40% power)

2. The turbine-driven auxiliary feedwater pump is started automatically on:

   a. 2/3 low low level in any two SG

   b. Loss of voltage on 4 kV buses 1 and 4. Two sensors are provided for each bus with 2/2 logic to indicate a loss of voltage on any one bus.

   c. Manually

   d. AMSAC trip (two of three SG below low-low setpoint at ≥ 40% power)

In the Loss of Normal Feedwater analysis, in Section 15.2.7, it has been assumed that the auxiliary feedwater pumps are started on the low low steam generator level signals. The analysis has been performed assuming only one motor-driven auxiliary feedwater pump is started at one minute after reaching the low low level setpoint in all three SG.

The relay logic for starting the auxiliary feedwater pumps is separated into train A and train B logic, as is done for the relay logic used to actuate ESF. Logic train A will start one motor driven pump and logic train B will start the second motor-driven pump. Either logic train will open appropriate steam system valves to start the turbine-driven pump. The circuits used to start the auxiliary feedwater pumps will also open the appropriate valves to ensure delivery of flow to the SG.

To prevent the start of the auxiliary feedwater pumps under shutdown conditions, key switches have been installed as discussed in Section 7.3.2.2.2.

Implemented for compliance with 10CFR50.62, the ATWS Mitigation System Actuation Circuitry (AMSAC) System provides a means to automatically trip the turbine and actuate auxiliary feedwater flow in the event of a complete loss of feedwater transient. The AMSAC System is independent of and isolated from the existing Reactor Protection System (RPS) from sensor to the output actuation device. The AMSAC setpoints and time-delayed actuation will ensure that the RPS has had time to perform its function before any AMSAC-initiated trip. Therefore, the AMSAC signal will be of no consequence unless the RPS has failed.

The AMSAC System utilizes the steam generator level monitoring option as defined by Logic 1 of WCAP 10858-P-A, Revision 1. The system uses the output from existing steam generator narrow-range level sensors fed into a microprocessor-based AMSAC controller. The AMSAC controller also monitors turbine first-stage pressure to identify the 40% power level at which the AMSAC must be armed. Class 1E qualified isolators protect the safety-related circuits currently associated with both of these sets of sensors from any perturbations that could be introduced by malfunction of the nonsafety-related AMSAC circuitry. A timer associated with the AMSAC arming logic maintains the AMSAC in an armed condition after turbine pressure drops below the 40% power level. This ensures that a turbine trip will not disarm AMSAC before it has had time to initiate auxiliary feedwater flow if the steam generator level criteria are met. During operation, the controller continuously scans the sensor inputs. The AMSAC System will be armed when the turbine pressure indicates that the plant is above 40% power. If AMSAC is armed and the controller identifies a coincident low level in two out of three steam generators, the controller will actuate a turbine trip and initiate auxiliary feedwater flow after appropriate timer delay to ensure that it does not preempt the RPS trip functions. The AMSAC outputs tie in to the existing safety-related actuation circuits using isolation relays to protect the existing systems from problems induced by AMSAC malfunctions.

MALFUNCTION ANALYSIS

COMPONENT	MALFUNCTION	COMMENT
Motor Driven Pump	Fails to start	Second pump or turbine-driven pump supplies adequate feedwater
Steam Generator Level Switch	Fails to signal low Level	Three switches per generator provided. Two required for initiation.
Steam Admission Valve to Pump Turbine	Fails to open	Three valves, one from each SG
Discharge Valve From Motor-Driven Pump Header	Fails to open	If steam driven pump has not started, one steam generator will reach low level alarm point. Operator must manually start steam driven pump.

7.3.1.1.2 ESF Instrumentation.

7.3.1.1.2.1 Design Basis. The ESF instrumentation measures temperatures, pressures, flows, and levels in the RCS, Steam System, Reactor Containment and Auxiliary Systems, actuates the ESF, and monitors their operation. Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated, recorded, and controlled from the Control Room. The quantity and types of process instrumentation provided ensure safe and orderly operation of all systems and processes over the full operating range of the plant.

Certain controls and indicators which require a minimum of operator attention, or are only in use intermittently, are located on local control panels near the equipment to be controlled. Monitoring of the alarms of such control systems are provided.

The same channel isolation and separation criteria as described for the reactor protection circuits (Section 7.2) are applied to the ESF actuation circuits.

The DC control supply associated with the ESF is designed to meet the single failure criterion such that one failure will not prevent actuation of sufficient ESF to meet the core and containment cooling criteria.

7.3.1.1.2.2 Design Features. The ESF instrumentation system is designed to use analog channels and initiation logic similar to that of the Reactor Protection System described in Section 7.2.

The initiating systems for the Containment Ventilation System, the Feedwater Isolation System, the Containment Spray System, and the Containment Isolation System are designed so that actuation cannot be over-ridden, and an open or failed reset switch will not impede manual operation. Key switches on the RTGB will allow the operator to override/block the Feedwater Isolation signal to the Feedwater Control Bypass valves and to the Main Feedwater pumps. The isolation signal to the Main Feedwater Control valves is not blocked or overridden by these switches. Placing of these key switches in the override/reset position will give an alarm on the RTGB and the keys cannot be removed when the switches are in the override/reset position. The Safety Injection Actuation System is designed so that an open or failed reset switch will not impede manual operation.

7.3.1.1.2.3 ESF instrumentation equipment. The following instrumentation ensures monitoring of the effective operation of the ESF.

1. Containment Pressure - Eight channels, monitoring containment pressure, and derived from three pressure taps monitor the effectiveness of the containment cooling systems and other ESF. High pressure indicates high temperatures and reduced pressure indicates reduced temperatures. Indicators and alarms are provided in the Control Room to inform the operator of system status and to guide actions taken during recovery operations. Containment pressure indication will be used to distinguish between various incidents.

Redundant containment pressure signals are provided to isolate the containment. Each of the three pairs of differential pressure transmitters external to the containment in the Auxiliary Building have their own connection to the containment. Remote indicating facilities and alarm and control signals are provided from each transmitter.

Remote indicating facilities are provided which afford the operator the opportunity to read containment pressure.

2. Refueling Water Storage Tank Level - Level instrumentation on the refueling water storage tank consists of three channels. One channel provides a local indication and low level alarm function. The second channel provides remote indication (on the control board) and two low level alarms. One of these is a normal operating low level and the other is a low low level alarm. The low level alarm has redundant alarm switches read from separate level transmitters and power supplies. The third channel provides remote indication on the control board.

3. Emergency Core Cooling System Pumps Discharge Pressure - These channels clearly show that the emergency core cooling system pumps are operating. The transmitters are outside the containment.

4. Pump Energization - All pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board.

5. Radioactivity - Means are provided to measure the radioactivity in the containment atmosphere after the incident, since this information will be required for any subsequent entry into the containment following a loss-of-coolant accident (LOCA). In the event of a major LOCA, radioactivity levels would be such that area monitors located outside the containment would respond to the activity levels inside the containment. The containment system particulate and gaseous monitoring equipment would also provide information useful in post-accident recovery operations at pressures below 5 psig, and with favorable containment temperature and radiation conditions.

6. Valve Position - All ESF remote-operated valves have position indication on the control board to show proper positioning of the valves. Air-operated and solenoid-operated valves are selected to move in a preferred direction with the loss of air or power. SI-856A and B fail to the preferred position during normal operation but fail to the unpreferred position with a manual handwheel as backup during the recirculation mode of operation. After a loss of power to the motors, motor-operated valves remain in the same position as they were prior to the loss of power.

7. Air Coolers - The cooling water discharge flow of each of the coolers is alarmed in the Control Room if the flow is low. The transmitters are outside the reactor containment. In addition, the exit flow is monitored for radiation and alarmed in the Control Room if high radiation should occur. This is a common monitor and the faulty cooler can be located locally by manually valving each one out in turn.

8. Sump Instrumentation - The containment sump instrumentation consists of four level switches with gasketed junction boxes designed to operate in a post-accident environment. The transmitter housings are located above any possible flooding level. The indicators and alarm system are located in the Control Room.

Indicated on the reactor and turbine-generator board (RTGB) are two status lights which light when the water level in the reactor vessel cavity sump rises above 0.5 ft. The containment sump level is indicated on the RTGB from 0 to 7 ft above the containment floor in 0.5 ft increments. Two extended range (analog channels) level indicators are displayed on the core cooling and containment panel which indicate the water level from 3.5 in. above the reactor vessel cavity floor to 423.5 in.

9. Local Instrumentation - In addition to the above, the following local instrumentation is available.

a. Residual heat removal pumps discharge pressure

b. Residual heat exchanger exit temperatures

c. Containment spray test lines total flow

d. Safety injection test line pressure and flow

10. Alarms - Visual and audible alarms are provided to call attention to abnormal conditions. The alarms are of the individual acknowledgement type; that is, the operator must recognize and silence the audible alarm for each alarm point.

11. Indication - All transmitted signals (flow, pressure, temperature, etc.) which can cause actuation of the ESF features are either indicated or recorded for every channel.

12. RHR Pit Level Indication and Alarms - Level indication has been provided on the RTGB to monitor water level in the RHR pits. This indication in conjunction with corresponding HI and HI-HI RHR Pit A&B Level Annunciation on APP-001 will provide operators with sufficient time to isolate any water sources to the particular RHR pump pit to preclude a common mode RHR pump failure.

7.3.1.1.2.4 Interlocks to prevent diesel generator overload during safety injection and loss of offsite power.

1. To limit the load on the diesel generators, the following circuits will trip or inhibit the start of the following loads:

a. Trip the Charging Pumps upon coincident safety injection and loss of offsite power.

b. Trip the Component Cooling Pumps upon coincident safety injection and loss of offsite power plus CV spray signal.

c. Inhibit the start of the Component Cooling Pumps upon loss of offsite power plus low CCW header pressure.

d. Inhibit the start of the Auxiliary FW pumps upon loss of offsite power plus low S/G level, loss of FW pumps, or AMSAC.

2. Pressurizer Heaters - The 150 kW group of pressurizer heaters used to assure natural circulation at hot standby conditions are fed from redundant diesel generator buses during loss of off-site power. However, upon initiation of a safety injection signal, the pressurizer heater load will be shed to prevent overloading its DG.

3. Safety Injection Block - During shutdown, the SG differential pressure safety injection signal is blocked during normal shutdown operation to prevent spurious safety injection due to large deviations in the SG pressure which normally occurs during plant shutdown.

<u>7.3.1.2 Design Basis Information</u>. The information presented in 7.2.1.2.2 is applicable. Additional design basis information is presented in 7.3.1.1, above.

<u>7.3.1.3 Instrumentation Cable Separation</u>. The Engineered Safety Features (ESF) System is divided into two channels with each channel run in individual cable tray systems throughout the plant. Cables from different channels are never routed through the same penetrations. These penetrations are grouped into two groups for channel 1 consisting of penetration C-3, D-2, and D-4 and channel 2 consisting of penetration B-8, D-8, and D-9. The penetration in these two groups are separated by a horizontal distance of approximately 14 ft. Additional physical separation is provided by placing one complete channel consisting of penetration C-3, D-2, and D-4 on one side of a concrete wall separating this channel from channel 2 consisting of penetration B-8, D-8, and D-9.

The relays and associated circuitry for the ESF are located in the upper relay room in the southwest corner of the Reactor Auxiliary Building. The initiating systems are divided into four channels physically arranged so that each channel is at the extremity of two rows of process racks.

The rack arrangements and separation criteria are the same as that provided for the Reactor Trip System cable described in Section 7.2.1.3.

<u>7.3.1.4 Final System Drawings</u>. Figures 7.2.1-2, 7.2.1-3, 7.2.1-5, 7.2.1-6, 7.2.1-14, and 7.2.1-17 through 7.2.1-34 are applicable.

7.4 Systems Required For Safe Shutdown

7.4.1 Description

The Control Room Building, its equipment, and furnishings have been designed so that the likelihood of fire or other conditions which could render the Control Room inaccessible even for a short time is extremely small.

As a further measure to assure safety, provisions have been made so that plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the Control Room. During such a period of Control Room inaccessibility, the reactor will be tripped and the plant maintained in the hot shutdown condition. If the period extends for a long time, the Reactor Coolant System (RCS) can be borated to maintain shutdown as Xenon decays, via the refueling water storage supply. The capability to achieve and maintain cold shutdown conditions from outside the Control Room, in the event of a fire, is also provided.

Local controls are located so that the stations to be manned and the times when attention is needed are within the capability of the plant operating crew. The plant intercom system provides communication among the personnel so that the operation can be coordinated.

For a description of the systems required for safe shutdown in the event of a fire, refer to Appendix 9.5.1C. For a description of the functions and systems required for safe shutdown in the event of a Station Blackout (10CFR50.63) event, refer to the Station Blackout Coping Analysis, Document Number 8S19-P-101.

The functions for which local control provisions have been made are listed below along with the type of control and its location in the plant. Transfer to these local controls is annunciated in the Control Room.

7.4.1.1 Equipment Control Outside Control Room.

7.4.1.1.1 Reactor shutdown. If the Control Room should be evacuated suddenly without any action by the operators, the reactor can be tripped by either of the following:

1. Open rod control breakers at the reactor trip switchgear
2. Actuate the manual turbine trip

When the reactor is held at hot shutdown conditions, boration of the plant is not required immediately after shutdown. The Xenon transient does not decay to the equilibrium level until some 10 to 15 hr after shutdown, and a further period would elapse before the 1 percent reactivity shutdown margin provided by the full length control rods had been cancelled. This delay would provide time for useful emergency measures.

7.4.1.1.2 Residual heat removal. Failure to maintain water supply to the steam generators following a normal plant shutdown would result in steam generator dry out after some 400 sec and loss of the secondary system for decay heat removal. Independently controlled relief valves on each steam generator maintain the steam pressure. These relief valves are further

backed up by coded safety valves on each steam generator. Numerous calculations, verified by startup tests on the Connecticut-Yankee and San Onofre Power Plants have shown that with the steam generator safety valves operating alone, the RCS maintains itself close to the nominal no-load condition. The steam relief facility is adequately protected by redundancy and local protection.

For the continued use of the steam generators for decay heat removal, it is necessary to provide a source of water, a means of delivering that water and, finally, instrumentation for pressure and level indication.

Feedwater may be supplied to the steam generators by the motor driven auxiliary feed pumps or by the steam-driven auxiliary feed pump. In addition to the normal feed circuit the plant may fall back on:

1. The condensate storage tanks

2. Service water

3. Onsite deep well water

7.4.1.1.3 Pressurizer pressure and level control. Following a reactor trip the primary temperature will automatically reduce to the no-load temperature condition as dictated by the steam generator temperature conditions. This reduction in the primary water temperature reduces the primary water volume and if continued pressure control is to be maintained primary water makeup is required.

The pressurizer level is controlled in normal circumstances by the Chemical and Volume Control System (CVCS). This requirement implies operation of a charging pump. In the event that all charging pumps are inoperable (as the result of a fire that causes damage to cables serving all three pumps), RCS inventory can be maintained by depressurizing the RCS and utilizing the safety injection pumps.

7.4.1.1.4 Indication and controls provided outside the control room. The specific indication and controls provided outside the Control Room for the above capability are summarized as follows:

1. Indication

   a. Level Indication for the Individual Steam Generators

      1. Motor Driven Auxiliary feed pumps room
      2. Main feed bypass control valves
      3. Turbine Building mezzanine dedicated shutdown (DS) panel
      4. Charging pump room DS panel

   b. Pressure Indication For the Individual Steam Generators

      1. Turbine Building mezzanine DS panel

3) Pressurizer Level and Pressure Indicators

(a) Motor Driven Auxiliary feed pumps room (level only)
(b) Turbine Building mezzanine DS panel
(c) Charging pump room DS panel

4) Wide range RCS Loop "A" T_H and T_C Instrumentation

(a) Turbine Building mezzanine DS panel
(b) Charging pump room DS panel

5) Nuclear Instrumentation

(a) Charging pump room DS panel (meter only)

b) Controls

Local stop/start motor controls are provided at each of the following motors:

1) Motor-Driven Auxiliary Feedwater Pumps

2) Charging Pumps

3) Boric Acid Transfer Pumps

4) Component Cooling Water (CCW) Pump A for the DS system (at the charging pump room DS panel)

5) Service Water Pump D for the DS system (at the charging pump room DS panel)

The selector switch will transfer control of the switchgear from the Control Room to local at the motor, or remote panel. Placing the local selector switch in the local operating position will give an annunciator alarm on the Control Room panel.

Remote stop/start motor controls are provided for each of the following motors:

1) Service Water Pumps

2) Containment Air Recirculation Fans

These controls are grouped at two points. Service Water Pumps A and B and Containment Air Recirculation Fans HVH-1 and 2 in the emergency switchgear room convenient for operation. Service Water Pumps C and D and Containment Air Recirculation Fans HVH-3 and 4 in the Rod Drive Room convenient for operation. The selector switch will transfer control of the switchgear from the Control Room to the remote point. Placing the selector switch to local operation will give an annunciator alarm in the Control Room and will turn out the motor control position lights on the Control Room panel.

Alternate motor control points are not required for the following:

1) Component Cooling Water Pumps B and C. (Automatically restarted on a loss of offsite power once the diesel generators are operating.)

2) Instrument Air Compressors and Cooling Pumps. (These will start automatically on low pressures in the air and water services, once the diesel automatically energizes the bus, and the motor control centers are manually energized. Instrument Air Compressors must be reset and restarted upon reenergizing motor control centers. The control point is local to the compressors.)

c) Speed Control

Speed control is provided locally for:

1) The Steam-Driven Auxiliary Feed Pump

2) The Charging Pumps

d) Valve Control

Valve control is provided locally for:

1) Main Feed Regulators

2) Main Feed Bypass Regulators

3) Auxiliary Feed Control Valves. (These valves are located local to the auxiliary feed pumps and turbine building mezzanine DS panel)

4) Steam generator power operated relief valves

5) All other valves requiring operation during hot shutdown can be locally operated at the valve

6) Letdown orifice isolation valves (local to the charging pumps); local control and selector switches and position indicating lamps are provided

e) Pressurizer Heater Control

Stop and start buttons with selector switch and position lamp locally in the Rod Drive Room adjacent to containment for two 450 kW backup heater groups.

f) Lighting

Emergency lighting is provided in operating areas described above (as required to support post-fire shutdown operation), as well as in access and egress paths to those areas.

7.4.1.2 <u>Safe Shutdown System Improvement Modifications</u>

Major modifications were made to improve the alternative shutdown system ability to withstand common mode failures and particularly fires, as described below.

In the original plant configuration, fires occurring in some areas could impair the use of any or all of this equipment, primarily through destruction of power and control cables. Consequently, provisions have been made for the transfer of power and/or the control of select components to alternate sources to mitigate the consequences of a severe fire in these critical plant areas (e.g., Control Room, cable spreading room, emergency switchgear room, or battery room or Auxiliary Building Hallway first floor).

Plant modifications have been implemented to provide alternative and dedicated shutdown features as required to support the post-fire shutdown modes described in Section 7.4.1.3. The alternative/dedicated features are summarized as follows:

7.4.1.2.1 Steam-Driven Feedwater Pump Shutoff Valves

A transfer switch panel located in the Auxiliary Building enables the transfer of control for the steam-driven feedwater pump shutoff valves V1-8A and V2-14A from the existing remote control signals to local control at the turbine building mezzanine DS panel. The modification does not change the existing control voltage or power source alignment with the valves. The transfer to local control is annunciated in the Control Room.

7.4.1.2.2 Steam Generator Power-Operated Relief Valves

The turbine deck control panel also provides for disabling the existing remote control of steam generator power-operated relief valves RV1-1, RV1-2, and RV1-3. When transferred to local control, the valves can be operated by using the valve controllers in the turbine building mezzanine DS panel. The transfer to local control is annunciated in the Control Room.

7.4.1.2.3 Component Cooling Pump A Control Transfer

A transfer switch is provided on the charging pump room control panel to disable the existing remote control of component cooling pump A and to transfer control of the pump to a local switch on the panel. The transfer to local control is annunciated in the main Control Room. The pump power and control source is normally from 480V Bus DS.

7.4.1.2.4 Alternate Power Source for Service Water Pump D

The normal supply for service water pump (SWP) "D" is 480V Bus E2, with control from the plant Control Room. To provide a power supply and controls

independent of the critical fire areas, an alternate supply has been installed via the DS Bus. When properly aligned, these breakers provide an alternate power supply and control station for SWP "D". The breakers are provided with a key interlock to prevent the simultaneous closure of both breakers.

Service water discharge valve V6-12D, which isolates SWP "D" from the service water header, is powered via an administratively controlled breaker and a local switch. The valve is normally powered from MCC-6 but administrative controls allow alternative operation from MCC-5. Power train isolation is maintained by administrative control of the MCC breakers, and valve operation is available from the dedicated shutdown bus.

7.4.1.2.5 Charging Pump A

Alternate controls, independent of the critical fire areas, have been provided for charging pump A. The normal power supply for this pump (480V bus DS) is outside the emergency switchgear room.

The alternate controls for charging pump A, consisting of a control transfer switch and control switch, are located on the charging pump room control panel.

7.4.1.2.6 Alternate Power Supply for MCC-5

The normal power supply for MCC-5 is 480V Bus E1. To provide a power supply independent of the emergency switchgear room, key-interlocked manual circuit breakers 3 and 4 have been installed; by manually realigning these circuit breakers, MCC-5 is supplied from 480V Bus DS, which is independent of the emergency switchgear, control, cable spreading, and battery rooms.

7.4.1.2.7 Dedicated Shutdown (DS) Instrumentation

The DS instrumentation provides the following local displays at the charging pump room DS panel:

a) Wide range RCS Loop 'A' hot and cold leg temperatures
b) Nuclear instrumentation
c) Steam generator 1 wide range level
d) Steam generator 2 wide range level
e) Steam generator 3 wide range level
f) Pressurizer level
g) Pressurizer pressure

With the exception of the nuclear instrumentation, duplicate shutdown instrumentation displays are provided at the turbine building mezzanine DS panel. In addition, the condensate storage tank level is displayed at the turbine building mezzanine DS panel.

7.4.1.2.8 Separation of Power and Control Cables

The existing design is in compliance with the intent of the <u>separation</u> criteria defined by Regulatory Guide 1.75. The <u>isolation</u> criteria applied in this design are consistent with those of the existing plant designs and with the requirements of IEEE-279 and IEEE-384-1977.

All new components that provide alternate power or control capabilities for the DS system have been located so that alternate power sources or control stations will not be affected by any fire that could damage the normal shutdown systems. In addition, all conduits and cable for the DS systems have been routed through areas that will not be affected by fires that could damage systems normally required for shutdown.

All new dedicated shutdown cable has been installed in rigid steel conduit routed through areas remote from cables presently used for the normal shutdown systems. Where this level of separation was not achievable, selective installation of rated fire-protective cable wraps and related protective measures (e.g., fire suppression systems) have been implemented.

7.4.1.3 Alternative and Dedicated Shutdown Capability

Carolina Power & Light Company has performed and documented a comprehensive analysis of the separation between redundant safe-shutdown components and cables in the context of post-fire shutdown system separation requirements defined by 10CFR50, Appendix R, Section III.G (Reference 7.4.1-1). The analysis considered the effects of fire on plant equipment and identified methods of achieving a stable cold shutdown condition from normal plant power operation.

Refer to Appendix 9.5.1C for a description of this analysis and the basis for establishment of alternative and dedicated post-fire shutdown capabilities.

Procedures have been established for achieving safe shutdown by using a combination of alternative equipment, depending upon the fire location.

7.4.2 Analysis

7.4.2.1 Compliance With Applicable Codes and Standards. The engineered safety feature systems were designed in accordance with the applicable General Design Criteria (GDC) effective in 1968. The reactor protection system was also designed in accordance with applicable GDC and IEEE 279, "Proposed Criteria for Nuclear Power Plant Protection Systems," August, 1968. No regulatory guides were available for incorporation into the original design criteria for the engineered safety features.

The alternative/dedicated shutdown system modifications do not impact the physical integrity of the auxiliary shutdown system components. The only penetrations into the existing system pressure boundary were for the installation of new impulse lines for new DS system instrumentation. The modification did not impact the system process and the auxiliary shutdown system will continue to meet all of the original mechanical and operational design criteria.

The post-fire safe-shutdown modifications provide for:

1. Separation of Redundant Circuits. Where safety-related circuits have been modified, new wiring and components have been installed so that, as a minimum, the separation requirements of Regulatory Guide 1.75 are met. The basis for the modifications (fire hazards analysis) dictated that power and control wiring for selected components (e.g., one charging pump, one service water pump) be rerouted so that cables serving redundant pumps would not pass through common fire areas.

2. Fault Isolation for Safety-Related Circuits and Power Supplies. Electrical isolation, in accordance with Regulatory Guide 1.75, is provided to ensure that external faults (fire-induced) will not degrade existing or new safety-related electrical systems.

3. Separation of Safety and Non-Safety Related Circuits. Isolation devices and/or physical separation are provided to ensure that failures in non-safety related circuits will not jeopardize adjacent safety-related circuits.

4. Annunciation in Main Control Room or Bypass or Assumption of Local Control. For those components provided with a "control transfer" features, auxiliary contacts on each control transfer switch are used to provide annunciation (in the Control Room) when the component is switched out of its "remote control" mode.

This annunciation feature has been implemented for all auxiliary shutdown components having remote/local control capabilities.

5. Interlocks and Administrative Controls to Limit the Consequence of Faulted Conditions. Features such as key interlocks or racking out of selected circuit breakers prevent the inadvertent cross-connection or simultaneous faulting of redundant power supplies.

6. Seismic Installation in Safety-Related Areas or Safety-Related Cabinets. Interfaces with existing safety-related cabinets and new safety-related cabinets (e.g., charging pump room panel, transfer switch panels) and their included components have been designed to remain functional through a safe shutdown earthquake (SSE).

7. Single-Failure Criterion. All new safety-related components and safety-related interfaces are designed so that a single failure cannot cause the loss of redundant safety systems. The modifications generally affect only one of redundant equipment trains. The failure of one of these equipment trains will not initiate the failure of the redundant train; electrical and physical separation of the redundant trains have not been degraded as a result of the modification.

7.4.2.2 Control and Power Circuit Separation. In conducting the fire hazard analysis, it was determined that several plant fire areas were critical in that cables for redundant shutdown-related components were routed through these areas. As a result, a severe fire in one of these areas could incapacitate redundant equipment trains by destroying power and control cables, or by destroying power supplies.

In order to mitigate the consequences of a fire in any one of the plant fire areas, power and control cables for selected shutdown-related components were rerouted to avoid these areas. The alternate power sources and local control panels and the device itself are independent of the areas of concern or a means of manual or remote operation has been provided.

7.4.2.3 Operating Requirements.

7.4.2.3.1 Operators. Sufficient qualified operators will be available to conduct shutdown activities, whether from the control room or following a control room evacuation. Operator staffing is adequate for implementation of post-fire shutdown procedures in the event of a fire in any plant fire area.

7.4.2.3.2 Equipment adequacy. The functions required for post-fire shutdown are equivalent to those functions that must be maintained, as a minimum, in a safe-shutdown scenario that does not involve accident mitigation functions. The specific equipment credited to perform these functions, and the adequacy of the equipment to fulfill the necessary operational objectives are discussed in Appendix 9.5.1C.

Pages 7.4.2-3 through 7.4.2-6 have been deleted

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

7.5.1 DESCRIPTION

The design of a centralized Reactor-Turbine Generator Control Board (RTGB) incorporates the arrangement of controls and information instrumentation for the safe operation of both the Nuclear Steam System and conventional plant equipment in such a manner as to effectively reduce the amount of board area that the control operator needs to keep under his surveillance, and to provide quick access to controls. Control stations on the board are packaged in a modular concept and are grouped according to function to minimize the possibility of operator error due to juxtaposition of unrelated control functions. Control stations with both automatic and manual positions are provided with "bumpless" transfer of function.

Instrumentation, trend recorders, and annunciator panels are incorporated in the vertical section of the RTGB to keep the operator informed on process flows, pressure, temperatures, etc., as well as alarms for out-of-limit points requiring operator action. The console section contains control devices (switches and control stations) and related indicating lights.

The general layout of the Control Room and the RTGB is shown in Figure 9.5.1-13. Section "A" contains control and instrumentation for Nuclear Steam Supply Systems. The left portion contains components less frequently used (e.g., for startup, shutdown, or less frequent surveillance).

The center portion contains control and instrumentation for Engineered Safety Features Systems. Redundant indicators are provided where required for high reliability. Monitoring lights provide a means of quickly evaluating the status of components in these systems should they be actuated. Controls and indicators for backup or redundant components are located on separate modules.

The right portion of Section "A" (adjacent to Section "B") contains those components more frequently used during normal plant operation. This includes pressurizer level control and reactor makeup control, as well as related indicators and recorders.

Section "B" contains rod control system and nuclear instrumentation system control and instrumentation. This includes a position indicator and rod bottom limit light manually controlled at the console. All nuclear instrumentation information required to operate the reactor is displayed here. Some of the reactor makeup system control devices are also included on the left portion of this section.

Sections "C" and "D" contain instrumentation and controls for secondary plant functions including feedwater and condensate systems, heater vent and drain systems, electrical systems, heating, ventilating, and air conditioning systems (except containment air recirculation system which appears in engineered safeguards portion of Section "A").

7.5.1.1 Pressurizer Power Operated Relief Valve Position Indication

A visual indication of the position of the pressurizer power operated relief valve and an audible alarm are provided in the Control Room to alert the operator should the valve open. The position indication system is a direct position indication system which employs limit switches actuated by the valve stem as a sensor for valve position. This system is part of the original design of the H. B. Robinson Plant and does not qualify as "safety grade" in the strictest sense of current standards; however, it does satisfy the short-term lessons learned requirements in that it is a reliable, single channel, direct indication powered from a vital instrument bus. In addition, this system is backed up by indirect means of determining valve position such as temperature and pressure downstream of the valves.

An acoustic system which senses flow through the pressurizer Safety Relief Valves has been installed. This newly installed position indication system provides the capability to continuously and automatically detect acoustic signals generated by flow through the valves. These signals are transmitted to an instrument panel mounted in the Cable Spreading Room where the system compares the current noise level to a quiescent level determined during calibration. When the quiescent level is exceeded by a predetermined amount, visual indication and an audible alarm informs the operator that the valve is open.

7.5.1.1.1 Control Stations Layout, Information Display, and Recording

The principal criterion of control station design and layout is that all controls, instrumentation displays and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the Control Room.

The Control Room (Figure 9.5.1-13) is located as an integral part of the HBR-2.
The Control Room is approximately 40 ft x 40 ft.

7.5.1.1.2 Computer System

This section deleted. This equipment has been replaced by the ERFIS system which is described in Section 7.7.1.9.

The computer system obtains data by scanning analog and digital sensors. It logs data on typewriters, sequentially logs trip and post trip data, and alarms various off-normal conditions. Monitoring programs are also included for surveillance of reactor control and protection system operations, and for nuclear process calculations.

The basic pieces of equipment used to perform these functions include: a computer, an operator's console with output typewriters, and a programmer's console.

7.5.1.1.3 Local Control Panels

Local control panels are provided for certain systems and components which do not require full time operator attendance or are not used on a continuous basis. Such systems are the Waste Disposal System, Sampling System, Boron Recycle System, and the Turbine-Generator Hydrogen Cooling System. In these cases, however, appropriate alarms are located in the Control Room and are activated to alert the operators of equipment malfunction or approach to unsafe conditions.

The waste disposal control board is located in the Reactor Auxiliary Building, in the vicinity of the boric acid and waste evaporators. This board permits the auxiliary operator to control and monitor the processing of wastes from a central location in the general area where equipment is located. Alarm signals from waste disposal components annunciate on this board. Actuation of any alarm on this panel actuates a general "Waste Disposal" alarm on the RTGB. In this manner, the control operator can maintain general surveillance over the system from the Control Room, and by means of the public address system, dispatch an operator to the waste disposal board if necessary.

Although the waste disposal control board provides the instrumentation required to control the release of wastes, instrumentation provided to monitor activity release is indicated and/or alarmed in the Control Room. The auxiliary operator has complete knowledge of permissible discharge rates and quantities before any scheduled release is made, and the waste disposal board permits him to control those parameters. By monitoring activity release from the Control Room, the control operator maintains surveillance.

7.5.1.1.3.1 Technical Support Center (TSC)

The TSC provides a location to house individuals who are knowledgeable of and responsible for engineering and management support or reactor operations following an event. The plant operators and operating staff are responsible for the safe operation of the plant, and for the initial action to minimize the consequences of the event. The TSC supports the operating staff with the up-to-date plant records of the plant configuration. Plant design/operation information are available in the form of drawings, FSAR, Technical Specifications and visual display of parameters. In addition, direct communications with the Control Room is provided which allows the TSC personnel to assess the status of the plant and stay abreast of the plant parameters. With this information, the TSC staff can provide short and long term technical advice and support during and after an event.

7.5.2 ANALYSIS

7.5.2.1 Control Room Environment

The safety-related electrical equipment is designed to operate and perform its design function within specified safe limits without degradation of performance (accuracy, repeatability, time response) under the expected normal and abnormal ambient conditions associated with its location. The normal ambient design temperature is 75°F (plus or minus 10°F) for Control Room located equipment. The abnormal ambient condition associated with the design of Control Room located safety equipment is 120°F for short term operation associated with a loss of air conditioning. Safety-related electrical equipment in other than the Control Room, such as the cable spread room, electrical equipment room and the cable vault is designed to operate under the worst case environment for which it is required to perform its function.

Provision for air conditioning has been made by supplying the two redundant Control Room air conditioners from separate emergency diesel power supplies. Thus, interrupted stay time or equipment malfunction due to loss of air conditioning is considered to be highly unlikely.

7.5.2.2 Instrumentation Power Supplies

The instrumentation is designed into four channels and each channel is powered by its respective instrument bus. Table 8.3.1-2 gives information about these power supplies. The instruments feed into the two trains of Reactor Protection and Engineered Safeguards which are powered by DC from the "A" and "B" Station Batteries to the respective trains. The loss of one of the instrument buses should not result in a reactor trip. In the event of a loss of an instrument bus, there remains adequate indication and protection in service from the remaining channels such that the safety of the plant is not jeopardized. From instrument status lights panels on the RTGB, the operator would be aware of which bus was lost and could have it manually switched to its back-up supply.

The four instrument channel status lights are in horizontal rows, with each row indicating in a different color corresponding to a different bus. The instrument status lights each indicate the existence of a specific alarm condition for an instrument on the bus. The loss of an instrument bus would result in the entire corresponding row of instrument channel status lights for reactor protection being illuminated.

Power to the status light modules is supplied by two instrument buses to preclude the loss of all lights due to a loss of power. The module on the Section "A" (Safeguards) portion of the RTGB is powered by Instrument Bus 3 and the modules on the Section "B" (Reactor Protection) portion of the RTGB are powered by Instrument Bus 1.

The RCCA are divided into several main banks, and each bank into several subgroups, to follow load changes over the full range of power operation. Each subgroup in a bank is driven by the same variable speed rod drive control unit which moves the subgroups sequentially one step at a time. The sequence of motion is reversible; that is, a withdrawal sequence is the reverse of the insertion sequence. The variable speed sequential rod control affords the ability to insert a small amount of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband.

Manual control is provided to move a control bank in or out at a preselected fixed speed.

Proper sequencing of the RCCA is assured by fixed programming equipment in the Rod Control System, and through administrative control of the reactor plant operator. Startup of the plant is accomplished by first manually withdrawing the shutdown rods to the full out position. This action requires that the operator select the SHUTDOWN BANK position on a control board mounted selector switch and then position the IN-HOLD-OUT lever (which is spring return to the HOLD position) to the OUT position.

Additional RCCA are then withdrawn under manual control of the operator by first selecting the MANUAL position on the control board mounted selector switch and then positioning the IN-HOLD-OUT level to the OUT position. In the MANUAL selector switch position, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

When the reactor power reaches approximately 15 percent, the operator may select the AUTOMATIC position, where the IN-HOLD-OUT lever is out of service, and rod motion is controlled by the Reactor Control and Protection Systems. A permissive interlock limits automatic control to reactor power levels above 15 percent. In the AUTOMATIC position, the rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

Programming is set so that as the first bank out (control bank C-2) reaches a preset position near the top of the core, the second bank out (control bank C-3) begins to move out simultaneously with the first bank. When control bank C-2 reaches the top of the core, it stops, and control bank C-3 continues until it reaches a preset position near the top of the core where the control bank C-4 motion begins. This withdrawal sequence continues until the plant reaches the desired power level. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank out is the first control bank in.

With the simplicity of the rod program, the minimal amount of operator selection, and two separate direct position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could be made.

7.7.1.1.1.2 Shutdown Groups Control

The shutdown groups of control rods together with the control groups are capable of shutting the reactor down. They are used in conjunction with the adjustment of chemical shim and the control groups to provide shutdown margin of at least one percent following reactor trip with the most reactive control rod in the fully withdrawn position for all normal operating conditions.

The shutdown groups are manually controlled during normal operation and are moved at a constant speed. Any reactor trip signal causes them to fall into the core. They are fully withdrawn during power operation and are withdrawn first during startup. Criticality is always approached with the control groups after withdrawal of the shutdown groups.

7.7.1.1.2 Reactivity Control

7.7.1.1.2.1 General

Overall reactivity control is achieved by the combination of chemical shim and RCCA. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes or reactor trip is accomplished by moving RCCA.

There is no provision for a direct continuous visual display of primary coolant boron concentration. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to plant power and average coolant temperature. There is a direct relationship between control rod position and power and it is this relationship which establishes the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints to alert the operator to take corrective action in the event a control group approaches or reaches its lower limit.

Any unexpected change in the position of the control group under automatic control or a change in coolant temperature under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples of coolant boron concentration are taken. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

7.7.1.1.2.2 Control Group Rod Insertion Monitor

The control group rod insertion limits, Z_{LL}, are calculated as a linear function of power and reactor coolant average temperature. The equation is:

$$Z_{LL} = A\ (\Delta T)_{avg} + B\ (\bar{T}_{avg}) + C$$

where A, B are preset manually adjustable gains and C is a preset manually adjustable bias. The $(\Delta T)_{avg}$ and $(\bar{T}_{avg})$ are the average of the individual temperature differences and the coolant average temperatures respectively measured from the reactor coolant hot leg and the cold leg.

This 70 volt supply, which receives its input from the AC power source downstream of the reactor trip breakers, is distributed to each power cabinet and permits holding mechanisms in groups of four by manually positioning switches located in the power cabinets. The 30 ampere output capacity limits the holding capability to eight rods.

7.7.1.2 Turbine By-Pass

A turbine by-pass system is provided to accommodate a reactor trip with turbine trip, or a 50 percent loss of load without reactor and turbine trip. The turbine by-pass system removes steam to reduce the transient imposed upon the RCS. The control rod system can then reduce the reactor power to a new equilibrium value without causing overtemperature and/or overpressure conditions.

The turbine by-pass is actuated when the compensated average coolant temperature exceeds the programmed value by a given amount and electrical load decrease is greater than a given value. All the turbine by-pass valves stroke to full open immediately upon receiving the maximum by-pass signal. After they are full open, the by-pass valves are modulated by the compensated coolant average temperature signal. The turbine by-pass reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The turbine by-pass steam capacity is 50 percent of full load steam flow at full load steam pressure. Forty percent of the by-pass steam flows to the main condenser and 10 percent flows to atmosphere.

7.7.1.3 Feedwater Control

Each steam generator is equipped with a three-element feedwater controller (see Figure 7.7.1-3) which maintains a programmed water level as a function of load on the secondary side of the steam generator. The three-element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, and the steam flow signal which is compensated by a steam pressure signal. The steam generators are operated in parallel, both on the feedwater and on the steam side.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor coolant following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature or when the respective steam generator level rises to a given value. Manual override of the feedwater control systems is also provided.

7.7.1.4 Pressure Control

The RCS pressure is maintained at constant value by using either the heaters (in the water region) or the spray (in the steam region of the pressurizer). The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater groups are proportional heaters which are used to control small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The

remaining (backup) heaters are turned on either when the pressurizer pressure controller signal is below a given value or when pressurizer level is above a given level.

The spray nozzles are located at the top of the pressurizer. Spray is initiated when the pressure controller signal is above a given setpoint. The spray rate increases proportionally with increasing pressure until it reaches a maximum value. Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Two power relief valves limit system pressure to 2350 psia for large load reduction transients.

Three spring-loaded safety valves limit system pressure to 2750 psia following a complete loss of load without direct reactor trip or turbine by-pass.

7.7.1.5 Incore Instrumentation

7.7.1.5.1 Design Basis

The incore instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information obtained from the incore instrumentation system, it is possible to confirm the reactor core design parameters and calculated hot channel factors. The system provides means for acquiring data and performs no operational plant control.

7.7.1.5.2 System Design

7 The incore instrumentation system consists of environmentally and seismically qualified, bottom-mounted thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations, and flux thimbles, which run the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core.

The measured data obtained from the incore temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculational techniques alone. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitations determine the maximum core capability.

The incore instrumentation provides information which may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and an estimate of the coolant flow distribution.

7 The information provided by the incore instrumentation system is available through the system's Indication System which consists of two plasma display panels (one per instrumentation channel) installed in the main control room. Both instrumentation channels comply with R.G. 1.97 requirements.

Both radial and azimuthal symmetry of power may be evaluated by combining the detector and thermocouple information from the one quadrant with similar data obtained from the other three quadrants.

7.7.1.5.2.1 Thermocouples

Chromel-alumel, bottom-mounted thermocouples are inserted into the neutron flux thimble guide tubes that enter the reactor vessel through the seal table, and terminate at the end of the thimbles. For every thermocouple that is 7
electrically connected to the system there is one spare thermocouple installed in the same guide tube and electrically connected through the seal table and thimble fittings to the corresponding intermediate junction box in the seal table area to allow easy replacement if necessary. Thermocouple outputs are recorded in the Control Room.

7.7.1.5.2.2 Movable Miniature Neutron Flux Detectors

Five fission chamber detectors (employing U_3O_8 which is 90 percent enriched in U_{235}) can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. Maximum chamber dimensions are 0.188 in. in diameter and 2.10 in. in length. The stainless steel detector shell is welded to the leading end of the helical-wrap drive cable and the stainless steel sheathed coaxial cable. Each detector is designed to have a minimum thermal neutron sensitivity of 1.5×10^{-17} ampere/nv and a maximum gamma sensitivity of 3×10^{-14} ampere/R/hr. Operating thermal neutron flux range for these probes is 1×10^{11} to 5×10^{15} nv. Other miniature detectors, such as gamma ionization chambers and boron-lined neutron detectors, can also be used in the system. Retractable thimbles into which the miniature detectors are driven are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal zone.

The thimbles, which are dry inside, are closed at the leading ends, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line.

During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of five drive assemblies, five path group selector assemblies and five rotary selector assemblies. The drive system pushes hollow helical-wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the trailing ends of the drive cables. Each drive assembly generally consists of a gear motor which pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length.

7.7.1.5.2.3 Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors at a selected speed while plotting a level of induced radioactivity versus detector position. Each detector can be driven in or out at speeds of 72 ft/min or 12 ft/min. In normal operation, the detectors would move at a speed of 72 ft/min outside the reactor core and 12 ft/min when scanning the neutron flux. The average path length external to the core is 120 ft.

Five separate fuel assemblies can be scanned simultaneously. A full core map is read in one hour. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the Control Room. Limit switches in each drive conduit provide means for pre-recording detector and cable positioning in preparation for a flux mapping operation. Each gear box drives an encoder for positional data plotting. One group path selector is provided for each drive unit to route the detector into one of the flux thimble groups. A rotary transfer assembly is a transfer device that is used to route a detector into any one of up to ten selectable paths. Ten manually operated isolation valves allow free passage of the detector and drive wire when open, and prevent leakage of coolant in case of a thimble rupture, when closed. A path common to each group of flux thimbles is provided to permit cross calibration of the detectors.

The Control Room contains the necessary equipment for control, position indication, and flux recording. Panels are provided to indicate the core position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting and gain controls. A "flux-mapping" consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven or inserted to the top of the core and stopped automatically. An x-y plot (positon vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner, other core locations are selected and plotted.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

7.7.1.5.3 Evaluation

The thimbles are distributed nearly uniformly over the core with about the same number of thimbles in each quadrant. The number and location of thimbles have been chosen to permit measurement of local to average peaking factors to an accuracy of ± 10 percent (95 percent confidence). Measured nuclear peaking factors will be increased by 10 percent to allow for possible instrument error. The departure from nucleate boiling (DNB) ratio calculated with the measured hot channel factor will be compared to the DNB ratio calculated from the design nuclear hot channel factors. If the measured power peaking is larger than expected, reduced power capability will be indicated.

7.7.1.6 Axial Power Distribution Monitoring System

The purpose of the Axial Power Distribution Monitoring System (APDMS) is to provide periodic surveillance of the axial peaking factor (F_z) when the reactor is operating at core power levels requiring F_z monitoring. The APDMS is a surveillance and alarm system only and performs no operational plant control or protection functions.

The APDMS is dependent upon the Flux Mapping System for initial selection and positioning of detectors, and for some selected functions during APDMS operation. Four detector/drive assemblies of the Flux Mapping System are utilized by the APDMS. The four particular thimbles and detectors to be used will be selected at the Flux Mapping System control console and the detectors positioned at their parked position inside the reactor vessel, but below the core. With this setup completed, control of the detector drives will be switched to the APDMS mode. Conversely, normal use of the Flux Mapping System requires that the APDMS be deactivated.

There are four control board annunciators:

a) "APDMS High F_z"

b) "APDMS Malfunction"

c) "APDMS on Test"

d) "APDMS not in Normal Mode"

The APDMS is automatically activated into normal operation when reactor power is at or above a preset power level as indicated by either of two Nuclear Instrumentation System power range signals and a single scan is made. The APDMS is automatically deactivated when reactor power is below the preset power level. The power setpoint will be fixed, but manually adjustable. While the system is active, a scanning sequence will be automatically initiated by significant movement of Control Bank D full length rods. The rod bank demand signals are monitored and integrated such that cumulative full length demanded rod motion (in either direction) outside a preset deadband will initiate an automatic typical scanning sequence which consists of scans at preset times following initiation.

In the event no rod movement occurs beyond the preset deadband, a scan will be automatically initiated if the time since the last scan exceeds eight hours. A manual scan can be initiated at any time, except when a scan is already in progress, without disruption of normal operation. When a scan is called for, two detectors are inserted at slow speed (12 ft/min). The F_z calculations begin at bottom-of-core and end at top-of-core. Both detectors are then

withdrawn to their park positions. The calculated value from each detector F_z computer and the Time of Scan will be displayed on the APDMS Scan Display panel. The readouts will be retained until the next APDMS scan is performed, at which time the readouts will change to display the updated information. Since F_z is a simple calculation of the peak to average factor for the detector trace, it is not necessary to normalize or cross-calibrate the movable detectors at part of APDMS operation.

For xenon ocsillations caused by changes in power level, and/or rod movements, plant procedures exist which provide for operator initiated damping of the oscillations by control rod movement. Adverse axial power distributions caused by xenon shifts which result from routine load changes during power operation are controlled using Power Distribution Control 3 (PDC-3) procedures. The PDC-3 procedure limits the peaking factor to the Technical Specification limit by restricting xenon redistribution during power changes. This is done by monitoring the power difference between the top and bottom of the core as a function of different power levels and core conditions.

7.7.1.7 Automatic Load Dispatch. Load changes on generating units in the Carolina Power and Light Company (CP&L) System are initiated by a computer located at a central system dispatch center. This computer constantly receives information from the system on the load requirements, compares this information to the generation on the system, and automatically sends out signals to the generating plants to adjust the plant generation to match the load requirements. Generation is allocated to the plants in such a manner that the incremental cost of the power delivered to the load by all units is equal, taking into account fuel costs and transmission losses.

Experience has proved this method of load dispatch to be very satisfactory from a generating plant standpoint as well as from a system operation standpoint.

From a generating plant standpoint, the following three criteria have been strictly adhered to in order to ensure that operation of all plants are maintained well within the bounds of what is considered good operating practice from a safety standpoint as well as from an equipment reliability standpoint.

1. The plant control operator, by operating one switch located on the plant control board, has the ability to switch the plant control system to a mode of operation that will make the plant unresponsive to load change signals from the load dispatch computer.

It is the responsiblity of the plant control operator to switch to this mode of operation at any time if in his judgment the generation of his plant should not be changed due to some condition within the plant.

2. The plant control operator, by the adjustment of two dials located on the plant control board, has the ability to set the generation range over which the plant will respond to signals to increase or decrese generation on the plant.

It is the responsibility of the plant control operator to set the limits on the control range in accordance with the procedures that have been established for this particular plant.

3. The control system on each turbine governor is set in a manner that precludes it from responding to signals to increase or decrease generation at a rate exceeding that which has been established as safe and well within the bounds of good operating practice for the particular unit. This setting cannot be changed without a modification of the control system.

The automatic dispatch signal initiates action of the turbine governor only and does not affect or in any way interfere with the Reactor Protection System.

7.7.1.8 Core Subcooling Monitor. The purpose of the subcooling monitor is to provide a continuous indication of margin to saturated conditions. The monitor uses inputs from core outlet thermocouples, RCS hot and cold leg resistance temperature detectors and RCS system pressure to drive a microprocessor which calculates saturation temperature and determines the margin to saturation based on the inputs. The individual inputs as well as the margin to saturation can be displayed on the monitor's plasma display panels (there is one plasma display panel for each of the two instrumentation channels).

7.7.1.9 Emergency Response Facility Information System (ERFIS). The Robinson Steam Electric Plant (HBR-2) Emergency Response Facility Information System (ERFIS) is a centralized, integrated signal data gathering, processing, and information display system that performs the process monitoring and calculations defined (in NUREG-0737, Supplement 1, and USNRC RG 1.97, Revision 3) as being necessary for the effective evaluation of emergency operation of a nuclear power plant. ERFIS has no plant control functions. The ERFIS acquires and records process data, including temperatures, pressures, flows, and status indicators. These data are processed by the ERFIS to produce meaningful displays, logs, and plots of current or historical plant performance for plant personnel in the Main Control Room (MCR), Technical Support Center (TSC), Emergency Operating Facility (EOF), or other user-definable locations. It shows the basic hardware configuration and Man-Machine Interface (MMI) hardware in the various plant locations.

7.7.1.9.1 System description. The ERFIS consists of the following three major hardware subsystems:

1. Data Acquisition System Hardware
2. Computer System Hardware
3. Display System Hardware

and 11 major software subsystems:

1. Applications Executive Subsystem
2. Data Base Management Subsystem
3. Data Acquisition Subsystem (DAS)

4. Man-Machine Interface Subsystem (MMI)
5. Log Generation/Reporting Subsystem
6. Data Archival/Retrieval Subsystem
7. Safety Parameter Display Subsystem (SPDS)
8. Nuclear Steam Supply System (NSSS)/Balance of Plant (BOP) Subsystem
9. Software Support Services Subsystem
10. Applications Software Utilities Subsystem
11. Special Software Subsystem

7.7.1.9.1.1 System hardware. The data acquisition, computer, and display subsystems are the three major building blocks of the ERFIS hardware.

The data acquisition hardware consists of five remote multiplexer cabinets in the cable spreading room of the plant and redundant data concentrators located in the ERFIS computer room in the TSC/EOF building. Provisions have been made for the future installation of remote multiplexers, as needed.

Each remote multiplexer cabinet consists of the following:

1. The termination interface including isolation devices for the analog/digital field inputs.

2. The electronics for signal conditioning, scanning, and digitizing of the input signals.

3. The communications and control equipment for each location.

The data concentrator is a high-performance, microprocessor system that receives, decodes, and buffers the data and makes it available to the ERFIS computer. Two data concentrators are provided for redundancy and each data concentrator communicates with each remote multiplexer via a high-speed fiber-optic link. Two dual data links between the remote multiplexers and the data concentrators are provided.

The computer system hardware is redundantly configured, each with a Gould/SEL 32/6780 central processing unit (CPU) as nucleus and common (i.e., shared) hardware such as a high-speed data link, line printer, peripheral/communications switch subsystem, and limited distance modems as required to ensure data integrity. The SEL 32/6780 computer is a high-speed general purpose, digital computer specifically designed for data acquisition in real-time applications. The system is configured to support failover to backup units for all critical hardware in order to provide a high level of maximum availability and reliability for the ERFIS.

The display system hardware consists of 12 color graphic display units mounted in consoles in the MCR, Computer Room, TSC, and EOF of the plant. Three display units will be located in the Control Room: one wall-mounted, two in the operator's consoles. The wall-mounted display is accessed via a keyboard located at the STA workstation. A character printer and a graphics printer are also in the MCR. .The TSC and EOF will each have four

display units, two color hard copy units, two character printers, and a video image store and copy system (VISCS). One display unit will be in the Main Computer Room at the programmer/engineer's console.

7.7.1.9.1.2 System Software

Of the 11 functional software subsystems that comprise the ERFIS, some are dedicated to generic-type system control and communication functions. For example, the primary functions of the applications executive subsystem are system initialization and startup, task maintenance, and intersystem communication. Other software subsystems perform functions unique to the ERFIS. The safety parameter display subsystem (SPDS), for example, processes, monitors, and displays information regarding plant safety parameters.

The data base management subsystem is responsible for the allocation, generation, and maintenance of the ERFIS system data base and memory areas.

The data acquisition subsystem (DAS) performs the real-time collection and processing of plant parameter (i.e., point) data inputs to the ERFIS.

The man-machine interface (MMI) subsystem controls the outputs to and inputs from the operator console CRT/keyboards.

The log generation/reporting subsystem creates all hard copy log/report outputs to the line printer(s). Subsystem functions include periodic, on-demand, and post trip printed outputs.

The data archival retrieval subsystem is responsible for storing and retrieving selected point data. The following historical data archive files are generated/maintained by this subsystem:

a. Short-Term Archival File: This file contains the most recent 3 days of selected data point values that have been scanned/calculated by the system.

b. Long-Term Archival File: After the short-term archival file is filled with data, the data is recorded on a storage media (such as magnetic tapes) for permanent storage for historical purposes.

c. Transaction File: This file contains the most recent 14 hours of console/printer transaction messages generated by the system: point alarms, sequence of events (SOE) notices, data base changes, hardware/software errors, system failovers, etc.

The nuclear steam supply system (NSSS)/balance of plant (BOP) subsystem software provides the functions of the plant process computer applications programs, which include: Incore Thermocouple, Movable Detector, Primary Plant Performance, and the Secondary Plant Performance (BOP) calculations. The NSSS application programs

have been converted from the Westinghouse P2500 series of process control software. The Secondary Plant Performance program incorporates changes to reflect HBR-2 unique features specific modeling.

The software support services subsystem contains general-purpose software routines used by other subsystems such as graphic I/O routines, data conversion/validation routines, system data base interface routines, and mathematical computations routines.

The applications software utilities subsystem contains utility programs available within the ERFIS system such as the off-line hardware diagnostic utilities and the error message file maintenance utilities.

The special software subsystem contains the system-unique software packages/options that were purchased to support the vendor-supplied operating system and the ERFIS applications system.

7.7.1.9.1.2.1 Safety Parameter Display System

The Safety Parameter Display Subsystem is based upon the Westinghouse Owners' Group critical safety function definitions and status trees.

6 SPDS is a combination of displays arranged in a three-level hierarchy: SPDS level one or primary displays, SPDS level two or secondary displays, and the SPDS level three displays.

The SPDS level one display is dedicated to overall plant safety. It consists of a series of six color-coded boxes horizontally arranged and always present on the screen of the CRT once any of the SPDS displays have been brought up on a display console. Each box is dedicated to a specific critical safety function (CSF), whose performance is important in maintaining the plant in a safe condition. For HBR-2, the set of CSFs in decreasing order of importance is:

- Subcriticality
- Core Cooling
- Heat Sink
- RCS Integrity
- Containment Integrity
- RCS Inventory

The subcriticality box appears at the bottom left and remaining CSFs in descending hierarchy to the right, with the RCS inventory CSF appearing on the right-most box. Each box can be lit with one of the five colors.

The following five-color status hierarchy is used to identify the priority status of operator action for current plant conditions:

- Green - the CSF is satisfied; no operator action is called for
- Yellow - the CSF is not fully satisfied; operator action may eventually be needed

References: Section 7.7

1. U.S. Nuclear Regulatory Commission, "Requirements for Emergency Response Capability," Supplement No. 1 to USNRC Report NUREG-0737, December 1982

2. Westinghouse Owners' Group Emergency Response Guidelines, Revision 1

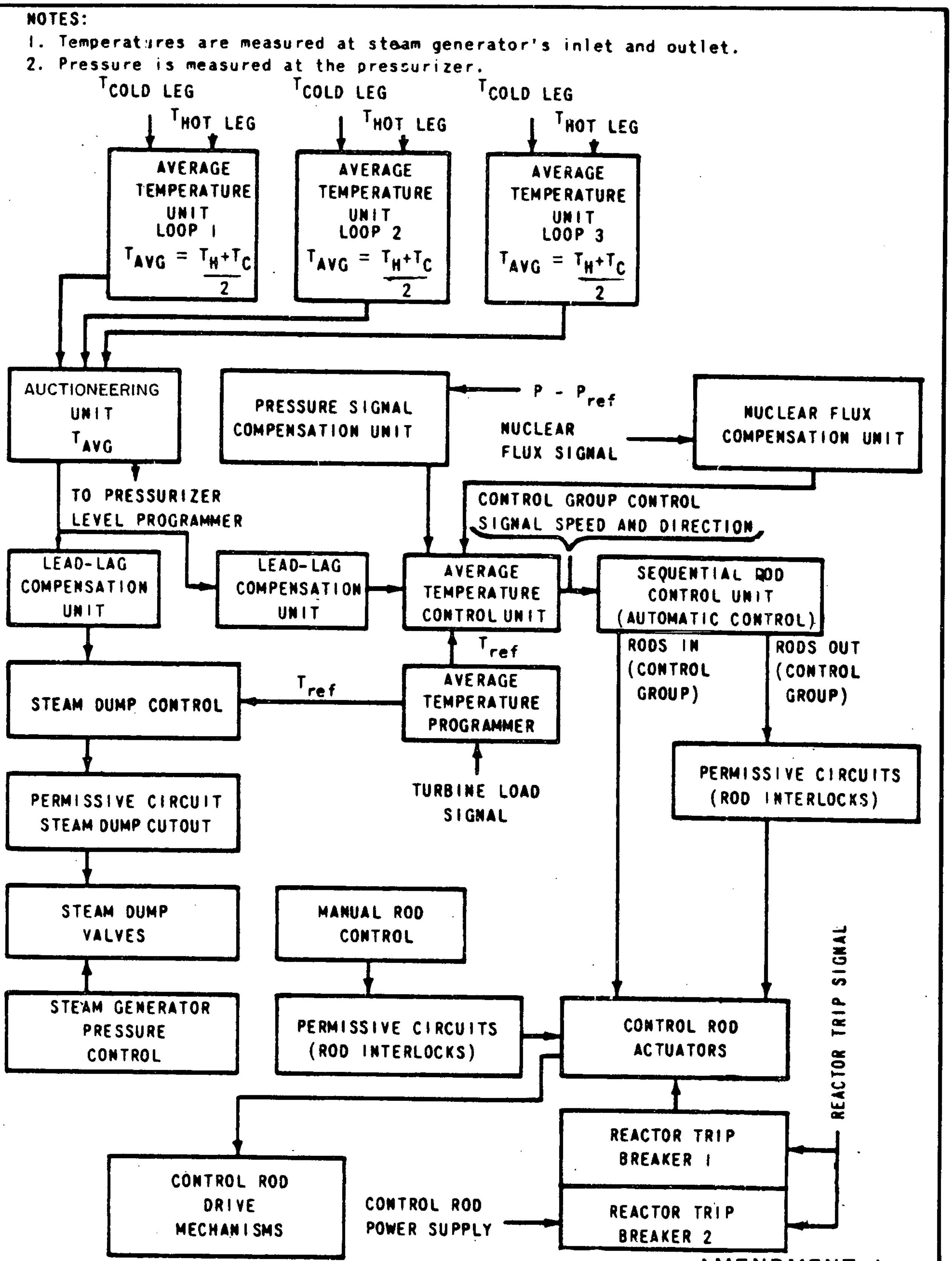
3. Nuclear Operations Department, H. B. Robinson Unit 2 Steam Electric Plant (HBR-2) Emergency Operating Procedures

4. "Safety Evaluation Report on the Emergency Response Guidelines," Generic Letter 83-22, D. G. Eisenhut, NRC, to all licensees, June 3, 1983 6

5. "Emergency Response Facilities Information System, H. B. Robinson Unit 2," SAIC, Volumes 1 through 13, Volume 1, Revision A, July 1985, Volume 13, Revision A, May 1985

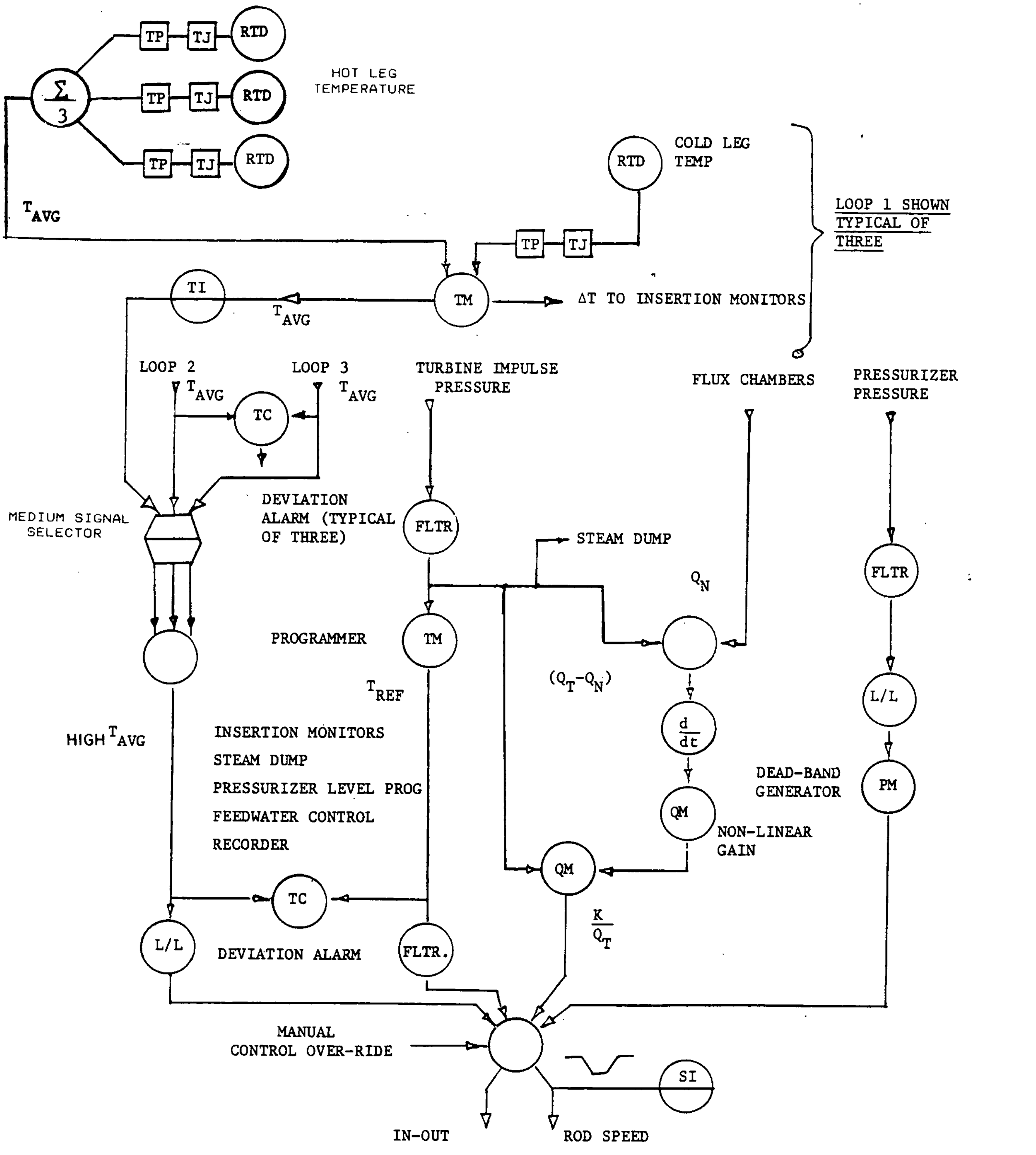
6. Standard Review Plan (SRP) 18.2, "Safety Parameter Display System," Revision 0, 84/12, with Appendix A, Revision 0, December 1984

7. "Emergency Response Facilities Information System, H. B. Robinson Unit 2," SAIC, Systems Overview Document, Revision C, October 1984



AMENDMENT 4

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	SIMPLIFIED BLOCK DIAGRAM OF REACTOR CONTROL SYSTEMS	FIGURE 7.7.1 - 1



NOTE: SEE FIGURE 7.2.1-12 FOR DEFINITION OF SYMBOLS

AMENDMENT NO. 7

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	T_{AVG} CONTROL SYSTEM	FIGURE 7.7.1 - 2

CHAPTER 8
ELECTRIC POWER

LIST OF FIGURES

8.1.2 POWER DISTRIBUTION SYSTEM

The Auxiliary Electrical System is designed to provide a simple arrangement of buses requiring the minimum of switching to restore power to a bus in the event that the normal supply to that bus is lost.

8.1.2.1 One-Line Diagrams

A one-line diagram illustrating switchyard and plant buses for the off-site and on-site sources of power is shown in Figures 8.1.2-1, 8.1.2-1a, and 8.3.1-1.

The basic components of the Station Electrical System are shown on the Main Electrical One Line Diagrams (Figures 8.3.1-2 through 8.3.1-5) which include the 4160 volt, the 480 volt, and the 125 volt DC system.

8.1.2.2 Unit Auxiliary and Station Auxiliary Transformers

The plant's generator serves as the main source of auxiliary electrical power during "on-the-line" operation of the plant. Power to the Auxiliary Electrical System is supplied via an auxiliary transformer that is connected to the main leads from the generator. Power to the 480 volt buses is supplied by 4160 to 480 volt station service transformers.

Auxiliary power required during plant startup, shutdown, and after reactor trip is supplied from the 115 kV switchyard. The 115 kV switchyard is served by the 115 kV system lines and two ties to the 230 kV switchyard.

8.1.2.3 4160 Volt System

The 4160 volt system supplies power via five buses to plant loads as shown in Figure 8.3.1-2. These buses can be connected in several different ways to provide power to loads from off-site sources.

8.1.2.4 480 Volt System

The 480 volt system is divided into 9 power center buses as shown in Figures 8.3.1-3 and 8.3.1-4. This system also includes several 480V nonsafety motor control centers (MCC) and one nonsafety 208V MCC, 4 - 480V safety-related MCC, 2 - 208V safety-related MCC, and one dedicated shutdown bus. These buses may be connected to various sources depending on power supplies available. The emergency buses are also supplied by the emergency diesel generators. The generators start automatically on a loss of power to the emergency bus. The Dedicated Shutdown System bus is fed by either off-site power, the main generator, or the dedicated shutdown diesel generator.

8.1.2.5 125 Volt DC System

As shown in Figure 8.3.1-5, the DC power system consists of three 125 V station batteries, each with its' own battery charger(s) and DC buses. Two of the batteries are safety-related.

8.1.2.6 120 Volt AC System

The 120 volt vital AC instrument supply is split into 8 safety-related buses and 1 nonsafety-related bus. Instrument buses 2 and 3 are fed from the "A" battery distribution system and the "B" battery distribution system, respectively. Instrument buses 1 and 4 are normally fed from 480 volt MCC-5 and MCC-6 respectively via their constant voltage transformers. The alternate power supply for instrument buses 1, 2, 3, and 4 is 208/120 volt MCC-8. Instrument buses 6, 7 (panels 7A and 7B), 8, and 9 (panels 9A and 9B) are powered from instrument buses 1, 2, 3, and 4 respectively, via breakers.

8.2 OFFSITE POWER SYSTEM

The HBR offsite power system consists of those facilities necessary to interconnect the HBR 2 generating unit with the remainder of the CP&L system. It provides capability for delivering power from HBR 2 when the unit is generating power, and also provides capability for delivering power to the unit when it is not. It includes the HBR 2 generator, the main power transformers, the 230 kV and 115 kV switchyards, the unit auxiliary and startup transformers, and the transmission lines from the site. The coal fired HBR Unit 1 and an internal combustion turbine-generator are physically located adjacent to the nuclear unit, but are not considered to be part of the offsite power system.

8.2.1 DESCRIPTION

Figure 8.1.2-1 is a one-line diagram of the offsite power system. The generator is rated at 854 MVa at a power factor of 0.9. Its calculated capability curves are shown in Figure 8.2.1-1. It feeds electric power at approximately 22 kV through an isolated phase bus to the main transformers. The bulk of the power required for station auxiliaries during normal function is supplied by the unit auxiliary transformer which is also connected to the isolated phase bus.

The main transformer bank, which steps up the voltage from 22 kV to 230 kV, consists of three single phase transformers. From the main transformers, the power is delivered through the 230 kV switchyard. The 230 kV switchyard is of the "breaker-and-a-half" design with five outgoing 230 kV transmission lines and two connections to the adjacent 115 kV switchyard through 300 MVa auto-transformers. The 115 kV switchyard is a split bus design incorporating two bus sectionalizing breakers. The 115 kV switchyard is connected to various points on the transmission system with three 115 kV lines and to the 230 kV switchyard with the two auto transformers mentioned above. Figure 8.2.1-2 shows the transmission system of CP&L.

The five 230 kV lines extending from the 230 kV switchyard connect to intrasystem tie points at the following locations:

a) Darlington, S. C., an interconnection tie point with South Carolina Public Service Authority

b) Rockingham, N. C., which is also an interconnection tie point with the Duke Power Company over a double circuit 230 kV line

c) Sumter, S. C., which is also an interconnection tie point with South Carolina Electric & Gas Company over two 230 kV lines,

d) Florence, S. C., which is also an interconnection tie point with South Carolina Public Service Authority, and

e) The Darlington County Electric Plant which is also an interconnection tie point with South Carolina Public Service Authority.

Three 115 kV lines emanate from the Robinson switchyard and tie into the transmission system at the following locations:

1. Florence, S. C.

2. Rockingham, N.C., which is connected to the Blewett and Tillery Hydroelectric Generating Plants of the CP&L system, and

3. Camden S.C. which is connected to Duke Power Company at the Wateree Hydroelectric Generating Plant near Lugoff, S.C.

The arrangement provides for continuity of external power to Unit 2 through the following independent sources:

1. Hydroelectric generating plants on the CP&L system (Blewett and Tillery)

2. A hydroelectric generating plant on the Duke Power System (Wateree)

3. System connections with the South Carolina Electric and Gas System (Sumter)

4. System connections with Duke Power System (Rockingham)

5. System connections with the South Carolina Public Service Authority (Darlington, Darlington County Electric Plant, and Florence)

6. Intra-system connections with the CP&L system, and

7. Existing Unit 1 and internal combustion turbine generation at Robinson.

Protective features inherent within the arrangement of 230 kV "breaker-and-a-half" switchyard design coupled with switchyard bus and auto-transformer differential relaying provide reliable protection for isolation of faults to facilitate continuity of power supply from alternate sources. Further protection associated with each transmission line includes high speed distance relaying, breaker failure relaying, carrier relaying, ground overcurrent relaying, and selective-automatic reclosing of lines to facilitate isolation of a sustained fault and continuity through reclosing in the event of transient faults. Synchronizing facilities, control, indication, annunciation, and metering associated with the lines and transmission equipment in the switchyard are located in a 230 kV switchyard building. Synchronizing facilities, control, indication, annunciation, and metering associated with the breakers for HBR Unit #2 are located in the HBR2 control room.

Supervisory equipment at the Robinson 115/230 kV Switchyard provides the CP&L Skaale Energy Control Center (ECC) in Raleigh, NC with parallel control, indication, annunciation and metering of the 115/230 kV transmission lines and

8.2.2 Analysis

The nominal switchyard voltages for the Robinson Plant are 115 kV and 230 kV. A voltage schedule supplied by the Systems Operations Section calls for voltages to be maintained between 101.3 percent and 102.2 percent of the nominal voltage on the 115 kV bus while the Robinson units are operating.

Because of the close proximity of the Darlington County Internal Combustion Turbine Plant (eleven units), the Robinson Unit 1, the strong 230 kV and 115 kV transmission system connecting the area to the rest of the CP&L system, and the location of capacitor banks throughout the system, adequate voltage can be maintained at the switchyard to meet plant requirements. Should the system voltage begin to drop for any reason, capacitor banks in the affected area will come on line by automatic voltage control or by dispatcher intervention. The system dispatcher closely monitors the plant 115 kV switchyard bus voltage and will be alerted to voltages outside acceptable limits (which are fixed through setpoint adjustments at the Energy Control Center) as determined by plant operating requirements.

The HBR 2 operators also monitor the voltage on the 115 kV switchyard bus by means of a digital voltmeter located in the HBR-2 Control Room. Control Room alarms (which are fixed through setpoint adjustments on the meter) are set to go off should the voltage fall below 100 percent or rise above 103.5 percent. In addition, loss of power to the monitor circuit will also set off the alarm in the Control Room.

HBR 2 was constructed prior to the issuance of General Design Criteria 17. Therefore, a single startup transformer connects the multiple sources of offsite power to the onsite electric distribution system. Should a failure of the startup transformer occur, a spare startup transformer located onsite could be jumpered into service. During the time that the startup transformer was out of service, the unit auxiliary transformer could supply power to the onsite distribution system by back-feeding the main transformer from the 230 kV switchyard. Prior to back-feeding the main transformer from the 230 kV switchyard, the generator must be disconnected from the main transformer by removing the connecting straps. The main transformer backfeeding will only be done during cold shutdown unless nuclear safety consideration require it to be done during hot shutdown when no other power sources are available.

The spare startup transformer for Unit 2 is a spare unit stored onsite and has no wiring connections other than a cabinet heater to prevent accumulation of condensate in the control panel. A minimum of twenty-four hours is the estimated time required to temporarily connect the spare transformer for service. The type of failure of the normal startup transformer (i.e., fire, loss of duct bank, etc.) could cause this time to be greater. A minimum time of four hours is estimated to disconnect the generator straps to enable backfeeding through the unit auxiliary transformer.

8.3 Onsite Power Systems

8.3.1 AC Power Systems

The AC power system uses the unit's main generator, offsite supplies, onsite diesel generator, and battery powered inverters to supply various site loads. The bus system and interconnections have been sized to meet expected plant normal and abnormal operating conditions.

The unit turbine generator is equipped with an alarm set at 59.8 Hz to warn the operator of an impending reactor coolant pump (RCP) trip situation. The unit has protection from connection to the line while stopped or on turning gear.

8.3.1.1 Description. As described in Section 8.1, the plant power requirements are supplied from the unit auxiliary transformer, fed from the unit generator; and the unit startup transformer. The startup transformer has a spare located onsite that could be installed should the startup transformer fail. The unit auxiliary and startup transformers feed various 4.16 kV buses in the station. Power requirements at lower voltages are supplied from the 4.16 kV buses through stepdown transformers. This arrangement is shown in Figure 8.3.1-1.

8.3.1.1.1 4160 volt system. As shown by Figures 8.3.1-2 and 8.1.2-1, the 4160 volt system is divided into five buses. Bus number 3 is normally connected to the 115 kV system via the bus main breaker and startup transformer number 2. During normal operation, buses 1, 2, and 4 are normally connected to the generator leads via bus main breakers and unit auxiliary transformer number 2. 4160 V Bus Number 5 is connected to 4160 V Bus Number 4. Buses 1 and 2 or buses 3 and 4 can be tied together via bus tie breakers. A generator lockout causes buses 1, 2, and 4 to be automatically transferred to the 115 kV system. Bus supply and bus tie circuit breakers are equipped with stored energy closing mechanisms to provide fast dead bus transfers. All 4160 volt auxiliaries are split between buses 1, 2, 4 and 5. In addition, 4.16 kV Buses 1, 4 and 5 each serve one 4160 to 480 volt station service transformer and 4.16 kV Buses 2 and 3 each serve two station service transformers. The plant also has a 4160 volt diesel generator and associated equipment to supply the 480 volt dedicated shutdown system.

8.3.1.1.2 480 volt system. The 480 volt system is divided into nine buses. These include six nonsafety buses, two emergency buses, and one dedicated shutdown bus. The 480 volt buses are supplied from the 4160 volt buses as follows:

1. 1 from 4.16 kV bus 2 through station service transformer 2A

2. 2A and 2B from 4.16 kV bus 1 through station service transformer 2B

3. 3 and DS from 4.16 kV bus 3 through station service transformer 2C,

4. 4 from 4.16 kV bus 4 through station service transformer 2D,

5. 5 from 4.16 kV bus 5 via station service transformer 2E,

6. E1 from 4.16 kV bus 2 through station service transformer 2F, and

7. E2 from 4.16 kV bus 3 through station service transformer 2G.

Tie breakers are provided between 480 volt buses 1 and 2A, buses 3 and 2B, and buses E1 and E2.

Engineered safety features (ESF) equipment circuits are connected to 480 volt buses E1 and E2. The normal source of power for bus E1 is the Unit 2 generator through 4.16 kV bus 2 and station service transformer 2F. The normal source of power for bus E2 is the 115 kV system through startup transformer 2 and station service transformer 2G.

One emergency diesel generator set is connected to bus E1 and the other to bus E2. A diesel will be automatically started and connected to its bus if voltage on its associated bus is lost. The 480 volt bus arrangement is shown in Figure 8.3.1-3.

The plant has a 480 V AC dedicated shutdown bus as part of the dedicated shutdown system. This nonsafety related bus supplies power as shown in Figure 8.3.1-4. The dedicated shutdown diesel generator also serves as the Alternate Alternating Current (AAC) supply, in accordance with 10CFR50.63, for the Station Blackout event.

The power for engineered safety systems is supplied from Motor Control Centers 5, 6, 9, 10, 16, and 18.

MCCs 5/5A1/5A2 and 16 are 480 VAC MCCs and are supplied by 480 VAC Bus E1. MCC 10 is supplied from MCC 5 through a 45 KVa, 480-120/208 VAC, 3Ø, 60 Hz step-down transformer.

MCC 6/6A and 18 are 480 VAC MCCs which are supplied by 480 VAC Bus E2. MCC 9 is supplied from MCC 6 through a 30 KVA, 480-120/208 VAC, 3Ø, 60 Hz step-down transformer.

Motor Control Center 5 has an alternate feed from the dedicated shutdown bus. The dedicated shutdown bus does not supply MCCs 16 as it is isolated from MCCs 5 when MCCs 5 is supplied from the dedicated shutdown bus. No branch circuit loads supplied by MCC 16 are required to be supplied from the dedication shutdown bus.

Emergency Diesel generator supplied loads are listed in Table 8.3.1-1.

The 480 V AC system has two levels of protection for undervoltage conditions. Either of these conditions will trip the 480 V bus E1 and E2 normal incoming breaker (off-site system) and initiate the start and operation of the diesel generators as described in Section 8.3.1.1.5. The first level (loss of voltage) occurs at 328 volts, ± 10% with a time delay of ≤ 1.0 seconds (at zero voltage). The second level (degraded voltage) occurs at 430 V ± 4 V with a time delay of 10.0 seconds ± 0.5 seconds. The relays (except voltage sensing relays) and associated circuitry are designed to be testable and redundant.

8.3.1.1.3 120 Volt AC System. The safety-related 120 volt instrument system configuration is shown in Figure 8.3.1-5. Instrument buses 1, 2, 3 and 4 each have a normal and an alternate power supply controlled by a break-before-make transfer switch. Instrument bus 2 is fed from invertor "A" and instrument bus 3 is fed from invertor "B". Instrument buses 1 and 4 are normally fed from 480 volt MCC-5 and MCC-6 respectively, via their constant voltage transformers. The alternate power supply for instrument buses 1, 2, 3, and 4 is 208/120 volt MCC-8. Instrument buses 6, 7, (panels 7A and 7B), 8, and 9 (panels 9A and 9B) are fed from instrument buses 1, 2, 3, and 4 respectively, via breakers. Instrument Channel 1 is fed from instrument buses 1 and 6, Channel 2 from instrument buses 2 and 7, Channel 3 from instrument buses 3 and 8, and Channel 4 from instrument buses 4 and 9. This arrangement is shown in Table 8.3.1-2.

8.3.1.1.4 Evaluation of Layout and Load Distribution. The physical location of electrical distribution system equipment is such as to minimize vulnerability of vital circuits to physical damage.

The startup transformer, the unit auxiliary transformer, and the main transformer are located outdoors and are physically separated from each other. Lightning arresters are used where applicable for lightning protection.

The 4160 volt switchgear and 480 volt load centers are located in areas which minimize their exposure to mechanical, fire, and water damage. The 480 volt switchgear and motor control centers serving ESF circuits are located in Class I structures. Safety-related 480 V switchgear and 480 V motor control centers are coordinated electrically to minimize the impact on the electrical distribution system and its loads due to faults.

The 480 volt motor control centers are located in the areas of electrical load concentration. Those associated with the Turbine Generator Auxiliary System in general are located below the turbine generator operating floor level. Those associated with the Nuclear Steam Supply System (NSSS) are located in the Reactor Auxiliary Building (RAB).

Nonsegregated, metal enclosed 4160 volt buses are used for all major bus runs where large blocks of current are to be carried. The routing of this metal enclosed bus is such as to minimize its exposure to mechanical, fire and water damage.

The dedicated shutdown system has a separate 480 V AC bus located in the 4.16 kV nonsafety related switchgear area. This system is segregated from all other electrical systems by physical barriers, including separate conduit for DC supply.

The application of routing of control, instrumentation and power cables are such as to minimize their vulnerability to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction. Insulation and jacket materials selected shall be suitable for maximum conductor temperature, the service conditions of the intended installation (i.e. wet and dry locations), and the voltage class of the cabling. Cables are selected for maximum resistance to radiation, heat, humidity, and fire propagation. Appropriate instrumentation cables are shielded to minimize induced voltage and magnetic interference. Wire and cables related to ESF and Reactor Protection Systems (RPS) are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage. Separate cable trays are installed for each redundant circuit group. Cables of redundant circuits are routed through separate containmemt electrical penetration assemblies. Separation criteria is discussed further in Sections 7.2, 7.3, and 8.3.1.3.

8.3.1.1.5 Emergency Power Sources

8.3.1.1.5.1 Description of Sources

The first source of emergency power is the 115 to 4.16 kV startup transformer. As described above, this transformer has multiple sources of supply from the lines connecting to the 115 kV grid and two ties to the 230 kV grid as shown in Figure 8.1.2-1.

The second method to obtain off-site power is by backfeeding the safety-related busses through the main and unit auxiliary transformer. This will only be done during cold shutdown unless nuclear safety considerations require it to be done during hot shutdown when no other power sources are available.

Onsite emergency power is available from two emergency diesel generator sets. Each diesel generator set consists of a Fairbanks-Morse Model 38TD8-1/8 engine coupled to a Fairbanks-Morse generator. Diesel generator design data are shown in Table 8.3.1-3.

As a backup to the normal standby AC power supply, each diesel generator is capable of sequentially starting and supplying power to its' respective safety feature equipment as required for accident mitigation. A third source of power is the 2450 kW dedicated shutdown system diesel*. It has controls and instrumentation similar to the emergency diesels.

The dedicated shutdown system diesel generator serves as the AC power source for plant shutdown loads under both the post-fire (10CFR50, Appendix R) and Station Blackout (10CFR50.63) scenarios.

The emergency diesels are automatically started by injecting compressed air into the cylinders. Each engine has compressed air storage sufficient for 8 cold diesel engine starts. The diesel will consume, however, only enough air for one automatic start during any particular power failure. This is due to the engine control system which is designed to stop cranking within 10 sec. Failure of the engine to start within the timing period of the overcrank time (10 sec) indicates a malfunction. Shutdown conserves the starting air supply so that the engine can be subsequently started after the malfunction is corrected. Further cranking must be initiated manually.

The piping and the electrical services are arranged so that manual transfer between units is possible. The emergency units are capable of being started and reaching rated speed and voltage within 10 sec. The EDGs have a specified capability to start 900 hp of motor load within a single load block and to pick up full rated load within 45 seconds. To ensure rapid start, each unit is equipped with pumps for circulation of lube oil and jacket water when the unit is not running. The units are located in heated rooms.

The diesel generators have trip defeat circuitry in place which prevents any signals but those listed below from shutting down the diesels. This circuit is keyswitch operated and is alarmed in the Control Room when the switch is out of the normal position. The out-of-normal position allows testing the diesels without endangering them if a valid trip signal is received.

The conditions which can shut down a running diesel generator are:

1. Local start/auto/stop switch and remote start/stop switch,

2. Lockout relay,

3. Local stop push button,

*Due to a bus limitation of 3000 amps between the stepdown transformer and the 480 VAC DS bus, only 2000 kW can be supplied by this system.

4. Local manual trip push button for the engine fuel rack,

5. Mechanical overspeed, which trips the engine fuel rack, and

6. Initiation of CO_2 fire suppression system in the specific diesel generator room stops the appropriate fuel oil pump supplying the diesel fuel day tank.

The conditions which can prevent the diesel generator from starting on a valid signal are:

1. Overcranking (not applicable on manual starts)

2. Engine fuel rack tripped, and

3. Remote / local switch in local position.

These conditions are alarmed in the Control Room via the diesel disability annunciator.

The diesel generator can also be prevented from starting and can be shut down by a loss of 125V control voltage to the field flash circuit. The generator can be manually restarted after locally switching to the emergency flash battery.

An audible and visual alarm system is located in the Control Room and will alarm abnormal conditions of jacket water temperature, lube oil temperature, fuel oil level, and starting air pressure. Trips and setpoints used to protect the diesel generators during periods of testing are shown in Table 8.3.1-4 with setpoints. The alarms also shown in Table 8.3.1.-4 are used to warn the operator of an impending problem with the diesel generators.

A shutdown of the diesel generator is indicated in the Control Room by an audible alarm on the control board.

Low oil pressure when the trip disabled switch is out of the normal position shuts down the diesel generator since the engine cannot run without proper lubrication. Shutdown permits corrective action to be taken before the engine is damaged, and the diesel generator can then be returned to normal operation. The diesel generator can be started without service water flow and run until the service water pumps are started.

The emergency diesel units use fuel oil No. 2 as specified by the diesel manufacturer. A 275 gallon day tank is located at each of the units. The level in the day tanks is maintained by two electric motor driven transfer pumps taking suction on the 25,000 gallon storage tank. A minimum of 34,000 gallons of fuel oil is maintained on site. This is sufficient to operate one diesel at full load for seven days.

Additional supplies of diesel oil are available in the Hartsville area and from port terminals at Charleston, S.C. and Wilmington, N.C., and from Fayettevlle, NC and Raleigh, N.C. Ample trucking facilities exist to assure

deliveries to the site within eight hours. Diesel fuel is also available from the internal combustion turbine diesel fuel oil storage tanks (approximately 95,000 gallon total capacity) located at the site and connections are provided for fuel oil transferral to the Unit 2 diesel fuel oil storage tank.

8.3.1.1.5.2 Diesel generator separation. The Fairbanks-Morse diesel generator units are each housed in separate rooms in the Reactor Auxiliary Building.

A control panel is located in each diesel generator room which contains relays and metering equipment for its respective diesel engine generator.

Fire protection for the safety-related diesel generator rooms consists of an automatic CO_2 system with separate detectors in each diesel room so that the room containing a fire will be the only one blanketed. Hose stations are available adjacent to the diesel generator rooms.

Portable fire extinguishers are located in each room and in the hallway adjacent to the rooms.

The room ventilation system is interlocked so that ventilation supply and exhaust fans will be de-energized in the affected room on a CO_2 system actuation. Also, the diesel room dampers are closed on a fire detector initiation. Initiation of the CO_2 system also shuts down the fuel supply system to the affected diesel day tank without affecting the other diesel. Indication of system actuation is available in the Reactor Auxiliary Building (RAB) at fire detection actuation panels A1 and B1 and in the Control Room at the fire alarm console.

The diesel generators have separate fuel supply lines, one for each diesel. These lines do not pass through the opposite diesel generator room.

The diesel generator room floor drains are isolated from each other and run to separate areas.

The dedicated shutdown diesel generator is housed in an outdoor weatherproof skid mounted enclosure. The dedicated shutdown diesel generator is located next to the HBR 2 Turbine Building as shown in Figure 1.2.2-1.

The enclosure meets the Station Blackout (10CFR50.63) environmental requirements for severe weather conditions.

8.3.1.1.5.3 Loading description. Each of the emergency diesel generator units is started by any of the following events:

1. Initiation of safety injection (SI)

2. Undervoltage on its 480 volt bus, and

3. Manual start.

For example, upon undervoltage on 480 volt emergency bus E1, diesel generator A is started. The automatic sequence upon undervoltage (without a concurrent SI) on an emergency bus is as follows:

1. All motor feeder breakers, the main supply and the tie breakers which are on the affected bus are tripped, except MCC-5 and 16

2. The diesel generator is started

3. After the unit comes up to voltage, the emergency generator breaker is automatically closed and the electrically driven auxiliary feedwater, service water, and component cooling pumps connected to that bus automatically start, and

4. Other auxiliaries are manually started as required for safe plant operation.

The maximum magnitude of loads for the diesel generators is given in Table 8.3.1-1.

In the event the emergency generator does not start and come on the line when called for and there is no fault on the 480 volt emergency buses, the tie breaker may be manually closed to the bus served by the other diesel generator.

If there is a requirement for ESF operation coincident with undervoltage on the 480 volt bus, the ESF equipment is sequentially started as shown in Table 8.3.1-5.

Motor control centers are energized upon closing of the generator breaker and injection valves are opened.

Should any of the feeder breakers associated with the safety features components or the 480 volt bus tie breaker trip due to overload, the trip is indicated in the Control Room. The breakers can be manually reclosed from the Control Room. Overload trip elements on the reversing starters associated with the various motor-operated valves can be reset at the motor control centers.

8.3.1.1.5.4 Test and Inspection Capabilities. The diesel generators are tested to assure that they will provide power for operation of equipment. These tests also assure that the emergency system controls and the control systems for safety features equipment will function automatically in the event of a loss of all normal 480 V AC station service power. The starting of the diesel generator sets can be tested from their respective rooms.

The testing frequency is often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The control components are in dust-tight enclosures. The fuel supply and starting circuits and controls are continuously monitored and faults are alarm indicated. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

To verify that the emergency power system will respond within the required time limit and properly when required, surveillance testing is conducted as required by the Technical Specifications.

8.3.1.2 Analysis. The plant was built before the inception of the various Institute of Electrical and Electronic Engineers (IEEE) standards, Regulatory Guides, and other criteria now in place. The system was however compared to General Design Criteria 2 and 39, as discussed in Section 3.1.

8.3.1.2.1 Studies. Several studies of plant electrical system adequacy have been done.

A study of degraded grid voltage effects on the plant is given in Reference 8.3.1-1 and 8.3.1-2. The degraded grid voltage studies demonstrated that expected plant grid voltages were acceptable for expected running safety loads to operate within voltage tolerances. Additionally, the degraded grid voltage requirements required the installation of a second level of voltage protection for undervoltage. This protection was installed on the 480 V AC E1

and E2 emergency buses. This protection occurs when voltage decreases to 89.6 percent of 480 V AC for greater than or equal to 10 seconds. Activation of this protection results in the affected emergency bus being separated from its off-site supply and loaded onto its emergency diesel generator. The protection circuitry also prevents load shedding when the emergency bus is already being supplied by its emergency diesel generator. The design bases for this added undervoltage protection is provided in Reference 8.3.1-3 and Reference 8.3.1-8.

Additional studies are conducted as plant and/or grid conditions change to ensure that grid voltages remain acceptable for expected running safety loads to operate within voltage tolerances.

A study of equipment needed to safely shut down the plant in the event of a fire (10CFR50 Appendix R) in any area was a part of the safe shutdown component/cable separation analysis (Reference 8.3.1-4). A description of this analysis is provided in Appendix 9.5.1C.

The dedicated shutdown diesel generator (and associated 480v DS switchgear, bus duct, transformer, and appurtenances) also supports all AC loads that are required to operate during the Station Blackout (10CFR50.63) event.

8.3.1.2.2 Reliability assurance. The electrical system equipment is arranged so that no single active failure can inactivate enough safety features equipment to jeopardize the plant safety. The 480 volt equipment is arranged on 9 buses. The 4160 volt equipment is supplied from 5 buses.

Multiple outside sources of power are available to the plant. Normal operations utilize both outside and unit-generated power. Separation of these two sources is maintained in the 4160 volt, 480 volt, and lower voltage systems. See Figure 8.1.2-1.

The plant auxiliary equipment is arranged electrically so that redundant items receive their power from the two different sources. An alternate feed to service water pump D and MCC 5, and a primary feed to component cooling pump A and charging pump A are all supplied from the 480 volt dedicated shutdown bus. Redundant valves are supplied from motor control centers connected to buses E1 and E2.

Refer to Table 8.3.1-5 for the engineered safety features automatic actuation sequence and times after the initiation signal for the cases when the normal power source is available and when only the diesel power source is available.

The components of the sequencing circuits are control relays, digital timers, and interposing relays. These relays are standard devices universally

TABLE 8.3.1-1

EMERGENCY DIESEL GENERATOR LOADS AND STARTING SEQUENCE

A. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'A' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 1 (T= 0 SEC) [INJECTION PHASE]				
Containment Spray Pump A	1	170	0 sec - 62 min	140
Boric Acid Tank A Heaters	1 lot	(15)	0 sec - cont	15
Diesel Gen A Air Compressor	1	4.5	0 sec - cont	4
Cable Room A/C System HVA-2	1	6.75	0 sec - cont	7
Instrument Bus 1	1 lot	[7.5]	0 sec - cont	7
DG A Room Exh Fan HVE-18	1	6.75	0 sec - cont	7
DG A Room Supply Fan HVS-6	1	18	0 sec - cont	16
Power Panel 60	1 lot	[2.25]	0 sec - cont	2
Lighting Panel 42	1 lot	[5]	0 sec - cont	3
SI Pump Area Clg Unit HVH-6A	1	4.5	0 sec - cont	5
AFW Pump Area Clg Unit HVH-7B	1	3	0 sec - cont	3
RHR Pump Area Clg Unit HVH-8A	1	3.3	0 sec - cont	3
Heat Tracing B	1 lot	[28.13]	0 sec - cont	28
EDG Fuel Oil Transfer Pump-A	1	0.45	0 sec - cont	1
Power Panel 39 (RVLIS)	1 lot	[4.25]	0 sec - cont	4
Fire Detection System Train A	1 lot	[0.75]	0 sec - cont	1
Battery Room Fan HVE-8B	1	0.9	0 sec - cont	1
Lighting Panel 29 (ES)	1 lot	[25.2]	0 sec - cont	25

TABLE 8.3.1-1 (CONTINUED)

A. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'A' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
Control Room A/C WCCU-1A	1	41	0 sec - cont	32
Control Room A/C HVA-1A	1	9.4	0 sec - cont	8
Charcoal Bstr Fan HVE-19A	1	5.9	0 sec - cont	5
Charging Pump Leakoff Return Pump	1	1.8	0 sec - cont	3
Boric Acid Transfer Pump A	1	15	0 sec - 67 min	10
TOTAL FOR BLOCK 1				330 kW (333 kW)
BLOCK 2 (T = 5 sec)				
Safety Injection Pump A	1	370	5 sec - 62 min	292
TOTAL FOR BLOCK 2				622 kW (628 kW)
BLOCK 3 (T = 15 sec)				
Residual Heat Removal Pump A	1	275	15 sec - 28 min	218
TOTAL FOR BLOCK 3				840 kW (848 kW)
BLOCK 4 (T = 20 sec)				
Service Water Pump A	1	296	20 sec - cont	235
Service Water Booster Pump A	1	109	20 sec - cont	88
TOTAL FOR BLOCK 4				1,163 kW (1,178 kW)

TABLE 8.3.1-1 (CONTINUED)

A. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'A' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW),[kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 5 (T = 25 sec)				
Service Water Pump B	1	308	25 sec - cont	244
TOTAL FOR BLOCK 5				1,407 kW (1,430 kW)
BLOCK 6 (T = 30 sec)				
Containment Fan Cooler (HVH-1)	1	350	30 sec - cont	280
TOTAL FOR BLOCK 6				1,687 kW (1715 kW)
BLOCK 7 (T = 35 sec)				
Containment Fan Cooler (HVH-2)	1	244	35 sec - cont	195
TOTAL FOR BLOCK 7				1,882 kW (1,914 kW)
BLOCK 8 (T = 39.5 sec)				
Auxiliary Feedwater Pump A	1	350	39.5 sec - 62 min	277
TOTAL FOR BLOCK 8				2,159 kW (2,194 kW)
BLOCK 9 (T = 3 min)				
Charging Pump B	1	135	3 min - 62 min	109
Instrument Air Compressor A	1	45	3 min - cont	36
Instrument Air Dryer B	1	0.9	3 min - cont	2
TOTAL FOR BLOCK 9				2,306 kW (2,344 kW)

TABLE 8.3.1-1 (Continued)

A. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'A' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 10 (T = 28 min)				
Residual Heat Removal Pump A	1	275	stops at 28 min	-218
TOTAL FOR BLOCK 10				2,088 kW (2,121 kW)
BLOCK 11 (T = 30 min)				
Component Cooling Pump B	1	310	30 min - cont	247
Battery Charger A	1	(45)	30 min - cont	34
TOTAL FOR BLOCK 11				2,369 kW (2,418kW)
BLOCK 12 (T = 40 min)				
Residual Heat Removal Pump A	1	275	40 min - 64 min	218
TOTAL FOR BLOCK 12				2,587 kW (2,641kW)
BLOCK 13 (T = 62 min) (High Head Recirculation)				
Containment Spray Pump A	1	170	stops at 62 min	-140
Safety Injection Pump A	1	370	stops at 62 min	-292
Auxiliary Feedwater Pump A	1	240	recirc at 62 min	-87
Charging Pump B	1	135	stops at 62 min	-109
TOTAL FOR BLOCK 13				1,959 kW (2,000 kW)

TABLE 8.3.1-1 (Continued)

A. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'A' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 14 (T = 63 min)				
Safety Injection Pump A	1	370	63 min - cont	292
TOTAL FOR BLOCK 14				2,251kW (2,299 kW)
BLOCK 15 (T = 64 min)				
Containment Spray Pump A	1	185	64 min - 175 min	152
Residual Heat Removal Pump A	1	235	64 min - 175 min	-32
Auxiliary Feedwater Pump A	1	350	64 min - 94 min	87
TOTAL FOR BLOCK 15				2,458 kW (2,510 kW)
BLOCK 16 (T = 67 min)				
Boric Acid Transfer Pump A	1	15	stops at 67 min	-10
TOTAL FOR BLOCK 16				2,448 kW (2,500 kW)
BLOCK 17 (T = 94 min)				
Auxiliary Feedwater Pump A	1	240	94 min - 175 min	-87
TOTAL FOR BLOCK 17				2,361 kW (2,411 kW)
BLOCK 18 (T = 175 min to END)				
Auxiliary Feedwater Pump A	1	240	stops at 175 min	-190
Containment Spray Pump A	1	3.3	stops at 175 min	-152
Residual Heat Removal Pump A	1	200	175 min - cont	-28
TOTAL FOR BLOCK 18				1,991 kW (2035 kW)

TABLE 8.3.1-1 (Continued)

B. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'B' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 1 (T=0 SEC) [INJECTION PHASE]				
Containment Spray Pump B	1	170	0 sec - 62 min	140
Boric Acid Tank B Heaters	1 lot	(15)	0 sec - cont	15
Diesel Gen B Air Compressor	1	4.5	0 sec - cont	4
Instrument Bus 4	1 lot	[7.5]	0 sec - cont	7
DG B Room Exh Fan HVE-17	1	6.75	0 sec - cont	7
DG B Room Supply Fan HVS-5	1	18	0 sec - cont	16
Power Panel 62	1 lot	[2.25]	0 sec - cont	2
Lighting Panel 43	1 lot	[4]	0 sec - cont	3
SI Pump Area Clg Unit HVH-6B	1	4.5	0 sec - cont	5
AFW Pump Area Clg Unit HVH-7A	1	3	0 sec - cont	3
RHR Pump Area Clg Unit HVH-8B	1	3.3	0 sec - cont	3
Heat Tracing A	1 lot	[28.13]	0 sec - cont	28
EDG Fuel Oil Transfer Pump-B	1	0.45	0 sec - cont	1
Power Panel 46 (RVLIS)	1 lot	[4.25]	0 sec - cont	4
Fire Detection System Train B	1 lot	[0.75]	0 sec - cont	1
Battery Room Fan HVE-8A	1	0.9	0 sec - cont	1
Lighting Panel 29 (ES)	1 lot	[25.2]	0 sec - cont	25
Control Room A/C WCCU-1B	1	41	0 sec - cont	32
Control Room A/C HVA-1B	1	9.4	0 sec - cont	8

TABLE 8.3.1-1 (Continued)

B. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'B' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
Charcoal Bstr Fan HVE-19B	1	5.9	0 sec - cont	5
PA - System	1 lot	[9.03]	0 sec - cont	8
Post Accident Sampling System	1 lot	[12.5]	0 sec - cont	11
Boric Acid Transfer Pump B	1	15	0 sec - 67 min	10
Stm Drvn Fwr Aux Oil Pump	1	.25	0 sec - cont	1
TOTAL FOR BLOCK 1				340 kW (342 kW)
BLOCK 2 (T = 5 sec)				
Safety Injection Pump C	1	370	5 sec - 62 min	292
TOTAL FOR BLOCK 2				632 kW (638 kW)
BLOCK 3 (T = 15 sec)				
Residual Heat Removal Pump B	1	275	15 sec - 28 min	218
TOTAL FOR BLOCK 3				850 kW (858 kW)
BLOCK 4 (T = 20 sec)				
Service Water Pump C	1	309	20 sec - cont	245
Service Water Booster Pump B	1	109	20 sec - cont	88
TOTAL FOR BLOCK 4				1,183 kW (1,201 kW)
BLOCK 5 (T = 25 sec)				
Service Water Pump D	1	314	25 sec - cont	249
TOTAL FOR BLOCK 5				1,432 kW (1,459 kW)

TABLE 8.3.1-1 (Continued)

B. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'B' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 6 (T = 30 sec)				
Containment Fan Cooler (HVH-3)	1	350	30 sec - cont	280
TOTAL FOR BLOCK 6				1,712 kW (1,745 kW)
BLOCK 7 (T = 35 sec)				
Containment Fan Cooler (HVH-4)	1	244	35 sec - cont	195
TOTAL FOR BLOCK 7				1,907 kW (1,946 kW)
BLOCK 8 (T = 40 sec)				
Auxiliary Feedwater Pump B	1	350	40 sec - 62 min	277
TOTAL FOR BLOCK 8				2,184 kW (2,229 kW)
BLOCK 9 (T = 3 min)				
Charging Pump C	1	135	3 min - 62 min	109
Instrument Air Compressor B	1	45	3 min - cont	37
Instrument Air Dryer A	1	0.9	3 min - cont	2
TOTAL FOR BLOCK 9				2,332 kW (2,380 kW)
BLOCK 10 (T = 28 min)				
Residual Heat Removal Pump B	1	275	stops at 28 min	-218
TOTAL FOR BLOCK 10				2,114 kW (2,155 kW)

TABLE 8.3.1-1 (Continued)

B. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'B' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW),[kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 11 (T = 30 min)				
Component Cooling Pump C	1	310	30 min - cont	247
Battery Charger B	1	(45)	30 min - cont	34
TOTAL FOR BLOCK 11				2,395 kW (2,455 kW)
BLOCK 12 (T = 40 min)				
Residual Heat Removal Pump B	1	275	40 min - 64 min	218
TOTAL FOR BLOCK 12				2,613 kW (2,680 kW)
BLOCK 13 (T = 62 min) (High Head Recirculation)				
Containment Spray Pump B	1	170	stops at 62 min	-140
Safety Injection Pump C	1	370	stops at 62 min	-292
Auxiliary Feedwater Pump B	1	240	recirc at 62 min	-87
Charging Pump C	1	135	stops at 62 min	-109
TOTAL FOR BLOCK 13				1,985 kW (2,033 kW)
BLOCK 14 (T = 63 min)				
Safety Injection Pump C	1	370	63 min - cont	292
TOTAL FOR BLOCK 14				2,277 kW (2,334 kW)

TABLE 8.3.1-1 (Continued)

B. LOCA WITH E-BUS UNDERVOLTAGE FOR DIESEL GENERATOR 'B' (Notes 1 & 2)

Load Description	Quantity Number Required	Design BHP (kW), [kVA] (Note 3)	Timing Sequence Starts At - Runs To (Note 4)	Load kW
BLOCK 15 (T = 64 min)				
Containment Spray Pump B	1	185	64 min - 175 min	152
Residual Heat Removal Pump B	1	235	64 min - 175 min	-32
Auxiliary Feedwater Pump B	1	350	64 min - 94 min	87
TOTAL FOR BLOCK 15				2,484 kW (2,548 kW)
BLOCK 16 (T = 67 min)				
Boric Acid Transfer Pump B	1	15	stops at 67 min	-10
TOTAL FOR BLOCK 16				2,474 kW (2,538 kW)
BLOCK 17 (T = 94 min)				
Auxiliary Feedwater Pump B	1	240	94 min - 175 min	-87
TOTAL FOR BLOCK 17				2,387 kW (2,448 kW)
BLOCK 18 (T = 175 min to END)				
Auxiliary Feedwater Pump B	1	240	stops at 175 min	-190
Containment Spray Pump B	1	3.3	stops at 175 min	-152
Residual Heat Removal Pump B	1	200	175 min - cont	-28
TOTAL FOR BLOCK 18				2,017 kW (2,068 kW)

NOTES TO TABLE 8.3.1-1

ABBREVIATIONS:

"CONT" - CONTINUOUS
"LOT" - COMPONENT GROUP OF A SYSTEM/EQUIPMENT OPERATING IN GIVEN TIME FRAME.
"SEC" - SECONDS
"MIN" - MINUTES
"CV" - CONTAINMENT VESSEL
"RWST" - REFUELING WATER STORAGE TANK
"EOP" - EMERGENCY OPERATING PROCEDURE

NOTE 1 - LOCA with E-Bus undervoltage assumes that a Safety Injection (SI) signal is received coincident with the Loss of Off-site Power (LOOP) and the failure of the opposite train EDG.

NOTE 2 - With the SI pump load inclusion in last section, this case also envelopes Low Head Recirculation (SI pump secured) loading.

NOTE 3 - Design Break Horsepower (BHP), Kilo Watts (kW), or Kilo Volt-Amperes (kVA) for the equipment is as indicated.

NOTE 4 - All timing sequences in Table 8.3.1-1 were extracted from Reference 8.3.1.5.

NOTE 5 - Total Load Block kW loads in parentheses represent total equipment loading plus system losses.

NOTE 6 - The negative (-) sign before the kw value means a load decrease, and the positive (+) sign before the kw value means a load increase due to alignment change.

TABLE 8.3.1-2

INSTRUMENT CHANNELS POWER SOURCES

INSTRUMENT CHANNELS	1	2	3	4
SUPPLIED BY INSTRUMENT BUSES	1 and 6[1]	2 and 7[1]	3 and 8[1]	4 and 9[1]
Normal Feeder Source	MCC-5[2,3]	A Battery	B Battery	MCC-6[3]
Normal Feeder Voltage	480V AC	125V DC	125V DC	480V AC
Transforming Device	Transformer	A Inverter	B Inverter	Transformer
Output Voltage	120V AC	120V AC	120V AC	120V AC
Back-up Feeder Source	MCC-8	MCC-8	MCC-8	MCC-8
Back-up Feeder Voltage	120V AC	120V AC	120V AC	120V AC
Method of Swap-over	Manually Interlocked	Manually Interlocked	Manually Interlocked	Manually Interlocked

[1] Instrument buses 6,7,8, and 9 are fed from instrument buses 1, 2, 3, and 4, respectively.

[2] MCC-5 has an alternate feed from the dedicated shutdown bus.

[3] Reference UFSAR Figure 8.3.1-5.

TABLE 8.3.1-3

EMERGENCY GENERATOR DESIGN DATA

Rated Load Capacity, Continuous	2500 kW
Rated Overload Capacity, 2 hr in any 24 hr period	2750 kW
Generator Rated Output	3125 kVa at 0.8 PF
Rated Speed	900 rpm
Frequency	60 Hz 3 phase
Voltage	480 volts

TABLE 8.3.1-4

DIESEL GENERATOR TRIPS AND ALARMS

TRIP FUNCTION	SETPOINT
High Jacket Coolant Temperature, °F	205
Low Lube Oil Pressure, psig	18 (decreasing)
Local Control Electrical Trip	Manual
Starting Failure, sec	10
High Crankcase Pressure, in. H_2O	+0.5
Low Jacket Coolant Pressure, psig	12
Generator Overcurrent, amp (instantaneous)	24,000
Mechanical Overspeed, rpm	1,052 Max.
Local RTGB Manual Trip	Manual
125 VDC Field Flash Power Lost	N/A

ALARM FUNCTION*	SETPOINT
1. Diesel Trouble	
Start Failure	10 sec
Crankcase Pressure Hi	0.5 in. H_2O
Lube Oil Pressure Lo (decreasing)	18 psig
Day Tank Level High	3 in. from top
Service Water Pressure Lo	8 psig
Coolant Pressure Lo	12 psig
Expansion Tank Low Level	4 in. from bottom
2. Diesel Lube Oil Temp.	
Lube Oil Temp. Hi	225°F (increasing)
Lube Oil Temp. Lo	130°F (decreasing)
3. Diesel Coolant Temperature	
Coolant Temperature Lo	105°F
Coolant Temperature Hi	205°F (increasing)
4. Diesel Start Air Pressure Lo	210 psig
5. Diesel Control Power Lost/Diesel Disabled	
125 VDC Control Power Lost to Engine	NA
Fuel Rack Manually Tripped or by Overspeed	NA
Remote/Local Switch in Local	Manual
6. Diesel Day Tank Level	
Day Tank Level Lo	12 in. from bottom

*Alarm at local panel and RTGB except as noted. Each diesel has the set of alarms.

TABLE 8.3.1-4 (Continued)

	ALARM FUNCTION	SETPOINT
7.	Emergency Generator Ground (RTGB only)	NA
8.	EDG A/B Air Compressor Ovld (RTGB only)	NA
9.	EDG Fuel Oil Pump A/B Ovld (RTGB only)	NA
10.	Diesel Oil Storage Tank Level Lo (RTGB only)	80% of 25,000 gal
11.	Diesel Room Cooling Fan OL/Temp. Hi (RTGB only)	110°F

TABLE 8.3.1-5

ENGINEERED SAFETY FEATURES ACTUATION SEQUENCE

TIME IN SEC	ACTION (TRAIN A) (TRAIN B ACTION IDENTICAL)
With offsite power:	
0	Starting signal will be given to emergency generator A
0	Reactor trip and feedwater isolation will occur
0	Safeguard sequence will be actuated (see note)

Note: With offsite power available the sequence will follow that given in the Diesel Generator Loading tabulation shown below. In this case 10 seconds should be subtracted from the times given in the tabulation starting with "Safeguards Buses Energized."

Without offsite power the automatic sequence will proceed as follows:

0	All loads will be tripped off bus E1 with the exception of motor control center No. 5 and 16.
10	Emergency generator A will have started and reached no load speed and voltage at which time the breakers connecting it to bus E1 will close.
10-45	The sequence will follow that given in the Diesel Generator Loading Tabulation.

TABLE 8.3.1-5 (Continued)

DIESEL GENERATOR LOADING

BUS E1 - TRAIN A

TIME IN SEC	(GEN. A)
0	Safety Injection Signal
10	Safeguards Bus E1 Energized
15	Safety Injection Pump A Running
15	Safety Injection Pump B Running (When Safety Injection Pump A is out of service, Safety Injection Pump B is aligned to run with Train A.)
25	Residual Heat Pump A Running
30	Service Water Pump A Running
30	Service Water Booster Pump Running
35	Service Water Pump B Running
40	Containment Fan HVH-1 Running*
45	Containment Fan HVH-2 Running*
49.5	Aux. Feedwater Pump A Running
**	Containment Spray Pump A Running

BUS E2 - TRAIN B

TIME IN SEC	(GEN. B)
0	Safety Injection Signal
10	Safeguards Bus E2 Energized
15	Safety Injection Pump C Running
15	(When Safety Injection Pump C is out of service, Safety Injection Pump B is aligned to run with Train B.)
25	Residual Heat Pump B Running
30	Service Water Pump C Running
30	Service Water Booster Pump Running
35	Service Water Pump D Running
40	Containment Fan HVH-3 Running*
45	Containment Fan HVH-4 Running*
49.5	Aux. Feedwater Pump B Running
**	Containment Spray Pump B Running

* The inlet louvers are actuated to the safeguards position by the safety injection sequence signal.

**Start immediately upon receipt of signal, if the respective emergency bus is energized.

8.3.2 DC Power System (125 Volt)

As shown in Figure 8.3.1-5, the DC power system consists of three 125 V batteries, each with its' own battery charger(s) and DC buses. Two of the batteries are safety-related. The battery chargers supply the normal DC loads as well as maintaining proper charges on the batteries. Each charger has the capacity to supply all normal DC loads and maintain the battery fully charged. For each safety-related station battery, there are two safety-related battery chargers. One battery charger supplies the normal DC loads while the other is providing 100% back-up capability. Only one safety-related battery charger per station battery will be on-line at a time. The DC power system is shown in Figure 8.3.1-5.

Each of the two safety-related station batteries is sized to carry its expected shutdown loads following a plant trip and a loss of all AC power for a period of 1 hr without battery terminal voltage falling below minimum allowable voltage. Shutdown loads with their approximate operating times on each safety-related battery are listed in Table 8.3.2-1.

Each of the four safety-related battery chargers have been sized to charge it's partially discharged battery within 24 hr while carrying its normal load.

Cells in the "A" battery are type NCX-15 with a capacity of 1070 ampere hours (based on an 8 hour discharge to 1.75 volts/cell). The "A" bank is composed of 60 cells of the lead calcium type. Cells in the "B" battery are type MCX-9 with a capacity of 340 ampere hours (based on an 8 hour discharge to 1.75 volts/cell). It is composed of 60 cells of the lead calcium type. The battery capacities are 525 A-Hr and 170 A-Hr for the NCX-15 and MCX-9 batteries respectively for a 1 hour discharge to 1.75 volts/cell. The actual designed final discharge voltage following an emergency discharge will be based on required equipment voltages.

The safety-related batteries and equipment are separated physically in the plant. The existing configuration provides adequate separation with equipment for one division on the north side of the battery room and the other division on the south side. The fire hazards analysis for the battery room is contained in Section 9.5.1.

The "C" battery (non-safety related) is located on the auxiliary building roof above the battery room. Cells in the "C" battery are type NCX-1800 with a rating of 1800 ampere hours (based on an 8 hour discharge to 1.75 volts/cell). The "C" bank is composed of 58 cells of the lead calcium type.

The following non-safety related loads are supplied by the "C" battery:

1. Turbine emergency bearing oil pump (50 HP), and
2. air side seal oil backup pump (10 HP).

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

Cable loading of trays and, consequently, heat dissipation of cable throughout the plant have been carefully studied and controlled to ensure no overloading. The criteria for electrical loading were developed using Insulated Power Cable Engineers Association (IPCEA) Standard P-46-426, Manufacturer Recommendations and Good Engineering Practice.

Derating factors for cables in trays without maintained spacing were taken from Table VIII of the IPCEA publication. Derating factors for the maximum ambient temperature existing in any area of the plant were also taken from the IPCEA publication. These factors were applied against ampacities selected from appropriate tables in other portions of the standard.

For physical loading of trays, the following criteria were followed: 4 kV power, one horizontal row of cables was allowed in a tray; 480 volt power, 30 percent of the usable cross-sectional area of tray is filled; control and instrumentation, 30 percent of the usable cross-sectional area of the tray is filled with a maximum of 70 percent of the cross-section of tray. This was exceeded in 6 cases which have been analyzed and found to be satisfactory (Reference 8.3.3-1).

In general, for instrumentation cables, four basic channels are routed through the plant. These channels include cables for systems 65 volts and less. Cables assigned to these four channels will remain in their respective channels throughout the run.

Certain other cables are run in with the four instrument channels; such as, thermocouple cable, public address system cabling and instrument power supplies.

To assure that only fire retardant cables are used throughout the plant, a careful study of cable insulation systems was previously undertaken.

Insulation systems that appeared to have superior flame retardant capability were selected. An extensive flame testing program took place which included ASTM vertical flame testing and bonfire tests. Cables were specified on the basis of results from these tests.

The following tests were made to determine the flame resistant quality of various cable covering and insulations:

a) Standard Vertical Flame Test - made in accordance with ASTM-D-470-59T,
Tests for Rubber and Thermalplastic Insulated Wire and Cable.

b) Five Minute Vertical Flame Test - made with cable held in vertical position and 1750°F flame applied for 5 minutes, and

c) Bon-Fire Test - consisting of exposing, for 5 minutes, bundles of three
or six cables to flame produced by igniting transformer oil in a 12 in. pail. The cable was supported horizontally over the center of the pail, the lowest cable located 3 in. above the top of the pail. The time to ignite the cable and the time the cable continued to flame after the fire was extinguished were noted.

In areas where missile protection could not be provided, such as near the reactor coolant system (RCS), redundant instrument impulse lines and cables were run by separate routes. These lines were kept as far apart as physically possible, or were protected by heavy (1/4 in.) metal plates interposed where inherent missile protection could not be provided by spacing.

Cable trays are entirely of metal construction and present no combustible hazard. Safety-related cable trays outside the cable spread room have been evaluated for fire protection provisions.

Since safety-related cable runs in the Auxiliary Building do not satisfy the requirements of Regulatory Guide 1.75 and consist primarily of polyvinyl chloride (PVC) jacketed cables, consistent with the requirements of BTP APCSB 9.5-1, Appendix A, Section D.3, a flame-retardant coating was applied to cables in trays containing engineered safeguards cable. In addition, automatic water sprinklers were installed to protect safety-related cables in the hallway of the Auxiliary Building ground floor near the station air compressors. Critical equipment potentially subject to water damage from sprinkler system discharge has been identified, the effects of sprinkler discharge have been assessed, and water spray protection measures have been implemented where appropriate. This area and other areas have manual hose stations and portable fire extinguishers available for additional protection.

The cabling inside containment installed during original plant construction has silicone rubber jacket material, which has fire-resistant properties which are superior to those of the PVC cable.

A cable tray fire would be a rather slowly propagating fire (1-2 in./min) even without flame retardant coating, so use of a coating and automatic detection would provide adequate protection unless there is a significant exposure fire hazard.

Cable and cable tray penetration of fire barriers have been sealed to provide a fire-rated seal commensurate with the required rating of the affected fire barriers. The penetration seal designs have been qualified for the required fire ratings in accordance with the provisions of ASTM E-119.

The need for derating of cable as a result of the application of the flame retardant coating has been investigated and is not necessary due to inherent ampacity safety margins.

REFERENCES: SECTION 8.3

8.3.1-1 Calculation RNP-E-8.002, "AC Auxiliary Electrical Distribution System Voltage/Load Flow/Fault Current Study".

8.3.1-2 Calculation RNP-E-8.016, "Emergency Diesel Generator Static and Dynamic Analysis".

8.3.1-3 "System Design Basis for Degraded Grid Voltage and Emergency Power System Modification," (taken from Letter, GD-79-222, dated January 24, 1979, to NRC from CP&L).

8.3.1-4 Safe Shutdown Component/Cable Separation Analysis [10CFR50, Appendix R, Section III.G] for H.B. Robinson Unit No. 2.

8.3.1-5 10CFR50.63, Loss of All Alternating Current Power; June 21, 1988.

8.3.1-6 Regulatory Guide 1.155, Station Blackout; August 1988.

8.3.1-7 Engineering Evaluation EE107-CS-39 (Rev. 1) for Emergency Diesel Generator Static and Dynamic Analysis Calculation RNP-E-8.016, Rev. 4 Comment Resolution.

8.3.1-8 RNP-I/INST-1010, "Emergency Bus-Degraded Grid Voltage Relay".

8.3.1-9 Modification 1065, Degraded Grid Voltage Relay Setpoint Change.

8.3.2-1 Response to NRC Inspection Report No. 50-261/87-06, dated July 10, 1987, Serial No. NLS-87-145 to NRC from CP&L.

8.3.2-2 Request for License Amendment - Battery Service Test, dated September 19, 1990, Serial No. NLS-90-110 to NRC from CP&L.

8.3.3-1 "Report on Cable Tray Volumetric Overloading," CP&L HBR Unit 2, dated August, 1981, and Letter, CWC-1093, dated July 29, 1970, from Westinghouse Electric Corporation Power Systems to CP&L.

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

CHAPTER 9
AUXILIARY SYSTEMS

TABLE OF CONTENTS (Cont'd)

9.0 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.1 New Fuel Storage

New fuel storage data are given in Table 9.1.2-1. New fuel storage requirements are given in Table 9.1.2-2 and Reference 9.1.1-3.

9.1.1.1 Design Basis.

9.1.1.1.1 Quantity of fuel stored. The new fuel storage racks are designed to store up to 72 uniradiated fuel assemblies and inserts.

9.1.1.1.2 Maintaining a subcritical array. The new fuel storage racks are designed so that it is impossible to insert assemblies in other than the prescribed locations. The center-to-center spacing of the assemblies is 21 in. and provides a geometrically safe configuration. While stored in the new fuel storage racks, encapsulation of assemblies in water tight containers is not allowed by the criticality analysis of reference 9.1.1-3.

9.1.1.1.3 Degree of subcriticality. The fuel in the new fuel storage pit is stored vertically in an array; some storage locations are secured to prevent maximum fuel storage packing. With the storage locations secured, diffusion theory criticality calculations indicate that K_{eff} will be less than 0.95 for new fuel enriched to a maximum of 5.0 w/o (nominal 4.95 w/o) assuming the new fuel racks are flooded with unborated water, and the K_{eff} is less than 0.98 in an optimum moderation event (Reference 9.1.1-3).

9.1.1.2 Facilities Description.

9.1.1.2.1 New fuel storage facilities. New fuel assemblies are received and stored in racks in the new fuel storage area as shown in figure 9.1.1-1. This is a separate area whose location facilitates the unloading of new fuel assemblies and control rods from fuel containers. This storage vault was designed to hold new fuel assemblies in specially constructed racks and is utilized primarily for the storage of the replacement fuel assemblies required for cycle loading. The new fuel assemblies are stored in racks arranged to space the fuel assemblies with a center-to-center spacing of 21 in.

New fuel is delivered to the reactor by transferring it to the spent fuel pit (SFP) and taking it through the transfer system. The new fuel storage area is sized for storage of the fuel assemblies and inserts normally associated with a typical core reload.

9.1.1.2.2 Storage complex location. The location of the new fuel storage facilities within the station complex is provided in Figure 1.2.2-7.

9.1.2 Spent Fuel Storage

Spent fuel storage data are given in Table 9.1.2-1. Spent fuel storage requirements are given in Table 9.1.2-2.

9.1.2.1 Design Basis.

9.1.2.1.1 Quantity of fuel stored. The spent fuel storage system utilizes a combination of low-density and high-density fuel storage racks to accommodate up to 544 fuel assemblies which is equivalent to over 3 1/3 cores.

9.1.2.1.2 Maintaining a subcritical array. The spent fuel storage racks were designed so that it is impossible to insert assemblies in other than fuel cell locations. The low-density racks provide storage space for 176 fuel assemblies with a center-to-center distance of 21 inches. The high-density racks provide spaces for 368 fuel assemblies with a center-to-center distance of 10.5 inches with a neutron absorbing material between storage cells. The center-to-center distance between low-density cells and high-density cells is 14.75 inches or 15.75 inches, also with a neutron absorbing material between the cells. These arrangements provide that $K_{eff} \leq 0.95$.

9.1.2.1.3 Degree of subcriticality. The effective neutron multiplication factor, K_{eff}, was calculated for the most conservative conditions of temperature, fuel enrichment, fuel spacing, structural poisoning, and other parameters (Reference 9.1.1-3). For both the high density and low density spent fuel racks 5.0 w/o (4.95 w/o nominal) enrichment was assumed as the maximum permissible. The maximum K_{eff} for the high density spent fuel racks, including the above allowances for uncertainties, is 0.94658. The maximum K_{eff} for the low density spent fuel racks is 0.94255. Thus, the spent fuel pool meets the 0.95 limit of K_{eff}.

9.1.2.1.4 Shielding requirements. Adequate shielding for radiation protection is provided during reactor refueling by conducting all spent fuel transfer and storage operations under water. This permits visual control of the operation at all times while maintaining low radiation levels, less than 2.5 mR/hr, for periodic occupancy of the area by operating personnel. Pit water level is indicated, and water removed from the pit must be pumped out since there are no gravity drains. Shielding is provided to permit operation of waste handling and storage facilities within the requirements of 10CFR20.

Gamma radiation is continuously monitored in the Auxiliary Building. A high level signal is alarmed locally and is annunciated in the Control Room.

9.1.2.1.5 Design loadings. The SFP was designed as a Seismic Category I structure. This design considered loads due to the water, spent fuel assemblies, spent fuel racks, and seismic activity. The analysis was performed using the design criteria contained in ACI-318-63, "Building Code Requirements for Reinforced Concrete."

Originally, the SFP was designed for spent fuel racks to occupy the entire floor of the pit. Initially, however, only 240 cells with a center-to-center distance of 21 inches were provided. Subsequently, the storage capacity was expanded by the addition of 36 cells with a center-to-center distance of 15.5 inches. In 1983, the 36 added cells and 64 of the original cells were removed and 368 high-density storage cells were added with center-to-center spacing of 10.5 inches.

The load carrying capability of the Fuel Handling Building was augmented by the installation of a steel column in the space below the pool floor and above the base slab as shown in Figure 9.1.2-2. This configuration was evaluated and the results showed that the structure is adequate to withstand the forces imposed by the maximum load in the pool (see Section 3.8.4.1.2).

The spent fuel pool, storage racks, and supports are designated as Seismic Category I and are designed to withstand the effects of the safe shutdown earthquake while loaded with fuel in any configuration (see Section 3.7.3.5).

The racks are designed for vertical and horizontal seismic loadings acting simultaneously. To preclude overturning, the low-density racks are fastened together and braced to the SFP walls. The high-density racks are designed to be self-standing.

9.1.2.2 Spent Fuel Storage Facilities Description

Fuel assemblies will be stored in the racks in a vertical square array. The rack design precludes inserting a fuel assembly in other than a prescribed location, assuring that the designed pitch is maintained and thus keeping the fuel in a subcritical array. An entry guide at the top of each cell is provided to guide the fuel assembly into that cell without damage. The cells are constructed of structural members which support the fuel assembly at the top and bottom nozzles only, and which permit the flow of coolant around the entire fuel assembly. The inside surfaces of each cell are free of rough edges which might damage fuel. The racks sit on the floor of the SFP on supports which can be adjusted to assure a level orientation. Seismic support for the low-density racks is provided by lateral supports which transmit horizontal seismic loads into the SFP walls. The floor supports and lateral supports for the low-density racks are welded to the SFP liner. The 368 high-density cells are constructed in four separate modules, one 8 cell x 10 cell and three 8 cell x 12 cell. Each module is free-standing and self-supporting in a seismic event. The modules are supported on pads that are designed to limit horizontal loads during a seismic event by slipping on the SFP floor liner. The high-density racks are not attached to the SFP liner.

The location of the spent fuel storage facilities within the station complex is provided in Figure 1.2.2-7 and in Figure 9.1.2-1. Spent fuel storage rack arrangement is shown in Figure 9.1.2-3 and a typical high-density fuel storage rack module is shown in Figure 9.1.2-4.

9.1.2.3 Safety Evaluation

9.1.2.3.1 Degree of Subcriticality

The racks were designed to preclude buckling, and hence change in pitch, due to a dropped fuel assembly. Thus, the only concern relative to a dropped fuel

assembly is whether there will be a criticality condition with one fuel assembly lying across the top of the racks.

The space between active fuel in the dropped assembly and active fuel in assemblies in the storage racks is occupied by the top nozzle, the gap between the fuel rods and top nozzle, and the gas plenum in the top of each fuel rod. If it is conservatively assumed that the dropped assembly completely crushes the lead-ins on top of the racks, the distance between active fuel is about 14.3 in. This is greater than the 12.5 in. (nominal) space between active fuel in the original fuel storage racks (21 in. center-to-center distance). Since that is the case, and since the original rack array maintains the fuel in 2
a sufficiently subcritical state, it is concluded that no criticality will result from a fuel drop accident.

9.1.2.3.2 Governing Codes for Design

Low-density fuel storage racks: 2

Weld procedures and welders were qualified for the welding of Type 304 stainless steel according to the rules and regulations of Section IX of the ASME Code for Manual Metal Arc, Tungsten Inert Gas, and Metallic Inert Gas for the materials to be welded in the storage racks. Welding is in accordance with Section IX of the ASME Boiler and Pressure Vessel Code. Inspection was per AWS D1.1, "Structural Welding Code."

High-density fuel storage racks:

The high-density fuel storage racks were fabricated, welded, and inspected in 2
accordance with ASME Boiler and Pressure Vessel Code Section III, "Nuclear Power Plant Components" Division I, Subsection NF.

9.1.2.3.3 External Loads and Forces

The high-density fuel storage racks are designed to maintain dimensional and structural integrity and to allow subsequent fuel assembly removal and insertion for the following conditions:

a) the maximum dead load of the fuel assemblies (with RCCA's) and the fuel pool water,

b) thermal expansion loads on the racks and loads imposed by the rack feet on the SFP floor based on a pool water temperature change at the bottom of the pool from the 65°F to 254°F, and 2

c) loads resulting from seismic disturbances (DBE and OBE).

The high-density racks are designed to preclude a change in the center-to-center distance between adjacent storage cells due to:

a) the combined fuel assembly and control component weight (1605 pounds less buoyancy) dropped from a height of 30 inches above the top of the rack straight to the top of the rack, inclined to the top of the rack, or straight through a cell to the bottom of the rack, and

2 b) the maximum uplift load that can be produced by the spent fuel handling crane (assumed 3000 pounds for 2000 pounds rating).

9.1.2.3.4 Continuous Cooling

Heat balances were performed on the entire cooling system for both the refueling case and the core unload case. The results of the two heat balances
2 show the maximum SFP water temperature will be about 132°F for the normal refueling situation and about 166°F for the core unload situation. Because of the conservatisms in the analysis upper limit margins on the decay heat, minimum achievable fuel movement times, and maximum service water temperature, it is expected that the SFP water temperatures will never reach these values. However, considering the thermal inertia of just over 1.5 hr projected for the worst case and the desire to prevent the temperature of the
2 SFP from reaching 166°F, the rate of fuel movement into the SFP is regulated to maintain the SFP temperature at or below 150°F. A Technical Specifications commitment to this effect was made. For both cases, there is sufficient thermal inertia to allow alternative cooling means to be implemented.

To provide added assurance that the SFP containing spent fuel can be adequately cooled during breakdown or maintenance of the component cooling system, an emergency cooling connection is attached to the Component Cooling Water System inside the SFP heat exchanger isolation valves.

9.1.2.3.5 Material Compatibility Requirements

The racks and pit liner are constructed almost entirely of Type 304 stainless steel. There are two exceptions:

a) The neutron absorber material, Boraflex, is a silicone based polymer containing fine particles of boron carbide in a homogeneous, stable matrix. Boraflex contains a minimum B_{10} areal density of 0.02 gm/cm^2. The manufacturer, Brand Industrial Services, Inc., has demonstrated in a test
2 program that Boraflex maintains a long-term material stability and mechanical integrity under exposure to substantial levels of neutron flux, gamma radiation, and high temperature borated water. A periodic test procedure will monitor coupon samples of Boraflex in the SFP for signs of degradation.

b) The springs in the stainless steel expansion joints are Type 302 stainless steel since Type 304 stainless steel springs were not available. Type 302 is adequate for this service.

The racks have been designed to be compatible with external interfaces (i.e., building and existing racks) and with internal interfaces (i.e., fuel assemblies).

Rack design and fabrication were performed using CP&L approved Quality Assurance program.

9.1.2.3.6 Radiological Considerations

The principal source of radiation exposure levels at the surface of the spent fuel pool is the concentration of radionuclides within the pool water during

approximately the first 100 days following a refueling. These radionuclides are removed from the water by the spent fuel pool demineralizer during and after refueling. After the first 100 days, the demineralizer is required only to maintain water clarity. After this point, exposure levels at the surface of the pool become insignificant.

For the low-density spent fuel storage racks, the center lines of fuel assemblies stored closest to the wall are approximately 27 in. from the stainless steel plate liner. The high-density racks are approximately 10 in. from the wall at the closest point. 2

The SFP is located outside the reactor containment and is not affected by any loss-of-coolant accident (LOCA) in the containment. The water in the pit is isolated by a valve from the water in the refueling canal during most of the refueling operation. Only a very small amount of interchange of water occurs as fuel assemblies are transferred during refueling.

9.1.3 Spent Fuel Pool Cooling and Cleanup System.

9.1.3.1 Design Basis.

9.1.3.1.1 Continuous and Intermittent Cooling. The refueling water storage tank and SFP water provide a reliable and adequate cooling medium for spent fuel heat transfer. The SFP cooling loop is designed to remove the heat generated by stored spent fuel elements from the pool water. Loop design incorporates redundant active components. A second cooling pump is available for anticipated malfunctions or failures (expected fault conditions). Loop piping is so arranged that failure of any pipeline does not drain the SFP below the top of the stored fuel elements. This manually controlled loop may be shutdown safely for reasonable time periods, as shown in Table 9.1.3-1 for maintenance or replacement of malfunctioning components.

9.1.3.1.2 Cooling Capacity. The original design basis for the loop (used to determine SFP cooling loop component capacities and sizes) was to provide the capability to totally unload the reactor vessel for maintenance or inspection at the time that 1/3 of a core already occupies the SFP. When the storage capacity was increased in the Spent Fuel Pool Expansion project (Reference 9.1.3-1), the existing SFP cooling loop capacity was evaluated for both a full core and 1/3 core discharge which filled the SFP to its new capacity. This evaluation established a conservative heat load of 26.0×10^6 Btu/hr for the full core discharge case as the current basis for SFP cooling capacity.

9.1.3.1.3 Pool Water Temperature Requirements. The Spent Fuel Pool Expansion project evaluated the SFP temperature for heat loads resulting from 1/3 and full core discharges which completely fill the SFP. The expected 1/3 core discharge maximum SFP temperature is 132°F. The expected full core discharge maximum SFP temperature would be 166°F if no actions are taken to limit the heat load added to the SFP. Therefore, during the discharge of the fuel into the SFP, the SFP temperature will be maintained at or below 150°F through administrative limitations on the movement of spent fuel into the SFP.

The SFP temperature is continuously monitored by local temperature indications in the SFP building, and by control room annunciators with a low temperature alarm setpoint of 74°F and a high temperature alarm setpoint of 121°F.

9.1.3.1.4 Pool Water Cleanliness Requirements. Whenever a leaking fuel assembly is transferred from the fuel transfer canal to the spent fuel storage pool, a small quantity of fission products may enter the spent fuel cooling water. A small purification loop is provided for removing these fission products and other contaminants from the water.

The SFP skimmer loop is provided to remove floating debris and surface films/contaminants that could adversely affect SFP water clarity.

9.1.3.1.5 Pool Water Level. During normal operation, the SFP water level is maintained at least 21 ft above the top of the fuel bundles (top of fuel bundles at about 14 ft SFP water depth).

The SFP water level is continuously monitored by a control room annunciator alarm with high and low water level setpoints at 37 ft 5/8 in. and 36 ft 2 1/2 in. SFP depth.

9.1.3.1.6 Classifications and Code Requirements. These data are provided in Section 3.2.

9.1.3.2 System Description.

9.1.3.2.1 System Components. The SFP cooling loop consists of two 100 percent capacity pumps, heat exchanger, filter, demineralizer, piping and associated valves, and instrumentation as shown by Figure 9.1.3-1. The pumps draw water from the pit, circulate it through the heat exchanger and return it to the pit. Another pump is used to circulate refueling water through the demineralizer and filter for purification. Component cooling water cools the heat exchanger. Redundancy of this loop is provided by the two cooling pumps.

The SFP skimmer loop consists of one pump, skimmer, strainer, filter, piping and associated valves, and instrumentation as shown by Figure 9.1.3-1. The water is removed from the SFP through the skimmer and skimmer strainer by the skimmer pump. Flow from this pump is then filtered and returned to the SFP.

Component data for the spent fuel cooling and cleanup system is provided in Table 9.1.3-1. The components for this system are as follows:

a) SFP Heat Exchanger - The SFP heat exchanger is of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and SFP water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

b) SFP Pumps - The SFP pump circulates water in the SFP cooling loop. All wetted surfaces of the pump are austenitic stainless steel, or equivalent corrosion resistant material. Pump operation is manually controlled from a local station near the pumps or from a station in the SFP building. An additional pump provides redundant pumping capacity to assure the systems capability to cool spent fuel during full core off load.

c) Refueling Water Purification Pump - The refueling water purification pump circulates water in a loop between the refueling water storage tank and the SFP demineralizer and filter. All wetted surfaces of the pump are austenitic stainless steel. The pump is operated manually from a local station.

d) SFP Strainer - A stainless steel strainer is located at the inlet of the SFP loop suction line for removal of relatively large particles which might otherwise clog the SFP demineralizer.

e) SFP Filter - The SFP filter removes particulate matter from the SFP water. The filter cartridge is synthetic material and the vessel shell is austenitic stainless steel.

h) SFP Valves - Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with SFP water are austenitic stainless steel or equivalent corrosion resistant material. 7

i) SFP Piping - All piping in contact with SFP water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance of the pumps, heat exchanger, and control valve.

f) SFP Demineralizer - The demineralizer is sized to pass 5 percent of the loop circulation flow, to provide adequate purification of the fuel pit water for unrestricted access to the working area, and to maintain optical clarity.

g) SFP Skimmer - A skimmer pump and filter are provided for surface skimming of the SFP water. Flow from this pump is returned to the SFP.

h) SFP Valves - Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with SFP water are austenitic stainless steel or equivalent corrosion resistant material.

i) SFP Piping - All piping in contact with SFP water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance of the pumps, heat exchanger, and control valve.

9.1.3.2.2 System Instrumentation. Instrumentation setpoints to monitor the SFP water level are provided to initiate a high water level alarm signal for SFP water level of 37 ft 5/8 in. (approximately 1 1/2 in. above normal water level), and to initiate a low water level alarm signal for SFP water level of 36 ft 2 1/2 in. (approximately 8 1/2 in. below normal water level).

Instrumentation setpoints to monitor the SFP water temperature are provided to initiate a high water temperature alarm signal for SFP water temperature of 121°F, and to initiate a low water temperature alarm signal for SFP water temperature of 74°F.

A high level alarm is provided for the Refueling Water Storage Tank to signal an overflow condition of the tank.

9.1.3.3 <u>Safety Evaluation</u>.

9.1.3.3.1 Spent Fuel Cooling. The most serious failure of this loop is the complete loss of water in the SFP. To protect against this possibility the SFP cooling pump suction penetrates the SFP wall and terminates at about 33 ft SFP water level (approximately 4 ft below the normal water level) so that a break in the pipe will not substantially gravity drain the SFP. The SFP cooling pump discharge piping penetrates the SFP wall at about 20 ft SFP water level (approximatly 6 ft above the top of the fuel assemblies). The SFP cooling pump discharge piping is prevented from siphon draining the SFP by a 1/2 in. hole in the pipe located at about 37 ft SFP water level. There is a SFP drain line (which is sometimes called a "lower suction line" for the SFP cooling pumps) that also penetrates the SFP wall at about 20 ft. SFP water level, but this drain line is extended with piping down to within 3 inches of the SFP bottom. This drain line is prevented from inadvertently draining the SFP by two normally closed and locked valves; one inside the SFP near the penetration into the SFP wall, and the other in the SFP pump room, near the suction inlet to the SFP cooling pumps.

In the event of a failure of both SFP pumps or a failure in the cooling water supply for the SFP heat exchanger, alternate means for cooling the SFP are provided. Alternate cooling connections are provided in the SFP loop and component cooling loop piping for connecting temporary piping. A temporary water supply (such as the fire water system) can be connected on the component cooling loop side of the SFP heat exchanger to supply cooling capability. Should both SFP cooling pumps fail, connections are provided to install a temporary pump in the SFP cooling loop.

The probability of inadvertently draining the water from the cooling loop of the SFP is exceedingly low. The only means of draining the cooling loop is through such actions as opening a valve on the cooling line and leaving it open when the pump is operating. In the unlikely event of the cooling loop of the SFP being drained, the SFP itself cannot be drained completely and no spent fuel is uncovered. These consequences are prevented by locating the SFP cooling pump suction connection at about 33 ft SFP water level, and locating the 1/2 in. vacuum break hole in the SFP cooling pump discharge line at about 37 ft SFP water level. The SFP temperature and SFP level indicators in the SFP building and the SFP temperature alarm and SFP level alarm in the control room warn the operator of the loss of cooling or inventory. With no heat removal, the time for the SFP water to rise from 150°F to boiling for a full core discharge which fills the SFP to capacity is approximately 6.8 hours. The warning provided by the instrumentation alarm setpoints, along with this slow heatup rate, would allow sufficient time to restore adequate cooling. Redundant SFP cooling pumps, along with procedurally established alternate means to supply heat sink water to the SFP heat exchanger, ensure that cooling capability for the SFP can be restored quickly.

9.1.3.3.2 Pool Water Makeup Capability. Evaporation, draining to the sump for minor level adjustments, and draining to the RWST for major level adjustments, are expected to be the only means of loss of water from the SFP. The SFP is a Class I concrete structure with a stainless steel liner of all-welded construction. All welds are liquid penetrant and vacuum box tested.

The SFP is filled for evaporative losses and other minor level adjustments by primary demineralized water from the plant 150,000 gallon primary water storage tank. A redundant supply of makeup is provided by the fire hoses in the vicinity of the SFP.

Leak detection is achieved by 10 one-inch diameter pipes imbedded in the concrete along the bottom of the pit where the walls join the floor approximately one inch below the liner plates. These leak detectors are valved and piped to an open floor drain in an area which is accessible at all times.

The makeup water requirement due to boiling in the fuel pool following a complete loss of cooling after a full core offload would be less than 42 gpm. The SFP large level makeup water source is the refueling water storage tank via the refueling water purification pump. This path has a capacity of 100 gpm which is more than adequate to replace the water lost.

9.1.3.3.3 Maintenance of Pool Water Conditions. The clarity and purity of the SFP water are maintained by passing approximately 5 percent of the loop flow through a filter and demineralizer. Loss of water which might result from a line break in this filter and demineralizer system will terminate prior to uncovering the fuel assemblies, since the only path to the cleanup system from the SFP passes through the SFP cooling pump suction and discharge piping. As described above, these lines are protected from draining the pit by the location of their SFP penetrations or by redundant locked closed valves.

The SFP water clarity is also enhanced by a skimming system which removes surface film and debris from the SFP water surface. The skimming system is separate from the cooling and purification system.

9.1.3.3.4 Radiological Evaluation. All fuel storage facilities are contained and equipment designed so that accidental releases of radioactivity directly to the atmosphere are monitored and do not exceed the guidelines of 10CFR100.

The reactor cavity, refueling canal, and spent fuel storage pit are reinforced concrete structures with a seam-welded stainless steel plate liner. These structures are designed to withstand the anticipated earthquake loadings as Class I structures so that the liner prevents leakage even in the event the reinforced concrete develops cracks. All operating areas in the fuel storage facilities contain ventilation systems.

All vessels in the Waste Disposal System which are used for waste storage are Class I seismic design.

9.1.3.4 Inspection and Testing Requirements. The active components of the SFP Coolant System, which is part of the Auxiliary Coolant System, are in either continuous or intermittent use during normal plant operation, thus no additional periodic tests are required. Periodic visual inspections and preventative maintenance can be conducted as necessary.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Design Basis 3

9.1.4.1.1 Performance and Load Handling Requirements

The Fuel Handling System provides a safe effective means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. The system is designed to minimize the possibility of mishandling or maloperations that cause fuel damage and potential fission product release.

The Fuel Handling System consists basically of:

a) The reactor cavity, which is flooded only during plant shutdown for refueling

b) The SFP, which is full of water during and after the first refueling and is always accessible to operating personnel

c) The Fuel Transfer System, consisting of an underwater conveyor that transports fuel assemblies between the reactor cavity and the SFP

The design criteria for the spent fuel handling crane support structure is as follows:

a) Design, fabrication, material, and erection are in accordance with AISC Manual of Steel Construction, 1963 Edition

b) The basic wind loading is 30 psf

c) Seismic loadings are 5 percent of the dead load

d) Dead load is the dead weight of the crane

e) Horizontal forces are as follows:

1) Lateral live load - 10 percent (lift load + weight of trolley)

2) Longitudinal live load - 10 percent (dead load + lift load)

f) The vertical impact load is 15 percent of the lift load.

9.1.4.1.2 Handling Control Features

Underwater transfer of spent fuel provides essential ease and corresponding safety in handling operations. Water is an effective, economic, and transparent radiation shield and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations are:

1. Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm in the Control Room of an abnormal core flux level

2. Violation of containment integrity is not permitted when the reactor vessel head is removed unless the shutdown margin is maintained $\geq$ 6% Δ k/k

3. Whenever any fuel is added to the reactor core, a reciprocal curve of source neutron multiplication is recorded to verify the subcriticality of the core

Safety features are incorporated in the system as follows:

1. Travel limit switches on the bridge and trolley drives

2. Bridge, trolley, and winch drives which are mutually interlocked to prevent simultaneous operation of any two drives

3. A position safety switch, the GRIPPER TUBE UP position switch, which prevents bridge and trolley main motor drive operation except when it is actuated

4. An interlock which prevents the opening of a solenoid valve in the air line to the gripper except when zero suspended weight is indicated by a force gage. As backup protection for this interlock, the mechanical weight actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder

5. To ensure its complete engagement and disengagement, the gripper has a double acting air cylinder with a power stroke in both directions

6. The EXCESSIVE SUSPENDED WEIGHT switch, which opens the hoist drive circuit in the up direction when the loading is excessive

7. An interlock on the hoist drive circuit in the up direction, which permits the hoist to be operated only when either the OPEN or CLOSED indicating switch on the gripper is actuated

8. An interlock of the bridge and trolley drives, which prevents the bridge drive from traveling beyond the north edge of the core unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is beyond the north edge of the core.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing and the manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper in the event of a maximum potential earthquake.

9.1.4.1.3 Prevention of Fuel Handling Accidents. Prevention of Fuel Handling Accidents is discussed in Section 15.7.4.

9.1.4.1.4 Prevention of Cask Drop Accidents. Provisions have been made to eliminate the spent fuel cask drop as a credible accident while the loaded cask is suspended over the spent fuel pool and other potentially safety related equipment on the path between the decontamination facility and the spent fuel pool. Redundancy has been incorporated in the design of the spent fuel cask lifting lugs, redundant lifting yoke and the 125-ton spent fuel cask handling crane to eliminate any risk to public health and safety. A detailed discussion of the safety features of the cask and handling components is contained in Reference 9.1.4-1. A non-redundant yoke is used to lift the cask from the railcar to the decontamination facility, and also to lift the loaded cask from the decontamination facility back to the railcar. These lifts do not go over any safety related structures, systems, or components (SSC's). Administrative controls are placed on the non-redundant cask lifting activities to limit the vertical distance between the cask and a flat essentially unyielding horizontal surface to less than 30 feet.

9.1.4.2 System Description. The reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the reactor vessel until it is placed in a cask for shipment from the site. Boric acid is added to the water to ensure subcritical conditions during refueling.

The Fuel Handling System as shown by Figures 9.1.4-1 and 9.1.2-1 may be generally divided into two areas: the reactor cavity which is flooded only during plant shutdown for refueling, and the SFP which is full of water during and after the first refueling and is always accessible to operating personnel. These two areas are connected by the Fuel Transfer System consisting of an underwater conveyor that carries the fuel through an opening in the plant containment.

The reactor cavity is flooded with borated water from the refueling water storage tank. In the reactor cavity, fuel is removed from the reactor vessel, transferred through the water and placed in the fuel transfer system by a manipulator crane. In the SFP the fuel is removed from the transfer system and placed in storage racks with a long manual tool suspended from an over-head hoist. After a sufficient decay period, the fuel may be removed from storage and loaded into a shipping cask for removal from the site. Both the manipulator crane and the long handled tool can handle only one assembly at a time.

9.1.4.2.1 Major Structures.

9.1.4.2.1.1 Reactor Cavity. The reactor cavity is a reinforced concrete structure lined with stainless steel that forms a pool above the reactor when it is filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water to 2.5 milliroentgens per hour during fuel assembly transfer.

The reactor vessel flange is sealed to the bottom of the reactor cavity by an inflatable seal (Pneuma) which prevents leakage of refueling water from the cavity. This seal is installed after reactor cooldown but prior to flooding the cavity for refueling operations.

The cavity is large enough to provide storage space for the reactor upper and lower internals, the control cluster drive shafts, and miscellaneous refueling tools.

9.1.4.2.1.2 Refueling canal. The refueling canal is a passageway extending from the reactor cavity to the inside surface of the reactor containment. The canal is formed by two concrete shielding walls, which extend upward to the same elevation as the reactor cavity. The floor of the canal is at a lower elevation than the reactor cavity to provide the greater depth required for the fuel transfer system tipping device and the control cluster changing fixture located in the canal. The transfer tube enters the reactor containment and protrudes through the end of the canal. Canal wall and floor linings are similar to those for the reactor cavity.

9.1.4.2.1.3 Refueling water storage tank. The normal duty of the refueling water storage tank is to supply borated water to the refueling canal for refueling operations. In addition, the tank provides borated water for delivery to the core following either a loss-of-coolant or a steam line rupture accident. This is described in Chapter 6.

The capacity of the tank is based upon the requirement for filling the reactor cavity and refueling canal.

The water in the tank is borated to a concentration which assures reactor shutdown margin $\geq$ 6% Δ k/k when all rod cluster control assemblies are inserted and when the reactor is cooled down for refueling.

The tank design parameters are given in Chapter 6.

9.1.4.2.1.4 Decontamination facility. To aid the rapid decontamination of the spent fuel cask, a cask decontamination facility is provided. The facility consists of a portable hydrolazer/steam jenny.

A concrete platform is provided in the Decontamination Room to support a spent fuel rail cask designed for simultaneous shipment of a number of fuel assemblies. The platform is a flat surface to provide a stable area to perform "decon" operations. The platform is constructed of 3000 psi concrete with steel reinforced sides.

9.1.4.2.2 Major equipment.

9.1.4.2.2.1 Reactor vessel stud tensioner. The stud tensioner is a hydraulically-operated (oil as the working fluid) device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. Stud tensioners were chosen in order to minimize the time required for the tensioning or unloading operations. Three tensioners are provided and they are applied simultaneously to three studs 120° apart. One hydraulic pumping unit operates the tensioners which are hydraulically connected in parallel. The studs are tensioned to their operational load in two steps to prevent high stresses in the flange region and unequal loadings in the studs. Relief valves are provided on each tensioner to prevent overtensioning of the studs due to excessive pressure.

Charts indicating the stud elongation and load for a given oil pressure are included in the operating instructions. In addition, stud elongation is measured after tensioning..

9.1.4.2.2.2 Reactor vessel head lifting device. The reactor vessel head lifting device consists of a welded and bolted structural steel frame with suitable rigging to enable the crane operator to lift the head and store it during refueling operations. The lifting device is permanently attached to the reactor vessel head.

9.1.4.2.2.3 Reactor internals lifting device. The reactor internals lifting device is a fixture provided to remove the upper reactor internals package and to move it to a storage location in the refueling canal. The device is lowered onto the guide tube support plate of the internals and is manually bolted to the support plate by three bolts. The bolts are controlled by long torque tubes extending up to an operating platform on the lifting device. Bushings on the fixture engage guide studs mounted on the vessel flange to provide close guidance during removal and replacement of the internals package. This lifting device can also be used to remove the lower internals once the vessel has been cleared of all fuel assemblies.

9.1.4.2.2.4 Manipulator crane. The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the reactor cavity and runs on rails set into the floor along the edge of the reactor cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered down out of the mast to grip the fuel assembly. The gripper tube is long enough so the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel is transported while inside the mast tube to its new position. The manipulator can lift only one fuel assembly at a time.

9.1.4.2.2.5 Spent fuel pit bridge. The SFP bridge is a wheel-mounted walkway, spanning the SFP which carries an electric monorail hoist on an overhead structure. The fuel assemblies are moved within the SFP by means of a long-handled tool suspended from the hoist. The hoist travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

9.1.4.2.2.6 Fuel transfer system. The fuel transfer system, shown in Figure 9.1.4-1, is an underwater conveyor car that runs on tracks extending from the refueling canal through the transfer tube and into the SFP. The conveyor car is driven by above water electric motor driven cable winches located on the containment operating floor. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised to a vertical position in the SFP.

During plant operation, the conveyor car is stored inside containment in the refueling canal. The gate valve is closed and a blind flange is bolted on the transfer tube to seal the reactor containment. A permanent davit arm is mounted on the fixed flange of the transfer tube for handling of the blind flange during refueling.

9.1.4.2.2.7 Rod cluster control (RCC) changing fixture. A fixture is mounted on the reactor cavity wall for removing RCC elements from spent fuel assemblies and inserting them into new fuel assemblies. The fixture consists of two main components: a guide tube mounted to the wall for containing and guiding the RCC element, and a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the RCC element and lifts it out of the fuel assembly. By repositioning the carriage, a new fuel assembly is brought under the guide tube and the gripper lowers the RCC element and releases it.

9.1.4.2.2.8 Spent fuel cask handling crane. The Spent Fuel Cask Handling Crane is a Whiting 125/5 ton capacity crane. The Whiting Redundant Hoist System incorporates a dual load path through the hoist gear train, the reeving system, and the hoist load block along with restraints at critical points to provide load retention and minimize uncontrolled motions of the load upon failure of any single hoist component. The system includes two complete gear trains connecting the single hoist motor to the hoist drum.

9.1.4.2.2.9 Spent fuel cask redundant lifting yoke. The redundant lifting yoke supplied for the spent fuel shipping cask is furnished as part of a package which includes the shipping cask and its special transport vehicle. Specific details of the redundant lifting yoke conform to the following criteria; the design and fabrication of the shipping cask, transport vehicle, and handling equipment conform to all the applicable regulations of the NRC (10CFR71) and the DOT (49CFR170-178). The shipping cask redundant lifting yoke is of all steel construction. In addition to the above criteria, the redundant lifting yoke was designed for protection against single failure in that both the primary and secondary parts of the yoke will alone support 300 percent of the fully loaded cask weight without exceeding the yield strength of the material. The secondary yoke is connected to the sister hook of the crane and the primary yoke is independently attached to the lifting eye of the crane.

Before shipment, both the primary and secondary parts of the redundant yoke were proof-load tested (200 percent of the rated capacity) to assure compliance with the single failure criteria, and nondestructively tested i.e., magnetic particle or dye penetrant, and examined to ensure that no permanent deformations and/or other damage occurred. This design and testing eliminated the redundant lifting yoke as a factor contributing to a cask drop accident.

9.1.4.2.2.10 Spent fuel cask non-redundant lifting yoke. A non-redundant lifting yoke was also supplied with the spent fuel shipping cask for lifting the cask where the redundant yoke was not needed, or not possible to use because of the configuration of plant equipment or buildings. The design of the non-redundant lifting yoke meets the same criteria listed above for the redundant lifting yoke, except for the additional criteria describing redundancy.

The physical configuration of the decontamination facility and the design of the railcar transportation system require that the non-redundant yoke be used to transfer the cask between the railcar and the decontamination facility. This load path does not suspend a heavy load over safety related structures, systems or components.

9.1.4.3 Refueling sequence of operation. The refueling is performed using detailed plant procedures. The general initial conditions and preparations before refueling are as follows:

1. Reactor is in cold shutdown condition and preparations made for head removal such as, removal of Control Rod Drive Mechanism (CRDM) missile shield, cables, and cooling ducts; RCS water level lowered below flange; vessel head insulation and instrument leads removal; and vessel head studs removed

2. The inflatable seal ring is installed, and the head is removed.

3. The fuel transfer tube blind flange is removed.

4. The fuel transfer tube isolation valve is open.

5. The refueling cavity is filled as the head is lifted off the reactor vessel and transferred to its storage pedestal.

6. The Control Rod Drive (CRD) shafts are unlatched.

7. The reactor vessel upper internals are lifted out using its lifting rig and stored on the underwater storage rack.

The refueling sequence is now started utilizing the manipulator crane. The sequence for fuel assemblies in positions where there are no RCC is as follows:

1. Spent fuel is removed from the core and placed into the fuel transfer system for removal to the spent fuel pit

2. Partially spent fuel is rearranged in the core

3. Replacement fuel assemblies are brought in from the spent fuel pit through the transfer system and loaded into the core

4. Whenever any fuel is added to the reactor core, a reciprocal curve of source neutron multiplication is recorded to verify the subcriticality of the core.

The refueling sequence is modified for fuel assemblies containing RCC elements, special maintenance or inspections requirements, surveillance capsule removal, or incore thimble replacement. If a transfer of the RCC elements between fuel assemblies is required, the assemblies are taken to the RCC change fixture to exchange the RCC elements from one assembly to another. Such an exchange is required whenever a fuel assembly containing RCC elements is removed from the core and whenever a fuel assembly is placed in or taken out of a control position during the refueling rearrangement.

The reassembly process is as follows:

1. The fuel transfer car and manipulator crane are parked and the fuel transfer tube isolation valve is closed and the blind flange is reinstalled.

2. The reactor vessel internals package is replaced in the vessel

3. The CRD shafts are relatched to the RCC elements

4. The old seal rings are removed from the reactor vessel head, the grooves cleaned and new rings installed

5. The reactor vessel head is slowly lowered over the reactor vessel until it is seated. The head studs are torqued.

6. Electrical leads and cooling air ducts are reconnected to the CRDM

7. Vessel head insulation and instrumentation leads are replaced

8. The reactor vessel to cavity seal ring is removed

9. CRD are checked

10. The CRDM missile shield is replaced

11. Equipment access door is sealed

12. A hydrostatic test is performed, and

13. Pre-operational tests are performed.

9.1.4.4 Fuel Handling System Evaluation. Underwater transfer of spent fuel provides essential ease and corresponding safety in handling operations. Water is an effective, economic and transparent radiation shield and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations are:

1. Gamma radiation levels in the containment and fuel storage areas are continuously monitored. These monitors provide an audible alarm at the initiating detector indication an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm in the Control Room of an abnormal core flux level

2. Violation of containment integrity is not permitted when the reactor vessel head is removed unless the shutdown margin is maintained $\geq 6\% \Delta k/k$, and

3. Whenever any fuel is added to the reactor core, a reciprocal curve of source neutron multiplication is recorded to verify the subcriticality of the core.

Direct communication between the Control Room and the refueling cavity manipulator crane is available whenever changes in core geometry are taking place. This provision allows the Control Room operator to inform the manipulator operator of any inpending unsafe conditions detected from the main control board indicators during fuel movement.

An analysis is presented in Chapter 15.0 concerning damage to all of the fuel elements in an assembly, assumed as a conservative limit for evaluation environmental consequences of a fuel handling incident.

9.2 WATER SYSTEMS

9.2.1 SERVICE WATER

9.2.1.1 Design Basis

The Service Water System (SWS) is designed to provide cooling water to those components necessary for plant safety either during normal operation or under accident conditions. Redundant supplies with isolation valves are provided for those components. The SWS also supplies cooling water to various other heat loads in both the primary and secondary portions of the plant. The system is also capable of supplying water to the suction of the auxiliary feedwater pumps in the event of loss of other sources. Lake Robinson is the source of service water.

The system is sized to ensure adequate heat removal based on highest expected temperatures of cooling water, maximum loadings, and leakage allowances.

9.2.1.2 System Description

The SWS provides cooling and heat removal from the following components:

a) Station air compressor and after cooler

b) Instrument air compressors and after coolers

c) Condensate pump motors

d) Seal water booster pumps

e) Heater drain pumps and motors

f) Main Feedwater pumps

g) Containment Air Recirculating Units

h) Component Cooling Water Heat Exchangers

i) Hot Pipe Containment Penetration Coolers

j) Auxiliary Building Air Handling Units

k) Main Generator Hydrogen Coolers

l) Turbine Lube Oil Coolers

m) Exciter Coolers

n) Electrohydraulic Control Unit Coolers

o) Condenser Vacuum Pump Heat Exchangers

p) Hydrogen Seal Oil Unit Coolers

q) Isolated Phase Bus Duct Heat Exchanger

r) Emergency Diesel Generators and Diesel Air Dryers

s) Auxiliary Feedwater Pumps Oil Coolers and (Motor Driven) Jacket Cooler

t) Safety Injection Pumps

u) Primary Air Compression and Aftercooler

v) Condensate Polisher Waste Water Sump Pumps

w) Auxiliary Boiler Sample Coolers

x) Hydrogen Side Cooler

y) Condensate Polisher Air Compressor Aftercooler

aa) Main Steam Sample Roughing Cooler

bb) Condensate Polisher Sample Cooler

cc) Secondary System Sampler Cooler, and

dd) Control Room Condensing Units.

The SWS flow diagram is shown in Figure 9.2.1-1. Four identical vertical wet pit pumps, each having a capacity of 8000 gpm at 120 ft total developed head (TDH), supply service water to two independent supply lines. Either of the two supply lines can be used to provide cooling water to all containment air recirculation cooling coils, the containment air recirculation fan motor coolers, the turbine-driven auxiliary feedwater pump, and the diesel generators. Components in the main Turbine Building can also be supplied with cooling water from either of the two supply lines. Each of the supply lines provides water to a motor-driven auxiliary feedwater pump, an instrument air compressor, and a component cooling heat exchanger. Water to Control Room condensing units is provided from north header downstream of the check valve. Component parameters are given in Table 9.2.1-1.

Water is drawn from the lake and passes through traveling screens. Two concrete walls separate the intake into three bays. A single service water pump is located in the two outside bays with the other two service water pumps located in the remaining bay.

The intake structure is designed as Seismic Class I, and is therefore not subject to collapse under earthquake loading. The only part of the SWS which is not seismic Class I design is the section in the Turbine Building. This section of the system can be isolated by redundant remotely operated isolation valves in series located in the Class I Auxiliary Building. The only exception to this is the service water supply and return lines to and from the emergency diesel air dryers. These lines are not seismically qualified. However, the consequence of failure of these lines was evaluated as acceptable in MOD-585.

The SWS is monitored and operated from the Control Room. Isolation valves are incorporated in all service water lines penetrating the containment. All supply header isolation valves are motor operated and controlled remotely from the Control Room.

As shown in Figure 9.2.1-1, the containment ventilation cooling units are supplied from the two auxiliary building service water headers through two booster pumps. Each of these pumps has a capacity of 3200 gpm at 100 ft TDH. Two of the four cooling units may be supplied from either booster pump. Each inlet line is provided with a motor-operated shutoff valve (or valves) and a drain valve. Similarly, each discharge line from the cooler is provided with a motor-operated shutoff valve. This allows each cooler to be isolated individually for leak testing of the system or to be drained and maintained open to the atmosphere during integrated leak tests of the containment. The ventilation cooler discharge lines are monitored for radioactivity by routing a small bypass flow from each through a radiation monitor. Upon indication of radioactivity in the effluent, each cooler discharge line would be monitored individually to locate the defective cooling coil. However, since the cooling coils and service water lines are completely closed inside the containment, no contaminated leakage is expected into these units. The SWS pressure at locations inside the containment is below the containment design pressure of 42 psig.

The motor-operated valves on the inlet and outlet service water lines for the fan coolers are equipped with indicating lights in the control room.

The emergency diesel-driven generator units are supplied with cooling water from the service water system. Two control valves, one on each supply line to the diesels, open fully when the corresponding diesel reaches 200 RPM to ensure a sufficient supply of cooling water to each diesel. The inlet valving is arranged so that either of the two diesels can be served by either of the supply lines.

As discussed in Section 8.3, electrical power for the four service water pumps can be supplied from the onsite diesel generators in the event of loss of all outside power. For this condition, the SWS is designed to supply cooling water to only the required emergency systems. Under the conditions of a concurrent loss-of-coolant accident (LOCA) and loss of offsite power, any two of four pumps using the emergency diesel power are capable of supplying the required cooling capacity.

To prevent degradation of the service water system pressure to vital components, service water supply to the Turbine Building is isolated on low service water header pressure for one minute coincident with a turbine trip signal.

During normal operation, the cooling loads are supplied by three of the four pumps. Following a simultaneous LOCA and loss of offsite power, the cooling water requirements for all four fan cooling units and the other essential loads can be supplied by any two of the four service water pumps during the injection and long term recirculation phase of the Safety Injection System (see Table 9.2.1-2).

Service water to at least two containment air recirculation units is assured with a single failure of any pipe or valve body in the SWS from the service water pumps to the containment air recirculation units themselves.

Service water to at least one component cooling heat exchanger is assured with a single failure of any pipe or valve body or in the system from the service water pumps to the heat exchangers themselves. Following a simultaneous LOCA and loss of offsite power, the component cooling heat exchangers are not needed during the injection phase. At the beginning of the recirculation phase at least one component cooling heat exchanger is placed in service.

The system is designed with two remotely-operated isolation valves in the center of the supply header. Two service water pumps normally serve one of the two separate supply lines. The flow provided by two pumps is ensured even with a single passive failure of a pipe or valve body or an active system component failure in the supply system. Due to the possibility of these remotely-operated isolation valves being rendered inoperable by flooding in the service water pit areas, level switches are located in these pits to provide annunciation in the control room to alert operators of impending flooding conditions. This will allow closing of these valves so that safe-shutdown service water requirements can be met should the control of these valves be lost.

Service water piping has mechanical joints, except for that downstream of the booster pumps, the main service water discharge and a portion of the north supply header. Joints on the service water piping downstream of the booster pumps, the main service water discharge and a portion of the north supply header are welded except for flanges on the fan and motor coolers, relief valves and connections to R-16.

The service water piping is of carbon steel with cement mortar or epoxy phenolic lining construction for sizes 12 in. to 30 in. AL6XN (UNS No 8367) Pipe. Stainless steel pipe, aluminum pipe, and carbon steel pipe are used for sizes 2 in. to 12 in. The aluminum pipe is lined with polyethylene Co-polymer. Pipe 1 1/2 in. and smaller is of stainless steel or other corrosion resistant material construction. This includes some brass pipe at the inlet and outlet of cooling coils HVH-6A, 6B, 8A, and 8B and the piping serving the turbine E-H oil coolers' temperature control valve, which is ASTM A312, 316L stainless steel.

The design code requirements for the SWS are given in Section 3.2.

A cathodic protection system was considered unnecessary for the SWS buried piping. Soil resistivity measurements taken in August 1958 prior to construction of Unit 1 and reconfirmed by measurements taken at the construction site in December 1966 have established that the soil resistivity is so high that the possibility of active corrosion is minimal. The average soil resistivity of 347,000 ohm-cm at 15.0 ft depth is well above the 10,000 ohm-cm value below which cathodic protection is necessary (See Section 3.8).

A chemical treatment system is provided to periodically inject biocide into the Service Water system at the intake structure to minimize fouling and corrosion due to biological activity in the lake water. The sodium hypochlorite system pump delivers sodium hypochlorite through independent lines to the 30" diameter service water header lines downstream of the service water intake pumps.

9.2.1.3 Safety Evaluation.

9.2.1.3.1 Intake structure. The four service water pumps are located in three separate bays in the intake structure, the middle bay containing two pumps. The pumps are sufficiently isolated to make it unlikely that a missile could damage more than one pump. The walls separating the bays and the deck above the piping are two and one half feet thick reinforced concrete. Thus it is highly unlikely that a missile could get to the pumps.

9.2.1.3.2 Leakage Provisions

During a LOCA the containment HVH units fan and motor coolers service water monitor checks the containment fan service water discharge lines for radiation indicative of a leak from the containment atmosphere into the service water. A small bypass flow from each of the heat exchangers is mixed in a common header and monitored by a scintillation detector mounted in a shielded detector assembly. Upon indication of a high radiation level each heat exchanger is individually sampled to determine which unit is leaking. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 1 min).

Gross leakage of the service water due to a faulty cooling coil in the Containment Air Recirculation Cooling System can be detected by stopping the fan and continuing the cooling water flow. Any significant cooling water leakage would be seen as flow into a collecting pan.

Leakage from a component in the SWS will be directed by floor drains to the auxiliary building sump. Pumps will then transfer this leakage to the waste holdup tank.

9.2.1.4 <u>Tests and Inspections</u>

Each service water pump was hydrostatically tested in the shop. All wetted parts were subjected to a hydrostatic pressure of one and one-half times the shut-off head of the pump. In addition, the normal capacity vs. head tests were made on each pump.

During original construction, all valves in the SWS were hydrostatically tested at three times the design pressure on the body and two and one-third times design pressure on the seat. SWS design pressure is 150 psig.

During original construction, all service water piping, except for the piping downstream of the service water booster pumps, was hydrostatically tested in the field at 225 psig or one and one-half times design. Service water piping downstream from the service water booster pumps was hydrostatically tested in the field at 150 psig or one and one-half times design. The welds in shop-fabricated service water piping were liquid penetrant or magnetic particle inspected in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII. The Inservice Inspection Program for the SWS is contained in Section 3.9.

Electrical components of the SWS can be tested periodically.

TABLE 9.2.1-1

SERVICE WATER SYSTEM
COMPONENT PARAMETERS

Flow Requirements

Normal Plant Operation	23,000 gpm
LOCA	15,000 gpm
Emergency Shutdown	23,000 gpm

Service Water Pumps

Number	4
Manufacturer	Johnston Pumps Inc.
Type	Vertical
Head	120 ft
Flow	8000 gpm
Stages	3
Material:	
Casing	Cast Iron
Impellers	Bronze
Shaft	Stainless Steel
Motor Rating	300 HP

Service Water Booster Pumps

Number	2
Manufacturer	Worthington Corporation
Type	Vertical Split/Centrifugal
Model	8C N6-104
Head	100 ft
Flow	3200 gpm
Material:	
Casing	Stainless Steel
Impellers	Stainless Steel
Shaft	Stainless Steel
Motor Rating	125 HP

TABLE 9.2.1-2

SERVICE WATER DESIGN REQUIREMENTS

NORMAL OPERATION	FLOW*** (gpm)	ACCIDENT	FLOW*** (gpm)
Containment fan and motor cooling coils (4)	3,200	Containment fan and motor cooling coils (4)	3,200
Component cooling heat exchanger (1)	10,000	Component cooling heat exchanger (1)	10,000
Feedwater pump (2)	50	Auxiliary feedwater pump*(1)	15
Air compressors (4)	26**	Air compressors (2)	13
Auxiliary building heating and ventilation	268	Auxiliary building heating and ventilation	268
Condenser vacuum pumps	30	Emergency water supply to auxiliary feedwater pump	600
Equipment in Turbine Building	9,290	Diesel generators (2)	1,200
Control Room Condensing Units	170	Control Room Condensing Units (2)	170
TOTALS	23,034		15,466

	Normal Operation	Accident
Number of pumps required	3	2
Required pump capacity (each), gpm	7,621	7,648
Rated capacity per pump, gpm	8,000	8,000

* Either one motor-driven auxiliary feedwater pump or the single turbine-driven auxiliary feedwater pump

** 26 gpm for three compressors plus quantity needed for the manually controlled primary compressor.

*** Flow values listed are for the sizing of the service water system. Individual component flows may vary on the low side from these values.

9.2.2 COMPONENT COOLING SYSTEM

9.2.2.1 Design Basis

The Component Cooling System (CCS) is designed to remove residual and sensible heat from the Reactor Coolant System (RCS) via the Residual Heat Removal System (RHRS) during plant shutdown, cool the letdown flow to the Chemical Volume and Control System (CVCS) during power operation, and to provide cooling to dissipate waste heat from various primary plant components.

Active components which are relied upon to perform the cooling function are redundant. Redundancy of components does not degrade the reliability of any system which the process loop serves.

The design provides for detection of radioactivity entering the system from reactor coolant sources and also provides means for isolation.

One pump and one component heat exchanger are normally operated to provide cooling water for various components located in the auxiliary and containment buildings. The water is normally supplied to all components being cooled even though one of the components may be out of service.

Makeup water is taken from the primary water treatment plant as required, and delivered to the surge tank. A backup source of water is provided from the primary water make-up pumps.

Welded construction is used where possible throughout the component cooling loop piping, valves, and equipment to minimize the possibility of leakage.

9.2.2.2 System Description

The Component Cooling System, as shown on Figures 9.2.2-1 through 9.2.2-3, consists of three pumps, two heat exchangers, a surge tank, associated piping, valves, instrumentation, and chemical pot feeder.

During normal full power operation, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads. One of the two standby pumps and one heat exchanger provides 100 percent backup during normal operation. Three pumps and two heat exchangers are utilized to remove the residual and sensible heat during plant shutdown. If one of the pumps or one of the heat exchangers is not operative, safe shutdown of the plant is not affected, but the time for cooldown is extended.

Component cooling is provided for the following heat sources:

a) Residual heat exchangers (Auxiliary Coolant System, ACS)

b) Reactor coolant pumps (RCS)

c) Non-regenerative heat exchanger (CVCS)

d) Excess letdown heat exchanger (CVCS)

e) Seal water heat exchanger (CVCS)

f) Boric acid recycle evaporator and condensate coolers (CVCS)

g) Sample heat exchangers (Sampling System)

h) Waste evaporator condenser (Waste Disposal System)

i) Waste gas compressors (Waste Disposal System)

j) Residual heat removal pumps (ACS)

k) Safety injection pumps (Safety Injection System, SIS)

l) Containment spray pumps

m) Spent fuel pit heat exchanger (ACS)

n) Charging pumps (CVCS), and

o) Control rod drive air-water heat exchanger.

At the reactor coolant pump, component cooling water removes heat from the bearing oil and the thermal barrier. Since the heat is transferred from the component cooling water to the service water, the component cooling loop serves as an intermediate system between the reactor coolant and the service water cooling system. This double barrier arrangement reduces the probability of leakage of high pressure, potentially radioactive coolant to the service water system.

The surge tank accommodates expansion, contraction and in-leakage of water, and ensures a continuous component cooling water supply until a leaking cooling line can be isolated. A radiation monitor in the component cooling pump inlet header annunciates in the control room in the unlikely event that the radiation level reaches a preset level above the normal background.

The following is a description of the major components of the system. (Component parameters are given in Table 9.2.2-1).

9.2.2.2.1 Component Cooling Pumps

The three component cooling pumps which circulate component cooling water through the component cooling loop are horizontal, centrifugal units. The pump casings are made from cast iron (ASTM 48) based on the corrosion-erosion resistance and the ability to obtain sound castings. The material thickness is dictated by high quality casting practice and ability to withstand mechanical damage and, as such, they are substantially overdesigned from a stress level standpoint.

9.2.2.2.2 Component Cooling Heat Exchangers

The component cooling heat exchangers are of the shell and straight tube type. Service water circulates through the tubes while component cooling water circulates through the shell side. The heat exchanger tubes are 90/10 copper nickel. The heat exchangers have a protective coating on the end bells and tube sheets to minimize erosion.

9.2.2.2.3 Component cooling surge tank. The component cooling surge tank which accommodates changes in component cooling water volume is constructed of carbon steel. In addition to piping connections, the tank has a flanged opening at the top which can be used, if required, for the addition of the chemical corrosion inhibitor to the component cooling loop.

9.2.2.2.4 Chemical pot feeder tank. The chemical pot feeder tank provides for the direct addition of corrosion additive to the component cooling water.

9.2.2.2.5 Component cooling valves. The valves used in the component cooling loop are constructed primarily of carbon steel with bronze or stainless steel trim. Stainless steel valves may also be installed on a case by case basis. Since the component cooling water is not normally radioactive, special valve features to prevent leakage to the atmosphere (such as special leakoff lines to the Waste Disposal System) are not provided.

Self-actuated spring-loaded relief valves are provided for lines and components that could be pressurized to their design pressure by improper operation or malfunction.

9.2.2.2.6 Component cooling piping. All component cooling loop piping is carbon steel with welded joints and connections except at components which might need to be removed for maintenance. The spent fuel pool heat exchangers, the SI pumps, and the RHR pumps have emergency connections for cooling water if component cooling water must be isolated.

For continued cooling of the reactor coolant pumps and the excess letdown heat exchanger, most of the piping, valves, and instrumentation inside containment are located outside the primary system concrete shield at an elevation well above the anticipated post-accident water level in the bottom of the containment. This location provides radiation shielding which allows for maintenance and inspections to be performed during power operation. The cooling lines for the reactor coolant pumps are located inside the primary shield wall but are also above the anticipated post accident water level. Based on leak-before-break criteria for the primary system and the location of all piping above the post accident water level, all the component cooling equipment is protected against credible missiles and from being flooded during post-accident operation.

Outside the containment, the residual heat removal pumps, the residual heat exchangers, the spent fuel heat exchanger, the component cooling pumps and heat exchangers, and associated valves, piping and instrumentation are maintainable and inspectable during power operation. System design provides for the replacement of one pump or one heat exchanger while the other units are in service.

Several of the components in the component cooling loop are fabricated from carbon steel. The component cooling water contains a corrosion inhibitor to protect the carbon steel. The entire system is seismic Class I design. The components are designed to the codes as presented in Section 3.2. The components are not subjected to any high pressures (see Table 9.2.2-1) or stresses; therefore, a rupture or failure of the system is very unlikely.

During the recirculation phase following a loss-of-coolant accident, one of the three component cooling water pumps delivers flow to the shell side of one of the residual heat exchangers to cool the recirculating containment spray fluid.

9.2.2.3 Safety Evaluation

9.2.2.3.1 Leakage Provisions

The component cooling water could become contaminated with radioactive water due to a leak in any heat exchanger tube in the Chemical and Volume Control, the Sampling, the Residual Heat Removal, or Spent Fuel Pit Cooling Systems, or a leak in the cooling coil for the reactor coolant pump thermal barrier.

Tube or coil leaks from components inside the reactor containment would be detected during normal plant operation by the leak detection system described in Section 5.2. Such leaks are also detected anytime by a radiation monitor located on the main return header.

Gross leakage from the section of the component cooling loop inside the containment which does not flow into another closed loop will flow into the containment sump. Outside, the containment major leakage would be drained to the auxiliary building sump. From here it is pumped to the waste holdup tank. Leakage from the Component Cooling System can be detected by a falling level in the component cooling surge tank. The rate of water level fall and the area of the water surface in the tank permit determination of the leakage rate. To assure accurate determinations, the operator would check that temperatures are stable.

The component which is leaking can be located by sequential isolation or
6 inspection of equipment in the loop. If the leak is found to be in one of the CCW heat exchangers, the other heat exchanger would continue to operate while the leaking heat exchanger is isolated and repaired. During normal operation the leaking exchanger could be left in service with leakage up to the capacity of the makeup line to the system from the primary water treatment plant. By manual transfer, emergency power is available for makeup pump operation.

A cooling water temperature increase of about 250°F (considered to be incredible) would be required to overfill the component cooling surge tank. However, should a large tube side to shell side leak develop in a residual heat exchanger, the water level in the component cooling surge tank would
6 rise, and the operator would be alerted by a high water alarm. The vent on the tank (RCV-609) is blocked open. Thus, any overflow out of the tank would flow through RCV-609 and be routed to the auxiliary building waste holdup tank. If the leaking residual heat exchanger is not isolated from the component cooling loop before the inflow completely fills the surge tank, and the overflow exceeds the flow capacity of RCV-609, the relief valve on the surge tank would lift. The discharge of this relief valve is also routed to the auxiliary building waste holdup tank.

The severence of a cooling line serving an individual reactor coolant pump cooler would result in substantial leakage of component cooling water. However, the piping is small as compared to piping located in the missile protected area of the containment. Therefore, the water stored in the surge tank after a low level alarm, together with makeup flow, provides ample time for the closure of the valves external to the containment to isolate the leak before cooling is lost to the essential components in the component cooling loop.

The relief valves on the component cooling water header downstream from each of the reactor coolant pumps are designed with a capacity equal to the maximum rate at which reactor coolant can enter the component cooling loop from a severence type break of the reactor coolant pump thermal barrier cooling coil. The valve set pressure equals the design pressure of the component cooling piping.

Relief valves are provided on the cooling water lines downstream from the sample, excess letdown, seal water, non-regenerative, spent fuel pit and residual heat exchangers. Each is sized to relieve the volumetric expansion occurring if the exchanger shell side is isolated when cool, and high temperature coolant flows through the tube side. Each set pressure equals the design pressure of the shell side of the heat exchanger.

The relief valve on the component cooling surge tank is sized to relieve the maximum flow rate of water which enters the surge tank following a rupture of a reactor coolant pump thermal barrier cooling coil. The set pressure equals the design pressure of the component cooling surge tank. Initial protection is provided by an isolation valve which automatically closes on high flow in the event of a thermal barrier coil rupture.

9.2.2.3.2 Incident control. Remotely operated containment isolation valves are automatically closed on either a Phase A or Phase B Containment Isolation Signal. The cooling water supply header to the reactor coolant pumps contains a check valve inside and two remotely operated valves outside the containment wall. The cooling water supply line to the excess letdown heat exchanger contains a check valve inside the containment wall which is closed during normal operation. Except for the normally closed makeup line and equipment vent and drain lines, there are no direct connections between the cooling water and other systems. The equipment vent and drain lines outside the containment have manual valves which are normally closed unless the equipment is being vented or drained for maintenance or repair operations. The vent lines are also capped as an additional safety feature.

Following a loss-of-coolant accident, one component cooling pump and one component cooling heat exchanger accommodate the heat removal loads. If either a component cooling pump or component cooling heat exchanger fails, one of the two standby pumps and the standby heat exchanger provide 100 percent backup. Valves on the component cooling return lines from the safety injection, containment spray and residual heat removal pumps are normally open. Each of the component cooling return lines from the residual heat exchangers has a normally closed remotely operated valve. If one of the valves fails to open at initiation of long-term recirculation, the valve which does open supplies a heat exchanger with sufficient cooling to remove the heat load.

If the break of a cooling line occurs inside the containment, adequate valving is available outside the containment on the component cooling supply and return lines to isolate the leak (see Figure 9.2.2-2). None of the components inside the containment require component cooling water during recirculation. If the break occurs outside the containment, the leak could either be isolated by valving or the broken line could be repaired, depending on the position in the loop at which the break occurred.

Once the leak is isolated or the break has been repaired, makeup water is supplied from the reactor makeup water tank by either one of the reactor makeup water pumps.

9.2.2.3.3 Malfunction Analysis

A failure analysis of pumps, heat exchangers, and valves is presented in Table 9.2.2-2.

9.2.2.4 <u>Tests and Inspections</u>

The Inservice Inspection Program for the Component Cooling System is contained in Section 3.9.

9.2.2.5 <u>Instrumentation Applications</u>

The operation of the Component Cooling System is monitored with the following instrumentation:

a) Temperature detectors in the inlet and outlet lines for the component cooling heat exchangers

b) A pressure detector on the line between the component cooling pumps and the component cooling heat exchangers

c) A temperature and flow indicator in the outlet header from the heat exchangers, and

d) A radiation monitor on the inlet header to the component cooling pumps.

TABLE 9.2.2-1

COMPONENT COOLING SYSTEM
COMPONENT PARAMETERS

Component Cooling Pumps

Quantity	3
Type	Horizontal centrifugal
Rated capacity, gpm	6000
Rated head, ft H_2O	180
Motor horsepower, HP	350
Casing material	Cast iron
Design pressure, psig	150
Design temperature, °F	200

Component Cooling Heat Exchangers

Quantity	2
Type	Shell and straight tube
Heat transferred, Btu/hr (Shutdown Condition)	29.35×10^6
Shell side (component cooling water) -	
Inlet temp., °F	115
Outlet temp., °F	108
Design flow rate, lb/hr	4.46×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Carbon steel
Tube side (service water) -	
Inlet temperature, °F	95
Outlet temperature, °F	101
Design flow rate, lb/hr	4.96×10^6
Design pressure, psig	150
Design temperature, °F	200
Material	90/10 Copper Nickel

Component Cooling Surge Tank

Quantity	1
Volume, gal	2000
Normal water volume, gal	1000
Design pressure, psig	100
Design temperature, °F	200
Construction material	Carbon steel

9.2.3 Primary and Demineralized Water Makeup System

9.2.3.1 Design Basis. The Primary and Demineralized Water Makeup System supplies demineralized and/or deaerated water using mixed bed ion exchange and a vacuum deaeration process. The system consists of three primary mixed demineralizers, two mixed bed demineralizers and a vacuum deaerator. Also included in the system are pumps and storage tanks for water, acid, and caustic. Demineralized and/or deaerated water produced by the system provides makeup for primary and secondary systems.

9.2.3.2 System Description. The Primary and Demineralized Water Makeup System is shown on Figures 9.2.3-1 and 9.2.3-2.

Well water is pumped by three parallel deepwell pumps, each rated at 200 gpm, to a two stage vacuum degasifier. The deoxygenated well water in the vacuum degasifier is pumped by two of three parallel transfer pumps each rated at 150 gpm, to two of three parallel primary mixed bed demineralizers and then through one of two parallel polishing mixed bed demineralizers.

The primary and polisher demineralizers are vertical tanks with well mixed cation, anion, and neutral exchange resins packed in the bottom half. Raw water enters the primary vessels from the top, has its cations and anions exchanged when passing through the resins beds, and exits at the bottom. The majority of the cations are exchanged in the primary demineralizers, and the remaining cations and all of the anions are exchanged in the polishing mixed bed demineralizers.

The deoxygenated/demineralized water is then piped to the condensate storage tank, demineralized water header, and/or to the primary water storage tank. Water going to the condensate storage tank and the primary storage tank is deoxygenated.

The water in the demineralized water header can come directly from the mixed bed outlet header when a train of demineralizers is in service but normally comes from the condensate storage tank via the demineralized water pump.

The demineralized water header supplies the following:

1. Fuel handling building decontamination facility,

2. Seal water for condenser vacuum pumps,

3. Backup supply for component cooling makeup,

4. Water for backflushing and sluicing the spent fuel pit demineralizer,

5. Water supply to labs,

6. Water to auxiliary steam desuperheaters through an automatic control valve,

7. Makeup to emergency diesel generator expansion tank,

8. Backup supply to "A" and "B" auxiliary boiler condensate tank via a manual valve,

9. Alternate demineralized water supply to the Environmental & Radiation Control Building,

10. Flushing water and alternate water supply to Secondary Sampling System,

11. Supply seal water to vacuum degasifier vacuum pump header in the CST recycle mode, and

12. Alternate supply water for oxygen, silica, and sodium analyzers in the MWT and the Condensate Polishing Systems.

13. Demineralized water supply to Radwaste Building.

The primary water header supplies the following:

1. Water for backflushing and sluicing the following:

    a. Mixed bed demineralizers (Chemical and Volume Control System, CVCS),

    b. Cation bed demineralizer (CVCS),

    c. Deborating demineralizers (CVCS),

    d. Base and cation ion exchangers (Boron Recycle System),

    e. Evaporator condensate demineralizers (Boron Recycle System),

    f. Polishing ion exchangers (Waste Disposal System).

2. Water supply to the drumming room for backflushing lines and hoses

3. Flushing water to boric acid evaporators, gas strippers, boric acid transfer pumps, waste evaporators, and boron injection tank sample line

4. Water supply to the portable resin tank for adding resins

5. Makeup supply to the isolation valve seal water tank

6. Supply to containment for the pressurizer relief tank, reactor coolant pump, standpipes, and hose connections

7. Normal makeup to the component cooling water system

8. Boric acid batch tank and chemical addition pot

9.3 Process Auxiliaries

9.3.1 Station and Instrument Air Systems

The Station and Instrument Air System uses air compressors and air dryers to supply station air at 100 psig/110°F and instrument air at 100-110 psig/85°F to station air headers and instrument air headers located in Turbine Building, Reactor Containment Building, Reactor Auxiliary Building, Corridor, Fuel Handling Areas, and Radwaste Facility.

9.3.1.1 Design Basis. The design basis of the instrument air system is to supply the air requirements to the entire plant with compressed air which is oil free, dried to a specified dew point and free of foreign materials. The term "oil-free" (or "non-lubricated") instrument air is defined as a system containing not more than 1 ppm oil. Instrument air is also used for breathing inside containment and a carbon monoxide monitor is used either before or during this usage to assure the air is safe for breathing.

9.3.1.2 System Description. The air systems consist of the instrument and station air subsystems. The instrument air system has a 516 scfm reciprocating, non-lubricated primary air compressor. Air from the primary air compressor goes to an after cooler,a 700 scfm refrigerant evaporator air dryer and then to a 427 ft^3 air receiver. The system also has an additional 528 ACFM rotary air compressor with a dessicant dryer, and a 427 ft^3 air receiver, as well as two 200 scfm non-lubricated air compressors with aftercoolers, one 150 ft^3 air receiver, two 200 scfm air dryers, controls and accessories. The "D" air compressor normally supplies the instrument air system.

The station air system has one 400 scfm oil lubricated air compressor with aftercooler, one 150 ft^3 air receiver, controls, and accessories, but no air dryer.

Since station air differs from instrument air only in its higher oil and moisture contents, station air can be used as a back-up for instrument air by passing the station air receiver discharge through a filter and then through the instrument air dryers.

For the instrument air subsystem, ambient air enters the compressors through dry-type inlet filter silencers. Outlet air from the compressors at a pressure greater than 100 psig will go through aftercoolers, and air separators to an air receiver. The "A", "B", and "primary" compressors are of the reciprocating type with water jackets for cylinder cooling. The aftercoolers are shell and tube heat exchangers with cooling water on the shell side. Both the separators and the air receiver are vertical tanks equipped with internal baffles, traps and relief valves. Air temperature at the receiver discharge is maintained at about 110°F by adjusting the cooling water flow to the compressor water jackets and to the aftercoolers. Air pressure at this point is about 100 psig.

Air discharged from the 150 ft^3 "A" and "B" compressor receiver is piped to two air drying systems and then distributed to various headers. The air drying system is of the refrigeration type. Air enters the system through a reverse Ultipor prefilter which removes liquid oil and water. The humid air

then passes through a precooler which cools it and exchanges the heat to the dry air discharge line. The air then continues on to a refrigerant evaporator, or air dryer, which chills the air to 35°F, condensing out oil and water. The liquid is then separated from the gas stream via another reverse Ultipor separator. The dry air then cycles back to the downstream side of the precooler and is reheated by the incoming air, further reducing its relative humidity. Air quality at this point is 85°F at 90 psig with a maximum dew point of -10°F at 14.7 psig.

Air discharged from the primary air compressor and aftercooler is dried in a manner similar to that described above, and then enters the 427 ft^3 receiver for distribution and use. Air discharged from "D" air compressor is dried by an adsorption type air dryer, and then enters a 427 ft^3 receiver for distribution and use.

For the station air subsystem, the description is similar except that this subsystem has no air dryers and thus the air output may have a higher moisture and oil content. Temperature and pressure of the air are 110°F and 100 psig.

A listing of the system and component design parameters is shown in Table 9.3.1-1.

9.3.1.3 Safety Evaluation. The station and instrument air system has no functions to perform either in a safe shutdown or in an accident condition. It is therefore classified as a nonsafety system. The only parts of the system which are Class I is the containment penetration and the associated isolation valves and auxiliary air accumulators with connected tubing/piping for the main steam isolation valve operators. Failure of any other portion of these systems will not compromise the safety of the plant.

9.3.1.4 Testing and Inspection. Since the system is in constant use during normal plant operation, no special tests or inspections are necessary.

9.3.1.5 Instrumentation Requirements.

9.3.1.5.1 Carbon monoxide. A carbon monoxide monitor is provided to test the instrument air before and/or during its use for breathing.

9.3.1.5.2 Control of air temperature. Instrument and station air temperature at the discharge of the reciprocating air compressors is controlled by varying the amount of cooling water supplied to the compressor water jackets through temperature control valves, with temperature controllers located at the air discharge of compressors. The outlet air temperature should be about 415°F. The outlet cooling water temperature should be at least 10-15°F above inlet air temperature. Cooling water flow through the aftercooler is manually set to maintain the aftercooler air discharge temperature at about 110°F. Instrument air temperature is maintained at 85°F at the dryer discharge by controlling the amount of refrigerant to the evaporators.

The discharge air temperature of the primary air compressor is manually controlled by varying the cooling water flow to the water jackets and coolers.

9.3.1.5.3 Dual Pressure Control for Compressors

Dual control regulations are provided for both station and the two 200 scfm instrument air compressors. A selector switch in the compressor control station can be set to either "Manual" for constant speed regulations, or "Auto" for automatic start and stop regulation. Constant speed regulation should be used when the unit must operate most of the time in order to meet the air requirements or when the number of starts exceeds ten per hour (to avoid too frequent start and stop which will shorten the life of electrical contacts). Automatic start and stop regulation should be used when the demand for air is intermittent and particularly for periods when the load is light. With constant speed regulation the compressor runs continuously, while the compressor cylinder is unloaded and reloaded automatically as the air receiver pressure reaches the cut out setting or drops to the cut in setting on the regulator. With automatic start and stop regulation the compressor always operates at full capacity, but the driving motor is started and stopped automatically at 95 and 105 psig air receiver pressure. For either control regulation, a 100 psig air receiver pressure is desirable for both instrument and station air system. The primary and "D" compressor controllers are set for constant speed regulation.

9.3.1.5.4. Minimum Air Pressures

Instrument air pressure at the discharge of air dryer and station air pressure at the discharge of air receiver are indicated separately on reactor and turbine-generator board (RTGB) in the Control Room. When the instrument air or station air pressure drops below 85 psig an alarm will be annunciated. For instrument air, if low pressure is caused by frozen air dryers, then the normally closed self-contained flow control valve will automatically open at 80 psig to bypass the air dryers and send instrument or backup station air directly from air receiver to the headers. Otherwise the operator shall check the system and take corrective action (i.e. manually bypass a leaking section of the system, etc.).

The primary and "D" air compressors should be checked first if a low pressure annunciator is received. A warning light on the RTGB will indicate a problem with either compressor.

9.3.2 PROCESS SAMPLING SYSTEM

Process Sampling Systems are provided for both normal operation and post-accident conditions. The Operational Sampling System, described in Section 9.3.2.1 below, provides samples for laboratory analysis to evaluate reactor coolant and other reactor auxiliary systems' chemistry during normal operation. The Post-Accident Sampling System, described in Section 9.3.2.2 below, provides capability for collecting samples of reactor coolant and containment atmosphere under accident conditions. It also provides means for remotely analyzing the samples and indicating results and for diluting samples for subsequent radiological analysis. 1

9.3.2.1 Operational Sampling System

9.3.2.1.1 Design Basis

The design basis for the Operational Sampling System are:

a) The system is capable of providing reactor coolant samples during both normal reactor operating conditions and cooldown when the system pressure is low and the residual heat removal loop is in operation

b) Access to the containment is not a requirement

c) Sampling of other process coolants, such as tanks in the waste Disposal System, can be accomplished locally, and

d) Equipment for sampling secondary and nonradioactive fluids is separated from the equipment provided for reactor coolant samples.

The system component code requirements are given in Section 3.2.

9.3.2.1.2 System Description

9.3.2.1.2.1 General Description 1

The Sampling System, shown in Figure 9.3.2-1, provides the representative samples for laboratory analysis. Analysis results provide guidance in the operation of the Reactor Coolant, Auxiliary Coolant, Steam, and Chemical and Volume Control Systems (CVCS). Analyses show both chemical and radiochemical conditions. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level, hydrogen, oxygen, and fission gas content, corrosion product concentration, and chemical additive concentration.

The information is used in regulating boron concentration adjustments, evaluating fuel element integrity and mixed bed demineralizer performance, and regulating additions of corrosion controlling chemicals to the systems. The Sampling System is designed to be operated manually, on an intermittent basis. Samples can be withdrawn under conditions ranging from full power to cold shutdown.

Reactor coolant liquid lines, which are normally inaccessible and require frequent sampling, are sampled by means of permanently installed tubing leading to the sampling room.

Sampling System equipment is located inside the Auxiliary Building with most of it in the sampling room. The delay coil and sample lines with remotely operated valves are located inside the reactor containment.

Reactor coolant hot leg liquid, accumulator liquid, pressurizer liquid and pressurizer steam samples originating inside the reactor containment flow through separate sample lines to the sampling room. Each of these connections to the Reactor Coolant System (RCS) has a remotely operated isolation valve located close to the sample source. The samples pass through the reactor containment compartment, to the Auxiliary Building, and into the sampling room, where they are cooled (pressurizer steam samples are condensed and cooled) in the sample heat exchangers. The sample stream pressure is reduced by a manual throttling valve located downstream of each sample pressure vessel. The sample stream is purged to the volume control tank in the CVCS until sufficient purge volume has passed to permit collection of a representative sample. After sufficient purging, the sample pressure vessel is isolated and then disconnected for laboratory analysis of the contents.

Alternately, liquid samples may be collected by bypassing the sample pressure vessels. After sufficient purge volume has passed to permit collection of a representative sample, a portion of the sample flow is diverted to the sample sink where the sample is collected.

The reactor coolant sample originating from the residual heat removal loop of the Auxiliary Coolant System has a remotely operated, normally closed isolation valve located close to the sample source. The sample line from this source is connected into the sample line coming from the hot leg at a point ahead of the sample heat exchanger. Samples from this source can be collected either in the sample pressure vessel or at the sample sink as with hot leg samples.

Liquid samples originating at the CVCS letdown line at demineralizer inlet and outlet pass directly through the purge line to the volume control tank. Samples are obtained by diverting a portion of the flow to the sample sink. If the pressure is low in the letdown line, the purge flow is directed to the chemical drain tank. The sample line from the gas space of the volume control tank delivers gas samples to the volume control tank sample pressure vessel in the sampling room. Purge flow for these samples is discharged to the vent header in the Waste Disposal System.

Because samples from the pressurizer steam phase, the reactor coolant dissolved gas and volume control tank gas phase may contain accumulated radioactive gases, the respective sample vessel stations are located in small, well ventilated and shielded cubicles within the sampling room.

Samples of the steam generator liquid are obtained from the blowdown lines. A separate sample line is provided from each steam generator blowdown line into the sample room. These lines are each equipped with two remotely operated isolation valves immediately outside the containment. These valves are automatically closed upon receipt of a signal from the respective blowdown sample radiation monitor or the containment isolation system. A key switch is provided for each valve to over-ride the isolation signals and allow the valve to be opened.

However, Steam Generator 'C' Blowdown Sample valves (FCV-1935 A & B) are presently in the closed position to meet the requirements of Operability Determination 93-008 (Serial: RNPD/19-1359). This Operability Determination was necessary to show that total allowable leakage for CV isolation valves served by the Isolation Seal Water (IVSW) system did not exceed the acceptance criteria as stated in EST-004. The Operability Determination states that "Opening or performing maintenance on either valve would violate the basis for this Operability Determination."

With FCV-1935 A & B closed, the Steam Generator 'C' Blowdown Radiation Monitor (R-19C) was rendered inoperable. Temporary Modification 93-708 was installed to provide an alternate flow path which bypasses FCV-1935 A & B and ties into the Secondary Sampling just upstream of the Steam Generator 'C' Blowdown Sample Cooler. This modification restored R-19C to operable status within 30 days, and prevented an explanation to be included in the next semi-annual report to the NRC. The temporary mod also restored the inoperable continuous monitoring system for Steam Generator 'C' Blowdown chemistry.

Additionally, since FCV-1935 A & B are closed and inoperable the key operated controls on the RTGB, which override the isolation signals from the blowdown sample radiation monitor or the containment isolation system, is currently unavailable. Installation of TM-93-708 did not restore this capability. In the event of a PHASE "A" Isolation, compensatory action will be taken at the discretion of the Operation Unit.

The sample lines are routed to the sample room where the liquid is cooled and the pressure reduced. Individual sample lines go to the sample sink to provide periodic grab samples for chemical analysis and to the steam generator blowdown radiation monitors to allow for continuous monitoring of blowdown radiations levels. After passing through the radiation monitor, sample flow continues to go to instrumentation in the Secondary Sample Room to provide for continuous sample analysis. The sample flow from each steam generator can also be routed to a common line. A sample from this common line can be routed to the Post-Accident Sample System.

The primary sample sink, which is contained in the laboratory bench as a part of the sampling hood, contains a drain line to the Waste Disposal System.

Two types of samples are obtained by the system: high temperature-high pressure RCS samples which originate inside the reactor containment, and low temperature-low pressure samples from the Chemical and Volume Control and Auxiliary Coolant Systems. These samples are taken as follows:

a) High Pressure - High Temperature Samples: A sample connection is provided from each of the following high pressure-high temperature samples:

1) The pressurizer steam space
2) The pressurizer liquid space
3) Hot legs of loops 2 and 3
4) Blowdown lines from each steam generator

b) Low Pressure - Low Temperature Samples: A sample connection is provided from each of the following low pressure-low temperature samples:

1) The mixed bed demineralizer inlet header
2) The mixed bed demineralizer outlet header
3) The residual heat removal loop, just downstream of the residual heat removal pumps
4) The volume control tank gas space
5) The accumulators

The high pressure, high temperature samples and the residual heat removal loop samples leaving the sample heat exchangers are held to a temperature of 130°F to minimize the generation of radioactive aerosols.

9.3.2.1.2.2 Components

A summary of principal component data is given is Table 9.3.2-1.

9.3.2.1.2.2.1 Sample Heat Exchangers

Six sample heat exchangers reduce the temperature of samples from the pressurizer steam space, pressurizer liquid space, each steam generator and the reactor coolant to 130°F before samples reach the sample vessels and sample sink. The tubes of the heat exchangers are austenitic stainless steel, and the shells are carbon steel.

The inlet and outlet tube sides have socket-weld joints for connections to the high presure sample lines. Connections to the component cooling water lines

are socket-weld joints. The samples flow through the tube side and component cooling water from the Auxiliary Coolant System circulates through the shell side.

9.3.2.1.2.2.2 Delay coil. The sample line contains a delay coil, consisting of coiled tubing, which has sufficient length to provide at least a 40 second sample transit time within the containment and an additional 20 seconds transit time from the reactor containment to the sampling hood. This allows for decay of short lived isotopes to a level that permits normal access to the sampling room.

9.3.2.1.2.2.3 Sample pressure vessels. The high pressure sample trains, the residual heat removal loop sample train and the volume control tank gas space sample train each contain sample pressure vessels which are used to obtain liquid or gas samples. The hot leg, CVCS, and the residual heat removal loop sample lines have a single sample pressure vessel in common. Integral isolation valves are furnished with the vessel and quick disconnect coupling valves containing poppet-type check valves are connected to nipples extending from the valves on each end. The vessels, valves and couplings are austenitic stainless steel.

9.3.2.1.2.2.4 Sample sink. The sample sink is located in a hooded enclosure which is equipped with an exhaust ventilator. The work area around the sink and the enclosure is large enough for sample collection and storage for radiation monitoring equipment. The sink perimeter has a raised edge to contain any spilled liquid.

9.3.2.1.3 Safety evaluation. The Sampling System is not required for safe shutdown nor to mitigate the consequences of an accident and is therefore designated as a non-safety related system. However, since the system does contain potentially radioactive material, the following discussion indicates the precautions taken to insure safe operation of the plant.

Isolation valves are provided outside the reactor containment which trip closed upon actuation of the containment isolation signal.

The system operates on an intermittent basis, and under administrative manual control.

Leakage of radioactive reactor coolant from this system within the containment is evaporated to the containment atmosphere and removed by the cooling coils of the Containment Air Recirculation and Cooling System. Leakage of radioactive material from the most likely places outside the containment is collected by placing the entire sampling station under a hood provided with an offgas vent to waste gas processing. Liquid leakage from the valves in the hood is drained to the chemical drain tank.

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant accident (LOCA), and the consequences were analyzed. The results are presented in Table 9.3.2-2. From this evaluation

it is concluded that proper consideration has been given to station safety in the system.

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high pressure service. With the exception of the sample vessel quick-disconnect couplings and compression fittings on various valves and components, socket welded joints are used throughout the Sampling System. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

Remotely-operated stop valves are used to isolate all sample points and to route sample fluid flow inside the reactor containment. Manual stop valves are provided for component isolation and flow path control at all normally accessible Sampling System locations. All valves in the system are constructed of austenitic stainless steel or equivalent corrosion resistant material. Manual throttle valves are provided to adjust the sample flow rate as indicated on Figure 9.3.2-1.

Check valves prevent gross reverse flow of gas from the volume control tank (VCT) into the sample sink.

9.3.2.1.4 Testing and inspection. Since the Sampling System is in use during plant operation, no special testing or inspection is required.

9.3.2.1.5 Instrumentation requirements. The liquid sample flow indicator (FI-903) indicates the sample line flow rate when purging the sample lines to the VCT. The normal rate is 0.42 gpm.

The gas sample flow indicator (FI-904) from the VCT gas space indicates purging flow to the vent header. The normal flow through this line is 1 cfm.

There are local pressure gauges (PI-902, 906, 908, 909) on the sample lines for the pressurizer steam space, pressurizer liquid space, hot legs, and the CVCS-to-hot leg tie-in. The pressure in these lines is regulated to 75 psig or less.

There are local temperature indicators (TI-901, 905, 907) on the sample lines from the pressurizer steam space, the pressurizer liquid space and the hot leg sample line. The flow in these lines is throttled so that the sample temperature out of the heat exchanger is 130°F or less.

There are switches for all remotely-operated valves. Valve position indicating lights are also on this panel, located above the switch for the valve.

The valves used for containment isolation purposes, 2 valves per line, are operated by a single switch for both valves.

<u>9.3.2.2 Post-Accident Sampling System</u>. The Post-Accident Sampling System (PASS) shown in Figures 9.3.2-2 and 9.3.2-3, provides a means to remotely collect reactor coolant and containment atmosphere samples following a nuclear accident, to remotely indicate results of chemical analyses of these samples, and to dilute these samples for subsequent radiological analysis.

The information obtained from analyses of these samples will improve efforts to assess and control the course of the accident.

9.3.2.2.1 System design basis. The PASS provides a means to obtain pressurized and unpressurized reactor coolant liquid and containment atmosphere samples. A reactor coolant sample can be drawn directly from the Reactor Coolant System (RCS) whenever the RCS pressure is between 200 psig and 2485 psig. At lower pressure, RCS samples can be drawn via the Residual Heat Removal (RHR) system. A containment atmosphere sample can be drawn with containment pressure between 10 and 75 psia.

The PASS provides a means to quantify the following parameters within an hour of obtaining samples:

1. certain isotopes that are indicators of the degree of core damage (i.e. noble gases, iodine, cesiums, and non-volatile isotopes);

2. dissolved gases (i.e., H_2), boron concentration, and pH of the reactor coolant. Total gas concentrations of up to approximately 2000 cc/kg at STP can be measured.

The PASS allows post-accident sampling with resulting personnel radiation exposure not exceeding 3 and 18 3/4 Rem to the whole body and extremities, respectively.

The PASS is capable of accommodating an initial reactor coolant radiochemistry spectrum corresponding to Regulatory Guide 1.4, Rev. 2 or 1.3, Rev. 1.

During accident conditions all sample flow is returned to the containment to preclude unnecessary contamination of other auxiliary systems and to ensure that high level waste remains isolated within the containment.

Outside of the containment isolation valves and safety injection system isolation valve to the sampling system, components and piping were designed to Safety Class 4, non-seismic requirements. This complies with NUREG-0578 for equipment downstream of the second isolation valve from safety coded systems.

The PASS consists of piping, tubing, valves, components, and instrumentation mounted in a sample station with an accompanying control panel. This equipment enables remote analysis of the reactor coolant chemistry and remote collection and dilution of the reactor coolant and containment atmosphere samples for subsequent radiological analysis using existing equipment. System components are all non-IE, non-seismic, non-code. System parameters are given in Table 9.3.2-3. The system is divided into two basic sections described below:

1. Reactor Coolant Sampling. The system permits the operator to remotely purge the reactor coolant hot leg samples through in-line instruments for the measurement of boron and pH. The sample purge flow is returned to the pressurizer relief tank or containment, thereby precluding a buildup of highly contaminated fluid outside the containment. A sample of the pressurized

reactor coolant is collected, and degassed via depressurization and circulation. When degassing of the sample is completed, burette level is recorded for total gas concentration determination and the gas is circulated through in-line instruments to determine hydrogen concentrations. The gas is then diluted with nitrogen so that the existing radioanalysis equipment can be used to quantify the radioisotopes in the gas sample. A volume of degassed liquid sample is likewise diluted with demineralized water so that existing radioanalysis equipment can be used to determine the radioisotopes within the liquid samples. The system is then purged with nitrogen and demineralized water and placed in standby for the next sample.

2. Containment Air Sampling System. The system permits the operator to remotely purge the containment atmosphere sample using an air pump. A containment atmosphere sample is then isolated and diluted with nitrogen so that the existing radioanalysis equipment can be used to determine the radiological quantification of the gas.

9.3.2.2.2 Component description.

9.3.2.2.2.1 Mechanical components.

1. Sample Station. The sample station is a free standing, totally enclosed metal panel measuring 6 ft (L) x 6 ft (H) x 4 ft (D). The enclosure contains system tubing, valves, components, and instrumentation necessary to provide chemistry and radiochemistry analysis capability for reactor coolant and containment atmosphere sampling per NUREG-0578, Section 2.1.8.a. Louvers are provided in the cabinet to pass airflow from the surrounding room to the ventilation system exhaust connection in the upper portion of the enclosure. This airflow precludes any possible buildup of radioactive gas or H_2 gas and provides for removal of heat generated by internal components. The station is skid-mounted and is provided with removable panels or doors on all four sides to ensure easy accessibility for any necessary maintenance on system components.

2. Components Contained Inside the Sample Station

a. Sample Circulation Pump. The sample circulation pump is a peristaltic type positive displacement pump. This pump is capable of pumping liquids and/or gases. The pump will be used in the total gas and hydrogen gas analyses operations to strip the gases out of solution in the sample fluid and circulate them through the hydrogen analyzer.

b. Surge Vessel Pump. The surge vessel pump is a progressing cavity (helical) positive displacement pump. The pump is used to pump down the surge vessel contents to the Chemical Drain Tank.

c. Containment Sample Pump. The containment sample pump is a vacuum pump/compressor unit that operates as a positive displacement compressor using a stainless steel diaphragm. The pump is used to collect a containment atmosphere sample and to dilute the sample via circulation through the containment sample vessel.

d. Gas Sample Vessel. The gas sample vessel is a 12,000 ml sample vessel initially filled with nitrogen gas. The vessel supplies the gas analysis loop with nitrogen gas to dilute the radioactive gases present in the sample line. The vessel is equipped with a septum plug which allows the operator to withdraw a diluted gaseous sample with a syringe for radiological analysis.

e. Depressurized Liquid Sample Vessel. The depressurized liquid sample vessel is 12,000 ml sample vessel. This vessel collects a 4.7 ml liquid sample trapped in the four-way valve located above the sample vessel. The vessel is partially filled with demineralized water before the sample is drained into the vessel. Additional demineralized water is then added to obtain the proper dilution factor so that a liquid sample can be withdrawn for radiological analysis. This vessel is equipped with a septum plug for sample withdrawal using a syringe.

f. Containment Sample Vessel. The containment sample vessel is a 12,000 ml sample vessel that is initially filled with nitrogen gas for dilution. The containment air pump draws a sample from containment and circulates it through the sample vessel where the nitrogen gas dilutes the sample so that it can be withdrawn for radiological analysis. This vessel is equipped with a septum plug for sample withdrawal.

g. Surge Vessel. The surge vessel has a 10 gallon capacity and serves as a vent and drain tank for the depressurized liquid sample vessel and the total gas analysis burette.

h. Sample Vessel/Heat Exchanger. The sample vessel/heat exchanger is a vertically mounted, shell and tube type heat exchanger. The heat exchanger uses component cooling water to cool the reactor coolant sample flow from a maximum RCS temperature of 650°F to 120°F or below, to allow low temperature sample analysis. The tube side of the heat exchanger serves as a sample vessel for collection of a pressurized reactor coolant sample.

i. Stainless Steel Burette. The stainless steel burette has a 1,000 ml capacity. The burette is used to determine the amount of total gas present in the sample fluid by measuring a difference in the fluid level of the burette upon degassification of the pressurized reactor coolant sample.

3. Components Located Outside Sample Station.

a. Strainer. The strainer is designed to remove insoluble particles which may cause sample station chemistry instrumentation to become plugged. The strainer can be backflushed with demineralized water remotely by operation of valves at the control panel.

9.3.2.2.2.2 Instrument and control description. The system is designed to be controlled remotely from a designated post-accident sample control area. This area will include the control panel and the stem extension handwheels from the system throttling valves. The control panel is a free-standing, straight front, vertical, metal panel measuring 5 ft (L) x 7 ft (H) x 2-1/2 ft (D). The panel is designed to meet NEMA 12 requirements. All sample system non-code isolation valves and pumps are controlled from this panel. Indication of all process parameters and chemistry readouts are displayed on

the panel. To facilitate system operability all controls and indications are arranged in a mimic of the system. The following is a description of the instrumentation and controls for the system.

1. The depressurized liquid sample vessel, surge vessel, and stainless steel burette are equipped with level indication instrumentation to monitor for total gas, dilution, flushing and calibration operations.

2. The sample vessel/heat exchanger tube side outlet is equipped with a temperature measuring device to indicate adequate sample cooling for downstream instrumentation protection.

3. All of the containment atmosphere sample piping is heat traced to limit plateout of radioisotopes which would result from condensation of containment atmosphere vapor.

4. The containment sample pump discharge and liquid sampling lines are equipped with flow measuring devices to monitor proper sample purging flow rate.

5. All PASS pumps are equipped with handswitches at the control panel.

6. The boron meter is a specific gravity measuring device which determines and indicates the amount of boron (ppm) present in the liquid sample fluid.

7. The pH meter determines and indicates pH in the liquid sample fluid.

8. The H_2 analyzer is a thermal conductivity device that determines and indicates the volume percent of H_2 present in the gas removed from the liquid sample.

9. All pneumatically operated valves have hand switches at the control panel.

10. Control switches are provided to automatically isolate the high pressure reactor coolant inlet to prevent system overpressurization.

This page was deleted by Amendment No. 12

9.3.4 CHEMICAL AND VOLUME CONTROL SYSTEM

9.3.4.1 Design Basis

The Chemical and Volume Control System performs the following functions:

a) Adjusts the concentration of chemical neutron absorber for chemical reactivity control

b) Maintains the proper water inventory in the RCS

c) Provides the required seal water flow for the reactor coolant pump shaft seals

d) Processes reactor coolant letdown and charging pump leakage for reuse of boric acid and reactor makeup water

e) Maintains the proper concentration of corrosion inhibiting chemicals in the reactor coolant, and

f) Maintains the reactor coolant and corrosion activities to within design levels.

The system is also used to fill and hydrostatically test the RCS.

During normal operation, this system also has provisions for supplying:

a) Hydrogen to the volume control tank

b) Nitrogen as required for purging the volume control tank, and

c) Hydrazine and lithium hydroxide, as required, via the chemical mixing tank to the charging pumps suction.

All pressure retaining components (or compartments of components) which are exposed to reactor coolant, comply with the following codes:

a) System pressure vessels - ASME Boiler and Pressure Vessel Code, Section III, Class C, including para. N-2113, and

b) System valves, fittings and piping - USAS B31.1, including nuclear code cases.

System component code requirements are described in Section 3.2.

The tube and shell sides on the regenerative heat exchanger and the tube side of the excess letdown heat exchanger are designed as ASME Section III, Class C. This designation was based on: each exchanger is connected to the primary coolant system by lines equal to or less than 3 in., and each is located inside the reactor containment. Analyses show that the accident associated with a three inch line break does not result in clad damage or failure. Additionally, previously contaminated primary coolant, escaping from the primary coolant system during such an accident is confined to the reactor containment building and no public hazard results.

9.3.4.2 System Description

9.3.4.2.1 General Description

The CVCS, shown in Figures 9.3.4-1 through 9.3.4-6, provide a means for injection of control poison in the form of boric acid solution, chemical additions for corrosion control, and reactor coolant cleanup and degasification. This system also adds makeup water to the RCS, reprocesses water letdown from the RCS and charging pump leakage and provides seal water injection to the reactor coolant pump seals. Materials in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

System components whose design pressure and temperature are less than the RCS design limits are provided with overpressure protective devices. System discharges from overpressure protective devices (safety valves) and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions.

During plant operation, reactor coolant flows through the letdown line from a loop cold leg on the discharge side of the pump, and, after processing, is returned to the cold leg of another loop on the discharge side of the pump via a charging line. An alternate charging connection is provided on a loop hot leg. An excess letdown line is also provided for removing coolant from the RCS.

Each of the connections to the RCS has an isolation valve located close to the loop piping. In addition, a check valve is located downstream of each charging line isolation valve. Reactor coolant entering the CVCS flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through a letdown orifice which reduces the coolant pressure. The cooled, low pressure water leaves the reactor containment and enters the Auxiliary Building where it undergoes a second temperature reduction in the tube side of the nonregenerative heat exchanger followed by a second pressure reduction by the low pressure letdown valve. After passing through one of the mixed bed demineralizers, where ionic impurities are removed, coolant flows through the reactor coolant filters and enters the volume control tank through a spray nozzle.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank, which is predominantly hydrogen and water vapor. The hydrogen within this tank is supplied to the reactor coolant for maintaining a low oxygen concentration. Fission gases are periodically removed from the system by venting the volume control tank to the Waste Disposal System.

From the volume control tank the coolant flows to the charging pumps which raise the pressure above that in the RCS. Suction stabilizers/separators and
3 discharge pulsation dampeners are installed in each charging pump's suction and discharge lines to reduce excessive piping vibration from pressure pulses imparted to the system by the positive displacement reciprocating charging pumps. The coolant then enters the containment, passes through the tube side of the regenerative heat exchanger, and is returned to the RCS.

The makeup system also provides concentrated boric acid or primary water to increase or decrease the boric acid concentration in the RCS. To maintain the reactor coolant volume constant, an equal amount of reactor coolant at the existing reactor coolant boric acid concentration is letdown to the holdup tanks. Should the letdown line be out of service during operation, sufficient free volume exists in the pressurizer to accept the amount of boric acid necessary for cold shutdown.

Makeup water to the RCS is provided by the CVCS from the following sources:

a) The primary water storage tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced

b) The boric acid tanks, which supply concentrated boric acid solution when reactor coolant boron concentration is to be increased

c) The refueling water storage tank, which supplies borated water for emergency makeup

d) The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine or pH control chemical are necessary.

The reactor makeup control is operated from the control room by manually preselecting the makeup composition to the charging pump suction header or the volume control tank in order to adjust the reactor coolant boron concentration for reactivity control. Makeup is provided to maintain the desired operating fluid inventory in the RCS. The operator can stop the makeup operation at any time in any operating mode by remotely closing the makeup stop valves. One primary water makeup pump and one boric acid transfer pump are normally operated.

9.3.4.2.2.1 Automatic Makeup. The "automatic makeup" mode of operation of the reactor makeup control provides boric acid solution preset by the operator to match the boron concentration in the RCS. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under normal plant operating conditions, the mode selector switch and makeup stop valves are set in the "Automatic Makeup" position. A preset low level signal from the volume control tank level controller causes the automatic makeup control action to open the makeup stop valve to the charging pump suction, open the concentrated boric acid control valve and the primary water makeup control valve. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high level point, the makeup is stopped; the primary water makeup control valve closes, the concentrated boric acid control valve closes and the makeup stop valve to the charging pump suction closes.

9.3.4.2.2.2 Dilution. The "dilute" mode of operation permits the addition of a preselected quantity of primary water makeup to the RCS at a preselected flow rate. The operator sets the mode selector switch to "dilute," the primary water makeup flow controller to the desired flow rate, and the primary water makeup batch integrator to the desired quantity. When the operator positions the makeup control switch to "start," a primary water pump starts, the primary water addition valve opens, and the makeup addition valve to the volume control tank opens, admitting primary water to the volume control tank. A flow alarm warns the operator if the dilution flow deviates from the selected flow rate by a preset tolerance. Makeup water is added to the volume control tank and then goes to the charging pump suction header. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three way diversion valve, which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of primary water makeup has been added, the batch integrator causes the primary water pump to stop, the primary water addition valve to close, and the makeup addition valve to the volume control tank to close.

9.3.4.2.2.3 Boration. The "borate" mode of operation permits the addition of a preselected quantity of concentrated boric acid solution to the RCS at a preselected flow rate. The operator sets the mode selector switch to "borate," the boric acid flow controller to the desired flow rate, and the boric acid batch integrator to the desired quantity. When the operator positions the makeup control switch to "start," a boric acid transfer pump starts, the boric acid addition valve opens, and the makeup addition valve to the charging pump suction header opens admitting borated water to the charging pump suction. A flow alarm warns the operator if the boration flow deviates from the selected flow rate by a preset tolerance. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution has been added, the batch integrator causes the boric acid transfer pump to stop, the boric acid addition valve to close, and the makeup addition valve to the charging pump suction header to close.

The capability to add boron to the reactor coolant is sufficient so that no limitation is imposed on the rate of cooldown of the reactor upon shutdown. The maximum rates of boration and the equivalent coolant cooldown rates are given in Table 9.3.4-1. One set of values is given for the addition of boric acid from a boric acid tank with one transfer pump and one charging pump operating. The other set assumed the use of refueling water but with two of the three charging pumps operating. The rates are based on full operating temperature and on the end of the core life when the moderator temperature coefficient is most negative.

9.3.4.2.2.4 Alternate Dilution. The alternate dilute mode functions the same as the dilute mode with the exception that the primary makeup water is added to both the volume control tank and to the charging pump suction header simultaneously. The operator sets the mode selector switch to "alternate dilute," the primary water makeup flow controller to the desired flow rate, and the primary water makeup batch integrator to the desired quantity. When the operator positions the makeup control switch to "start," a primary water pump starts, the primary water addition valve opens, the makeup addition valve to the volume control tank opens, and the makeup addition valve to the

charging pump suction header opens. Makeup water is admitted directly to the charging pump suction header in addition to the volume control tank. Alternate dilution provides a more direct path for primary water addition to the RCS and reduces the time delay associated with primary makeup water addition to the volume control tank alone. The alternate dilute mode also provides a means for the operator to flush concentrated boric acid solution from the makeup addition line to the charging pump suction following a boration.

9.3.4.2.2.5 Alarm functions. The reactor makeup control is provided with alarm functions to call the operator's attention to the following conditions:

1. Deviation of primary water makeup flow rate from the control set point

2. Deviation of concentrated boric acid flow rate from the control set point

3. Low level (makeup initiation point) in the volume control tank when the reactor makeup control selector is not set for the automatic makeup control mode.

9.3.4.2.3 Charging pump control. Three positive displacement charging pumps with variable speed drive are used to supply charging flow to the RCS.

The speed of each pump can be controlled manually or automatically. During normal operation, only one of the three pumps is automatically controlled. During normal operation, only one charging pump is operating and the speed is modulated in accordance with pressurizer level. During load changes the pressurizer level set point is varied automatically to compensate partially for the expansion or contraction of the reactor coolant associated with the T_{avg} changes. T_{avg} compensates for power changes by varying the pressurizer level set points in conjunction with pressurizer level for charging pump control. The level set points are varied between 20 and 60 percent of the adjustable range depending on the power level. Charging pump speed does not change rapidly with pressurizer level variations due to the reset action of the pressurizer level controller.

If the pressurizer level increases, the speed of the pump decreases. Likewise if the level decreases, the speed increases. If the charging pump on automatic control reaches the high speed limit, an alarm is actuated and a second charging pump is manually started. The speed of the second pump is manually regulated. If the speed of the charging pump on automatic control does not decrease and the second charging pump is operating at maximum speed, the third charging pump can be started and its speed manually regulated. If the speed of the charging pump on automatic control decreases to its minimum value, an alarm is actuated and the speed of the pumps on manual control is reduced.

9.3.4.2.4 Components. A summary of principal component data is given in Table 9.3.4-2. A description of each component follows:

1. Regenerative Heat Exchanger - The regenerative heat exchanger is designed to recover the heat from the letdown stream by reheating the charging stream during normal operation. This exchanger also limits the temperature rise which occurs at the letdown orifices during periods when letdown flow exceeds charging flow by a greater margin than at normal letdown conditions.

The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is made of austenitic stainless steel, and is of all welded construction. The exchanger is designed to withstand 2000 step changes in shell side fluid temperature from 130°F to 552.2°F during the design life of the unit.

2. Letdown Orifices - One of the three letdown orifices controls flow of the letdown stream during normal operation and reduces the pressure to a value compatible with the nonregenerative heat exchanger design. Two of the letdown orifices are each designed to pass normal letdown flow. These orifices are used in parallel to pass maximum purification flow at normal RCS operating pressure. The remaining orifice is designed to pass three-fourths of the normal letdown flow. Orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. One or both of the standby orifices may be used in parallel with the normally operating orifice in order to increase letdown flow when the RCS pressure is below normal. This arrangement provides a full standby capacity for control of letdown flow. Each orifice consists of bored pipe made of austenitic stainless steel.

3. Nonregenerative (letdown) Heat Exchanger - The nonregenerative heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell. The letdown stream outlet temperature is automatically controlled by a temperature control valve in the component cooling water outlet stream. The unit is a multiple-tube-pass heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

4. Mixed Bed Demineralizers - Two flushable mixed bed demineralizers maintain reactor coolant purity. A lithium-7 cation resin and a hydroxyl form anion resin are initially charged into the demineralizers. Both forms of resin remove fission and corrosion products, and in addition, the reactor coolant causes the anion resin to be converted to the borate form. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium, and molybdenum, by a minimum factor of 10.

Each demineralizer is sized to accommodate the maximum letdown flow. One demineralizer serves as a standby unit for use should the operating demineralizer become exhausted during operation.

The demineralizer vessels are made of austenitic stainless steel, and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity to reduce the activity of the primary coolant to refueling concentration after operation for one core cycle with one percent defective fuel rods.

5. Cation Bed Demineralizer - A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of lithium-7 which builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has

sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 μc/cc with one percent defective fuel. The demineralizer would be used intermittently to control cesium.

The demineralizer is made of austenitic stainless steel and is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with a resin retention screen.

6. <u>Resin Fill Tank</u> - The resin fill tank is used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a dump valve and may be connected to any one of the demineralizer fill lines. The demineralizer water and resin slurry can be sluiced into the demineralizer by opening the dump valve. The tank, designed to hold approximately one-third the resin volume of one mixed bed demineralizer, is made of austenitic stainless steel.

7. <u>Reactor Coolant Filter</u> - The filter collects resin fines and particulates from the letdown stream. The vessel is made of austenitic stainless steel, and is provided with connections for draining and venting. Design flow capacity of the filter is equal to the maximum purification flow rate. Disposable synthetic filter elements are used.

8. <u>Volume Control Tank</u> - The volume control tank collects the excess water released from zero power to full power that is not accommodated by the pressurizer. It also receives the excess coolant release caused by the deadband in the reactor temperature control instrumentation. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant at 25 to 50 cc per kg of water (standard conditions).

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibrate the gas and liquid phases. A remotely operated vent valve discharging to the Waste Disposal System permits removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. The tank is constructed of austenitic stainless steel.

9. <u>Charging Pumps</u> - Three charging pumps inject coolant into the RCS. The pumps are the variable speed positive displacement type, and all parts in contact with the reactor coolant are fabricated of austenitic stainless steel and other materials of adequate corrosion resistance. These pumps have mechanical packing followed by a leakoff to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage may be routed to the drain header for disposal, or it can be routed to the charging pump leakage collection system for processing. The pump design precludes the possibility of lubricating oil contaminating the charging flow, and the integral discharge valves act as check valves.

Each pump is designed to provide the full charging flow and the reactor coolant pump seal water supply during normal seal leakage. Each pump is designed to provide rated flow against a pressure equal to the sum of the RCS maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve and equipment pressure losses of the charging system at the design charging flows.

One of the three charging pumps can be used to hydrotest the RCS. The pumps are normally energized manually from the control room, and flow is automatically controlled by pressurizer level.

10. Charging Pump Leakage Systems - The stuffing box leakage is normally collected in the charging pump leak off drain tank and then pumped to the CVCS holdup tank for reprocessing. Alternately, the stuffing box leakage can be drained to the Auxiliary Building sump tank which is then pumped to the waste holdup tank.

11. Chemical Mixing Tank - The primary use of the chemical mixing tank is in the preparation of caustic solutions for pH control and hydrazine for oxygen scavenging.

The capacity of the chemical mixing tank is determined by the quantity of 35 percent hydrazine solution necessary to increase the concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare the solution of pH control chemical for the RCS.

The chemical mixing tank is made of austenitic stainless steel.

12. Excess Letdown Heat Exchanger - The excess letdown heat exchanger cools reactor coolant letdown flow until the flow rate is equal to the nominal injection rate through the reactor coolant pump labyrinth seal, if letdown through the normal letdown path is blocked.
The unit is designed to reduce the letdown stream temperature from the cold leg temperature to 195°F. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded. The unit is designed to withstand 12,000 step changes in the tube fluid temperature from 80°F to the cold leg temperature.

13. Seal Water Heat Exchanger - The seal water heat exchanger removes heat from the reactor coolant pump seal water returning to the volume control tank and also from the reactor coolant discharged from the excess letdown heat exchanger. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet to prevent leakage in either direction which would result in undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

The unit is designed to cool the excess letdown flow and the seal water flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate.

14. Seal Water Filter - The filter removes particulates from the reactor coolant pump seal water return and from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump seals. The vessel is constructed of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter cartridges are used.

15. Seal Water Injection Filters - Two filters are provided in parallel, each sized for the injection flow. They remove particulates from the water supplied to the reactor coolant pump seal.

16. Boric Acid Filter - The boric acid filter removes particulates from the boric acid solution being pumped to the charging pump suction line. The filter is designed to pass the design flow of two boric acid pumps operating simultaneously. The vessel is constructed of austenitic stainless steel and the filter elements are disposable synthetic cartridges. Provisions are available for venting and draining the filter.

17. Boric Acid Tanks - The boric acid tank capacities are sized to store sufficient boric acid solution for a cold shutdown shortly after initial full power operation is achieved, even if the most reactive RCC is not inserted.

The concentration of boric acid solution in storage is maintained between 11.5 and 12.5 percent by weight. Periodic manual sampling is performed and corrective action is taken, if necessary, to ensure that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the chemical poison concentration. The combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution. The tanks are constructed of austenitic stainless steel.

18. Boric Acid Tank Heaters - Two 100 percent capacity electric immersion heaters located near the bottom of each boric acid tank are designed to maintain the temperature of the boric acid solution at 165°F with an ambient air temperature of 40°F thus ensuring a temperature in excess of the solubility limit (for 20,000 ppm boron this is 130°F). The temperature is monitored and low temperature is alarmed in the control room. The heaters are sheathed in austenitic stainless steel.

19. Batching Tank - The batching tank is sized to hold one week's makeup supply of boric acid solution for the boric acid tank. The basis for makeup is reactor coolant leakage of 1/2 gpm at beginning of core life. The tank may also be used for solution storage. A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid tank or for draining the tank.

The tank manway is provided with a removable screen to prevent entry of foreign particles. In addition, the tank is provided with an agitator to improve mixing during batching operations. The tank is constructed of austenitic stainless steel, and is not used to handle radioactive substances. The tank is provided with a steam jacket for heating the boric acid solution to 165°F.

20. Boric Acid Transfer Pumps - Two 100 percent capacity canned centrifugal pumps are used to circulate or transfer chemical solutions. The pumps circulate boric acid solution through the boric acid tanks and inject boric acid into the charging pump suction header.

Although one pump is normally used for boric acid batching and transfer, and the other for boric acid injection, either pump may function as standby for the other. The design capacity of each pump is equal to the normal letdown flow rate. The design head is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value (relief valve setting). All parts in contact with the solutions are austenitic stainless steel and other adequately corrosion-resistant material.

The transfer pumps are operated either automatically or manually from the main control room or from a local control point. The reactor makeup control operates one of the pumps automatically when boric acid solution is required for makeup or boration.

21. Boric Acid Blender - The boric acid blender promotes thorough mixing of boric acid solution and primary water from the primary water supply circuit. The blender consists of a coventional pipe fitted with a perforated

tube insert. All material is austenitic stainless steel. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample.

22. Holdup Tanks - Three holdup tanks contain radioactive liquid which enters the tank from the letdown line. The liquid is released from the RCS during startup, shutdown, load changes and during boron dilution to compensate for burnup. The contents of one tank are normally being processed by the gas stripper and evaporator train while another tank is being filled. The third tank is normally kept empty to provide additional storage capacity when needed.

A CVCS holdup tank can be recirculated through the demineralizers and/or gas strippers. It is thus possible to clean up a tank by recirculation without adding more water.

Each liquid storage tank size is based on 2/3 of the primary system volume. The tanks are constructed of austenitic stainless steel.

23. Holdup Tank Recirculation Pump - The recirculation pump is used to mix the contents of a holdup tank or transfer the contents of one holdup tank to another holdup tank. The wetted surface of this pump is constructed of austenitic stainless steel.

24. Gas Stripper Feed Pumps - The two gas stripper feed pumps supply feed to the demineralizer/filter processing trains from a holdup tank. The nonoperating pump is a standby and is available for operation in the event the operating pump malfunctions. These canned centrifugal pumps are constructed of austenitic stainless steel.

25. Base and Cation Ion Exchangers - Three flushable base and cation and activation products ion exchangers remove anions and cations (primarily cesium, molybdenum and activation products) from the holdup tank effluent. The mixed bed resin is initially in the HOH form. The demineralizer vessel is constructed of austenitic stainless steel and contains a resin retention screen.

26. Ion Exchanger Filters - These filters collect resin fines and particulates from the cation ion exchanger. The vessels are made of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter cartridges are used.

27. Gas Stripper Equipment - NOT USED.

Two gas strippers are provided. Each removes nitrogen, hydrogen, and fission gases from the holdup tank effluent. The gas stripper consists of a preheater, stripping column with a reflux condenser and associated pumps, piping, and instrumentation.

The gas stripper preheater, located upstream of the gas stripper, is a regenerative type shell and tube heat exchanger constructed of austenitic stainless steel. It heats the liquid effluent from the holdup tanks from ambient temperature to approximately 205°F using the gas stripper bottoms as the heat source. The bottoms are cooled in the preheater from approximately 220°F to 120°F.

The gas strippers consist of a hot well with a heating coil to store stripped water, a stripping section packed with pall rings, a spray type liquid inlet header and an overhead integral reflux condenser. Liquid flowing to the gas strippers is controlled to constant rate by a flow controller. The gas strippers are designed for the same flow rate as the evaporator and are designed to reduce the influent gas concentration by a factor of 10^5.

Two gas stripper bottom pumps are provided for gas stripper. Operated from level control, they transfer effluent from the gas stripper hot wells to the boric acid evaporator via the gas stripper preheaters. Each centrifugal pump is rated at the evaporator processing rate. The pumps are austenitic stainless steel and one is an installed standby for the operating pump.

28. Boric Acid Evaporator Equipment - NOT USED.

Two boric acid evaporators concentrate boric acid for reuse in the RCS. Borated water enters the evaporator and the liquid is concentrated to approximately 12 weight percent boric acid. Vapors leave the evaporator and are condensed. The solids decontamination factor between the condensate and the bottoms is approximately 10^6. All evaporator equipment is constructed of austenitic stainless steel and is supplied as a unit. The boric acid evaporator equipment consists of the boric acid evaporator feed tank, two boric acid evaporator concentrates pumps, boric acid evaporator, boric acid evaporator condenser, two boric acid evaporator condensate pumps, boric acid evaporator condensate cooler, vacuum pumps and associated piping and instrumentation.

The boric acid evaporator feed tank has sufficient capacity to hold one day's production of 12 percent boric acid solution produced from refueling concentration feed. The evaporator and condenser heat transfer area is sufficient to maintain the required feed rate. The evaporator is steam heated. Component cooling water flows through the tube of the condenser.

The boric acid distillate cooler reduces the temperature of the condensate to approximately 100°F. The condensate flows through the tubes and component cooling water through the shell.

The boric acid evaporator can be tied into the waste disposal system so that the evaporators can be used to process liquid wastes. For a fuller discussion see Section 9.3.4.3.

29. Evaporator Condensate Demineralizers - Two mixed bed demineralizers remove fission and activation products contained in the holdup tanks. The exhausted resin is flushed to the spent resin storage tank.

30. Condensate Filters - Two filters remove resin fines and particulates from the evaporator condensate process stream. Each vessel is made of austenitic stainless steel, and is provided with a connection for draining and venting. Disposable synthetic filter elements are used.

31. Monitor Tanks - Two monitor tanks permit storage of processed liquids. When one tank is filled, the contents are analyzed and either reprocessed, discharged to the Waste Disposal System, or pumped to the primary water storage tank. These tanks contain a diaphragm membrane and are constructed of stainless steel.

32. Monitor Tank Pumps - Two monitor tank pumps discharge water from the monitor tanks. The pumps are sized to empty a monitor tank in 2.0 hr. The pumps are constructed of austenitic stainless steel.

33. Primary Water Storage Tank - The primary water storage tank is used to store makeup water which is supplied from the monitor tanks and the water treatment plant. Makeup water from the tank discharges to the suction of the primary water makeup pumps. The tank contains a diaphragm membrane and is made of stainless steel.

34. Primary Water Makeup Pumps - Two primary water makeup pumps take suction from either the monitor tanks or the primary water storage tank. These pumps are used to feed dilution water to the boric acid blender and are also used to supply makeup water for intermittent flushing of equipment and piping. The primary water pumps are operated either automatically or manually from the main control room. The reactor makeup control operates one of the pumps automatically when primary makeup water is required.

Each pump is sized to match the maximum letdown flow. One pump serves as a standby for the other. These centrifugal pumps are constructed of austenitic stainless steel.

35. Concentrates Filter - NOT USED.

A disposable synthetic cartridge type filter removes particulates from the evaporator concentrates. Design flow capacity of the filter is equal to the boric acid evaporator concentrates transfer pump capacity. The vessel is made of austenitic stainless steel.

36. Concentrates Holding Tank - NOT USED.

The concentrates holding tank is sized to hold the production of concentrates from one batch of evaporator operation. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless steel.

37. Concentrates Holding Tank Transfer Pumps - NOT USED.

Two holding tank transfer pumps discharge boric acid solution from the concentrates holding tank to the boric acid tanks. The canned centrifugal pumps are sized to empty the concentrates holding tank in 20 minutes. The wetted surfaces are constructed of austenitic stainless steel and other adequately corrosion-resistant material.

38. Deborating Demineralizers - When required, two anion demineralizers remove boric acid from the RCS fluid. The demineralizers are provided for use near the end of a core cycle, but can be used at any time. Hydroxyl based ion-exchange resin is used to reduce RCS boron concentration by releasing a hydroxyl ion when a borate ion is absorbed. Facilities are provided for regeneration. When regeneration is no longer feasible, the resin is flushed to the spent resin storage tank.

Each demineralizer is sized to remove the quantity of boric acid that must be removed from the RCS to maintain full power operation near the end of core life without the use of the holdup tanks or evaporators.

39. Electrical Heat Tracing - Electrical heat tracing is installed under the insulation on all piping, valves, line-mounted instrumentation, and components normally containing concentrated boric acid solution. The heat tracing is designed to prevent boric acid precipitation due to cooling, by compensating for heat loss.

Exceptions are:

a. Lines which may transport concentrated boric acid but are subsequently flushed with reactor coolant or other liquid of low boric acid concentration during normal operation

b. The boric acid tanks, which are provided with immersion heaters

c. The batching tank, which is provided with a steam jacket, and

d. The concentrates holding tank, which is provided with an immersion heater.

Duplicate tracing on sections of the CVCS normally containing boric acid solution provides standby capacity if the operating tracing malfunctions.

Lines which are provided with heat tracing are shown on Figures 9.3.4-2 and 9.3.4-3.

40. Valves - Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System or have had packing live loaded and leakoff lines capped. All other valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. The basic material of construction is stainless steel for all valves except the batching tank steam jacket valves which are carbon steel.

Isolation valves are provided at all connections to the RCS. Lines entering the reactor containment also have check valves inside the containment to prevent reverse flow from the containment.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by the auxiliary spray line isolation valve which is designed to open when pressure under the seat exceeds reactor coolant pressure by 250 psi. Relief valve settings and capacities are given in Table 9.3.4-2.

41. Piping - All CVCS piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Socket welded unions may be installed in valve packing leak off lines to facilitate removal of the valve. Piping, valves, equipment and line-mounted instrumentation, which normally contain concentrated boric solution, are heated by duplicate electrical tracing to ensure solubility of the boric acid.

42. Suction Stabilizers/Separators - The suction stabilizers are flow through type, vapor dome vessels, in-line mounted. The vapor space created by an electric heater provides the capacitance effect to dampen upstream pressure pulsation and promotes the release of entrained gas.

43. Discharge Pulsation Dampeners - The discharge pulsation dampeners are in-line, spherical vessels with stationary internals that impart a rotating path to the incoming flow within the sphere. The spinning fluid motion dampens charging pump pulsations.

9.3.4.3 Safety Evaluation.

9.3.4.3.1 Availability and reliability. A high degree of functional reliability is assured in this system by providing standby components where performance is vital to safety and by assuring fail-safe response to the most probable mode of failure. Special provisions include duplicate heat tracing with alarm protection of lines, valves, and components normally containing concentrated boric acid.

The system has three high pressure charging pumps, each capable of supplying the normal reactor coolant pump seal and makeup flow.

The electrical equipment of the CVCS is arranged so that multiple items receive their power from various 480 volt buses (see Section 8.3). The three charging pumps are powered from separate 480 volt buses. The two boric acid transfer pumps are also powered from separate 480 volt buses. One charging pump and one boric acid transfer pump are capable of meeting cold shutdown requirements shortly after full-power operation. In cases of loss of AC power, a charging pump and a boric acid transfer pump can be placed on the emergency diesels if necessary.

9.3.4.3.2 Leakage prevention. Quality control of the material and the installation of the Chemical and Volume Control valves and pipings, which are designated for radioactive service, was provided in order to minimize leakage to the atmosphere. The components designated for radioactive service are provided with welded connections to prevent leakage to the atmosphere. However, flanged connections are provided in each charging pumps suction and discharge, on each boric acid pump suction and discharge, on the relief valves inlet and outlet, on three-way valves, and on the flow meters to permit removal for maintenance. Socket welded unions may be installed on valve packing leak off lines to permit removal for maintenance (REF EE90-039).

The positive displacement charging pumps stuffing boxes are provided with leakoffs to collect reactor coolant before it can leak to the atmosphere. With the exception of valves which have been live loaded and had leakoff lines capped, valves which are larger than 2 in. and which are designated for radioactive service at an operating fluid temperature above 212°F are provided with a stuffing box and lantern leakoff connections. Leakage to the atmosphere is essentially zero for these valves. Except for the two letdown stop valves (LCV-460A&B), all control valves are either provided with stuffing box and leakoff connections or are totally enclosed. Leakage to the atmosphere is essentially zero for these valves. Leakage from the letdown stop valves is addressed in 5.2.5.3.3.1

Diaphragm valves are provided where the operating pressure and the operating temperature permit the use of these valves. Leakage to the atmosphere is essentially zero for these valves.

9.3.4.3.3 Incident control. The letdown line and the reactor coolant pumps seal water return line penetrate the reactor containment. The letdown line contains three air-operated valves inside the reactor containment and two air-operated containment isolation valves outside the reactor containment which are automatically closed by the containment isolation signal.

The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the reactor containment which is automatically closed by the containment isolation signal.

The three seal water injection lines to the reactor coolant pumps and the charging line are inflow lines penetrating the reactor containment. Each line contains two check valves inside the reactor containment; however, the redundant containment isolation valves are located outside the reactor containment.

9.3.4.3.4 Malfunction analysis. To evaluate system safety, failure or malfunctions were assumed concurrent with an LOCA and the consequences analyzed and presented in Table 9.3.4-3. As a result of this evaluation, it was concluded that proper consideration has been given to plant safety in the design of the system.

If a rupture were to take place between the reactor coolant loop and the first isolation valve or check valve, this incident would lead to an uncontrolled loss of reactor coolant. The analysis of an LOCA is discussed in Chapter 15.

Should a rupture occur in the CVCS outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve would limit the release of coolant and assure continued functioning of the normal means of heat dissipation from the core. For the general case of rupture outside the containment, the largest source of radioactive fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Chapter 15.

When the reactor is subcritical; i.e., during cold or hot shutdown, refueling and approach to criticality, the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by BF_3 counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution

rate is slow enough to give ample time to start corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical. The maximum dilution rate is based on the abnormal condition of two charging pumps operating at full speed delivering unborated primary water to the RCS at a particular time during refueling when the boron concentration is at the maximum value and the water volume in the system is at a minimum.

At least two separate and independent flow paths are available for reactor coolant boration; i.e., the charging line, or the reactor coolant pumps labyrinths. The malfunction or failure of one component will not result in the inability to borate the RCS. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system the operator can align the refueling water storage tank outlet to the suction of the charging pumps.

Boration during normal operation to compensate for power changes will be indicated to the operator from the control rod movement and the flow indicators in the boric acid transfer pump discharge line. When the emergency boration path is used, three indications to the operator are available. The primary indication is a flow indicator in the emergency boration line. The charging line flow indicator will indicate boric acid flow since the charging pump suction is aligned to the boric acid transfer pump suction for this mode of operation. The change in boric acid tank level is another indication of boric acid injection.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually starting a standby charging pump. Even if the seal water injection flow is not reestablished, the plant can be operated indefinitely since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow which would pass through the thermal barrier cooler and seal leakoff from the pump volute.

9.3.4.3.5 Galvanic corrosion. The only types of materials which are in contact with each other in borated water are stainless steels, nickel-chrome-boron and Stellite hard-surfacing materials, Inconel, and Zircaloy fuel element cladding. These materials have been shown to exhibit only an insignificant degree of galvanic corrosion when coupled to each other (Reference 9.3.4-1).

For example, the galvanic corrosion of Inconel versus 304 Stainless Steel resulting from high temperature tests (575°F) in lithiated boric acid solution as found to be less than -20.9 mg/dm^2 for the test period of nine days. Further galvanic corrosion would be trivial since the cell currents at the conclusion of the tests were approaching polarization. Zircaloy versus 304 Stainless Steel was shown to polarize at 180°F in lithiated boric acid solution in less than eight days with a total galvanic attack of -3.0 mg/dm^2. Stellite versus 304 Stainless Steel was polarized in seven days at 575°F in lithiated boric acid solution. The total galvanic corrosion for this couple was -0.97 mg/dm^2.

As can be seen from the tests, the effects of galvanic corrosion are insignificant to systems containing borated water.

9.3.4.3.6 Use of the Boric Acid Evaporators for Liquid Waste Processing

Provisions have been made to avoid contamination of the boric acid storage tanks with concentated waste through the use of physical disconnections in the piping. Storage of concentrated waste in the existing concentrates holding tank presents no problems since the Auxiliary Building floor drains can contain any spillage that could occur. Also the location of the tank is such that increased personnel exposure does not occur with the use of current health physics procedures. All automatic level control valves were selected to fail closed in the event of loss of power or instrument air thus preventing overflow of the evaporators. The pump discharge/recirculation pressure control valve fails open to prevent dead heading the pump and excessive pressure in the lines. Redundant heat tracing also protects the system by preventing freeze up of the waste in pipes.

9.3.4.4 Testing and Inspection Requirements

No special testing inspection is required since this system is activated during normal plant operation.

9.3.4.5 Instrumentation Requirements

Controls for the following CVCS functions are on the RTGB:

a) Volume control tank level

b) Automatic makeup

c) Dilute

d) Alternate dilute

e) Borate

f) Makeup stop

g) Emergency makeup

h) Charging pump control

i) Boric acid tank heaters

j) Batch tank temperature control

The following also have local controls in the event that the control room is inaccessible:

a) Boric acid transfer pump

b) Charging pumps

c) Charging pump speed control

d) Letdown orifice isolation valves

TABLE 9.3.4-1

CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE REQUIREMENTS

Plant design life, years	40
Seal water supply flow rate, gpm*	24
Seal water return flow rate, gpm	9
Normal letdown flow rate, gpm	60
Maximum letdown flow rate, gpm	120
Normal charging pump flow (one pump), gpm	69
Normal charging line flow, gpm	45
Maximum rate of boration with one transfer and one charging pump, ppm/min, (from initial RCS concentration of 1800 ppm)	23.8
Equivalent cooldown rate to above rate of boration, °F/min	6.8
Maximum rate of boron dilution (two charging pumps) ppm/hr (from initial RCS concentration of 2500 ppm)	350
Two-pump rate of boration, using refueling water, ppm/min (from initial RCS concentration of 10 ppm)	6.2
Equivalent cooldown rate to above rate of boration, °F/min	1.7
Temperature of reactor coolant entering system at full power, °F (design)	555.0
Temperature of coolant return to RCS at full power, °F, (design)	493.0
Normal coolant discharge temperature to holdup tanks, °F	127.0
Amount of 12 percent boric acid solution maintained to meet cold shutdown requirements (EOL, 1 percent shutdown margin, xenon free) shortly after full power operation, gallons (including consideration for one stuck rod)	3,080

* Volumetric flow rates in gpm are based on 130°F and 2350 psig.

TABLE 9.3.4-2

PRINCIPAL COMPONENT DATA SUMMARY

	QUANTITY	HEAT TRANSFER Btu/hr	LETDOWN FLOW lb/hr	LETDOWN ΔT °F	DESIGN PRESSURE psig, shell/tube	DESIGN TEMPERATURE °F, shell/tube
Heat Exchangers						
Regenerative	1	8.65×10^6	29,826	265	2485/2735	650/650
Non regenerative	1	14.8×10^6	29,826	163	150/600	250/400
Seal water	1	2.17×10^6	126,756	17	150/150	250/250
Excess letdown	1	4.75×10^6	12,400	360	150/2485	250/650

	QUANTITY	TYPE	CAPACITY EACH gpm	HEAD	DESIGN PRESSURE psig	DESIGN TEMPERATURE °F
Pumps						
Charging	3	Pos. displ.	77	2385 psi	2570	250
Boric acid	2	Canned	60	235 ft	150	250
Holdup tank recirculation	1	Centrifugal	500	100 ft	150	200
Primary water makeup	2	Centrifugal	150	300 ft	150	250
Monitor tank	2	Centrifugal	100	150 ft	150	200
Concentrates holding tank transfer	2	Canned	20	150 ft	75	250
Gas stripper feed	2	Canned	12.5	200 ft	150	200
Gas stripper bottom	2	Canned	12.5	93 ft	75	300

TABLE 9.3.4-2 (Continued)

	QUANTITY	TYPE	VOLUME, EACH	DESIGN PRESSURE psig	DESIGN TEMPERATURE °F
Tanks					
Volume control	1	Vert.	300 ft^3	75 Int/15Ext	250
Boric acid	2	Vert.	7500 gal	0	250
Chemical mixing	1	Vert.	5.0 gal	150	250
Batching	1	Jacket Btm.	400 gal	0	250
Holdup	3	Horizontal	6,500 ft^3	15	200
Primary water storage	1	Diaphragm	150,000 gal	0	125
Concentrates holding	1	Vertical	925 gal	0	250
Monitor	2	Diaphragm	10,000 gal	0	150
Suction Stabilizer/ Separator	3	Vertical	18 gal/2.4 ft^3	150	250
Discharge Pulsation Dampener	3	Spherical	13 gal/1.8 ft^3	2735	250

	QUANTITY	TYPE	RESIN VOLUME ft^3	FLOW gpm	DESIGN PRESSURE psig	DESIGN TEMPERATURE °F
Demineralizers						
Mixed bed	2	Flushable	30	120	200	250
Cation bed	1	Flushable	20	60	200	250
Base and cation ion exchangers	3	Flushable	30	25	150	250
Evaporator condensate	2	Fixed	30	25	200	250
Deborating	2	Fixed	43	120	200	250

TABLE 9.3.4-2 (Continued)

RELIEF VALVES	TAG NO.	RELIEF PRESSURE psig	CAPACITY
Charging pump	CVC-283A, B, C	2735	100 gpm
Holdup tank	CVC-118A, B, C	12	120 gpm
Letdown line (intermediate pressure section)	CVC-203A	500	64 gpm
Letdown line (low	CVC-203B	630	$6.79(10^4)$ lb/hr
pressure section)	CVC-209	200	165 gpm
Seal water return line	CVC-382	150	
Batching tank heating jacket	CVC-322	20	320 lb/hr
Volume control tank	CVC-257	75	170 gpm

FILTERS	QUANTITY	DESIGN TEMPERATURE °F	DESIGN PRESSURE psig
Reactor coolant	1	250	200
Seal water	1	250	200
Boric acid	1	250	200
Seal water injection	2	200	2735
Concentrates	1	250	100
Condensate	2	250	150
Ion exchanger	2	250	200

9.4 Air Conditioning, Heating, Cooling, and Ventilation System

9.4.1 Summary Description

The Air Conditioning (A/C), Heating, Cooling, and Ventilation Systems are designed to accomplish the following performance objectives:

1. Remove the normal heat gain from the outdoors, equipment, lighting, and people

2. Replace the normal heat lost to the outdoors

3. Provide adequate ventilation for access requirements, and

4. Reduce the concentration of airborne radionuclides, nonradioactive particulate matter, and noxious gases.

The overall system is divided into the following component systems: Control Room Air Conditioning, Reactor Containment Building Ventilation, Reactor Auxiliary Building Ventilation, Fuel Handling Building Ventilation, Turbine Building Ventilation, Relay Room No. 2 and Cable Room No. 2 Ventilation, Engineered Safety Features Ventilation, Radwaste Facility Ventilation Building Exhaust, E&RC Building Hood Exhaust, and TSC/EOF Ventiliation.

The systems shown on Figures 9.4.1-1, 9.4.1-2, and 9.4.1-3 are schematically represented to indicate flow paths and equipment arrangements. The basic design is predicated on the criterion of controlling the direction of air flow to ensure that potentially contaminated areas are maintained at negative pressures and the exhaust therefrom is directed to the plant vent for discharge. This criterion further enhances proper operation since the plant vent effluent is continuously monitored, and high level activity can be traced to determine source, promote isolation, and effect a remedy.

All ventilation system actuators are remotely controlled from the Control Room by the operator except where automatic interlocks are involved. All actuators are designed to fail to the position required for post-accident operation upon loss of electric or pneumatic power, except the emergency diesel generator exhaust ventilation actuators which do require electric power but no pneumatic power for alignment to the post-accident position. Instrumentation in the Control Room will provide information to allow proper remote operation of the system. The E&RC Building Hood Exhaust System, Radwaste Facility Ventilation System and the TSC/EOF Ventilation System are locally controlled.

The TSC/EOF Ventilation System is automatically actuated by a radiation monitor or may be manually actuated. If power is lost to the TSC/EOF Building, there is an emergency power source.

9.4.1.1 Design Parameters. The A/C Heating, Cooling, and Ventilation Systems are based on the following design parameters:

1. Outdoor Air Condition

   a. Winter: 10°F dry bulb
   b. Summer: 95°F dry bulb, 78°F wet bulb

2. Indoor Air Temperatures to be Maintained

a.	Reactor Containment Building:	120°F max.
b.	Reactor Auxiliary, Fuel Handling, and Turbine Buildings:	104°F max.
c.	Control Room:	40°F min. 85°F max.,
d.	Cable Room No. 2 and Relay Room No. 2:	80°F

3. Contaminated Exhausts

Exhaust air from the following rooms may, under certain conditions, carry radioactive iodine and/or methyl iodide:

a. Residual heat removal pump room

b. Fuel Handling Building pipe space

c. Reactor Auxiliary Building pipe space

d. Demineralizer corridors

e. Safety injection pump room

f. Residual heat exchanger room

g. E&RC Building Hood Exhaust

h. Radwaste Facility Building Exhaust

The direction of air flow is such that air is always moved from areas of lower radioactive contamination or contamination possibility toward areas of higher radioactive contamination or contamination possibility, without separating the respective supply and exhaust systems.

4. The following systems must remain operable on emergency power following an accident:

a. Auxiliary Building Supply and Exhaust Ventilation System (HVS-1, HVE-2A and 2B, HVE-5A and 5B)

b. Diesel Generator Rooms A and B Supply and Exhaust Ventilation System (HVS-5 and 6, HVE-17 and 18)

c. Control Room Air Conditioning System (HVA-1, Air Handling Unit and HVE-19, Air Cleaning Unit.)

d. Containment Recirculation Coolers (HVH-1,2,3, and 4)

e. Emergency Safeguards Equipment Pump Room Air Coolers (HVA-6A and 6B, 7A and 7B, 8A and 8B)

The single exception to the above is for the HVH-8A and 8B coolers, where one HVH cooler may be inoperable, provided the components in the RHR Pump Room have been evaluated to be operable without the cooler.

Following a Station Blackout (SBO) event (10CFR50.63), the above HVAC equipment is not required or credited to be operable, since the areas containing equipment to cope with an SBO event has been determined to remain within the acceptable temperature range for component operability. The SBO loss-of-ventilation analyses are summarized and documented in SBO Coping Analysis 8S19-P-101.

5. Seismic Requirements

a. Class I seismic requirements:

1) All supply and exhaust systems in Auxiliary Building

2) Containment recirculation cooling system

3) Recirculation cooling system for:

a) Safety injection pumps

b) Auxiliary feedwater pumps

c) Residual heat removal pumps

All other systems installation shall be designed to satisfy Class III seismic requirements.

The seismic design requirements are discussed in Section 3.7.

9.4.1.2 Ventilation Failure Effects. The safety-related electrical equipment is designed to operate and perform its design function within specified safe limits without degradation of performance (accuracy, repeatability, time response) under the expected normal and abnormal ambient conditions associated with its location. The normal ambient design temperature range is plus or minus 10°F for Control Room located equipment. The abnormal ambient condition associated with design of the Control Room located safety equipment is 85°F maximum and 40°F minimum. Safety-related electrical equipment in other than the Control Room, such as the cable spread room, electrical equipment room, and the cable vault, is designed to operate under the worst case environment for which it is required to perform its function. (Reference 9.4.1-1)

Interim operability of equipment required to cope during a Station Blackout (SBO) event has been evaluated against the short-term effects of loss of ventilation by the SBO Coping Analysis, 8S19-P-101, in accordance with the requirements of 10CFR50.63, "Loss of All Alternating Current Power," dated June 21, 1988, and Regulatory Guide 1.155, "Station Blackout," dated August 1988. (Reference 9.4.1-2)

9.4.2 Control Room Air Conditioning System

The Control Room air conditioning system consists of an environmental control system and an air cleanup system to serve the Control Room. Additional details of the Control Room Habitability systems are given in Section 6.4.

9.4.2.1 Design Basis. The Control Room air conditioning system provides heating, ventilation, cooling, filtration, air intake, and exhaust isolation as described in Section 9.4.2.2 during normal operation and a design basis accident.

The Control Room air conditioning system is designed:

1. To maintain the Control Room at a design temperature between 70 and 77 degrees F dry bulb, assuring personnel comfort as well as a suitable environment for continuous operation of controls and instrumentation.

2. To detect the introduction of radioactive material into the Control Room and automatically place the system into the emergency pressurization mode of operation following an SIS signal or high radiation signal. The system removes airborne radioactivity from the Control Room envelope and outside air makeup to the extent that dose to the Control Room operator following a design basis accident does not exceed the limit specified in General Design Criteria 19.

3. To be powered by the redundant emergency buses.

4. To remain operable following any single active component failure or following a failure in a single emergency power supply coincident with loss of offsite power.

5. To meet Seismic Category I requirements for all components of the system designated safety related.

9.4.2.2 System Description. The Control Room air conditioning system is comprised of two parts, an environmental control system and an air cleanup system. The system is nuclear safety related and redundancy is provided for safety-related active components. Passive components and non-nuclear safety-related components of the system are not redundant. An elementary diagram of the air conditioning system is shown on Figure 9.4.1-3.

The environmental control system continually operates during normal and emergency conditions. This system consists of redundant 100% capacity centrifugal fans and gravity dampers arranged in a parallel and a stainless steel housing containing a medium efficiency filter and redundant 100% capacity direct expansion cooling coils. Redundant 100% capacity service water cooled condensing units are provided, one connected by refrigerant piping to each cooling coil. Redundant safety-related equipment and controls are powered from separate safety-related power supplies. A nonsafety-related fan provides exhaust from the Control Room kitchen and toilet areas to the outdoors during normal operation. A nonsafety-related electric duct heater provides heating when required during cold shutdown. The air cleanup system normally operates only during emergency conditions. This system consists of

redundant 100% capacity centrifugal fans and gravity dampers arranged in parallel and a stainless steel housing containing a prefilter, a pre-HEPA, charcoal adsorber, and post-HEPA filter banks.

The Control Room air conditioning system contains a single outside air intake with connecting duct containing redundant air operated control dampers in parallel. The Control Room kitchen and toilet exhaust duct contains redundant air operated control dampers in series. All air operated control dampers are designed to fail to safe positions following loss of instrument air supply or electric power and redundancy is provided for single failure protection.

9.4.2.2.1 System operation. The Control Room air conditioning system is designed to provide three operational modes, normal ventilation, emergency pressurization, and emergency recirculation.

During normal ventilation, one train of the environmental control system is in operation in conjunction with the kitchen and toilet area exhaust fan.

During emergency pressurization, a single train of both the environmental control system and the air cleaning system are in operation. The kitchen and toilet area exhaust fan is shutdown and exhaust dampers closed. A positive pressure is maintained in the Control Room envelope with respect to adjacent areas (with one exception as discussed in Section 6.4.2.3) and the outdoors. An SI signal or a signal from the Control Room radiation monitor will automatically place the system in the emergency pressurization operating mode. The emergency pressurization mode may also be manually selected.

The emergency recirculation mode of operation is activated by first placing the system in the emergency pressurization mode and then closing both outside air intake dampers via their control switches on the RTGB. This mode of operation is not a design basis requirement, but is provided to allow flexibility to isolate the Control Room outside air makeup.

In case of fire within the Control Room fire zone, the Control Room may be evacuated and the plant shutdown from the safe shutdown controls provided in other areas of the plant. Control Room smoke purge is provided by portable smoke purge fans which are stored at another location in the plant. Reference FSAR Sections 7.4 and 9.5.1 Appendix 9.5.1A.

<u>9.4.2.3 Safety Evaluation</u>. Continued operation of the Control Room air conditioning system during both normal and emergency conditions to maintain the Control Room habitable will be assured by the following:

1. Safety-related system components are designed to Seismic Class I requirements. Nonsafety-related system components are seismically supported to Seismic Class I requirements where failure during a seismic event could compromise the operability of safety-related components of the system.

9.4.3 Reactor Containment Building Ventilation System

9.4.3.1 Design Basis. The primary purpose of the Reactor Containment Ventilation System is to reduce personnel exposure to airborne radioactive contaminants and to prevent excessive equipment operating temperatures.

The Reactor Containment Ventilation System does not introduce any outside air to the containment during reactor operation. Except for infrequent releases which may be required due to leakage from the Instrument Air System or Penetration Pressurization System, the system does not exhaust any containment air to the atmosphere during reactor operation. Following a loss-of-coolant accident, the Containment Recirculation Cooling System is used to control the containment atmosphere temperature and pressure.

The ventilating system is designed to accomplish the following:

1. Remove the normal heat lost from all equipment and piping in the reactor containment during plant operation and maintain a temperature of 120°F or less inside the containment, with 95°F cooling water and three-out-of-four fans operating

2. Provide sufficient air circulation and filtering throughout all containment areas to permit safe and continuous access to the reactor containment within two hours after reactor shutdown assuming defects exist in 1 percent of the fuel rods

3. Provide for positive circulation of air across the refueling water surface to enhance personnel access and safety during shutdown

4. Provide for purging of the containment vessel to the plant vent for dispersion to the environment. The release rate maintains the offsite dose to less than the 10CFR20 limits using the methodology of the ODCM

5. Remove heat generated by the control rod drive mechanisms

6. Provide cooling for the reactor vessel and primary concrete shield

7. Reduce the concentration of radioactive iodine and other particulate matter in the containment atmosphere to permissible levels for purging and personnel access

8. Provide for routine containment building pressure and vacuum relief as required during normal power operation, and

9. Provide for depressurization of the containment vessel following an accident. The post-accident design and operating criteria are detailed in Section 6.2.

In order to accomplish these objectives the following systems as shown on Figure 9.4.1-2 are provided:

1. Containment Recirculation Cooling System
2. Control Rod Drive Mechanism Cooling System
3. Reactor Compartment Cooling System
4. Reactor Support Cooling System
5. Refueling Water Surface Purge System
6. Containment Charcoal Auxiliary Filter System
7. Containment Purge System, and
8. Containment Pressure and Vacuum Relief System.

The design characteristics of the equipment required in the containment for cooling, filtration, and heating to handle the normal thermal and air cleaning loads during normal plant operation are presented in Table 9.4.3-1. In certain cases where engineered safety features functions also are served by the equipment, component sizing is determined from the heavier duty specifications associated with the design basis accident (DBA), detailed further in Section 6.2.

9.4.3.2 System Description.

9.4.3.2.1 Containment recirculation cooling system. The Reactor Containment Air Recirculation Cooling System consists of four air handling units located adjacent to the containment wall above the operating deck.

Each air handling unit includes space for roughing filters; water cooling coils; and a motor driven centrifugal non-overloading fan.

Each unit draws air from the containment atmosphere and discharges to a header from where it is distributed through ductwork to the individual areas. In operating units the air is drawn through the open inlet louvers, and cooling coils by the unit fan, which discharges through an open outlet louver to a main distribution header. During reactor operation, the roughing filters are removed to reduce the amount of fibrous material in the containment. During outage conditions where activities in the containment may stir-up dust, the filter pads are installed, as required.

The distribution system is arranged to ensure against short circuiting the air flow back to the unit inlet. Air is never drawn directly into the unit from inside the reactor coolant loop compartments.

The cooling coils of each air handling unit are capable of removing 1.75 x 10^6 Btu/hr during the normal plant operation and 40 x 10^6 Btu/hr at design basis accident conditions when supplied with 750 gpm of cooling water at 95°F. Coils are provided with adequate drain pans to collect the condensate and conduct it to the containment sump.

The Recirculation Cooling units, ductwork, and accessories are designed as
Class I structures, and are designed to possess sufficient margin to withstand
an over-rated condition of 60 psig and 286°F for one hour without loss of 3
operability. No specific criteria for heat removal capability are applied at
the over-rated condition. The equipment is designed to operate at the
post-accident conditions at 42 psig and 264.7°F for three hours, followed by
operation in an air-steam atmosphere at 20 psig, 219°F for an additional 3
21 hr. The equipment design will permit subsequent operation in an air-steam
atmosphere at 5 psig, 152°F for an indefinite period. 3

The fans are designed for single speed operation with a capacity of 85,000 scfm for normal and 65,000 cfm for accident operating conditions. However, since the density of the air steam mixture at the accident conditions is much greater than at normal conditions, fan power requirements at accident conditions are considerably greater than at normal operating conditions. The fan motors are sized for the accident conditions.

The recirculation cooling system is part of the Containment Heat Removal System which is discussed in Section 6.2.

9.4.3.2.2 Control Rod Drive Mechanism Cooling System

Air from the containment atmosphere is drawn downward through a cooling shroud surrounding the control rod drive mechanisms to absorb heat generated by the mechanisms. The system consists of ductwork, a water cooled heat exchanger and two 100 percent capacity exhaust fans. The air is drawn from the lower portion of the cooling shroud, cooled by the heat exchanger, and then discharged by the operating fan to the containment atmosphere.

9.4.3.2.3 Reactor Compartment Cooling and Reactor Support Cooling Systems

In order to remove heat from the reactor vessel and primary concrete shield, and to cool the nuclear instrumentation external to the reactor, a flow of air cooled by the Recirculation Cooling System units is directed upward through the annulus between the surface of the reactor vessel and the primary concrete shield. A portion of this flow is drawn through the reactor supports by the Reactor Support Cooling System and then exhausted to the containment. The remainder is released to the containment through the passages between the primary concrete shield and the vessel flange and hot and cold leg piping.

The Reactor Compartment Cooling System consists of ductwork connected to the Recirculation Cooling Unit distribution header, two 100 percent capacity booster fans, and discharge ductwork.

The Reactor Support Cooling System consists of cooling air passages in the reactor supports, connected to an exhaust ductwork system penetrating the primary concrete shield. One of two 100 percent capacity exhaust fans maintains cooling air flow through this system.

9.4.3.2.4 Refueling Water Surface Purge System

This system consists of air intakes located above the refueling water surface around the refueling canal and reactor cavity, with exhaust ductwork penetrating the refueling canal concrete walls to connect to the purge exhaust system ductwork. During refueling, flow through the purge exhaust ductwork inside containment is throttled by a motor operated damper. Simultaneously, the motor operated damper in the Refueling Water Surface Purge System branch is opened, thus exhausting air from the refueling water surface to the plant vent via the purge exhaust system.

9.4.3.2.5 Containment Charcoal Filter System

This system, which consists of two 5000 cfm fan-filter units, is provided to remove radioactive iodine and particulate activity released to the containment atmosphere via Reactor Coolant System leakage during normal power operation. Each unit consists of ductwork connecting to the recirculation cooling units distribution header, HEPA filters, charcoal filters and an exhaust fan, which discharges between the containment wall and secondary shielding.

During power operation, the containment particulate and radiogas monitor indications will guide operation of either one or both of these units for pre-access cleanup or prior to purging.

9.4.3.2.6 Containment Purge System

The Containment Purge System is designed to exhaust a nominal 35,000 cfm of containment air to the atmosphere. The system capacity is based on a volumetric change in one hour so that an effective purge of the containment within two hours can readily be accomplished. The system functions independently of the Auxiliary Building Exhaust System, and includes both purge supply and purge exhaust sections.

The purge supply system consists of an outdoor air intake complete with motorized damper, prefilters and heating coils, and a supply duct penetrating containment which includes butterfly valves for isolation.

The purge exhaust system includes an exhaust duct penetrating containment which includes butterfly valves for isolation, exhaust ductwork, and two 100 percent capacity purge exhaust fans. The exhaust ductwork is connected to the suction side of the purge exhaust fans which are located in the Auxiliary Building. The Auxiliary Building Exhaust System discharges to the plant vent directly to avoid any interconnection between the two systems.

The supply and exhaust penetrations through the containment are each equipped with quick closing, tight seating, air operated butterfly valves, 150 lb. class inside and 300 lb. class outside containment. The inboard purge supply and exhaust isolation valves are installed so the seal replacement can be performed without removing the valves. This orientation requires that the
5 inboard valves be restricted from exceeding 70° open. This restriction is an anti-rotation measure to assure proper valve closure under dynamic conditions, as well as to limit offsite dose consequences under postulated LOCA conditions. These valves are designed to fail closed on loss of control signal or control air, and are closed during normal plant operation. The

containment purge supply and exhaust isolation valves may be opened during plant operation when needed for safety-reltaed considerations (equipment or personnel) to support plant operations and maintenance activities within the containment vessel. The containment purge valves must be operable and must close within the time limit specified in the IST program in order to limit post LOCA thyroid dose and to limit the increase in peak clad temperature due to reduction in containment internal pressure. The sections of the ducts between the closed butterfly valves are continuously or intermittently pressurized to a pressure slightly higher than containment design pressure by the Penetration Pressurization System. The containment isolation butterfly valves are protected by debris screens located inside containment in the purge.

ductwork, which will ensure that the airborne debris will not prevent their tight closure. 4

Prior to activating the purge system after shutdown, the containment particulate and gas monitor is used to monitor the airborne activity levels inside the containment, as a guide for routine release from the building.

9.4.3.2.7 Containment Pressure and Vacuum Relief System

Normal power operation is conducted with the closed containment building at essentially atmospheric pressure. The Containment Pressure and Vacuum Relief System is provided to control variations in containment pressure with respect to atmospheric pressure. These variations are due to changes in atmospheric pressure and leakage from the Instrument Air and Penetration Pressurization Systems.

This system includes separate 6 in. lines penetrating the containment, each equipped with two quick-closing, tight-seating, 125 psi air operated butterfly valves, one inside and one outside containment. These valves are designed to fail closed on loss of control signal or control air, and are closed during normal plant operation, except as required for pressure control. The sections of these lines between the closed butterfly valves are pressurized to a pressure slightly higher than the containment design pressure by the Penetration Pressurization System. Interlocks prevent admission of pressurization air to the spaces unless the butterfly valves are closed.

The butterfly valves are protected by debris screens, located inside containment and attached to the inboard pressure and vacuum relief valves, which will ensure that airborne debris will not interfere with their tight closure.

The pressure relief line discharges to the plant vent through a HEPA filter and charcoal filters. These filters are provided for removal of particulate and halogen radioactivity from the vented air.

Operation of the pressure and vacuum relief lines is manually controlled by the plant operator. A narrow range pressure transmitter continuously indicates containment pressure in the Control Room. Separate high and low pressure alarms are actuated by this transmitter to alert the operator to overpressure and vacuum conditions. These alarms are tentatively set for actuation at plus and minus 0.3 psig. Vacuum relief can be accomplished without regard to atmospheric conditions. In the event of pressure buildup, the operator will be guided by atmospheric conditions, and by the containment particulate and radiogas monitor in relieving the overpressure.

Manual operation of both these lines is overridden by automatic containment isolation and containment high radioactivity signals.

Post-accident containment venting which uses the containment pressure relief line is discussed in Section 6.2.5.

9.4.3.3 Instrumentation and Control

The following instrumentation is provided for the heat removal systems to provide annunciation and remedial action in case of "loss of fan" or "malfunctioning of dampers":

a) Control Rod Drive Mechanism Cooling System: On/off switch with indicating lights on Reactor Turbine Generator Board for each fan, and one air flow switch in the discharge duct of each fan

b) Reactor Vessel Support Cooling System: On/off switch with indicating lights on RTGB for each fan, and one air flow switch in the suction duct of each fan, and

c) Reactor Compartment Cooling System and out of core Nuclear Instrumentation Cooling System: On/off switch with indicating lights on RTGB for each fan, and one air flow switch in the discharge duct of each fan.

The air flow switches in these systems start the standby fan operation, annunciates "Low Flow", and sounds an alarm on the RTGB in the Control Room.

Loss of cooling air from any one of the four reactor containment fan coolers is annunciated on the Reactor Turbine Generator Board as well. This annunciation is actuated by air flow switches in the discharge duct of each reactor containment fan cooler unit.

9.4.3.4 Safety Evaluation

The control rod drive mechanisms require cooling to keep the coils in these mechanisms from gradually degrading. Above 400°F, the insulation life is shortened. A short in the coil may develop in 10-12 hr. This causes a full length rod to insert by gravity. A short in the power coil of a part length rod would cause it to fail in place. These failure modes are acceptable.

Nuclear Instrumentation System (NIS) operation at elevated temperatures is limited by the field cables to the detectors. The detectors themselves can operate at temperatures in the range of 300°F. The field cable is susceptible to insulation softening above about 175°F; however, this is a gradual process and not a catastrophic event. To provide adequate margin, the temperature specified for the continuous operation of the NIS is 135°F. The detector assemblies can operate at 175°F for eight hours after loss of cooling. Degradation of cable insulation would be apparent by abnormal channel operation and would be verified by insulation resistance (megger) tests.

In the unlikely event that cooling is lost to the reactor vessel supports, the maximum rate of temperature rise is expected to be 15°F/hr which provides the operator with ample time to reestablish cooling.

TABLE 9.4.3-1

PRINCIPAL COMPONENT DATA SUMMARY

SYSTEM	UNITS INSTALLED	UNIT CAPACITY	UNITS REQUIRED FOR NORMAL OPERATION	UNITS REQUIRED FOR *MCA OPERATION
Containment Air Recirculation Cooling Units	4 recirc. unit assemblies		3 recirc. unit assemblies	2 recirc. unit assemblies
** Prefilters - Normal - 56 per recirc. unit	224	1,520 cfm	168	-
Cooling Coils - Normal - 6 per recirc. unit	24	292,000 Btu/hr	18	-
Cooling Coils - MCA - 6 per recirc. unit	24	6,667,000 Btu/hr (minimum)	-	12
Fan - 1 per recirc. unit	4	85,000 cfm normal 65,000 cfm MCA	3	2
Fan Pressure - Normal	-	6.0 in. wc	3	-
Fan Pressure - MCA	-	26.0 in. wc max.	-	-
Fan Motor - 1 per recirc. unit	4	350 HP	3	2
Control Rod Drive Mechanism Cooling				
Cooling Coils	3	544,000 Btu/hr	3	-
Fans	2	35,000 cfm	1	-
Fan Pressure - Normal	-	8.0 in. wc	-	-
Fan Motors	2	60 HP	1	-
Reactor Compartment Cooling				
Fans	2	15,450	1	-
Fan Pressure - Normal	-	3/4 in. wc	-	-
Fan Motors	2	25 HP	1	-
Reactor Support Cooling				
Fans	2	9,000 cfm	1	-
Fan Pressure - Normal	-	7 in. wc	-	-
Fan Motor	2	15 HP	1	-

* MCA - Maximum Credible Accident
** Prefilters are only installed during outage conditions

9.4.4 REACTOR AUXILIARY BUILDING VENTILATION SYSTEM

9.4.4.1 System Description

The Reactor Auxiliary Building Ventilation System is shown on Figure 9.4.1-1.

The air supply unit for the building ventilation system consists of prefilters, steam heating coils, cell type air washer, and a 55,500 cfm capacity centrifugal fan with drive and motor enclosed in a sheet metal casing. The air intake of the unit is connected to dampered outdoor air louvers. The air is discharged from the fan into an air distribution system which supplies air to distribution terminals in the various areas of the building.

Heating steam to coils in the unit is supplied from the Auxiliary Steam System, and condensate is returned to the same system.

Interarea air transfer in the system is accomplished by maintaining a pressure differential between the supply air outlets and exhaust intakes so that the direction of air flow is always from areas of lower contamination to areas of higher contamination.

Air quantities that do not participate in the removal of airborne radioactive contaminants are recirculated under certain conditions.

Part of the air supplied by the air handling unit is collected and returned to the supply air unit during winter by a return air system. This system consists of air intake terminals, ductwork, ductwork auxiliaries, and a 6500 cfm capacity axial-flow fan with drive and motor. In summer this system discharges to the atmosphere through a motor-operated louver.

Two 100 percent capacity exhaust fans each rated at 54,150 cfm are provided to exhaust air from the various areas of the building. Prefilters and HEPA filters are provided on the inlet of the exhaust fans. The discharge from these units is directed to the plant stack.

An exhaust system consisting of two 100 percent capacity axial flow fans rated at 5750 cfm each, HEPA filters, activated carbon absorbers, and motor-operated dampers is provided to exhaust air from potentially contaminated areas. During normal plant operation, this system is not operating. On a high radiation signal, the unit is manually started, thus closing the bypass damper and opening the filter damper. The discharge of this system is connected to the intake of the main exhaust units.

Fresh air is drawn into the battery room through two 8" diameter holes in the outside (east) wall near the floor, the rate of flow being governed by two 308 cfm centrifugal, motor-driven exhaust fans. The battery room ambient temperature is regulated by two 1500 cfm cooling units and two (100% capacity) 30 KW unit heaters which operate on signal from a common temperature controller located inside the battery room. 6

A separate ventilation system has been provided for the waste evaporator enclosure on the roof of the Auxiliary Building. This system consists of a motor-operated outdoor air supply louver, filters, a supply fan rated at 2,750 cfm, an air distribution system, and an exhaust fan rated at 2,900 cfm. The exhaust fan discharges to the intake of the main exhaust units.

The ventilation system for the diesel generator rooms is provided by separate air supply and exhaust systems for each room. The air supply unit consists of 36,000 cfm centrifugal fan, a motor-operated inlet air louver, and the necessary ductwork to direct the air to the room. During winter operations a bypass damper is opened to allow 18,000 cfm air to be returned from the room to the inlet of the supply fan.

The exhaust system consists of a 36,000 cfm propeller fan and motorized outdoor louver. During summer operations, the full capacity of the fan is discharged to the atmosphere. During winter operations the fan discharges 18,000 cfm to the atmosphere. When starting either or both diesel generators, the supply and exhaust systems will start automatically.

During normal operations with the diesel generators not operating, ventilation to the rooms is supplied from the Auxiliary Building supply and exhaust system.

9.4.5 FUEL HANDLING BUILDING VENTILATION SYSTEM

9.4.5.1 System Description

Ventilation and cooling of the various areas in the Fuel Handling Building are accomplished with a continuous supply of treated outdoor air from two supply air units to various areas within the building, interarea air transfer from areas of lower contamination to areas of higher contamination, and three independent air exhaust systems as shown on Figure 9.4.1-2.

The air supply system consists of two air handling units: HVS-2 and HVS-4. Each air handling unit consists of prefilters, steam heating coils, a centrifugal fan with drive and motor, and enclosed by a sheet metal casing. The air intake of these units is connected to dampered outdoor air louvers, and the supply air is discharged into an air distribution system. The interarea air transfer is accomplished by maintaining a pressure differential between supply air outlets and exhaust intakes, so that the direction of air flow is always from areas of lower contamination to areas of higher contamination.

The air exhaust system consists of three separate air collecting systems which contain air intake terminals, ductwork and ductwork auxiliaries, and three air exhaust units, HVE-14, HVE-15, and HVE-15A. Each air exhaust unit contains prefilters, HEPA filters, centrifugal fans with drive and motor, and is enclosed by a sheet metal enclosure. HVE-15A also includes an electric duct heater and charcoal filters. The discharge of HVE-14 is connected to dampered outdoor air louvers.

The discharge of HVE-15 and 15A (only one can be run at a time) is directed to the plant stack. The systems are augmented by two exhaust systems which discharge directly to outdoors. Each system consists of a 2600 cfm capacity propeller fan with drive and motor and motorized outdoor air louver. When fuel movement is taking place in the spent fuel pit, exhaust air fan HVE-15A must be in operation.

9.4.6 Turbine Building Ventilation System

9.4.6.1 System Description. The Turbine Building Ventilation System furnishes air conditioned and filtered air to the enclosed utility spaces under the turbine concrete pedestal including the RCA Access Facility which is located in the Turbine Building. Basically, two separate recirculation paths are provided, one handling air from the potentially radioactive area, and the other from the non-radioactive area. The potentially radioactive area has an exhaust to the Auxiliary Reactor Building (RAB) exhaust system which processes air through roughing and absolute filters to remove particulate matter before discharge.

Ventilation, cooling, and air conditioning of the various enclosed areas in the Turbine Building are accomplished with a continuous air flow from areas of lower contamination to areas of higher contamination as shown on Figure 9.4.1-1.

The air recirculation system consists of treated air from the HVA-3 and HP-1 air conditioning system, a conditioned air supply system.

The exhaust air from the AO's office is processed by the Reactor Auxiliary Building exhaust system.

9.4.7 RELAY ROOM NO. 2 AND CABLE ROOM NO. 2 VENTILATION SYSTEM

9.4.7.1 System Description

Air conditioning of Relay Room No. 2 and Cable Room No. 2 is accomplished with a continuous supply of conditioned partly-outdoor-partly-recirculated air, and interarea air transfer as shown on Figure 9.4.1-1.

The air supply system consists of an air conditioning unit with prefilters, cooling coils, steam heating coils, centrifugal fan with drive and motor, and sheet metal casing, electrical duct heater, and an air distribution system.

The air recirculation system consists of air intake terminals, ductwork and ductwork auxiliaries, and dampered outdoor air intake and is connected to the air conditioning unit intake.

9.4.8 Engineered Safety Features Ventilation System

9.4.8.1 System Description. Separate redundant room chillers are located in all rooms containing engineered safeguards pump motors. These rooms contain low head and high head safety injection pumps, containment spray pumps, and auxiliary feedwater pumps. When starting any pump in these areas, the room chiller unit in that area will start automatically. These chiller units are automatically sequenced on the emergency diesel power supply in the event of loss of electrical power.

9.5 OTHER AUXILIARY SYSTEMS

9.5.1 FIRE PROTECTION SYSTEM

9.5.1.1 Introduction

The fire protection program at H. B. Robinson, Unit 2 (HBR2), is based on Nuclear Regulatory Commission (NRC) criteria, National Fire Protection Association (NFPA) standards, Institute of Electrical and Electronic Engineers (IEEE) standards, and other industry codes. The program complies with the intent of Appendix A of Branch Technical Position (BTP) APCSB 9.5-1, dated August 23, 1976. Details of the site-specific HBR2 fire hazards analysis and program description are provided in Appendices 9.5.1A and 9.5.1B.

CP&L has evaluated HBR2 against Title 10 to the Code of Federal Regulations, Section 50 (10CFR50), Appendix R, including clarification letters. Since HBR2 was licensed prior to January 1, 1979, and since HBR2 complies with the intent of Appendix A to BTP APCSB 9.5-1, 10CFR50.48 requires that HBR2 be evaluated only against Appendix R, provisions III.G, III.J, and III.0. Exemptions to Appendix R granted to HBR2 may be found in the HBR2 Fire Hazards Analysis Appendix 9.5.1A. CP&L committed to an administrative program meeting the requirements of 10CFR50 Appendix R, Section III.I.3 for Fire Brigade Training-Drills and Section III.K for Administrative Control of combustibles in a letter dated November 6, 1980. The NRC concluded that these commitments were accetable in their letter dated December 8, 1980.

The objective of the fire protection program is to minimize both the probability and consequences of postulated fires. The probability and consequences of fires are minimized by a combination of design features, procedural controls, and personnel training, including a well trained fire brigade. Design control and procedural controls are discussed in general terms in this document. Plant design features are described in detail in the plant Fire Hazard Analysis (FHA). The plant fire brigade is discussed in detail in plant documents.

This section of the updated FSAR summarizes the plant fire prevention features and fire protection system. The FHA evaluates the effectiveness of the overall program.

9.5.1.2 Design Basis

The HBR2 fire protection program was developed using the principles of defense in depth. Specifically, the program is designed to 1) minimize the incidence of fire; 2) detect, control, and extinguish those fires that may occur in order to limit their impact; and 3) ensure maintenance of safety functions in the event of failure of the first and second echelons by design features such as spatial and physical separation of redundant safe shutdown functions. The incidence of fire is minimized by controlling the heat/energy sources, controlling the transfer of this energy, and controlling the availability of fuel and its likelihood of ignition. The impact of fire is controlled by limiting the combustion process through combustible material control, detecting and suppressing fires that may occur, and preventing fire spread through construction features. Safe shutdown functions are preserved by limiting the exposure through spatial separation and by protection in place using design and/or construction features.

9.5.1.3 Fire Prevention Program

9.5.1.3.1 General. The fire protection program at HBR2 consists of design features, equipment, personnel, and procedures which combine to provide for a multitiered safeguard against a fire which could impact the health and safety of the public.

9.5.1.3.2 Program control. Amendment 142 to H. B. Robinson Operating License DPR-23, Technical Specifications deleted Fire Protection requirements. The program is implemented by administrative procedures FP-012 and FP-013 to control minimum Fire Protection equipment and surveillance testing.

The effective implementation of the HBR2 fire protection program depends to a large degree on the stipulation that activities which significantly impact fire safety will be performed in accordance with established procedural controls. These controls consist of two types, those which control specific work activities (e.g., surveillance test of a diesel fire pump) and those which are administrative or programmatic in nature (e.g., a welding permit system). A discussion of the controls follows:

1. Housekeeping - Proper housekeeping is considered essential to the operation of the Robinson plant since it can directly affect the safety and health of all personnel. From a fire protection standpoint, good housekeeping helps to limit the quantity of combustible material that could be ignited and the consequences of fires that may occur.

2. Combustible Hazards and Ignition Sources - The probability of the occurrence of fires at Robinson is minimized through the control of combustible materials and sources of ignition. The Plant Operating Manual contains written instructions regarding the storage and use of combustible materials; the use of welding, burning, and other open flame operations; and routine fire inspections of plant areas.

Welding, flame cutting, grinding, and other operations which constitute a source of ignition are controlled by a permit system. This permit system is in accordance with the general guidelines specified in NFPA 51B, Cutting and Welding Processes. A multilevel structure of responsibility ensures that carelessness or omission of any step in the system does not compromise fire safety.

Control of combustible material is achieved by providing guidelines regarding the storage and use of flammable and combustible liquids, gases, and solids. Specific guidelines for the control of flammable and combustible liquids generally follow the recommendations of NFPA 30, Flammable and Combustible Liquids Code. Similarly, guidelines for the control of flammable gases generally meet the intent of NFPA recommendations.

Periodic inspections of plant areas are performed and documented in accordance with established procedures.

3. Control of Maintenance and In-Plant Work Activities - A program of preventive maintenance has been established for appropriate fire protection items. These preventive maintenance requirements are met by either the preventive maintenance program or by the periodic testing activities.

The preventive maintenance program and surveillance activities are performed in accordance with procedures in the Plant Operating Manual.

Corrective maintenance is controlled by procedures which specify the reviews needed to evaluate Fire Protection's involvement. Maintenance work forms involving fire protection items are coordinated with the fire protection group.

4. Plant Modification and Design Change Review - Plant modifications and design changes are controlled in order to ensure that plant structures, systems, and components continue to meet their performance/functional objectives. The Plant Operating Manual includes written instructions that describe the modification process and the means for documenting the required changes and activities. As a part of this process, each engineer responsible for the plant modification is required to consider the effects of the modification on the fire protection program. When determined that fire protection is affected, the modification package receives a fire protection review in accordance with plant procecures.

Specifically, the fire protection review considers the type and quantity of combustibles introduced (both permanent and temporary) and any degradation of any fire protection features to determine if (1) additional fire suppression capability is required, (2) if a limiting condition of operation for a fire protection system is involved, and/or (3) if special administrative controls are necessary.

5. Fire Protection List - Fire Protection List components are those which must perform their intended function when required or the loss of safety-related and safe shutdown equipment may result during a postulated fire. The Fire Protection List components usually demand special ordering, material handling, installation, and/or testing requirements.

The Fire Protection List outlines boundaries to fire protection systems within which all Fire Protection List components are contained and is maintained as part of the Plant Operating Manual.

6. Procurement Activities - Written instructions concerning the procurement and storage requirements for safety- and nonsafety-related items are contained in approved procedures. These instructions provide for differing levels of quality control depending on the quality classification of the item. This quality classification includes Fire Protection List components.

Upon receipt of Fire Protection List items, a receipt inspection is performed in accordance with the instructions provided in the purchase requisition. In general, fire protection items are visually receipt inspected to ensure that the material being delivered is the type and quantity ordered, that no shipping damage has occurred, that specified protective coverings and coatings are in place, and that any required documentation is received.

9.5.1.3.3 Quality assurance. The Quality Assurance Program is described in Section 17.1.

9.5.1.3.4 Fire protection training. Training is an essential ingredient in developing and maintaining an effective fire protection program. The fire protection training program is designed to provide training to plant personnel commensurate with their respective responsibilities.

9.5.1.3.5 Hartsville fire department support. The Hartsville Fire Department is a supplement to the plant's fire fighting capability. To effectively utilize this support, indoctrination training and fire fighting coordination is conducted for this group.

9.5.1.4 Systems Description.

9.5.1.4.1 General. The fire protection system at Robinson integrates several design features to establish a defense in depth approach to protect against fire damage. This defense in depth approach consists of the following design features. Suppression systems comprise the primary tier and are used to extinguish and/or control fires. Fire detection systems alert operators to fires and also actuate selected automatic fixed suppression systems. Fire barriers are designed to limit fire spread and protect vital equipment. Emergency lighting is provided where necessary to enable a more efficient response by trained operators and fire brigade members.

9.5.1.4.2 Fire suppression systems.

9.5.1.4.2.1 Systems function. The fire suppression systems are designed to be actuated both manually and automatically, as applicable. System design is based on the degree of hazard present in an area when balanced with other concerns. Such concerns include plant area, ease of manual fire fighting, protection of safety-related equipment, and personnel safety.

9.5.1.4.2.2 Design Basis. Suppression systems are installed using NFPAcodes and standards as the basis for fire protection design. Individual hazards are evaluated to determine the degree of protection needed.

9.5.1.4.2.3 General Description. The fire suppression systems consist of a supply of extinguishing agents (water, CO^2, or Halon), a distribution system (underground exterior and interior piping) and an application system (valves, nozzles and sprinklers). The suppression system is installed to protect against identified fire hazards in various plant areas. The type of system is determined by the particular hazard.

The system is designed using the philosophy of defense in depth. Where provided, automatic extinguishing systems provide primary suppression. Hose stations and fire hydrants are located throughout the facility to allow manual fire fighting. Portable extinguishers are available as an additional level of protection.

The plant fire suppression systems include the water supply system, deluge, preaction and wet pipe sprinkler systems, hose stations, yard hydrants, and carbon dioxide and Halon systems.

9.5.1.4.2.4 Fire Suppression System Water Supply. The fire suppression water supply system consists of three vertical turbine pumps and an underground loop which supplies the fire water system. The three pumps are a 2500-gpm motor-driven fire pump, a 2500-gpm diesel-driven fire pump, and a 75-gpm motor-driven jockey pump (Figure 9.5.1-1, Sheets 1 through 3).

The fire loop and header system is normally pressurized by the fire water jockey pump. The main fire water loop is supplied by the electric motor-driven fire pump with backup by the diesel-driven pump. Two separate and independent pressure switches allow for automatic operation of the pumps. One switch initiates the electric motor-driven pump and the other initiates the diesel-driven pump. Both pumps are manually stopped.

The fire header is sized to deliver an adequate quantity of water throughout the plant to service all outlets. The yard piping consists of an underground 12-in. supply header to the 10-in. diameter fire water supply loop.

Branches from the underground fire loop and header system supply interior fire protection systems in the enclosed sections of the plant, including the Turbine Building. Sectionalizing valves in the yard piping system are provided to permit partial pipeline isolation without interruption of service to the entire system during maintenance or modification of facilities. The fire water loop has post indicator valves with the exception of three curb box valves.

Lake Robinson provides the source of water for fire protection. The individual Unit 2 fire pumps take their suction from the circulating water intake system on the clean side of the traveling screens between the screens and the circulating water pumps. This configuration provides adequate redundancy for water supply. Additional capability is available from the Unit 1 fire pump located at a separate intake structure. Lake Robinson is also the ultimate heat sink with sufficient capacity to provide fire protection water requirements. Failure of the fire protection system would not degrade the function of the ultimate heat sink.

The water supply system is capable of maintaining the pressure in the plant loop at 70 psi or higher with the largest deluge system in operation and with the system supplying an additional 1000 gpm to hoses.

The Robinson site is shared by Unit 1 (fossil) and Unit 2 (nuclear) with cross-connections to the Unit 1 fire water available for Unit 2. Two 8-in. water lines from the Unit 1 fire protection system are connected to the main loop for emergency use with isolation valves which are normally closed. In addition, the Hartsville fire department could pump water from the lake or discharge canal into the fire loop. The acceptability of this water supply arrangement is documented in NRC Safety Evaluation Report (SER) dated February 28,1978, Section 4.3.1.1.

9.5.1.4.2.5 Exterior Water Distribution and Fire Suppression Equipment. Fire protection water supply for the exterior of the plant is provided by fire hydrants. Hydrants are separated at distances of about 250 ft, with some at greater distances. Hydrants have 2-1/2 in. gated outlets and post indicator isolation valves. Hose houses are located near hydrants. Each hose house is equipped with appropriate fire fighting equipment. Standard fire hose threads are used on all fire protection equipment.

9.5.1.4.2.6 Interior Fire Suppression Systems. Fire suppression systems at Robinson include both manual and automatic systems. They are designed to provide building area protection, equipment protection, and backup suppression capability.

9.5.1.4.2.6.1 Fixed Manual Suppression. Fire hose stations are located throughout the entire plant for fire brigade use only. The Containment Building has eight stations and the Turbine Building has 15 stations, with six on the ground floor, five on the mezzanine and four on the turbine level. The Auxiliary Building has 10 stations, the Fuel Handling Building has one, the hot machine shop has two, and the Radwaste Building has five hose stations. The fire hose station standpipes are fed from branch headers that are connected at one end only to the fire water loop. Each hose station has readily accessible 1-1/2 inch hose lines with nozzles, and these are distributed to provide adequate protection. Manual hose stations serve as backup protection in areas where automatic suppression systems are installed.

The hose station provided in the Hagan Room is normally dry. It is supplied from a dry pipe valve in order to prevent accidental water discharge in the sensitive equipment areas of the Hagan and Control Rooms. Opening of the standpipe outlet valve will automatically actuate the dry pipe valve, allowing water to fill the standpipe.

9.5.1.4.2.6.2 Fixed Automatic Suppression. Automatic suppression systems are installed in areas of the plant where prompt application of water or other agent is needed or desirable to limit damage. Alarm notification is provided for each system upon system actuation or trouble. Several types of systems are installed including:

1. Wet pipe
2. Deluge
3. Preaction sprinklers
4. Total flooding Halon, and
5. Total flooding carbon dioxide.

System design is dependent on the specific hazard involved. The systems are installed as follows:

1. Wet Pipe Sprinkler System

Wet pipe sprinkler systems are installed in the Component Cooling Water Pump Room and Radwaste Building. Wet pipe systems contain water within the sprinkler piping and operate when the fusible element of a sprinkler reaches its preset temperature. When a sprinkler system operates, water is discharged over the fire area from only those sprinklers that have fused due to the heat of the fire.

2. Deluge Water Spray Systems

Automatic deluge water spray systems are installed at the plant to provide water suppression capability for areas of significant fire hazard. The automatic deluge systems protect the following subsystems:

a. Main Transformers,

b. Auxiliary and Startup Transformers,

c. Turbine Lube Oil Area, and

d. Hydrogen Seal Oil Unit.

The deluge systems consist of deluge valves, open spray nozzles, and actuating devices.

3. Preaction Sprinklers

Preaction sprinkler systems are installed in the electrical penetration area; reactor coolant pump bays A, B, and C; solid waste handling room; and one section of the Auxiliary Building ground level hallway.

The preaction sprinkler system consists of a preaction valve, which is automatically actuated by receipt of signals from two separate detection trains or may be manually actuated.

The preaction sprinkler systems are fed from branch headers that are connected at one end only to the fire water loop. For water sprinkler systems, piping connections are such that single failure will not impair both primary and backup suppression capability except for fire water to Containment. Water in containment is supplied by a 6-in. main that divides into two 4-in. supply lines which penetrate the Containment boundary. One line supplies the electric penetration area preaction sprinkler system. The other line supplies eight hose stations located in the annulus areas, along with the three preaction sprinkler systems located in Reactor Coolant Pump Bays A, B, and C.

4. Fixed Halon Fire Suppression System

A Halon 1301 fire extinguishing system provides a permanently installed automatic means of fire suppression for the Unit 2 Cable Spreading Room and the Emergency Switchgear Room.

The Halon 1301 extinguishing system is designed to supply a 5 percent atmospheric concentration of Halon to the rooms for fire suppression. To achieve this concentration, the Cable Spreading Room requires four cylinders and the Emergency Switchgear Room requires 10 cylinders. This design concentration is ensured by closure of the associated fire zone ventilation dampers. Minimal leakage around closed doors is expected and does not prevent the system from obtaining the design concentration.

The cylinders are divided into two distinct banks of 10 cylinders each, i.e., a main bank of cylinders and a reserve bank of cylinders. Within each bank, 4 of the 10 halon cylinders are shared between the two protected fire zones. Each room is provided with an initial discharge, followed by an extended discharge to insure concentration is maintained. The reserve bank is a redundant Halon supply.

5. Total Flooding Carbon Dioxide Fire Suppression Systems

a. Diesel Generator Rooms

A high pressure carbon dioxide fire extinguishing system (Cardox System) is provided for protection of the Diesel Generator Rooms.

One Cardox system protects both diesel generator rooms. Nineteen 75-lb. cylinders will discharge into either room containing the fire. The system is released automatically when the heat actuated device senses a temperature rise.

A 50-lb. cylinder of CO_2 is provided to operate the CO_2 whistle alarm which annunciates the discharge in the room. The system includes pressure trips to stop the fuel oil transfer pumps and shut off the exhaust and supply fan, which in turn closes the ventilation louver. Fire dampers are installed in the HVAC ducts and are automatically actuated by the low voltage fire detection system and actuates on a one out of two train logic. These dampers have an electrothermal link on one train and a frangible link on the other train for redundancy.

b. North and South Cable Vaults

A high-pressure CO_2 fire extinguishing system is provided for automatic fire suppression in the North and South Cable Vaults.

To provide design concentration in the North Cable Vault, seven cylinders of CO_2 will discharge. For the South Cable Vault, 18 cylinders of CO_2 will discharge. The design concentration is ensured by automatic damper closure upon actuation of the system.

The cylinders are divided into two distinct banks of 18 cylinders each, i.e., a main bank and a reserve bank for redundancy. Within each bank, 7 of the 18 cylinders are shared between the two protected fire zones.

6. Portable Extinguishers

Portable extinguishers are provided at strategic locations throughout the plant as listed in the HBR2 Fire Hazards Analysis (Appendix 9.5.1A). These consist of portable Halon 1211, ABC dry chemical, foam extinguishers, and large 150-lb. wheeled Halon 1211 fire extinguishers. Additional equipment is available in the Fire Equipment Building, including a 95-gpm foam cart and 125-gpm portable foam equipment.

9.5.1.4.2.7 Fire Suppression System Instrumentation and Control. Instrumentation and control of the water supply for fire protection is designed to maintain the system in a state of readiness.

The fire suppression water system is kept pressurized above the fire pump start pressures by the jockey pump which makes up inventory to the system under normal operating conditions. If rates of flow exceed the ability of the jockey pump to make up, the pressure in the system decreases. At approximately 100 ± 5 psi, the electric motor-driven fire pump controller energizes the motor-driven pump. If this pump is unable to meet the demand, the system pressure will continue to drop. At approximately 90 ± 5 psi the diesel engine driven pump will start.

The deluge systems are actuated automatically by heat sensing devices. These devices when actuated will trip open the deluge valve supplying water to the spray nozzles.

The Halon fire suppression system is actuated upon receipt of a "two-out-of-two coincidence" signal from the fire detection, and actuation system. The system may also be manually operated at the fire detection and actuation panels or it can be manually actuated at the cylinder bank.

Instrumentation and control of the Diesel Generator Room CO_2 fire suppression system includes the following principal features:

1. Automatic detection and release by heat actuated devices

2. Remote manual actuation by a pneumatic release that operates directly on pilot-operated discharge heads and is entirely independent of automatic releases

3. Direct manual actuation at the cylinder bank

4. Personnel evacuation alarm

5. Pressure switch operation causes shutdown of the fuel oil transfer pumps and sends an actuation signal to the fire detection and actuaion system.

6. While not physically connected or dependent on any other system, the fire detection and actuation system complements the CO_2 fire suppression system by closing the automatic fire dampers and shutdown of ventilation fans via the fire detection and actuation panel.

The North and South Cable Vault CO_2 fire suppression system is actuated upon receipt of a "two-out-of-two coincidence" signal from the fire detection and actuation system. The system may also be manually operated at the fire detection and actuation panels or it can be manually actuated at the cylinder bank and manual-pull stations outside the South Cable Vault.

9.5.1.4.2.8 Fire suppression system summary. Specific details of the fire suppression systems in the various plant areas can be found in the HBR2 Fire Hazards Analysis (Appendix 9.5.1A). Fire zones are as shown on Figures provided in Appendix 9.5.1A.

9.5.1.4.3 Fire detection and actuation system.

9.5.1.4.3.1 System function. The functions of the fire detection and actuation system (FDAS) are to continuously monitor for the presence of a fire, to promptly alarm in the event of a fire, and to actuate certain automatic fixed fire suppression systems and equipment. In some areas of the plant the fire detection system is integrated with other plant systems to provide auxiliary functions such as closing HVAC dampers and actuation of fire suppression systems.

9.5.1.4.3.2 Design basis. The system was designed for early warning of a fire. To ensure continuous and reliable detection, the system has been designed to monitor detection malfunctions through the use of an electrically supervised detection circuits. Four deviations were taken to NFPA-72D for the Fire Alarm System (FAS) as outlined in 9.5.1B, Section E.1.a.

9.5.1.4.3.3 General description. The FDAS provides centralized control of the detection, annunciation, and actuation for most HBR2 fire protection systems. The FDAS is composed of two independent, redundant trains of detection. Fire suppression system actuation is dependent on both trains. Each train consists of its own detectors, alarms, control devices, and annunciator/status indicators.

The FDAS provides the following primary functions:

1. Fire Detection (within specific plant areas)

2. Controlled activation of associated fire suppression systems, and

3. Fire Detection zone alarm and status indications.

The FDAS consists of the following major components:

1. Fire Detection and Actuation Panels (FDAP)

2. Fire Alarm Computer Console with a CRT located in the Control Room and a CRT in the Control Room Vestibule Area.

3. Containment Fire Protection Panel (CFPP) located in the Control Room, and

4. Smoke, heat, and flame fire detection devices which are located throughout the plant.

A suppression system will not be inadvertently activated by the momentary application of a high heat source (e.g., welding equipment, etc.) or smoke to a single detector. A single detector sensing an alarm condition does provide "one-out-of-two coincidence" actuation which will produce the following sequence of events:

1. The local FDAP will alarm and indicate the affected fire detection zone, and

2. The affected fire detection zone will alarm in the Control Room and be displayed on the Control Room CRT via locally mounted transceivers.

For the Diesel Generator Rooms only, a single detector in alarm will cause closure of the HVAC dampers and shutdown the ventilation fans for the fire affected room. Actuation of the redundant detection train will not result in any additional actions.

"Two-out-of-two coincidence" is used to automatically actuate the fire suppression systems.

9.5.1.4.3.4 Fire detection system components.

9.5.1.4.3.4.1 Fire Detection and Actuation System Panels. The following is a description of the major panels of the fire detection and actuation system:

a) There are four Fire Detection and Actuation Panels (FDAP) designated FDAP-A1, A2, B1, and B2. FDAP locations are

1) FDAP-A1 - Auxiliary Building Hallway near Air Compressor

2) FDAP-B1 - Auxiliary Building Hallway near Component Cooling Room

3) FDAP-A2 - Emergency Switchgear Room, and

4) FDAP-B2 - Second floor Auxiliary Building in access area around Emergency Switchgear Room.

Each FDAP consists of a variety of modules used to perform alarm, control, status, and annunciation functions.

b) Containment Fire Protection System Panel (CFPP)

The Containment Fire Protection System Panel provides control functions and the audible control room alarm for the FDAS.

The control functions provided by the Containment Fire Protection System Panel are: 1) to control the containment motor-operated isolation valves for the fire suppression water to the Containment Building preaction sprinkler systems and containment hose stations, 2) to manually actuate containment preaction valves, and 3) to provide remote control for the motor-driven fire pump.

c) Fire Alarm Console and Control Room CRT (FAC)

A Fire Detection console (which houses a computer, UPS, and CRT) and printer are located in the vestibule just outside the Control Room proper. Also, a "remote" CRT is located in the Control Room. This system provides complete monitoring of the FDAPs to a centralized point via data transmitted through 17 locally mounted transceivers.

9.5.1.4.3.4.2 Low Voltage Fire Detectors. Low voltage fire detectors are used to detect either fire and/or combustion by-products and provide an output signal to other fire protection systems; e.g., the fire detection and activation system. The low voltage fire/combustion byproducts detectors used at HBR2 are:

a) Ionization Smoke Detectors,

b) Photo-Electric Smoke Detectors,

c) Infrared Flame Detectors, and

d) Thermal Fire Detectors.

9.5.1.4.4 Fire Barrier Features.

9.5.1.4.4.1 System Function. Fire barriers divide buildings into fire zones/areas and prevent fire propagation between areas. They also protect conduits from fire exposure in specific cases (i.e., fire wraps). A summary of the fire barriers is found in the HBR2 Fire Hazards Analysis (Appendix 9.5.1A).

9.5.1.4.4.2 Design Basis. Barriers used to separate fire areas are designed to withstand fire exposures experienced during fire tests which model ASTM-E119 fire exposures. Barriers are designed for up to 3-hr. exposures depending on the hazard present. Fire wraps are rated for 1-hr. exposure.

9.5.1.4.4.3 Fire Barrier and Control Features. Fire barrier and control features consist of seals and wraps, which are installed to provide compartmentation, separation or containment of fire.

9.5.1.4.4.4 Fire Barrier and Control System Components.

9.5.1.4.4.4.1 Fire Barriers. The fire barriers which separate fire areas are building walls, ceilings, and floors which have been upgraded to the needed fire rating by the use of fire doors, fire dampers, and sealing materials in electrical and mechanical penetrations. Fire barriers generally have a 3-hour fire rating, and where necessary, have been evaluated for acceptability.

a) Walls, Ceilings, Floors - Auxiliary, Containment and Fuel Handling Buildings which contain components and systems important to safety are of reinforced concrete construction.

The plant layout subdivides the plant into several fire areas which contain safe shutdown equipment. The fire areas are further subdivided into fire zones for the purpose of the FHA. The barriers (walls, floors, and ceilings) which separate these fire areas are designed to isolate the fire areas from each other. Where redundant items of safe shutdown equipment or cables are not separated, an appropriate combination of fire wraps of conduits, fire detection and alarm, automatic and manual fire suppression and alternative shutdown capability is provided.

b) Fire Doors - Fire doors are installed in personnel access ways through fire barriers. The adequacy of fire doors has been evaluated based on the design and rating of the door compared to the exposing fire load. The fire doors in the barriers are qualified to either a 3-hr. fire rating or less depending on the combustible loading and configuration on either side of the barrier.

c) Fire Dampers - 3-hr. rated fire dampers are installed in ventilation duct work, where appropriate, to separate fire areas.

In fire zones with gaseous fire suppression systems, the automatic type fire dampers use both an electro-thermal link and a frangible-link connected in series such that either one can release the fire damper blade.

d) Penetration Seals - Electrical and mechanical penetrations through fire barriers have been sealed to give adequate fire resistance.

e) Wraps - Cable wraps are used as localized fire barriers in the Component Cooling Pump Room to protect conduit where the redundant trains are in the same area. These wraps are designed to provide at least 1-hr. protection.

f) Rockbestos Cable - Rockbestos cable has been installed in conduit as a noncombustible radiant energy shield inside of Containment.

9.5.1.4.4.4.2 Fire Propagation/Damage Control Features. These features are used to prevent the spread of fire and also to protect equipment from fire exposures:

a) Flame-Retardant Coatings - Flame-retardant coatings have been applied to safety-related cables within the Auxiliary Building routed in trays that do not meet the IEEE-383 flame test requirements. See also Section 8.3.3.

b) Curbes and Dikes - Curbs and dikes are used to direct and contain flammable and combustible liquid leaks. Curbs are used to direct the flow away from safe shutdown equipment while dikes are used to contain the leak in a specific area. Floor drains are provided throughout the plant as are curbs and pedestals for equipment. The Diesel Generator Rooms are the only Auxiliary Building rooms containing significant combustible liquid and are equipped with curbs and separate drain systems. Curbs are provided in RCP B and C pump bays. Refer to 9.5.1B, Section D.1.i for additional information on floor drains.

9.5.1.4.4.4.3 Fire Suppression Water Damage Control Features. These features are used to prevent damage to safety-related equipment by impingement or flooding in the event of rupture or inadvertent operation of the fire water system piping.

The fire water piping inside the "A" pump bay in Containment is seismically designed and afforded missile protection. Fire water piping in the "B" and "C" pump bays is designed to avoid damage to shutdown equipment in the event of an earthquake.

Safety-related equipment is mounted on pads and pedestals to avoid damage by flooding and floor drains are provided throughout the plant.

The fire suppression water system has been analyzed to determine the effects of a pipe rupture or inadvertent system operation on safety-related equipment due to impingement or flooding. The analysis is described in Reference 9.5.1-3. A spray shield has been installed to protect motor control center No. 5 in the Auxiliary Building from impingement. The results of the analysis indicate that damage that could be caused by flooding from pipe ruptures can be eliminated or minimized by prompt operator action to terminate the water flow and that no damage to safety-related equipment would occur from inadvertent actuation of, or pipe rupture in, the fire suppression water system.

9.5.1.4.5 Emergency Lighting.

9.5.1.4.5.1 System Function. The functions of the emergency lighting system are to provide 1) emergency lighting in all areas needed for operation of safe shutdown equipment, 2) emergency lighting for access and egress routes to and from these areas, and 3) general area lighting for personnel safety.

9.5.1.4.5.2 Design Basis. Lighting at Robinson is divided into four categories--normal, AC emergency, Control Room DC emergency, and individual DC emergency.

Normal AC plant lighting is taken from the 480 volt AC system. Upon loss of normal AC lighting, AC emergency lighting is supplied by the emergency diesel generators. Upon loss of all AC lighting, the Control Room DC emergency lighting automatically comes on. Power for this system is supplied from station batteries.

Individual DC emergency lighting is activated by the loss of normal lighting in a localized area. This system is designed to provide a minimum 8-hr. light supply to all areas of the plant needed for safe shutdown. Power is supplied by individual battery units.

9.5.1.4.5.3 Emergency Lighting System Description.

a) AC Emergency Light System - Selected normal AC lighting fixtures throughout the plant are supplied by the emergency 480 volt AC bus. Upon loss of normal power, these fixtures are powered by the emergency Diesel Generators and provide less than normal but sufficient lighting throughout the plant for operation and personnel safety.

b) Control Room DC Emergency System - The Control Room DC emergency lighting system is tied to the normal AC lighting system. Upon loss of this system, the station DC emergency lighting will come on automatically. The system will remain lit until AC lighting has been re-established, at which time it will automatically go off. This system is provided to ensure personnel safety in the event AC lighting is lost. The Control Room emergency DC lighting is fed from 125 volt DC Battery A.

c) Individual DC Emergency Lighting System - The individual emergency lighting system consists of fixed, self-contained, 8-hr. battery-powered units. The units are provided in areas of the plant where required for operation of safe shutdown equipment and along access and egress routes to those areas. Explicitly exempted from this requirement are certain cold shutdown equipment areas, along access routes outside the buildings, and access to three (3) valves located in outside areas illuminated by Diesel-Backed Security Lighting. Battery-powered portable lanterns are stored in the fire equipment building for emergency use.

9.5.1.5 Safety Evaluation

9.5.1.5.1 Fire Hazards Analysis. The evaluation of the fire protection program of the HBR2 plant has been carried out by performing a fire hazards analysis and a comparison of existing program provisions against the guidelines of Appendix A to BTP APCSP 9.5-1. The most recent HBR2 fire hazards analysis, fire protection program description and safe-shutdown analysis report (Appendices 9.5.1A, 9.5.1B and 9.5.1C) address the requirements of 10CFR50, Appendix R, and describes the plant fire protection features in the format of Appendix A to BTP APCSB 9.5-1. The description reflects the current plant configuration, including modifications implemented as a result of previous fire hazard analyses and NRC review comments and to meet Appendix R requirement.

9.5.1.5.2 Safe shutdown analysis. A comprehensive analysis of the separation between redundant safe-shutdown components and cables relative to postfire shutdown system separation requirements of 10CFR50, Appendix R, Section III.G, has been performed. This analysis is summarized in the safe-shutdown analysis report, Appendix 9.5.1C. The analysis is described in Reference 9.5.1-2. The HBR2 postfire safe shutdown capability is also discussed in Section 7.4.

9.5.1.6 Inspection and Testing Requirements

A periodic testing and surveillance program has been established to verify the ability of the Fire Protection System components to function as required. This program is contained in Fire Protection Procedures FP-012 and FP-013.

9.5.2 Communication Systems

9.5.2.1 Design Basis. Communications systems are designed to facilitate normal and emergency communications within the plant and between the plant and emergency facilities. Redundant means of communication are provided to locations which provide a vital emergency response role. Table 9.5.2-1 shows the Emergency Communications Matrix.

9.5.2.2 System Description.

9.5.2.2.1 Plant communications systems.

9.5.2.2.1.1 Public address system. The public address system provides paging and party-line communications between stations located throughout the plant. Inside and outside type wall and desk-mounted stations are used to communicate between roaming personnel and fixed work locations. Plant-wide instructions are issued using the paging feature. This system is powered from PP-48 which is powered from MCC 6. This is with the exception of Building 408 (ADMIN) which is powered by offsite power.

9.5.2.2.1.2 PBX telephone system. The private branch exchange (PBX) telephone system provides communication capability between telephone stations located within the plant by dialing the four-digit telephone station code. The PBX telephone system also provides for outside communications as discussed in Sections 9.5.2.2.2.1 and 9.5.2.2.2.2.

9.5.2.2.1.3 Deleted by Revision No. 13

9.5.2.2.1.4 Sound powered telephone system. The sound-powered telephone system is a communications system which uses the mechanical energy in the human voice to generate electrical pulses to power the system. It requires no outside source of power and is therefore very reliable. The system consists of phone jacks, wiring, and the sound-powered handsets. There is no separation in the circuits. A handset plugged into a jack is connected to all other handsets plugged into that circuit. Additional temporary circuits may be easily set up by attaching phone jacks to any used cable between any points requiring sound-powered communications. Sound-powered phone jacks are provided on selected instrument racks. Switch panels are provided in the Control Room to cross-tie any circuit with any other circuit providing sound-powered phone communications between several plant areas.

To compensate for the distance between stations and the number of phone stations involved, a 120 V AC power amplifier is provided for the sound powered phone circuit utilized in fuel handling operations.

9.5.2.2.1.5 Radio transceivers for Robinson and vicinity. Very high frequency (VHF) transceivers (portables) are used for point-to-point communications in the plant vicinity. Radio consoles located in the CAS and SAS provide radio communications through ultra-high frequency (UHF) radio repeaters to mobiles and portables. These mobiles and portables can communicate with each other through the same UHF radio repeaters. Also, radio communications are available from portable to portable through 800 MHz repeaters.

Primary and secondary sources of power are provided for the radio control consoles and radio repeaters. Portable and mobile units are battery powered.

9.5.2.2.1.6 Emergency telephone and radio system. The emergency telephone system consists of Centrex Lines (ESSX), a Selective Signaling System (SSS) which is used to communicate with state and county agencies and Decision Lines to State and County Emergency Operation Centers (EOC's). Extensions off the ESSX and the SSS are located in the Control Room and the emergency facilities. The leased Decision Lines are installed from the TSC and EOF to the EOC's. Each of the three separate systems bypass the plant PBX. Dedicated Bell lines appear on the PBX extensions in the emergency facilities and the Control Room. These are dependent on the operation of the plant PBX which is provided with a primary and secondary source of power. Communication with mobile and portable radio units reserved for an emergency is possible through repeaters on CP&L-assigned frequencies as well as a state-assigned frequency.

9.5.2.2.1.7 Plant security. These transceiver portables are used by the dedicated plant security force for communications in and around the plant through two UHF radio repeaters. A fixed radio link is available from the Plant Security to the Darlington County Sheriff's Dispatch Center.

9.5.2.2.1.8 Security intercom system. The Security Intercom System is powered from a security distribution panel in the Primary Access Portal (PAP) West Building. This intercom system provides for communications between the Central Alarm Station and the Access Control Console in the PAP West, and all card reader controlled access doors and turnstiles, as well as the Secondary Alarm Station and motor operated gates.

9.5.2.2.1.9 Data transmitters and receivers. Data transmission of various parameters, such as lake inflow, discharge canal weir temperature, etc., are accomplished by wireline and VHF radio links. The various encoder/transmitters are located near the field instrumentation and the receiver/decoders, which comprise the other end of the radio links, are located in the Communications Room.

Data transmission of radiological data, such as personnel dose, area dose rates, airborne activity concentrations, etc., are accomplished by UHF radio links. The various encoder/transmitters are mobile or stationary dependent upon use for personnel monitoring or area monitoring. The receiver/decoders, which comprise the other end of the radio links, are portable and will be located in various locations.

9.5.2.2.2 Offsite communications systems.

9.5.2.2.2.1 Corporate telephone communications system (Caronet). Interconnected through the Plant PBX, the Corporate telephone system provides a means to communicate with any other Corporate locations as well as access to CP&L centralized WATS services. A company-wide fiber optic network provides the site-to-site interconnection. This network makes a complete circle of the CP&L service area, allowing automatic alternate route selection in the event of a fiber break or outage. The fiber optic network power supply is battery backed-up.

9.5.2.2.2.2 Southern Bell lines. Southern Bell lines, which supply public telephone communications, are employed by CP&L in three ways:

1. Tie-ins through the PBX to any plant location

2. Lines to plant emergency facilities

3. Lines to the Joint Information Center for public information purposes. Southern Bell provides primary and secondary power for their lines at the Central Office.

9.5.2.2.2.3 Dedicated telephone system to load dispatcher (high-line). This system provides direct links between the Control Room and the load dispatcher. Transmission facilities are over fiber optics equipment. These lines appear on several phones in the Control Room and are selected by pushing the appropriate button on a multibutton phone. These lines are routed through the plant PBX. The lines are automatically rung at the load dispatcher identifying Robinson as the caller. Primary and secondary power sources are supplied at both ends.

9.5.2.2.2.4 Deleted by Revision 13.

9.5.2.2.2.5 Plant security. The plant security radio link station, which is a part of the system discussed in Section 9.5.2.2.1.7 provides for radio communications to the Darlington County Sheriff's Office. Primary and secondary power sources are supplied.

9.5.2.2.2.6 Load dispatcher radio communications. The load dispatcher can communicate with the Robinson Plant Control Room via Caronet facilities and a radio control station that operates through a UHF radio repeater located at High Hills, S.C. Primary and secondary power sources are located throughout this system.

9.5.2.2.2.7 Corporate informational data communications. Large central computers are located at the Corporate headquarters. Smaller special purpose computers are located at other Corporate facilities, including Robinson. The communications link between Robinson and Corporate headquarters allows the interchange, storage, and processing of information.

9.5.2.2.2.8 Nuclear Regulatory Commission (NRC) notification system. The NRC operates a dedicated telephone system (FTS-2000) which allows direct telephone communications from all nuclear power plants to NRC regional and national offices. Telephones connected to this network are located in the Control Room, Emergency Operations Office, and Technical Support Center. Primary and secondary sources of power are supplied.

9.5.2.2.2.9 NRC Health Physics network. The NRC also operates a second dedicated telephone circuit on the FTS-2000 system which allows telephone communications from all nuclear plants to NRC regional and national offices. Telephones connected to this system are located for access by Health Physics personnel. Primary and secondary power sources are supplied.

9.5.2.2.3 Loss of offsite communications. There are eight separate offsite communications systems. These are Selective Signaling, Decision Lines, FTS-2000, Centrex Service (ESSX), Radio, Bell lines, Caronet and Automatic Ringdown circuits. Two of these eight (Caronet and Radio) are susceptible to damage from high winds. Caronet has routing redundancy, and radio antennas are located in two different locations as shown in Figure 9.5.2-1. Due to the locations of the susceptible equipment, it is unlikely that either would fail completely or that both would be simultaneously damaged. In the event of such an occurrence, the other forms of offsite communications would be sufficient to allow adequte communications. Battery backup is provided as necessary to allow these systems to continue to operate in the event of a site power outage.

The telephone lines enter the plant area on the eastern edge of the corridor. It goes under ground about 800 ft from the plant switchyard.

The microwave tower is approximately 2600 ft north of the plant. The tower is a guyed structure 330 ft high. It is designed for a 98 mph wind, with a calculated 142 mph wind needed to stress the tower to its yield point. Fiber Optic cables from the plant to the tower are buried. Primary and secondary power sources are supplied.

TABLE 9.5.2-1
EMERGENCY COMMUNICATIONS MATRIX

EMERGENCY COMMUNICATIONS MATRIX	ARCHITECT ENGINEER	NUCLEAR STEAM SUPPLY SYSTEM SUPPLIER	A. J. SKAALE ENERGY CONTROL CENTER	OTHER CP&L LOCATIONS	OTHER GOVERNMENT AGENCIES	OFFSITE LOCAL EMERGENCY OPERATIONS CENTER	NUCLEAR REGULATORY COMMISSION	STATE RADIOLOGICAL MONITORING VEHICLES	CP&L RADIOLOGICAL MONITORING VEHICLES	ONSITE PLANT MEDIA CENTER	ONSITE RECOVERY CENTER	ONSITE TECHNICAL SUPPORT CENTER	PLANT CONTROL ROOM	CORPORATE EMERGENCY OPERATIONS CENTER
Corporate Media Center	1	1	1,3	1,3	1,10	1	1	9	9	1,3 4	1,3 4	1,3 4	1,3 4	1,3 4
Corporate Emergency Operations Center	1,4	1,4	1,3	1,3	1,10	1,4	1	9	9	1,3 4	1,3 4	1,3 4	1,3 4	
Plant Control Room	1,4	1,4	1,3-5	1,3	1,10	1,4 5	1,2	9	5	3-5	3-5,8	3-6,8		
Onsite Technical Support Center	1,4	1,4	1,3	1,3	1,10	1 4-6	1,2	9	5	3-5	3-5,8			
Onsite Recovery Center	1,4	1,4	1,3	1,3	1,10	1 4-6	1	5	5	3-5				
Onsite Plant Media Center	1	1	1,3	1,3	1,10	1,4 5	1	9	5					
CP&L Radiological Monitoring Vehicles	9	9	9	9	9	5	9	9	5					
State Radiological Monitoring Vehicles	9	9	9	9	9	7	7	7						
Nuclear Regulatory Commission	7	7	1	1	7	7								
Offsite Local Emergency Operations Center	1,4	1,4	1,3	1	7									
Other Government Agencies	7	7	1	1										
Other CP&L Locations	1	1	1,3,5											
A. J. Skaale Energy Control Center	1	1												
Nuclear Steam Supply System Supplier	7													

Legend:

Numbers in the blocks correspond to the following communications capabilities:

1. Commercial Telephone Company links
2. NRC dedicated Voice Links
3. CP&L Private Telephone Network Links
4. CP&L Emergency Telephone Network Links
5. Radio Links
6. Data Links
7. Responsibility of outside party to implement
8. In-plant communications systems
9. Messages dispatched over radio from onsite Technical Support Center
10. Communications to government agencies other than the NRC are to be forwarded through the local emergency operations center

9.5.3 LIGHTING SYSTEMS

In addition to the normal plant lighting, emergency lighting is provided by the station DC power. Because the plant lighting systems are divided into a number of circuits, a fire in an area could cause loss of both normal and emergency lighting in the fire area, but would not cause loss of lighting to areas served by other circuits.

A number of battery-operated portable lanterns are stored in the Control Room; these lanterns are dedicated for emergency use and are sufficient in number for the fire brigade. Also, 8 hour rated battery-powered lights are installed in key areas which automatically come on if loss of power occurs. 3

REFERENCES: SECTION 9.5

9.5.1-1 Fire Hazards Analysis, H. B. Robinson Unit 2. | 5

9.5.1-2 Safe Shutdown Component/Cable Separation Analysis [10CFR50, Appendix R, Section III.G] for H. B. Robinson Unit 2. | 5

9.5.1-3 Fire Water Pipe Rupture Analysis, CP&L Letter to NRC, dated June 12, 1980, Serial #NO-80-896.

APPENDIX 9.5.1A

FIRE HAZARDS ANALYSIS
H. B. ROBINSON, UNIT 2

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

1.0 INTRODUCTION

The purpose of this report is to provide a current evaluation and fire hazards analysis of H. B. Robinson, Unit 2. Due to the ongoing nature of fire protection review and the development of comprehensive new regulations, specifically 10CFR50, Appendix R, the Fire Protection Program Review submitted by Carolina Power & Light Company on January 1, 1977 no longer represents the current status of the HBR2 fire protection program.

After the Brown's Ferry fire in 1975, the Nuclear Regulatory Commission requested that all licensees analyze the fire protection programs at their facilities and document the results in a plant fire hazards analysis. Subsequent to the submittal of the H. B. Robinson FHA in 1977, additional NRC review of the HBR fire protection program took place in the form of written staff questions and CP&L responses, meetings, and telephone conferences with the staff. This review process was documented in an NRC Safety Evaluation Report dated February 28, 1978, with supplements dated September 4, 1979, February 21, 1980, and December 8, 1980.

The original Fire Hazards Analysis of 1977 was updated in 1982 in Section 9.5 of the updated FSAR. However, due to the need to reanalyze HBR2 to the current requirements of Appendix R, this report is a further revision of the Fire Hazards Analysis which addresses concerns specific to Appendix R. Appendix 9.5.1B is an updated discussion of the plant fire protection features in the format of Appendix A to Branch Technical Position APCSB 9.5-1. This discussion reflects the current plant configuration as a result of modifications implemented under the approved SER and supplements as well as modifications implemented to meet Appendix R requirements.

Appendix 9.5.1C provides a description of the Post-Fire Safe-Shutdown Analysis, identifying the required safe-shutdown functions, the systems and configurations analyzed and credited to achieve those functions, and the methodology applied in conducting the analysis.

Appendix 9.5.1D references the documentation which forms the basis for establishment of the adequacy of the safe-shutdown provisions and train separation as required by Appendix R, Section III.G.

2.0 FIRE HAZARDS ANALYSIS AND METHODOLOGY

This section describes the assumptions and methodology utilized in performing the fire hazards analysis for HBR2. The analysis contained in this report is intended to supersede previous submittals with respect to fire area and zone designation, including the January 1, 1977 Fire Protection Program Review. Table 9.5.1A-1 provides a cross-reference list of the new and previous fire area and zone designations.

Figures 9.5.1-2 through 9.5.1-10 show the location of all the fire zones and fire areas throughout the Robinson Nuclear Plant. The fire zone locations are shown by Plan and Elevation views outlined by heavy lines with the zone number indicated. A legend is provided on each drawing to identify the fire area barrier symbol from the fire zone barrier symbol. These locations were analyzed for their fire loadings and the adequacy of the fire containment enclosures or barriers. The designation and location of major equipment throughout the plant is also shown on these Fire Hazards Analysis drawings.

2.1 Assumptions

The fire protection evaluation utilized the following assumptions:

1. Fire areas are established based on as-built conditions. A fire area is designated as that portion of a building that is separated from other areas by boundaries (walls, floors, or roofs) which have three-hour fire ratings or have been evaluated as adequate barriers for the fire loading present. Engineering evaluations, conforming to the guidelines of Generic Letter 86-10, have been developed to address specific fire barriers and penetration seals. Some exterior fire areas which are not rooms or enclosures are also established to provide complete coverage of safe shutdown systems (e.g., tanks, intake structure).

2. Fire Area A is subdivided into fire zones. These zones are designated to facilitate identification of localized quantities of combustibles, and to maintain consistency with existing plant detection and suppression system designations. Due to the configuration of fire zones and adequacy of fire barriers within the Auxiliary Building, the fire damage will be limited to a specific zone rather than the area consisting of multiple zones. Fire loadings within individual zones are also more indicative of local fire severity than would be the case if a loading was calculated for the multiple-zone area.

Fire Area G is also subdivided into fire zones. These zones represent exterior plant structures or equipment. Due to the physical and spatial separation of these exterior zones and the lack of intervening combustibles within the yard area, the fire damage will again be limited to a specific zone.

The Turbine Building (Fire Zone 25) and Fuel Handling Building (Fire Zone 28) have been subdivided into smaller areas for purpose of analysis. The subdivisions are identified by a letter following the Fire Zone number (e.g., Fire Zone 25A). The subdivisions occur along physical barriers, rated or nonrated, whenever possible.

The Turbine Building in general does not contain exterior walls or a roof above the operating deck. This design feature enables the heat or smoke from a fire to easily exit the building, preventing heat buildup which could threaten the structure. This also aids fire fighting efforts by increasing fire fighter visibility and lowering area temperatures. Certain areas of the Turbine Building are enclosed where protection of equipment or plant functions from the weather is desirable.

3. The adequacy of fire doors and fire dampers or other protected penetrations of fire area boundaries is evaluated based on the design and rating of the door or damper compared to the exposing fire load. Protection of openings is qualified to either a three-hour fire rating or less depending on the combustible loading and configuration on either side of the barrier.

4. In analyzing the effects of a fire on electrical cables, the HBR2 Appendix R Separation Analysis demonstrates that if only one safe shutdown train is affected by a fire, then safe shutdown capability still exists.

5. Electrical cable insulation and components inside instrumentation, control and relay cabinets, motor control centers, switchgear cabinets and electrical motors need not be considered in the combustible loadings. This cable insulation is located within noncombustible metal enclosures with limited exposure potential and is generally of a small quantity in comparison to the quantity of cable insulation computed for exposed cable trays.

6. Equipment requiring small quantities of lubricant (generally less than one pint of fluid or one pound of grease) is normally accomplished through the use of seal bearings or oil/grease cup arrangements. These small quantities were not considered significant and were not included in the combustible loadings.

7. In calculating combustible loadings and equivalent fire severities, cable in conduit need not be considered as combustible material.

8. Combustibles located in six sided metal enclosures are normally not considered combustible as they do not represent a significant fire threat due to limited exposure (i.e., difficulty for the fire to either enter or exit the enclosure, limited air for combustion is present within the enclosure and the general fire resistive nature of the metal enclosure). This includes metal enclosures with minimal/small ventilation or access openings. Enclosures with excessive ventilation or access openings are to be reviewed using engineering judgement to determine if inclusion into the combustible loading is required.

9. Permanent non-fixed combustibles within metal storage cabinets, file cabinets or desks are generally included in the combustible loadings due to the potential for the contents to be removed and later exposed to the fire.

10. Flammable liquid storage cabinets and closed containers in accordance with NFPA 30 and fire rated file cabinets are not included in the combustible loadings.

11. "A" label three-hour rated fire doors and fire dampers provide adequate protection for barriers requiring a three-hour or greater fire resistance rating. "B" label 1-1/2-hour rated fire doors and fire dampers provide adequate protection for barriers requiring a two-hour or less fire resistance rating.

12. Airlock doors providing access to containment provide adequate protection for the hazards to which they could be exposed.

13. Containment purge ductwork that penetrates containment with isolation valves inside and outside of containment are adequate to prevent the passage of fire through the containment barrier. Fire dampers are not required at the point where the ducts penetrate containment.

14. All contaiment penetration assemblies are satisfactory to prevent the passage of fire through the containment barrier. While the penetration assemblies do not constitute a rated fire seal, they are designed and constructed to meet radiological and pressure boundary requirements and qualifications which provide an acceptable level of protection.

15. Concrete plugs are utilized to protect large equipment hatch openings that connect different levels in the plant. The plugs are constructed of the same material as the floor in which they are located and provide adequate protection for the fire area boundaries when they are in place. When removed, the opening must be considered as an unprotected opening in a fire zone/area boundary interface.

16. All mechanical and electrical penetrations in fire barriers separating adjacent interior fire areas are sealed commensurate to the hazards to which they could be exposed. For penetrations of exterior barriers, see Assumption 17.

17. Fire area boundaries that abut the exterior are required to have a fire resistance rating only if exterior fire hazards are present, per the criteria of Appendix A to BTP APCSB 9.5-1.

18. System piping cannot be damaged from direct exposure to a fire. The position of a manually operated valve will not be affected by a fire at the valve. The loss of power or air supply to an air operated valve will cause the valve to assume its safe position. The loss of power to a motor operated valve will cause the valve to remain in its last position, i.e., "Fail-as-is".

19. Exemption requests from certain requirements of Appendix R to 10CFR50 have received NRC approval. Engineering evaluations have also been prepared to demonstrate compliance with Appendix A to BTP APCSB 9.5-1 and Appendix R where fire barrier deficiencies were found. Some of the engineering evaluations have been reviewed by the NRC. Guidance is provided by Generic Letter 86-10, Enclosure 1-Interpretations of Appendix R, Item 4, dated April 24, 1986. Adequate protection is provided for each fire area boundary interface where reliance is made upon evaluations and/or exemptions, provided that the conditions identified in each evaluation and/or exemption still apply. When the conditions identified in each evaluation and/or exemption no longer apply, then the openings described in the evaluation and/or exemption must be considered as unprotected openings in fire area boundaries.

2.2 Fire Area Boundaries

In accordance with the NRC Staff Guidance, this report analyzes HBR2 in terms of fire areas. Such areas are generally bounded by rated fire barriers except for the exterior fire area.

A fire area is defined as that portion of a plant separated from other areas by rated boundary fire barriers. The rating of the barriers is determined by the fire hazard within each area and is required to be commensurate with the fire hazard to which the barrier is exposed. In addition to barrier construction, the definition of the fire area boundaries must also address the protection provided for the doors, dampers, stairways, hatches and other penetrations in the fire area boundary construction. Fire barriers, doors, dampers and penetration seals are not necessarily required to be three-hour rated. The rating is dependent upon the fire hazards to which they could be exposed. At Robinson Nuclear Plant, the construction of walls, floors and ceilings is typically of heavy, reinforced concrete with an inherent fire rating of at least three hours.

A program is in place to seal penetrtion openings in fire barriers. Any penetrations in fire barriers which remain unsealed have been evaluated and justified upon the basis of the particular hazard involved. Otherwise, the penetrations have been sealed to a three-hour rating.

Engineering evaluations also exist which document the acceptability of openings and penetration seal configurations which deviate from fire tested designs.

2.3 Fire Loading Calculations

Fire loadings given in this report were calculated using the following methodology. Field walkdowns were performed to determine/verify the amount and type of combustible material in each plant area. The combustible content of each material was determined from standard references. Finally, the total heat content (in Btu's) of the combustibles was divided by the square footage of the area under consideration to arrive at the fire loading. Once the fire loading for a particular zone has been calculated, the required fire barrier rating can be determined from the following table. By comparing the required rating against the actual rating, the adequacy of the designated fire barriers can be verified. This table relates the BTU/sq. ft. of fire loading to a required barrier rating and fire severity duration based on the area under the ASTM E-119 standard time-temperature curve.

REQUIRED BARRIER RATINGS FOR FIRE LOADINGS[1]

Hazard Classification [2]	Fire Loading (BTU/Sq. Ft.)	Fire Severity/Required Barrier Rating (minutes)
Negligible [3]	0 to ≤ 20,000	0 to ≤ 15
Low	> 20,000 to ≤ 80,000	> 15 to ≤ 60
Moderate	> 80,000 to ≤ 160,000	> 60 to ≤ 120
High	> 160,000	> 120

NOTES:

1. National Fire Protection Association Handbook, Fourteenth Edition, Table 6-8A, pages 6-81.

2. Hazard Classification column added to table based on information from the National Fire Protection Association Handbook, Fourteenth Edition, "British Fire Loading Studies," pages 6-82.

3. Engineering Judgement.

Many of the identified combustibles are used throughout the plant as part of normal maintenance and operating supplies. These combustibles are often transient in nature, may vary with time and can be moved throughout the plant. As a result, administrative controls are placed on the use, storage location and handling of these ordinary combustibles. Control measures include the use of metal trash cans, routine trash collection and storage of material

in assigned locations, within metal file cabinets or metal storage lockers.

For the fire hazards analysis, it was assumed that plant housekeeping procedures would keep permanent non-fixed combustibles in general plant areas to low levels. In those areas where it is known that maintenance and operating supplies must be maintained, it was assumed that a reasonable quantity of such materials was present. The assumed BTU content of these materials was based upon knowledge of the kinds of materials required in an area and surveys of operating installations.

Beyond the normal maintenance and operating supplies, the combustible material common to nearly all the fire zones was found to be cable insulation. Cabling runs essentially throughout the entire plant. As a result, a detailed survey of the cable insulation for all the fire zones was performed. Each fire zone contains many different types of cable insulation and each type may be a different size, different density and different BTU release. The calculations of BTU release from cable insulation are originally estimated based on an average mix of cables. Today, cable insulation values are estimated using a large diameter multi-conductor cable with a high insulation value which should encompass the cables used within the plant. The resulting BTU release for cable insulation represents a conservative value for each individual zone.

A normally postulated fire was evaluated for each fire zone to determine the adequacy of the containment features, the fixed fire detection and suppression systems provided and the manual supression equipment available to control and extinguish a fire. A normally postulated fire is a fire which would develop within an area/zone based on the combustible loading from fixed or transient combustibles that could reasonably be expected. The fixed combustible loading is based on the values itemized in each zone. The amount of transient combustibles considered was small based on the guidance provided in Generic Letter 83-33. Generic Letter 83-33 states that these transient hazards generally "arise from activities associated with operation, maintenance, repairs or modifications. They may arrive deliberately under approved work permits or inadvertently as a temporary expedient. Usually a fire involving such materials (transients) would not over power the fire protection features provided in accordance with Section III.G and, therefore, are only of concern when exemptions or deviations are requested."

The term "ordinary Class A combustibles" is used in the text to describe any number of combustible material types normally found in day to day operations of the plant. Examples of these ordinary Class A combustibles include paper (including cardboard), wood, cloth (anti-c clothing, rags, etc.), plastics (sheeting, bags, tubing, nylon, foamed plastics, etc.), rubbers (hoses, floor mats, foamed rubbers, etc.), and fiberglass (ladders, filters, insulation, etc.). The use of this term also eliminates the repeated listing of these combustible types in each of the fire zone analyses.

2.4 Safe Shutdown Capability

For areas of the plant which contain normal safe shutdown equipment, it is only necessary to demonstrate the availability of an alternative shutdown train. Appendix R, Section III.G.3 requires that fire detection and fixed suppression be provided in all areas for which alternative shutdown capability is required. Not all areas of HBR2 meet this requirement. Exemptions have

been granted by the NRC, where justified, for these areas. For a discussion of the equipment and functions required for safe shutdown, refer to the H. B. Robinson Appendix R Separation Analysis, which is summarized in Appendix 9.5.1C.

2.5 Fire Dampers

Administrative procedures are provided to manually trip HVAC fans where necessary upon acknowledgment of a significant fire. Fire dampers enclosing fire zones with gaseous fire suppression systems are actuated by the dual train fire detection system. One detection train closes the damper by operation of a frangible link(s), while the other closes the damper by operation of an electro-thermal link(s) (ETL). The ETL also serves as a fusible link for the fire damper in the event of a fire in an adjacent fire zone. Three-hour rated fire dampers are generally provided in rated fire barriers. In some instances an engineering evaluation has been performed to justify the acceptability of not installing a damper or installing a damper in a manner that is not in strict accordance with the manufacturer's instructions.

2.6 Fire Doors

Three-hour rated fire or security doors are installed in rated fire barriers, or an engineering evaluation has been performed to justify an unrated door. A 1 1/2-hour rated fire door exists between Fire Zones 17 and 18.

2,7 Fire Detection System

Wherever a low voltage fire detection system is provided for protection of an area, two detection circuits or trains are provided. The only exceptions to this are 4160 VAC Switchgear Room (Fire Zone 25A) and Battery C Enclosure (Fire Zone 37). The detection zones are monitored by the Fire Detection Alarm Panels (FDAP) A1, A2, B1 and B2.

3.0 FIRE AREA ANALYSIS

This Section provides an area-by-area fire hazards analysis and shutdown capability summary.

3.1 Appendix R Fire Area A - General Auxiliary Building Area (Fire Zones (FZ) 1, 2, 3, 6, 7, 8, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 36 and 38).

Fire Area A consists of all Auxiliary Building fire zones in which a fire would not preclude the use of Alternative Shutdown Train A for safe shutdown. All essential Alternate Train A cables are routed independent of this fire area, and remain available for safe shutdown in the event of a postulated fire anywhere in this area.

Fire Area A is subdivided into fire zones. These zones are clearly delineated rooms enclosed by reinforced concrete walls, floors, and ceilings. Fire zone boundaries are adequate to contain the combustible loading within the zone boundaries. Alternative shutdown capability is provided independent

of the room or zone under consideration, in accordance with Appendix R, Section III.G.3.

An exemption from the detection/automatic suppression requirements of Appendix R, Section III.G.3 for applicable zones within Area A was received by CP&L via NRC letter dated September 17, 1986.

3.1.1 Fire Zone 1 - Diesel Generator "B" Room

3.1.1.1 General Description. Zone 1, in the Diesel Generator "B" Room, is located on the ground floor of the Auxiliary Building on the 226.0 ft. elevation.

3.1.1.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour fire door (Fire Door 23) in the wall between this room and the hallway (FZ 7). Automatically closing three-hour fire dampers are provided in ventilation ducts to adjacent Fire Zones 3 and 7.

3.1.1.3 Safe Shutdown Equipment. This area contains Diesel Generator B, its associated diesel oil day tank, and control panel. A complete loss of this equipment will not prevent safe shutdown, which can be accomplished either with Diesel Generator A powering the 480V Bus E1, or with the DS Diesel Generator powering the DS Bus.

3.1.1.4 Combustibles. Combustible material located in this area consists of ordinary Class A combustibles, cabling, 275 gallons of diesel oil in the day tank and 250 gallons of lubricating oil. The hazard classification and expected fire severity for all combustibles in this zone is "moderate." Field flash batteries for the diesel generator are also located in this area. The design of the HVAC system maintains the level of hydrogen generation at less than the allowable limit of 2% concentration per volume.

3.1.1.5 Fire Detection. A total of five detectors are provided within the zone. Three of the fire detectors provide a limited actuation function, while the remaining two detectors provide a full suppression system operation function. The "Limited Actuation" function fire detection in this area includes two infrared flame detectors, one heat detector, and one manual pull station. Any one of these detectors will, through the Fire Detection and Actuation Panels (FDAP-A1 and B1):

1. Actuate the Fire Alarm Console in the Control Room,

2. Close Fire Dampers 1, 2, 3, 75, and

3. Trip Intake and Exhaust Fans HVS-5 and HVE-17, which in turn closes the ventilation louver.

The "full suppression system operation" function fire detection in this area consists of two heat-actuated devices which:

1. Actuate the CO_2 system and send an alarm to the FDAP-A1 and FDAP-B1 and the Fire Alarm Console in the Control Room,

2. Stop the Fuel Oil Transfer Pump "B" and Zone 1 Intake and Exhaust Fans HVS-5 and HVE-17, which in turn closes the ventilation louver, and

3. Sound the local alarm whistle in the room.

3.1.1.6 Fire Suppression. Automatic fire suppression for this area consists of an automatic high pressure carbon dioxide (CO_2) system. This system is actuated:

1. Automatically by either Heat-Actuated Devices (HAD),

2. Manually by activating the "B" Diesel Generator CO_2 System remote manual release located on the outside of the west wall of Diesel Generator "B" room, or

3. Manually by first opening the "B" Diesel Generator CO_2 System pilot control valve, then opening the valve on either CO_2 Bottle B9 or B8.

Upon automatic actuation, this system provides an approximately 25-second delay before discharging.

A fire hose station in adjacent FZ 7 and portable fire extinguishers within FZ 1 and 7 are provided for manual fire fighting.

3.1.2 Fire Zone 2 - Diesel Generator "A" Room

3.1.2.1 General Description. Zone 2, the Diesel Generator "A" Room, is located on the ground floor of the Auxiliary Building on the 226.0 ft. elevation.

3.1.2.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour fire door (Fire Door 24) in the wall between this room and the hallway (FZ 7). Automatically closing and fusible link three-hour fire dampers are provided in ventilation ducts to adjacent Fire Zones 7 and 15.

3.1.2.3 Safe Shutdown Equipment. This area contains Diesel Generator A, its associated diesel oil day tank, and control panel. A complete loss of this equipment will not prevent safe shutdown, which can be accomplished either with Diesel Generator B powering 480V Bus E2, or with the DS Diesel Generator powering the DS Bus.

3.1.2.4 Combustibles. Combustible material located in this area consists of ordinary Class A combustibles, cable, 275 gallons of diesel oil in the day tank and 250 gallons of lubricating oil. The hazard classification and expected fire severity for all combustibles in this zone is "moderate." Field flash batteries for the diesel generator are also located in this area. The design of the HVAC system maintains the level of hydrogen generation at less than the allowable limit of 2% concentration per volume.

3.1.2.5 Fire Detection. A total of five detectors are provided within the zone. Three of the fire detectors provide a limited actuation function, while the remaining two detectors provide a full suppression system operation function.

The "limited actuation" function fire detection in this area includes two infrared flame detectors, one heat detector, and one manual pull station. Any one of these detectors will, through the Fire Detection and Actuation Panels (FDAP-A1 and B1):

1. Actuate the Fire Alarm Console in the Control Room,

2. Close Fire Dampers 4, 5, 6, 7, and

3. Trip Intake and Exhaust Fans HVS-6 and HVE-18, which in turn closes the ventilation louver, and

The "full suppression system operation" function fire detection in this area consists of two heat-actuated devices which:

1. Actuate the CO_2 system and send an alarm to the FDAP-A1 and FDAP-B1 and the Fire Alarm Console in the Control Room,

2. Stop the Fuel Oil Transfer Pump "A" and Zone 2 Intake and Exhaust Fans HVS-6 and HVE-18, which in turn closes the ventilation louver, and

3. Sound the local alarm whistle in the room.

3.1.2.6 Fire Suppression. Automatic fire suppression for this area consists of an automatic high pressure carbon dioxide (CO_2) system. This system is actuated:

1. Automatically by either HAD,

2. Manually by activating the "A" Diesel Generator CO_2 System remote manual release located on the outside of the west wall of Diesel Generator "A" room, or

3. Manually by first opening the "A" Diesel Generator CO_2 System pilot control valve, then opening the valve on either CO_2 bottle B9 or B8.

Upon automatic actuation, this system provides an approximately 25-second delay before discharging.

A fire hose station in adjacent FZ 7 and portable fire extinguishers within FZs 2 and 7 are provided for manual fire fighting.

3.1.3 Fire Zone 3 - Safety Injection Pump Room

3.1.3.1 General Description. Zone 3, the Safety Injection Pump Room, is located on the ground floor of the Auxiliary Building on the 226.0 ft. elevation.

3.1.3.2 Fire Barrier Description. The area is enclosed by reinforced concrete fire barriers with the exception of a small wall section made of steel. Pyrocrete fire proofing material has been applied on both sides of the steel wall section separating the Safety Injection Pump Room from the hallway (FZ 7) in sufficient thickness to provide a three-hour fire resistance. A three-hour rated fire door (Fire Door 1) is provided within the Pyrocrete wall section. A three-hour rated fire door (Security Door 27) is provided in the outside wall. Three-hour fire dampers are provided in ventilation ducts to adjacent FZs 1, 7 and 11.

3.1.3.3 Safe Shutdown Equipment. This area contains the three Safety Injection Pumps, two Containment Spray Pumps, two Primary Water Pumps, and associated valving. The safety injection path is required for reactor makeup only in the event of a Charging Pump Room fire. Therefore, loss of the Safety Injection Pumps does not compromise safe shutdown capability for the area under consideration. The Primary Water Pumps are normally used in conjunction with the Boric Acid System. However, borated water from the Refueling Water Storage Tank is available for safe shutdown. Therefore, loss of the Primary Water Pumps does not compromise safe shutdown.

3.1.3.4 Combustibles. Combustible material located in this area includes ordinary Class A combustibles cable and 3.25 gallons of lubricating oil in the safety injection and containment spray pumps. The hazard classification and expected fire severity for this zone is "low."

3.1.3.5 Fire Detection. Fire detection in this area consists of two heat detectors, two ionization smoke detectors, and two manual pull stations. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room.

3.1.3.6 Fire Suppression. There is no automatic fire suppression system in this area. A fire hose station in adjacent FZ 7 and portable fire extinguishers within FZs 3 and 7 are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.4 Fire Zone 6 - Auxiliary Feedwater Pump Room

3.1.4.1 General Description. Zone 6, the Auxiliary Feedwater Pump Room, is located on the ground floor of the Auxiliary Building on the 226 ft. elevation.

3.1.4.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There are three-hour rated fire doors in the wall between this room and the hallway (FZ 7) (Fire Door 26) and the Turbine Building (FZ 25A)(Fire Door 5). Fusible link three-hour fire dampers are provided in ventilation ducts to FZs 7 and 25A.

3.1.4.3 Safe Shutdown Equipment. This area contains the two motor-driven Auxiliary Feedwater Pumps. The turbine-driven Auxiliary Feedwater Pump is located on the Turbine Building ground floor and can provide the steam generator makeup function for safe shutdown in the event the motor-driven pumps are not available.

3.1.4.4 Combustibles. Combustible material in this area includes ordinary Class A combustibles, cables and 3.5 gallons of lubricating oil in each of the two pumps. The hazard classification and expected fire severity for this zone is "low."

3.1.4.5 Fire Detection. Fire detection in this area consists of one heat detector, one ionization smoke detector, and one manual pull station. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room.

3.1.4.6 Fire Suppression. There is no automatic fire suppression in this area. A fire hose station and portable fire extinguishers are provided in adjacent FZ 25A for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.5 Fire Zone 7 - Auxiliary Building Hallway (Ground Floor)

3.1.5.1 General Description. Zone 7 is the Auxiliary Building Hallway and adjacent rooms. It is located on the ground level of the Auxiliary Building at the 226 ft. elevation, but also includes rooms on the second floor which communicate through a large opening with the first floor. The adjacent rooms on the first floor include the Demineralizer and Spent Resin Storage Area, the abandoned Waste Evaporator and Boric Acid Evaporator Areas, Concentrate Hold-up Tank Pump Room and abandoned Gas Stripper Area, Gas Analyzer Area and Steam Generator Blowdown Sample Heat Exchanger Room. The second floor includes the Waste Gas Compressor Area, Spray Additive Tank Room, Concentrates Holding Tank Area and upper portion of the Gas Strippers. Access to the Waste Evaporator Area (FZ 38) at El. 265 ft. is also provided from the second floor portion of this zone via stairs above the gas strippers.

3.1.5.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. Pyrocrete fire proofing material has been applied on both sides of the steel wall section separating the hallway from the Safety Injection (SI) Pump Room (FZ 3) in sufficient thickness to provide a three-hour fire resistance. On the first floor, three-hour rated fire doors are provided in the wall between this zone and the Diesel Generator Rooms "B" (FZ 1) (Fire Door 23) and "A" (FZ 2)(Fire Door 24), SI Pump Room (FZ 3)(Fire Door 1), CCW Pump Room (FZ 5)(Fire Door 3), AFW Pump Room (FZ 6)(Fire Door 26), Pipe Alley (FZ 11)(Fire Door 32), Waste Hold-up Tank Room (FZ 12)(Fire Door 20), RCA Entrance (FZ 25A)(Fire Door 4), and Personnel Dress Out Areas (Fire Door 18) and RCA Lower Containment Access Area (FZ 25C)(Fire Door 9). On the second floor portion of this zone, three-hour rated fire doors are provided to the second floor hallway (FZ 15)(Fire Door 31) and Waste Evaporator Area (FZ 38)(Fire Door 27). Three-hour rated Security Doors 25 and 26 are provided to the Yard area between the Auxiliary and Radwaste Buildings. Unrated Security Door 54 provides access to the Auxiliary Building roof at El. 262 ft. Three-hour fire dampers are provided in the ventilation ducts and openings to FZs 1, 2, 3, 4, 5, 6, 11, 12, 15, 25A and 25C.

3.1.5.3 <u>Safe Shutdown Equipment</u>. This area contains cable runs for both normal shutdown trains, Motor Control Centers 5 and 10 which power safe shutdown equipment, and the alternate feed to MCC 5 from the DS Bus. Safe shutdown can be accomplished by use of the DS bus and local manual operations in other fire zones in the event that equipment in this area is damaged, as described in the H. B. Robinson Appendix R, Section III.G Supplemental Submittal.

3.1.5.4 <u>Combustibles</u>. Combustible material in this area includes ordinary Class A combustibles, cables and 14 gallons of lubricating oil for the station and instrument air compressors and service water booster pumps. The hazard classification and expected fire severity for this zone is "low." Hydrogen bottles are maintained for the gas analyzer and Post Accident Sampling System.

3.1.5.5 <u>Fire Detection</u>. A total of 29 fire detectors are provided for the zone. Fire detection in this zone consists of the following:

1. Four ionization smoke detectors, four heat detectors, and two manual pull stations in the hallway near the Diesel Generators (Detector Zone 11).

2. Three heat detectors, three ionization smoke detectors, seven photoelectric smoke detectors, and two manual pull stations in the hallway near the Air Compressors (Detector Zone 12).

3. Four heat detectors, four ionization smoke detectors, and one manual pull station in the hallway near the Component Cooling Room (Detector Zone 13).

These detectors will alarm through the FDAPs, and actuate the Fire Alarm Console in the Control Room. In addition, the detectors in the hallway near the Air Compressor (Detector Zone 12) will actuate the preaction sprinkler system in the area upon receiving a signal from at least one detector on each detection train.

No fire detection is provided in rooms adjacent to the hallway which are considered part of this area, but which contain insignificant combustibles.

3.1.5.6 <u>Fire Suppression</u>. Partial automatic fire suppression for this area consists of a preaction sprinkler system which is actuated by:

1. Charging the spray header with water by opening the preaction valve:

   a. Automatically by the detection system.
   b. Manually at the FDAP-A1 or B1.
   c. Manually at the preaction valve.

2. Melting the fusible link at the individual sprinkler heads.

This system may be isolated by manually closing the isolation valve just below the preaction valve. The preaction valve is located against the north wall of the hallway near the Instrument Air Compressor.

Three fire hose stations and portable fire extinguishers are provided within FZ 7 on the ground floor for manual fire fighting. A fire hose station and portable fire extinguishers are provided in adjacent FZ 5 for use in the second floor area of FZ 7.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.6 Fire Zone 8 - Boron Injection Tank Room

3.1.6.1 General Description. Zone 8, the Boron Injection Tank Room, is located on the ground floor of the Auxiliary Building on the 226 ft. elevation.

3.1.6.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour fire rated door (Security Door 28) in the outside wall. Fusible link three-hour fire dampers are provided in ventilation ducts to adjacent FZ 11.

3.1.6.3 Safe Shutdown Equipment. This area contains Train B equipment and cables associated with safety injection. Safe shutdown capability is available independent of this fire zone.

3.1.6.4 Combustibles. Combustible material located in this area includes charcoal and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "Low".

3.1.6.5 Fire Detection. Fire detection in this area consists of one heat detector, one smoke detector, and one manual pull station. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room.

3.1.6.6 Fire Suppression. There is no automatic fire suppression system in this area. A fire hose station and portable fire extinguishers are provided outside the room for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.7 Fire Zone 11 - Pipe Alley

3.1.7.1 General Description. Zone 11, the Pipe Alley, is located along the west side of the Auxiliary Building ground floor at elevation 226 ft.

3.1.7.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour rated fire door (Fire Door 32) in the wall between this zone and the hallway (FZ 7). Fusible link three-hour fire dampers are provided in ventilation ducts to FZs 3, 4, 7, 8, 12 and 27.

3.1.7.3 Safe Shutdown Equipment. This area contains cables for both normal shutdown trains. However, the Dedicated Shutdown System will remain available in the event of a fire in this area. Mechanical equipment (valves) can be manually operated after the fire is extinguished as discussed in the exemption received for this zone by NRC letter dated September 17, 1986.

3.1.7.4 Combustibles. Combustible material in this area includes ordinary Class A combustibles and cables. The hazard classification and expected fire severity for this zone is "low."

3.1.7.5 Fire Detection. Fire detection in this area consists of five ionization smoke detectors, two heat detectors, and one manual pull station. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room.

3.1.7.6 Fire Suppression. There is no automatic fire suppression system in this area. Two fire hose stations and portable fire extinguishers are provided in FZs 7 and 11 for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.8 Fire Zone 12 - Waste Holdup Tank, RHR Heat Exchangers

3.1.8.1 General Description. Zone 12, the Waste Holdup Tank Room and RHR Heat Exchanger Room, is located on the ground floor of the Auxiliary Building at Elevation 226 ft. The RHR Heat Exchanger Room extends up to the second floor of the Auxiliary Building.

3.1.8.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour rated door (Fire Door 20) in the wall between this zone and the hallway (FZ 7) and a three-hour rated door (Fire Door 2) in the wall between this zone and the Charging Pump Room (FZ 4). Fusible link three-hour fire dampers are provided in ventilation ducts to FZs 7, 11, 15 and 20.

3.1.8.3 Safe Shutdown Equipment. This area contains the RHR Heat Exchangers, one of which is necessary for plant cooldown. Due to the negligible combustible loading in this zone, the water-filled metal heat exchangers will remain free of fire damage in the event of a fire in this zone.

3.1.8.4 Combustibles. The combustible material located in this area includes ordinary Class A combustibles. Thus, the hazard classification and expected fire severity for this zone is "negligible."

3.1.8.5 Fire Detection. Due to the lack of fixed combustibles in this area, detection is unnecessary.

3.1.8.6 Fire Suppression. There is no automatic fire suppression system in FZ 12. A fire hose station and portable fire extinguishers are provided in adjacent FZ 7 for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.9 Fire Zone 13 - Boric Acid Batch Tank Room

3.1.9.1 General Description. Zone 13, the Boric Acid Batch Tank Room, is located on the second floor of the Auxiliary Building at Elevation 246 ft.

3.1.9.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. One barrier includes a concrete block section. There is a three-hour rated door (Fire Door 28) in the wall between this room and the hallway (FZ 15), and a three-hour rated door (Fire Door 12) in the wall between this room and the Battery Room (FZ 16). Automatic three-hour fire dampers are provided in ventilation ducts to FZs 15, 16 and 20.

3.1.9.3 Safe Shutdown Equipment. This area contains the Boric Acid Batch Tank. Borated water for safe shutdown can be obtained from the Refueling Water Storage Tank.

3.1.9.4 Combustibles. Combustible material in this area includes paper bags containing boric acid and other ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible."

3.1.9.5 Fire Detection. Due to the insignificant fixed combustibles in this area, detection is unnecessary.

3.1.9.6 Fire Suppression. There is no automatic fire suppression system in Zone 13. Two fire hose stations in FZs 13 and 20 and portable fire extinguishers in adjacent FZs 15, 16 and 20 are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.10 Fire Zone 14 - Solid Waste Handling Room

3.1.10.1 General Description. Zone 14, the Solid Waste Handling Room, is located on the second floor of the Auxiliary Building on the 246 ft. elevation.

3.1.10.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. Fusible link three-hour fire dampers are provided in ventilation ducts to FZ 15. There is a three-hour rated door (Fire Door 10) in the wall between this room and the hallway (FZ 15) and an unrated exterior door (SD-62) in the east wall.

3.1.10.3 Safe Shutdown Equipment. This area contains no safe shutdown equipment.

3.1.10.4 Combustibles. This area is no longer routinely used for solid waste handling. Combustible loading is based on nonroutine transient ordinary Class A type combustibles in the zone. The maximum fire severity for these combustibles is "low."

3.1.10.5 Fire Detection. Fire detection in this area consists of twelve heat detectors (on two trains) and one manual pull station. These detectors will, through the FDAP-A2 and B2:

1. Actuate the Fire Alarm Console in the Control Room.

2. Automatically actuate the preaction water sprinkler system after receiving a signal from at least one detector on each detection train.

3.1.10.6 Fire Suppression. Automatic fire suppression for this area consists of a preaction sprinkler system which is actuated by:

1. Charging the spray header with water by opening the preaction valve:

- Automatically by the detection system
- Manually at the FDAP-A2 and B2
- Manually at the preaction valve

2. Melting the fusible link at the individual sprinkler heads.

This system may be isolated by manually closing the isolation valve just below the preaction valve. The preaction valve is located across from the Containment Purge Fan Area in the second floor hallway of the Auxiliary Building (FZ 15).

A fire hose station and portable fire extinguishers are provided in adjacent FZ 15 for manual fire fighting.

3.1.11 Fire Zone 15 - Auxiliary Building Second Level Hallway

3.1.11.1 General Description. Zone 15, the Auxiliary Building Second Level Hallway, is located on the 246 ft. elevation of the Auxiliary Building. Adjacent rooms which are considered part of this area for analysis purposes include the Auxiliary Building supply and exhaust fan rooms, Diesel Generator Intake fan room and the containment purge fan area.

3.1.11.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. Three-hour rated fire doors are provided in the walls between this zone and the Solid Waste Handling Room (FZ 14)(Fire Door 10), Emergency Switchgear Room (FZ 20)(Fire Door 14 and Fire Door 15), Boric Acid Batch Tank Room (FZ 13)(Fire Door 28), Reactor Coolant Filter Room (FZ 4)(Fire Door 29), Nonregenerative Heat Exchanger Room (FZ 4)(Fire Door 30) and Spray Additive Tank Room (FZ 7)(Fire Door 31). There is one fire rated security door (SD-46) in the outside wall. Three-hour fire dampers are provided in ventilation ducts to FZs 2, 4, 7, 8, 11, 12, 13, 14 and 20.

3.1.11.3 Safe Shutdown Equipment. This area contains cables for safe shutdown equipment. This area also contains Auxiliary Building supply and exhaust ventilation fans. Safe shutdown can be accomplished in the event of a fire in this area by use of portable ventilation fans, as required for cubicle cooling, and the Dedicated Shutdown System. The necessary portable ventilation equipment consists of a portable generator and blower assembly.

3.1.11.4 Combustibles. Combustible material located in this area consists of ordinary Class A combustibles, cables and 7,520 lbs. of charcoal. There is also 2,160 lbs. of charcoal in the HVE-15A filter located on the roof and connected to this zone and the Fuel Handling Building by an undampered duct. Hydrogen piping to the Volume Control Tank is routed for a short distance in this area. This piping is supported so as to maintain its integrity in the event of a safe shutdown earthquake. Hydrogen is not included in the fire severity. The hazard classification and expected fire severity for this zone is "low".

3.1.11.5 Fire Detection. Fire detection in this area consists of five heat detectors, five ionization smoke detectors, and two manual pull stations. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room. Detection is provided only in the hallway itself where safe shutdown cables are routed.

3.1.11.6 Fire Suppression. There is no automatic fire suppression system in this area. A fire hose station and portable fire extinguishers are provided within this zone for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.12 Fire Zone 16 - Battery Room

3.1.12.1 General Description. Zone 16, the Battery Room, is located on the 248 ft. elevation of the Auxiliary Building.

3.1.12.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. There are three-hour rated doors in the walls between this room and the Boric Acid Batching Tank Room (FZ 13)(Fire Door 12) and Emergency Switchgear Room (FZ 20)(Fire Door 11). Three-hour fire dampers are provided in ventilation ducts FZs 5, 13, 17, 18 and 20.

3.1.12.3 Safe Shutdown Equipment. This area contains the 125 VDC station batteries, chargers, and MCCs. This equipment provides control power for the normal shutdown systems. In the event this equipment is damaged, safe shutdown can be accomplished by the Dedicated Shutdown System which utilizes 120 VAC control power from the DS bus and transformer.

3.1.12.4 Combustibles. Combustible material located in this zone consists of ordinary Class A combustibles, plastic battery cases and cables. The hazard classification and expected fire severity for this zone is "low". The design of the HVAC system maintains the level of hydrogen generation at less than the allowable limit of 2% concentration per volume.

3.1.12.5 Fire Detection. Fire detection in this area consists of two ionization smoke detectors, two explosion proof heat detectors, and two manual pull stations. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.12.6 Fire Suppression. There is no automatic fire suppression system in this zone. Fire hose stations are available in adjacent FZs 13 and 20 and a portable fire extinguisher is provided within this zone for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.13 Fire Zone 17 - HVAC Equipment Room for Control Room

3.1.13.1 General Description. Zone 17, HVAC Equipment Room for the Control Room, is located on the 242.50 ft. elevation of the Auxiliary Building.

3.1.13.2 Fire Barrier Description. This zone is enclosed in reinforced concrete fire barriers. Fusible link three-hour fire dampers are provided in ventilation ducts to FZs 16 and 18. There is a 1-1/2 hour rated door (Fire Door 22) in the wall between this room and the Unit 1 Cable Room (FZ 18), and three-hour fire rated security doors in the outside wall (Security Door 41) and, wall to the Turbine Building (FZ 25E)(Security Door 42).

3.1.13.3 Safe Shutdown Equipment. This area contains ventilation equipment for the Control Room. If evacuation of the Control Room is required due to fire in this area, safe shutdown can be accomplished by use of the Dedicated Shutdown System.

3.1.13.4 Combustibles. Combustible material located in this area consists of 1300 lbs. of charcoal filters and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low".

3.1.13.5 Fire Detection. Fire detection in this area consists of two ionization smoke detectors, two heat detectors, and one manual pull station in the room and two ionization detectors in HVAC ductwork. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.13.6 Fire Suppression. There is no automatic fire suppression system in this zone. A fire hose station is located in adjacent FZ 25E and a portable fire extinguisher within this zone is provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.14 Fire Zone 18 -Unit No. 1 Cable Spreading Room

3.1.14.1 General Description. Zone 18, the Unit No. 1 Cable Spreading Room, is located on the 242.50 ft. elevation of the Auxiliary Building.

3.1.14.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. There is a 1-1/2 hour rated door (Fire Door 22) in the wall between this room and the Control Room HVAC area (FZ 17) and a three-hour fire rated security door (Security Door 43) in the wall to the Turbine Building (FZ 25E). Three-hour fire dampers are provided in ventilation ducts to FZs 16, 17, 19 and 22.

3.1.14.3 Safe Shutdown Equipment. No safe shutdown equipment is located in this area.

3.1.14.4 Combustibles. Combustible material located in this zone consists of cable insulation and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low."

3.1.14.5 Fire Detection. Fire detection in this area consists of two ionization detectors and two manual pull stations. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.14.6 Fire Suppression. There is no automatic fire suppression system in this zone. A fire hose station is located in adjacent FZ 25E and a portable fire extinguisher within the zone is provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.15 Fire Zone 19 - Unit 2 Cable Spreading Room

3.1.15.1 General Description. Zone 19, the Unit 2 Cable Spreading Room, is located on the 242.50 ft. elevation of the Auxiliary Building.

3.1.15.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Automatic fire dampers are provided in ventilation ducts to FZs 18 and 22. There is a three-hour rated door (Fire Door 21) in the wall between this room and the Emergency Switchgear Room (FZ 20), and a three-hour fire rated security door (Security Door 44) in the wall to the Turbine Building (FZ 25E).

3.1.15.3 Safe Shutdown Equipment. Cables located in this area include control and instrumentation for all of the normal shutdown systems. In the event of significant damage to these cables, safe shutdown can be accomplished utilizing the local controls and instrumentation of the Dedicated Shutdown System.

3.1.15.4 Combustibles. Combustible material located in Zone 19 consists of cable insulation and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "high."

3.1.15.5 <u>Fire Detection</u>. Fire detection in this zone consists of two detection zone circuits containing two heat detectors, four photoelectric smoke detectors and eight ionization smoke detectors, and one manual pull station. These detectors will, through the FDAP-A2 and B2:

1. With one detector in alarm, actuate the Fire Alarm Console in the Control Room.

2. With one detector from each detector zone in alarm,

   a. Actuate three-hour rated dampers in ventilation ductwork, and

   b. Actuate the Halon System.

3.1.15.6 <u>Fire Suppression</u>. Automatic suppression for this area consists of a Halon 1301 Suppression System. This system is actuated:

1. Automatically by the FDAP which requires a detection signal from both detection trains,

2. Manually from either FDAP-A2 (at south end of MCC-2) or FDAP-B2 (east of the IVSW Tank Area), or

3. Manually at the Halon Supply Cylinders.

Upon automatic actuation, this system has an approximate 17-second delay before discharge. Manual actuation from the cylinders has no time delay.

Two fire hose stations located in adjacent FZs 20 and 25E and a portable fire extinguisher within this zone is provided for manual fire fighting.

3.1.16 <u>Fire Zone 20 - Emergency Switchgear Room and Electrical Equipment Area</u>

3.1.16.1 <u>General Description</u>. Zone 20, Emergency Switchgear Room, is located on the 242.50 ft. and 246 ft. elevation of the Auxiliary Building. This room is also known as the E1-E2 Switchgear Room.

3.1.16.2 <u>Fire Barrier Description</u>. This area is enclosed by reinforced concrete fire barriers. Automatic three-hour fire dampers are provided in ventilation ducts to FZs 12, 13, 15, 16 and 36. There are three-hour rated doors in the wall between this zone and the Battery Room (FZ 16)(Fire Door 11), stairwell (FZ 25C)(Fire door 13), hallway (FZ 15)(Fire Door 14 and Fire Door 15), Rod Control Room (FZ 21)(Fire Door 16), and Unit 2 Spreading Room (FZ 19)(Fire Door 21), and a three-hour fire rated security door (Security Door 45) in the wall to the Turbine Building (FZ 25E).

3.1.16.3 <u>Safe Shutdown Equipment</u>. This area contains Safety-related Switchgear E1 and E2, Motor Control Center 6 and Instrument Buses which power normal shutdown equipment. In the event this equipment is damaged, safe shutdown can be accomplished by use of the Dedicated Shutdown Diesel Generator powering the DS bus.

3.1.16.4 Combustibles. Combustible material located in this area consists of cable insulation and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "moderate."

3.1.16.5 Fire Detection. Fire detection in this zone consists of two Detection Zone Circuits containing six heat detectors, four ionization smoke detectors, four photoelectric smoke detectors, and one manual pull station. These detectors will, through the FDAP-A1 and B1:

1. With one detector in alarm, actuate the Fire Alarm Console in the Control Room,

2. With one detector from each detector zone in alarm,

    a. Actuate the three-hour rated fire dampers in the ventilation ductwork, and

    b. Actuate the Halon 1301 system.

3.1.16.6 Fire Suppression. Automatic fire suppression for this area consists of a Halon 1301 suppression system. This system is actuated:

1. Automatically through the FDAPs which requires a detection signal from both detection trains,

2. Manually from either FDAP-A1 (south of the instrument and service air compressors on the first floor Auxiliary Building Hallway) or FDAP-B1 (across from the Inside AO Office) in FZ 7, or

3. Manually at the Halon supply cylinders.

Upon automatic actuation, this system has approximately a 17-second delay before discharge. Manual actuation from the cylinders has no time delay.

Two fire hose stations located in this zone and adjacent FZ 25E and portable fire extinguishers within the zone are provided for manual fire fighting.

3.1.17 Fire Zone 21 - Rod Control Room

3.1.17.1 General Description. Zone 21, the Rod Control Room, is located on the second floor of the Auxiliary Building on the 249.50 ft. elevation.

3.1.17.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour rated door (Fire Door 16) in the wall between this room and the the E1-E2 Switchgear Room (FZ 20) and a three-hour rated security door (SD-56) in the outside wall. Automatic three-hour fire dampers are provided in ventilation ducts to FZs 9, 10 and 11.

3.1.17.3 Safe Shutdown Equipment. This area contains safe shutdown cabling routed from the cable vaults below. The local/remote control selection switches for Service Water Pumps C and D are also located in this area. In the event of damage to this equipment, safe shutdown can be accomplished using the charging pump room panel alternate controls for Service Water Pump D and the Dedicated Shutdown System.

3.1.17.4 Combustibles. Combustible material located in Zone 21 consists of cable insulation and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low."

3.1.17.5 Fire Detection. Fire detection in this area consists of three ionization detectors and one manual pull station. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.17.6 Fire Suppression. There is no automatic fire suppression system in this area. A fire hose station located in adjacent FZ 20 and portable fire extinguisher within the zone is provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.18 Fire Zone 22 - Control Room

3.1.18.1 General Description. Zone 22, the Control Room, is located on the 254 ft. elevation of the Auxiliary Building.

3.1.18.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. Three-hour fire dampers are provided in ventilation ducts to FZs 18, 19 and 23. There are two, three-hour rated security doors in the outside wall to the Observation Deck (Security Door 48), and in the wall to the Turbine Building (FZ 25E)(Security Door-49). A three-hour rated door (Fire Door 17) is also provided in the wall between this room and the Hagan Room (FZ-23).

3.1.18.3 Safe Shutdown Equipment. This area contains the control and instrumentation panels for all of the normal shutdown systems. Safe shutdown can be accomplished in either event of damage to this equipment or forced evacuation from the control room by use of the local controls and instruments of the Dedicated/Alternative Shutdown System.

3.1.18.4 Combustibles. Combustible material located in this area consists of cable insulation, ordinary Class A combustibles (most notably paper and plastics), office furnishings and carpeting. The hazard classification and expected fire severity for this zone is "high."

3.1.18.5 Fire Detection. Fire detection in this area consists of four heat detectors and 17 ionization smoke detectors. Six of the 17 ionization smoke detectors are located inside the RTGB. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.18.6 Fire Suppression. There is no automatic fire suppression system in this area. Two fire hose stations located in adjacent FZs 23 and 25E and portable fire extinguishers within the zone are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated November 13, 1981.

3.1.19 Fire Zone 23 - Hagan Room

3.1.19.1 General Description. Zone 23, the Hagan Room, is located on the third level of the Auxiliary Building on the 254 ft. elevation.

3.1.19.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. There is a three-hour rated fire door (Fire Door 17) in the wall between the Hagan Room and the Control Room (FZ 22) and a three-hour rated bullet-proof security door (Fire Door 25) in the stairwell wall (FZ-25c). Automatic three-hour fire dampers are provided in ventilation ducts FZs 20 and 22.

3.1.19.3 Safe Shutdown Equipment. This area contains instrumentation, control, and relay racks for shutdown systems. A safe shutdown can be accomplished in the event of damage to this equipment by use of the local controls and instruments of the Dedicated Shutdown System.

3.1.19.4 Combustibles. Combustible material located in Zone 23 consists of cables and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low."

3.1.19.5 Fire Detection. Fire detection in the Hagan Room consists of two heat detectors, two ionization smoke detectors, and one manual pull station. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.1.19.6 Fire Suppression. Manual fire suppression for the Hagan Room consists of a dry standpipe (Hose Station 52) supplied by a dry pipe valve. This system is actuated manually by opening Valve FP-95 at the hose connection in the Hagan Room, which exhausts air from the system and opens the dry pipe valve to allow free flow of water through the standpipe and hose.

The dry standpipe system can be isolated by closing the Valve FP-87.

Portable fire extinguishers withi this zone and adjacent FZ-22 are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.1.20 Fire Zone 36 - CCW Surge Tank Room

3.1.20.1 General Description. This zone is the Component Cooling Water Surge Tank Room, located on the Auxiliary Building roof at Elevation 267 ft. This zone is located above the Hagan Room (FZ 23).

3.1.20.2 Fire Barrier Description. This zone is enclosed by reinforced concrete barriers. The zone is separated from other zones on the Auxiliary Building roof by distance and lack of fixed combustibles. Access to this zone is from the Auxiliary Building roof through an exterior three-hour rated metal door. No fire dampers are provided in the ventilation ducts to adjacent FZ 23.

3.1.20.3 Safe Shutdown Equipment. This zone contains one valve, CC-710, which is credited for Safe Shutdown (SSD). This valve is a manual, normally open valve that remains in this position for SSD. A fire in this zone will not impact the function of this valve for SSD.

3.1.20.4 Combustibles. Minor amounts or ordinary Class A combustibles are located in this room. The hazard classification and expected fire severity level for this zone is "negligible".

3.1.20.5 Fire Detection. Due to the lack of combustibles in the area, automatic fire detection is not provided.

3.1.20.6 Fire Suppression. No automatic fire suppression system is provided for this area. A fire hose on the turbine deck and a portable fire extinguisher located on the outside wall of this room are available for manual fire fighting.

The detection/fixed suppression requirements of Appendix R, Section III.G.3 are not applicable for this zone. Since this valve is normally open and remains open for Appendix R Safe Shutdown, a fire in this area will not cause damage to the valve or prevent it from performing its SSD function. Additionally, there are no cables associated with the valve that could cause misoperation of the valve during a fire.

3.1.21 Fire Zone 38 - Waste Evaporator Area

3.1.21.1 General Description. Zone 38 is the Waste Evaporator Area, which is located in the Auxiliary Building at the 265 ft. Elevation. This zone is considered to be part of Fire Area A for analysis purposes. This zone was later added to Auxiliary Building over top of the existing roof at elevation 262 ft. A void space exists between the old roof and concrete floor slab of the zone. Waste Evaporator "B" located within the zone has been abandoned. Only a skid mounted waste water demineralizer is in use in this zone.

3.1.21.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Normal access to this room is obtained from the stairs located in FZ 7 at El. 246 ft. A three hour fire rated door (Fire Door-27) is provided between this zone and FZ 7. Security doors were provided in the outside walls leading to the Auxiliary Building Roof at El. 262 ft. (Security Door-54), and north exterior balcony (Security Door-55). Fire dampers are not provided in the ventilation system where the duct work exits the exterior walls of the zone.

3.1.21.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.1.21.4 Combustibles. Combustibles materials for this zone includes ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low".

3.1.21.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.1.21.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A fire hose station and portable fire extinguisher are provided within the zone.

3.2 Appendix R Fire Area B (Fire Zone 4) - Charging Pump Room, VCT Room and Nonregenerative Heat Exchanger Room

3.2.1 General Description

Zone 4 is located on two elevations of the Auxiliary Building. The Charging Pump Room, Nonregenerative and Seal Water Heat Exchanger Room are located on the ground floor of the Auxiliary Building at the 226 ft. elevation. The Nonregenerative and Seal Water Heat Exchanger Room extends up to the second floor through large floor openings. The Volume Control (VC) Tank Room and Reactor Coolant Filter Room are also located at the 246 ft. elevation.

3.2.2 Fire Barrier Description

This area is enclosed by reinforced concrete 3-hour fire barriers. There are three-hour rated doors (Fire Doors 2, 29, 30, and 33) in the walls between these rooms and the Auxiliary Building lower (FZ-7) and upper (FZ-15) hallways. Three-hour dampers are provided in ventilation ducts FZs 7, 11 and 15.

3.2.3 Safe Shutdown Equipment

This area contains the three Charging Pumps and VC Tank. The A Pump is part of Dedicated Shutdown System Train A. The C Pump is part of Dedicated Shutdown System Train B. Existing DSS local control and instrumentation panels are also located in this area. Loss of the Charging Pumps and VCT will not prevent safe shutdown since the Safety Injection Pumps, Refueling Water Storage Tank, Pressurizer Power-Operated Relief Valves, and associated cabling are available independent of this area. Damage to the local panels will also not prevent safe shutdown since the controls and instruments are part of the dedicated train only.

3.2.4 Combustibles

Combustible material located in this area consists of ordinary Class A combustibles and 40 gallons of lubricating oil in each charging pump. The hazard classification and expected fire severity for this zone is "low." Hydrogen piping to the Volume Control Tank is routed on the second level. This piping is supported so as to maintain its integrity in the event of a safe shutdown earthquake. Hydrogen is not included in the fire severity.

3.2.5 Fire Detection

Fire detection in this area consists of two heat detectors, two ionization smoke detectors, and one manual pull station. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room. Detection is provided only in the Charging Pump Room itself.

3.2.6 Fire Suppression

There is no automatic fire suppression system in this area. Fire hose stations and portable fire extinguishers located in adjacent FZs 7 and 15 are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this area via NRC letter dated September 17, 1986.

3.3 Appendix R Fire Area C (Fire Zone 5) - Component Cooling Pump Room

3.3.1 General Description

Zone 5, the Component Cooling Pump Room, is located in the southeast corner of the Auxiliary Building ground floor at the 226 ft. elevation. This zone contains the component cooling pumps and heat exchangers as well as the boric acid tanks and transfer pumps.

3.3.2 Fire Barrier Description

This area is enclosed by reinforced concrete fire barriers. One barrier includes a three-hour rated concrete block section and a three-hour rated security door (SD-24) to the Turbine Building (FZ 25A). There is a three-hour rated fire door (Fire Door 3) in the wall between this room and the Auxiliary Building hallway (FZ 7). Three-hour fire dampers are provided in ventilation ducts to FZs 7, 16 and 25A.

3.3.3 Safe Shutdown Equipment

This area contains the three Component Cooling Pumps, two Component Cooling Heat Exchangers, Boric Acid Tanks, and Boric Acid Transfer Pumps. The A Component Cooling Pump is part of Dedicated Shutdown System Train A. The C Component Cooling Pump is part of Dedicated Shutdown System Train B. One Component Cooling Pump and both Component Cooling Heat Exchangers are required for safe shutdown.

The loss of the Boric Acid Pumps due to a fire has no safe shutdown consequences since the reactor can be borated using RWST water.

Existing local service water transfer switch panels for the dedicated shutdown system are located in this area. Loss of this equipment would not prevent safe shutdown since redundant service water equipment is available independent of this area.

Due to the low combustible content in this area, the one-hour cable wraps for the power cables to Component Cooling Pumps A and C, and partial area coverage wet pipe sprinkler system over the Component Cooling Pumps, the required equipment will remain available to support safe shutdown in the event of a fire.

An exemption was received for this area by CP&L from the separation requirements of Appendix R, Section III.G.2 via NRC letter dated October 25, 1984 and October 17, 1990.

3.3.4 Combustibles

Combustible material in this area includes cable insulation and ordinary Class A combustibles. In addition, there is an insignificant amount of lubricating oil in the pumps. The hazard classification and expected fire severity for this area is "low."

3.3.5 Fire Detection

Fire detection in this area consists of three heat detectors, three ionization smoke detectors, and one manual pull station. These detectors will, through the FDAP-A1 and B1, actuate the Fire Alarm Console in the Control Room.

3.3.6 Fire Suppression

A partial area coverage wet pipe automatic sprinkler fire suppression system is installed in this area over the Component Cooling Pumps. A fire hose station in adjacent FZ 7 and portable fire extinguishers within the zone and in adjacent FZ 7 are provided for manual fire fighting.

3.4 Appendix R Fire Area D (Fire Zone 9) - North Cable Vault

3.4.1 General Description

Zone 9, the North Cable Vault Room, is located on the ground floor of the Auxiliary Building on the 226 ft. elevation.

3.4.2 Fire Barrier Description

This area is enclosed by reinforced concrete fire barriers. There are three-hour rated doors (Fire Doors 8A and 8B) in the wall between this room and the South Cable Vault (FZ 10). Automatic three-hour dampers are provided in ventilation ducts to FZ 21.

3.4.3 Safe Shutdown Equipment

This area contains cables in Train A & B equipment and instrumentation located inside containment. In the event of damage to these cables, sufficient Train A and Train B equipment remains available to accomplish the required safe shutdown functions.

3.4.4 Combustibles

Combustible material in this area consists of minor amounts of ordinary Class A combustibles and cable insulation. The hazard classification and expected fire severity for this zone is "low."

3.4.5 Fire Detection

Fire detection in this area consists of two photoelectric smoke detectors, one ionization smoke detector, one heat detector, and one manual pull station. These detectors will, through the FDAP-A1 and B1:

1. Actuate the Fire Alarm Console in the Control Room.
2. Close Fire Dampers 22 and 23 upon receiving a signal from at least one detector on each detection train.
3. Actuate the CO_2 suppression system upon receiving a signal from at least one detector on each detection train.

3.4.6 Fire Suppression

Automatic fire suppression for this area consists of a high pressure carbon dioxide (CO_2) system. This system is activated:

1. Automatically through the FDAPs by signals from at least one detector on each detection train.
2. Manually from either FDAP-A1 (located just south of Instrument Air and Service Air Compressor in Zone 7) or FDAP-B1 (located across from the Inside AO Office) in Zone 7.
3. Manually from either of the manual actuation stations (located outside the South Cable Vault in the Personnel Access Corridor.
4. Manually from the CO_2 storage area (located in the Pipe Alley).

This system provides for an approximately 17-second delay except when activated manually.

A fire hose station in FZ 25C and portable fire extinguishers within the zone and adjacent FZ 10 are provided for manual fire fighting.

3.5 Appendix R Fire Area E (Fire Zone 10) - South Cable Vault

3.5.1 General Description

Zone 10, the South Cable Vault Room, is located on the ground floor of the Auxiliary Building on the 226 ft. elevation.

3.5.2 Fire Barrier Description

This area is enclosed by reinforced concrete fire barriers. There are three-hour rated doors (Fire Doors 6 and 7) in the wall between this room and the Turbine Building containment access area (FZ 25C) and three-hour rated doors (Fire Doors 8A and 8B) in the wall between this zone and the North Cable Vault (FZ 9). Automatic three-hour fire dampers are provided in ventilation ducts to FZ 21.

3.5.3 Safe Shutdown Equipment

This area contains cables for Trains A and B equipment and instrumentation located inside containment. In the event of damage to these cables, sufficient Train A and Train B equipment remains available to accomplish the required safe shutdown functions.

3.5.4 Combustibles

Combustible material in this area consists of cable insulation and minor amounts of the ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "low."

3.5.5 Fire Detection

Fire detection in this area consists of two heat detectors, two ionization smoke detectors, two photoelectric smoke detectors, and one manual pull station. These detectors will, through the FDAP-A1 and B1:

1. Actuate the Fire Alarm Console in the Control Room.

2. Close Fire Dampers 24 and 25 upon receiving a signal from at least one detector on each detection train.

3. Actuate the CO_2 suppression system upon receiving a signal from at least one detector on each detection train.

3.5.6 Fire Suppression

Automatic fire suppression for this area consists of a high pressure carbon dioxide (CO_2) system. This system is actuated:

1. Automatically through the FDAPs by signals from at least one detector on each detection train.

2. Manually from either FDAP-A1 (located just south of Instrument Air and Service Air Compressor in Zone 7) or FDAP-B1 (located across from the Inside AO Office) in Zone 7.

3. Manually from the manual actuation stations (located outside the South Cable Vault in the Containment Access Area in FZ 25C.

4. Manually from the CO_2 storage area (located in the pipe alley).

This system provides for an approximately 17-second delay except when activated manually.

A fire hose station in adjacent FZ 25C and portable fire extinguishers within the zone and adjacent FZ 9 are provided for manual fire fighting.

3.6 Appendix R Fire Area F (Fire Zone 24) - Containment

3.6.1 General Description

Zone 24, the Containment Vessel, is a self-contained cylindrical structure. Equipment areas within containment include the electrical penetration area, the reactor coolant pump bays, and the containment general area.

3.6.2 Fire Barrier Description

This area is enclosed by the containment vessel, a reinforced concrete structure. Access is provided by the personnel entry door.

3.6.3 Safe Shutdown Equipment

This area contains power, instrumentation, and control cable for safe shutdown systems. Cables are protected in containment by several means: in the penetration area, a preaction sprinkler system is installed; the coolant pump bays are each protected by a preaction sprinkler system; and Dedicated Shutdown System cables are Rockbestos cables in conduit which are equivalent to the protection of a radiation energy shield. Therefore, at least one primary loop will remain available to support safe shutdown in the event of a fire in this area.

An exemption from the separation requirements of Appendix R, Section III.G.2 (to the extent that Rockbestos fire-resistant cable is functionally equivalent to a radiation heat shield) was granted by the NRC for this area. The exemption is documented by NRC letter dated September 17, 1986.

3.6.4 Combustibles

Combustible material in the area includes cable insulation. In addition, there are 600 lbs. of charcoal. Reactor Coolant Pumps A and B contain 200 gallons of lubricating oil, Reactor Coolant Pump C contains 250 gallons of lubricating oil. The localized hazard classification and expected fire severity in RCP Bay A is "low," RCP Bay B is "negligible," RCP Bay C is "low," and "low" in the remaining area.

3.6.5 Fire Detection

Fire detection in the penetration area consists of four ionization smoke detectors, four heat detectors, and one manual pull station. These detectors will, through the FDAP-A2 and B2:

1. Actuate the Fire Alarm Console in the Control Room.

2. Actuate the preaction valve after receiving a signal from at least one detector from each detection train.

Fire detection in each coolant pump bay includes two 190°F heat detectors and four infrared flame detectors. These detectors will, through the FDAP-A2 or B2:

1. Actuate the Fire Alarm Console in the Control Room.
2. Actuate the preaction valve after receiving a signal from at least one detector on each detection train.

Fire detection on the CV operating deck includes four photoelectric smoke detectors and four heat detectors. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.6.6 Fire Suppression

Automatic fire suppression for the penetration area consists of a preaction water sprinkler system which is activated by:

1. Charging the spray header with water by opening the preaction valve either:
   a. Automatically through the FDAPs by signals from at least one detector on each detection train,
   b. Manually at the Containment Fire Protection Panel (Control Room), or
   c. Manually at preaction valve, located in the stairwell to the second level of the Auxiliary Building.
2. Melting the fusible link at individual sprinkler heads.

This system may be isolated by either:

1. Manually closing the OS&Y valve upstream of the preaction valve. The valve is located in the ground floor landing of the stairwell to the second floor of the Auxiliary Building (FZ 25C), or
2. Remote closing either of two motor-operated isolation valves from the Control Room (FZ 22). These valves are located in the Auxiliary Building Pipe Alley (FZ 11). These valves can also be manually closed.

Automatic fire suppression for each coolant pump bay consists of a preaction water sprinkler system which is actuated by:

1. Charging the spray header with water by opening the preaction valve either:

   a. Automatically through the FDAPs by signals from at least one detector on each detection train,

   b. Manually at the Containment Fire Protection Panel (Control Room), or

   c. Manually at deluge valve control panel in CV.

2. Melting the fusible link of each individual sprinkler head.

This system may be isolated by either:

1. Manually closing the OS&Y valve upstream of each pump bay preaction valve. The valve is located in the containment vessel next to the Polar Crane Wall, west of the personnel entry.

2. Remotely closing either of two motor-operated isolation valves from the Control Room. These valves are located in the Auxiliary Building pipe alley. These valves can also be manually closed.

3. Manually closing the OS&Y valve upstream of the motor-operated isolation valves which is also located in the Auxiliary Building Pipe alley.

By letter dated March 7, 1985, CP&L received an exemption from the requirements of Appendix R, Section III.O, for a reactor coolant pump lube oil collection system. In lieu of installing such a system, fixed fire suppression is maintained and additional detection and dikes are installed in the pump bays.

Eight fire hose stations and portable fire extinguishers are provided for manual fire fighting in Containment.

3.7 Appendix R Fire Area G - Exterior Area

Fire Area G consists of all exterior zones located outside the fire barriers of the Auxiliary Building, Containment Vessel, and RHR Pit. This area is divided into multiple zones based upon distance or structural separation (for those zones containing safe shutdown equipment) or fire suppression systems (e.g., the yard transformers). With the exception of zones for which exemptions have been received, one train of alternative shutdown capability has been provided independent of each fire zone under consideration. Therefore, a fire in one exterior zone within Area G will not preclude access for manual operation elsewhere within the area if necessary.

The term "Yard" refers to any portion of the exterior area, above or below grade, directly adjacent to a fire zone or fire area boundary. Included in the "Yard" area are miscellaneous structures such as access platforms, roof decks (i.e., Auxiliary and Fuel Handling Buildings, and Control Room observation deck), elevator shaft, etc., which do not fall within the outline of the Turbine, Auxiliary, Fuel Handling or Radwaste Buildings. These miscellaneous structures serve only a support function and are generally not enclosed. Some fire zones do extend into Yard areas as noted in their general descriptions to encompass miscellaneous equipment (i.e., the DS transformer in FZ 25A, the condensate and seal water booster pumps and equipment area north of Column Line G in FZ 25B, the dedicated shutdown diesel generator fuel oil storage tank and radiator in FZ 25D, the north platforms of FZs 25F and 25G). Correspondence and documents prior to UFSAR Revision 14, 1997, may refer to portions of the "Yard" area as part of Fire Zone 25.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 for applicable zones within Area G was received by CP&L via NRC letter dated September 17, 1986.

3.7.1 Fire Zone 25A - Turbine Building East Ground Floor

3.7.1.1 General Description. Zone 25A is the Turbine Building East Ground Floor at grade El. 226 ft. and east of Column Line 10. This portion of the Turbine Building is an open structure containing the hydrogen seal oil unit, condenser tube cleaning control panels and Radiation Controlled Access (RCA) Entrance. The RCA Entrance is an enclosed area. This zone includes the dedicated shutdown (DS) transformer located in the Yard immediately adjacent to this zone at the southeast corner of the building.

3.7.1.2 Fire Barrier Description. This area is an open structure with the exception of the RCA Entrance which is enclosed by concrete block. The zone is separated from the Auxiliary Building by reinforced concrete fire barriers having a fire rating in excess of three-hours. Three-hour rated fire doors are provided at the entrance to the Auxiliary Building hallway (FZ 7) (Fire Door 4) and Auxiliary Feedwater Pump Room (FZ 6) (Fire Door 5). Three-hour rated fire dampers are provided to adjacent Auxiliary Building FZs 5, 6 and 7. The fire wall is erected on the north and west sides of the DS transformer.

3.7.1.3 Safe shutdown equipment. This zone contains the DS transformer and cables. The transformer is located in the Yard at southeast corner of the zone. A fire wall is built along the north and west sides of the transformer. The DS cables are routed along the outside of the turbine building on the south side at the mezzanine floor elevation and down to the transformer on the east side of the building. The normal on-site power distribution system remains available for safe shutdown of the plant in the event the DS cables or transformer are damaged in a fire.

3.7.1.4 Combustibles. Combustible material in this fire zone includes ordinary Class A combustibles, cabling, lube oil piping on the south side of the zone, hydrogen piping on the south side and middle of the zone, hydrogen seal oil unit, several small pumps (5 gallons total), waste oil storage drum (55 gallons) located at Column A/6, and DS transformer oil (approximately 452 gallons).

The turbine lube oil system contains approximately 10,000 gallons of oil, the hydrogen seal oil unit contains approximately 200 gallons of oil, and the turbine hydraulic oil system contains approximately 200 gallons of oil. Due to the fact that the turbine lube oil, hydrogen seal oil and turbine hydraulic oil piping are routed throughout the turbine building, the entire quantity of each system will be included in the combustible loading for each of the Turbine Building FZs 25A, 25B, 25E, 25F and 25G. This is a very conservative assumption and assumes catastrophic failure of the turbine generator and each of these systems. The hydrogen piping system is not included in this assumption since the Turbine Building is an open structure, it is anticipated that the hydrogen will either dissipate or be isolated prior to ignition.

The hazard classification and expected fire severity for this zone is "high". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is "moderate".

3.7.1.5 Fire detection. The hydrogen seal oil area is provided with heat actuated devices (HAD). Actuation of the HADs will automatically trip the deluge valve protecting the hydrogen seal oil unit and manifold. Fire detection in the RCA Entrance area (Fire Detection Zone 6) consists of one heat detector, four smoke detectors and one manual pull station. These detectors will actuate the Fire Alarm Console in the Control Room via FDAP-A1 and B1.

3.7.1.6 Fire suppression. A deluge water spray system is provided for the hydrogen seal oil unit and hydrogen manifold. The system is automatically actuated by the fire detection system and can be manually actuated at the deluge valve. Actuation of the system will annunciate in the Control Room on the Fire Alarm Console. The system can be manually isolated by closing the isolation valve just below the deluge valve. The deluge valve is located south of the Turbine Building in the yard area at the transformer valve manifold.

Fire hose stations and portable fire extinguishers are located within this fire zone and in adjacent Fire Zone 25B for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.2 Fire Zone 25B - Turbine Building West Ground Floor

3.7.2.1 General Description. Zone 25B is the Turbine Building West Ground Floor at grade El. 226ft. and west of Column Line 10. This portion of the Turbine Building is an open structure containing the turbine lube oil reservoir tank and coolers, lube oil storage tank, turbine lube oil conditioning equipment, feedwater pumps, turbine driven auxiliary feedwater pump, auxiliary plant heating boiler and its conditioning tanks and fuel oil pumps, condensate pumps, seal water booster pumps, the equipment area north of Column Line G and water treatment area. The water treatment area is an enclosed area.

3.7.2.2 Fire Barrier Description. This area is an open structure with the exception of the water treatment area which is enclosed by unrated steel siding. The zone is separated from the Auxiliary Building and Containment Vessel by reinforced concrete fire barriers having a fire rating in excess of three-hours. The condensate polishing building is located directly to the south in an unrated structure. The secondary sample room is located directly to the west in a concrete block structure. The caustic building is also located directly to the west in an unrated metal structure. This zone contains no fire rated doors or dampers.

3.7.2.3 Safe Shutdown Equipment. This zone contains the turbine driven auxiliary feedwater pump and its associated valves. Dedicated shutdown (DS) cables are routed along the outside of the turbine building on the south side at the far west end where they rise up to the operating deck floor elevation. These cables are being routed from the DS diesel (FZ 25D) to the DS transformer in FZ 25A. The motor driven AFW pumps and normal on-site power distribution system remains available for safe shutdown of the plant in the event this equipment is damaged in a fire.

3.7.2.4 Combustibles. Combustible material in this fire zone includes ordinary Class A combustibles, cabling, lubricating oil for miscellaneous pumps, fuel oil for the auxiliary boilers (approximately 18 gallons), turbine lube oil storage tank, lube oil storage tank (normally empty during plant operation), oil conditioning tank and its components and hydrazine drums.

The miscellaneous pumps having lubricating oil include the two main feedwater pumps containing 85 gallons each, two condensate pumps containing 18 gallons each (located in the Yard immediately south of this zone), primary air and instrument air "C" compressors containing 4.5 gallons each, two heater drain pumps containing 3.5 gallons each and three steam generator blowdown wet layup pumps containing 1 gallon total.

The turbine lube oil system contains approximately 10,000 gallons of oil, the hydrogen seal oil unit contains approximately 200 gallons of oil, and the turbine hydraulic oil system contains approximately 200 gallons of oil. Due to the fact that the turbine lube oil, hydrogen seal oil and turbine hydrolic oil piping are routed throughout the turbine building, the entire quantity of each system will be included in the combustible loading for each of the Turbine Building FZs 25A, 25B, 25E, 25F and 25G. This is a very conservative assumption and assumes catastrophic failure of the turbine generator and each of these systems. The hydrogen piping system is not included in this assumption since the turbine building is an open structure, it is anticipated that the hydrogen will either dissipate or be isolated prior to ignition.

The hazard classification and expected fire severity for this zone is "moderate". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is "low".

3.7.2.5 Fire Detection. The turbine lube oil reservoir tank and lube oil storage tank area is provided with heat actuated devices (HAD). Actuation of the HADs will automatically trip the deluge valve protecting the tank and coolers.

3.7.2.6 Fire Suppression. A deluge water spray system is provided for the turbine lube oil tank, lube oil storage tank, laydown area adjacent to the tanks, oil conditioning tank and component area and deluge valve area. The system provides nozzles directed at the tanks as well as area type closed sprinklers. The system is automatically actuated by the fire detection system and can be manually actuated at the deluge valve or from a remote station located on a column in the tank area. Actuation of the system will annunciate in the Control Room on the Fire Alarm Console. The system can be manually isolated by closing the isolation valve just below the deluge valve. The deluge valve is located adjacent to the lube oil storage tank on the north side.

Fire hose stations and portable fire extinguishers are located within this fire zone and in adjacent Fire Zone 25A for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.3 Fire Zone 25C - Turbine Building CV Access and RCA Tool Area

3.7.3.1 General Description. Zone 25C is the Turbine Building Containment Vessel (CV) and RCA Tool Area at grade El. 226 ft. This portion of the Turbine Building is enclosed containing RCA dress out areas, RCA tool area and lower CV access.

3.7.3.2 Fire Barrier Description. This area is enclosed by unrated metal siding to the yard on the west, an unrated roof and concrete block at the interface with FZs 25A and 25B. The zone is separated from the Auxiliary Building and CV by reinforced concrete fire barriers having a fire rating in excess of three-hours. Three-hour rated fire doors (Fire Door 9 and Fire Door 18) are provided at the entrance to the Auxiliary Building, FZ 7. A three-hour rated fire damper is provided to adjacent Auxiliary Building FZ 7.

3.7.3.3 Safe Shutdown Equipment. This zone has no safe shutdown equipment.

3.7.3.4 Combustibles. Combustible material in this fire zone includes ordinary Class A combustibles, cabling, concentrations of anti-C dress out clothes and miscellaneous work tools. The tools include electrical extension cords, rope, plastic buckets, rubber and plastic hoses, leather pouches and straps, wooden handled tools, hard hats, rubber floor mats, masks, grease guns, welding gloves, etc. The hazard classification and expected fire severity for this zone is "moderate".

3.7.3.5 Fire Detection. There is no fixed fire detection system provided for this area.

3.7.3.6 Fire Suppression. There are no fixed fire suppression systems provided for this area. Fire hose stations and portble fire extinguishers are located within this fire zone and in adjacent Fire Zone 7 for manual fire fighting. Additionally, yard fire hydrant and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.4 Fire Zone 25D -Dedicated Shutdown Diesel Generator

3.7.4.1 General Description. Zone 25D is the Dedicated Shutdown Diesel Generator located in the Yard area at Grade El. 226 ft. This zone contains the dedicated shutdown diesel generator, its fuel oil storage tank, radiator and other support components located in the Yard area directly south of the diesel enclosure.

3.7.4.2 Fire Barrier Description. The diesel generator is located in a self contained unrated metal enclosure approximately 10 ft. by 45 ft. This zone is spatially separated from the Turbine Building by approximately 65 feet. A three foot high concrete dike is erected around the diesel fuel oil tank and designed to contain the capacity of the tank. The dike is approximately 16 ft. by 21 ft. and located approximately 12 feet from the diesel generator enclosure and approximately 65 feet from the Turbine Building.

3.7.4.3 Safe Shutdown Equipment. This zone contains the dedicated shutdown diesel generator and accessories. Also included in this zone is the diesel fuel oil day tank. DS cables are routed to the Turbine Building along the turbine crane structure.

3.7.4.4 Combustibles. Within the diesel generator enclosure, combustible material in this fire zone includes 358 gallons of lubricating oil, a 150 gallon diesel fuel oil day tank, cables, and a small quantity of ordinary Class A combustibles. Within the diked area of the yard, the diesel fuel oil tank contains 5000 gallons. The hazard classification and expected fire severity for this zone is "high". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is "low".

3.7.4.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.4.6 Fire Suppression. There is no fixed fire suppression system provided for this zone. Portable fire extinguishers are located within this fire zone for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.5 Fire Zone 25E - Turbine Building East Mezzanine

3.7.5.1 General Description. Zone 25E is the Turbine Building East Mezzanine at El. 242'-6" and east of Column Line 10. This portion of the Turbine Building is an open structure containing the condenser vacuum pumps, miscellaneous heat exchangers, miscellaneous electrical panels, and 480VAC and 4160VAC switchgear room. The 4160VAC switchgear room is an enclosed area.

3.7.5.2 Fire Barrier Description. This area is an open structure with the exception of the 4160VAC switchgear room which is enclosed by unrated siding. The condenser vacuum pump room is enclosed by unrated metal walls with no ceiling. The zone is separated from the Auxiliary Building by reinforced concrete fire barriers having a fire rating in excess of three-hours. Three-hour rated fire doors are provided to the Auxiliary Building fire zones, HVAC Equipment Room (FZ 17)(Fire Door 42), Unit 1 Cable Spreading Room (FZ 18)(Fire Door 43), Unit 2 Cable Spreading Room (FZ 19)(Fire Door 44) and Emergency Switchgear Room, Electrical Equipment Area (FZ 20)(Fire Door 45) and Control Room (FZ 22)(Fire Door 49). No ventilation openings exist to the adjacent Auxiliary Building.

3.7.5.3 Safe Shutdown Equipment. This zone contains the dedicated shutdown (DS) cables, DS bus, DS control panel, DS batteries and battery charger. These DS components are located in the 4160 VAC swithgear room. The DS cables are routed from the operating deck down to the mezzanine floor elevation along the outside of the turbine building on the south side prior to entering the 4160 VAC switchgear room. The normal on-site power distribution system remains available for safe shutdown of the plant in the event the DS cables or equipment are damaged in a fire.

3.7.5.4 Combustibles. Combustible material in this fire zone includes ordinary Class A combustibles, cabling, DS battery rack, the turbine lube oil piping on the south side of the zone, hydrogen piping on the south side and middle of the zone, hydrogen seal oil piping, turbine hydraulic oil system piping, and portable generator cabinet (5 gallons of fuel).

The turbine lube oil system contains approxiately 10,000 gallons of oil, the hydrogen seal oil unit contains approximately 200 gallons of oil, and the turbine hydraulic oil system contains approximately 200 gallons of oil. Due to the fact that the turbine lube oil, hydrogen seal oil and turbine hydraulic oil piping are routed throughout the turbine building, the entire quantity of each system will be included in the combustible loading for each of the Turbine Building FZs 25A, 25B, 25E, 25F and 25G. This is a very conservative assumption and assumes catastrophic failure of the turbine generator and each of these systems. The hydrogen piping system is not included in this assumption since the turbine building is an open structure, it is anticipated that the hydrogen will either dissipate or be isolated prior to ignition.

The hazard classification and expected fire severity for this zone is "high". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is "moderate".

3.7.5.5 Fire Detection. Fire detection is provided in the 4160 switchgear room by nine heat detectors, nine smoke detectors and two manual pull stations (Detection Zone No. 29). These detectors will actuate the Fire Alarm Console in the Control Room through the FDAP-A2.

3.7.5.6 Fire Suppression. There is no fixed suppression system provided for this zone. Fire hose stations and portable fire extinguishers are located within this fire zone and in adjacent Fire Zone 25F for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.6 Fire Zone 25F - Turbine Building West Mezzanine

3.7.6.1 General Description. Zone 25F is the Turbine Building West Mezzaine El. 242 ft.-6 in. and west of Column Line 10. This portion of the Turbine Building is an open structure containing miscellaneous heat exchangers, miscellaneous electrical cabinets and associated turbine equipment, including oil pumps and north platform at El. 251.75 ft. Additionally, steam generator feed regulator valves, turbine driven AFW valves, turbine deck/secondary control and steam header pressure transmitter panels are located in this zone in an enclosed area.

3.7.6.2 Fire Barrier Description. This area is an open structure with the exception of the unrated metal siding enclosure for the turbine driven AFW valves and turbine deck/secondary control panel. The zone is spatially separated from the Auxiliary Building and CV which are constructed of reinforced concrete fire barriers having a fire rating in excess of three hours. There are no fire doors or dampers provided.

3.7.6.3 Safe Shutdown Equipment. This zone contains the turbine driven AFW discharge valves, turbine deck/secondary control panel, controls for instrument air and nitrogen for steam generator PORVs and DS cables. Steam generator supply valves to AFW pumps are located on the north platform. The DS cables are routed along the outside of the turbine building on the south side at the far west end of the zone where they rise up to the operating floor elevation. The motor driven AFW pumps and normal on-site power distribution system remains available for safe shutdown of the plant in the event this equipment is damaged in a fire.

3.7.6.4 Combustibles. Combustible material in this fire zone includes ordinary Class A combustibles, cabling, turbine lube oil piping on the south side of the zone, turbine lube oil reservoir tank which extends slightly above the floor elevation, and turbine hydraulic oil system. A combustible laydown area exists at the far west end of this zone which can extend no more than 20 ft. from the western edge of the building.

The turbine lube oil system contains approximately 10,000 gallons of oil, the hydrogen seal oil unit contains approximately 200 gallons of oil, and the turbine hydraulic oil system contains approximately 200 gallons of oil. Due to the fact that the turbine lube oil, hydrogen seal oil and turbine hydraulic oil piping are routed throughout the turbine building, the entire quantity of each system will be included in the combustible loading for each of the Turbine Building FZs 25A, 25B, 25E, 25F and 25G. This is a very conservative assumption and assumes catastrophic failure of the turbine generator and each of these systems. They hydrogen piping system is not

included in this assumption since the turbine building is an open structure, it is anticipated that the hydrogen will either dissipate or be isolated prior to ignition.

The hazard classification and expected fire severity for this zone is "moderate". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is "low".

3.7.6.5 Fire Detection. Fire detection above the turbine lube oil reservoir tank is provided. Refer to Fire Zone 25B for description of this detection system.

3.7.6.6 Fire Suppression. A deluge water spray system is provided above the turbine lube oil reservoir tank. Refer to Fire Zone 25B for a description of the suppression system.

Fire hose stations and portable fire extinguishers are located within this fire zone and in adjacent Fire Zone 25E for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.7 Fire Zone 25G - Turbine Building Operating Deck

3.7.7.1 General Description. Zone 25G is the Turbine Building Operating Deck at El. 267 ft. This portion of the Turbine Building is an open deck containing the turbine generator, safety valves, moisture separators and north platforms at El. 260.25, 262.5 and 267 ft.

3.7.7.2 Fire Barrier Description. The operating deck is an open area. Heavy metal lagging is provided around the turbine and over the turbine bearings. There are no fire doors or dampers provided or required.

3.7.7.3 Safe Shutdown Equipment. Steam generator main isolation valves and by-pass valves are located on the north platforms. The DS cables are routed along the outside of the turbine building on the south side at the operating deck floor elevation. The normal on-site power distribution system remains available or manual operation of equipment is credited for safe shutdown of the plant in the event the cables are damaged in a fire.

3.7.7.4 Combustibles. Combustible material in this fire zone includes turbine hydraulic oil system, turbine lube oil at the generator bearings and hydrogen in the generator. These combustibles are located beneath the turbine generator heavy metal lagging enclosure, minimizing their risk on the operating deck. Some of the turbine hydraulic oil system piping exists external to the metal lagging. Ordinary Class A combustibles also exist on the operting deck. Turbine deck cranes contain approximately 270 gallons of oil. Combustible laydown areas exist north and south of, or outside, the rails for the portable weather enclosures and at the east and west end of the operating deck (where they can be no closer than 20 feet to the turbine generator enclosure).

The turbine lube oil system contains approximately 10,000 gallons of oil, the hydrogen seal oil unit contains approximately 200 gallons of oil, and turbine hydraulic oil system contains approximately 200 gallons of oil. Due to the fact that the turbine lube oil, hydrogen seal oil and turbine hydraulic oil piping are routed throughout the turbine building, the entire quantity of each system will be included in the combustible loading for each of the Turbine Building FZs 25A, 25B, 25E, 25F and 25G. This is a very conservative assumption and assumes catastrophic failure of the turbine genertor and each of these systems. The hydrogen gas within the generator and piping system is not included in this assumption since the turbine building is an open structure, it is anticipated that the hydrogen will either dissipate or be isolated prior to ignition.

The hazard classification and expected fire severity for this zone is "low". Excluding the lubricating and fuel oil hazards, the hazard classification for the zone is greatly reduced.

3.7.7.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.7.6 Fire Suppression. There is no fixed fire suppression system provided for this zone. Fire hose stations and portable fire extinguishers are located within this fire zone for manual fire fighting. Additionally, yard fire hydrants and portable foam equipment are available in the surrounding yard area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.8 Fire Zone 26 - Yard Transformers

3.7.8.1 General Description. The main and unit auxiliary and startup transformers are located outside south of the Turbine Building. The spare transformer, which is not connected to the power distribution system, is located southwest of the Turbine Building.

3.7.8.2 Fire Barrier Description. This area is located outside adjacent to the Turbine Building Structure.

3.7.8.3 Safe Shutdown Equipment. No safe shutdown equipment is located in this area.

3.7.8.4 Combustibles. Combustibles in this area consist of 41,960 gallons of transformer oil:

Main Transformers (3):	7,293 gallons each
Startup Transformer:	8,547 gallons
Auxiliary Startup Transformer:	5,760 gallons
Spare Transformer (unconnected):	5,654 gallons
Small Transformers (6):	20 gallons each (estimated)

The fire severity level in this zone is not calculated, since this zone is an outdoor area.

3.7.8.5 Fire Detection. Fire detection in this area consists of heat actuating devices which activate the deluge system. These detectors will, through Transceiver No. 17, actuate the Fire Alarm Console in the Control Room.

3.7.8.6 Fire Suppression. Automatic fire suppression in this area consists of open head deluge systems (which can also be manually actuated) on all transformers except the unconnected spare unit. Manual fire fighting equipment is available to this area from the Turbine Building or from yard fire hydrants.

3.7.9 Fire Zone 28A - New and Spent Fuel Storage Areas

3.7.9.1 General Description. Zone 28A is the New and Spent Fuel Storage Areas located in the Fuel Handling Building. The New Fuel Storage Area is located at El. 226 ft. The Spent Fuel Storage Area is located at El. 275 ft., which represents the area around the top of the fuel pool. The two storage areas are connected by the open elevator shaft. Adjacent to the New Fuel Storage Area is the Spent Fuel Pit Heat Exchanger Area at El. 226 ft. Stairs from the heat exchanger area lead to the spent fuel pit pump cubicles at El. 235.5 ft. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.9.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Access to the New Fuel Area is from an exterior security door (SD 38) at grade level. Access to the Spent Fuel Pit Heat Exchanger Area is through exterior security door (SD 37) at grade. Exterior Security Door 36 provides access from the spent fuel pit pump area to the Yard, where stairs lead to the Boron Injection Tank Room (FZ 8) and RHR Pit (FZ 27). Access to the Spent Fuel Area is obtained from the exterior stairs located on the North side of the building through Security Door 52. Fire dampers are not provided in the ventilation system.

3.7.9.3 Safe Shutdown Equipment. This zone contains Train B valve SFPC-805B, which isolates the RWST from the spent fuel pit. Due to the lack of combustibles in this area, it is not credible that this equipment could be damaged in a fire.

3.7.9.4 Combustibles. Combustibles for this zone includes ordinary Class A combustibles. Wood flooring is provided under the new fuel racks. Small quantities of lubricating oils exist for the hoists, cranes, elevator and spent fuel pool cooling pumps. The hazard classification and expected fire severity for this zone is "negligible".

3.7.9.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.9.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. For the New Fuel Storage Area, a fire hydrant is available in the surrounding Yard area for manual fire fighting. A portable fire extinguisher is provided outside the New Fuel Storage Area in the Yard along side of the building. A fire hose station and portable fire extinguisher are provided within the Spent Fuel Storage Area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.10 Fire Zone 28B - Gas Decay Tank and Decontamination Areas

3.7.10.1 General Description. Zone 28B is the Gas Decay Tank and Decontamination Areas located in the Fuel Handling Building at El. 226 ft. This zone also includes the sump pump area at El. 214 ft. Access to the gas decay tank and sump pump areas is from the decontamination room. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.10.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Access to these areas is from an exterior door at grade level or from doors leading to the Hot Machine Shop (FZ 28D). Fire dampers are not provided in the ventilation system.

3.7.10.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.10.4 Combustibles. Combustibles for this zone includes ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.7.10.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.10.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A fire hose station is located outside in the Yard next to the south entrance to the Hot Machine Shop (FZ 28D). A portable fire extinguisher is provided in adjacent FZ 28D. A fire hydrant is also available in the surrounding Yard area for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.11 Fire Zone 28C - CVCS Hold-Up Tank Area

3.7.11.1 General Description. Zone 28C is the CVCS Hold-Up Tank Areas located in the Fuel Handling Building at El. 226.25 ft. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.11.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Access to these areas is from an exterior door at grade. Fire dampers are not provided in the ventilation system.

3.7.11.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.11.4 Combustibles. Combustibles for this zone includes ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.7.11.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.11.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A fire hydrant is available in the surrounding Yard area for manual fire fighting. A portable fire extinguisher is provided outside in the Yard area along the side of the building.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.12 Fire Zone 28D - Hot Machine Shop

3.7.12.1 General Description. Zone 28D is the Hot Machine Shop located in the Fuel Handling Building at El. 226 ft. The tool room is also considered to be part of this zone. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.12.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Access to these areas is from exterior doors at each end of the shop at grade level. Fire dampers are not provided in the ventilation system.

3.7.12.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.12.4 Combustibles. Combustibles for this zone includes ordinary Class A combustibles and lubrication oil for the machinery and overhead crane. The hazard classification and expected fire severity for this zone is "negligible".

3.7.12.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.12.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A fire hose station and a portable fire extinguisher are provided within the zone for manual fire fighting. A second hose station is located outside in the Yard next to the south entrance to the Hot Machine Shop. A fire hydrant is also available in the surrounding Yard area for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.13 Fire Zone 28E - Fuel Handling Building HVE-15 Fan Room

3.7.13.1 General Description. Zone 28E is the Fuel Handling Building HVE-15 Fan Room located at El. 246 ft. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.13.2 Fire Barrier Description. This zone is enclosed by unrated metal walls. Access to this area is from the Auxiliary Building roof through a unrated exterior door. Fire dampers are not provided in the ventilation system.

3.7.13.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.13.4 Combustibles. Combustibles for this zone includes ordinary Class A combustibles and 2160 lbs. of charcoal in the ventilation units. The hazard classification and expected fire severity for this zone is "low".

3.7.13.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.13.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A portable fire extinguisher is available in FZ 15 for manual fire fighting. Fire hose water could be made available from either FZ 15 or from a fire hydrant in the surrounding Yard area for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.14 Fire Zone 28F - Fuel Handling Building HVE-14 Fan Room

3.7.14.1 General Description. Zone 28F is the Fuel Handling Building HVE-14 Fan Room located at El. 246 ft. This zone is considered to be part of Fire Area G for analysis purposes.

3.7.14.2 Fire Barrier Description. This zone is enclosed by unrated metal walls. Access to this area is from the Fuel Handling Building roof through an unrated exterior door. Fire dampers are not provided in the ventilation system.

3.7.14.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.14.4 Combustibles. Combustibles for this zone includes negligible amounts of ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.7.14.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.14.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A portable fire extinguisher is provided within the zone for manual fire fighting. A fire hydrant is also available in the surrounding Yard area for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.15 Fire Zone 29 - Service Water Pump Area

3.7.15.1 General Description. This fire zone is located within the plant intake structure in the Service Water Pump (SWP) enclosure. The plant intake area is enclosed by a security fence.

3.7.15.2 Fire Barrier Description. The SWP structure is formed by metal walls, a reinforced concrete floor and an open roof. This area is located outside and is separated from other plant areas by distance.

3.7.15.3 Safe Shutdown Equipment. This area contains the four Service Water Pumps, one of which is required for safe shutdown. Due to the low combustible content and existing separation in this area, at least one pump will remain available to support safe shutdown in the event of a fire.

An exemption was received for this area by CP&L from the separation requirements of Appendix R, Section III.G.2 via NRC letter dated November 25, 1983.

3.7.15.4 Combustibles. The fixed combustibles within the SWP enclosure include lubricating oil contained within each service water pump (six gallons each). The only cables in this enclosure are the two cables per pump which rise out of floor penetrations and terminate directly above into the motor end of each service water pump. Additional combustibles at the intake structure include ordinary Class A combustibles, lube oil in the four Circulating Water Pumps (70 gallons each) and in the Diesel Fire Pump (8 gallons) and 450 gallons of diesel oil in the Fire Pump Day Tank. The hazard classification and expected fire severity for this zone is "low". The impact of this fire loading is minimized by the fact that this zone is an open outside area.

3.7.15.5 Fire Detection. No fire detection system is provided for the zone. The security control procedures for the intake structure require that a guard be present whenever personnel enter the intake structure fence. This feature, combined with a camera surveillance system for the intake structure (which provides visual fire detection capability), provides this fire zone with additional fire protection beyond those inherent in the existing administrative controls.

3.7.15.6 Fire Suppression. A yard hydrant is available outside the security fence for manual fire fighting. The fire pump test header, and portable fire extinguishers are provided within the security fence for manual fire fighting.

3.7.16 Fire Zone 30 - Diesel Oil Storage Tank

3.7.16.1 General Description. Zone 30, the Diesel Oil Storage Tank, is located outside approximately 100 feet north of the Auxiliary Building in the yard area. The tank is a 25,000 gallon, 15' diameter, 19' high cylindrical metal tank enclosed within a concrete dike 3-1/2 feet in height. The A and B Diesel Oil Transfer Pumps are also located in this diked area.

3.7.16.2 Fire Barrier Description. This area is separated by at least 20 feet of clear space from other safety related areas. In addition, this area is enclosed by a concrete dike 3-1/2 ft in height, which is sufficient to hold the entire contents of the storage tank.

3.7.16.3 Safe Shutdown Equipment. Diesel fuel is pumped from this tank to Diesel Generators A and B day tanks. The Dedicated Shutdown Diesel storage tank is located over 500 ft from this area, and would be available for safe shutdown in the event of a fire in Zone 30.

3.7.16.4 Combustibles. Combustibles in this area consist of 25,000 gallons of diesel oil. The hazard classification and expected fire severity for this zone is "high". The impact of this fire loading is minimized by the fact that this zone is an open outdoor area. Excluding a fuel oil spill in this zone, the hazard classification and expected fire severity in this zone is "negligible".

3.7.16.5 Fire Detection. Due to the separation of this tank from other safety-related areas, fire detection is not provided.

3.7.16.6 Fire Suppression. No automatic fire suppression is provided in this area. A yard hydrant and portable foam equipment are provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.17 Fire Zone 31 - Refueling Water Storage Tank

3.7.17.1 General Description. This area includes the Refueling Water Storage Tank, located approximately 15 feet north of the Auxiliary Building.

3.7.17.2 Fire Barrier Description. This tank is located outside, separated from other plant areas by distance.

3.7.17.3 Safe Shutdown Equipment. The RWST is the alternative shutdown source of water for RCS makeup. The Primary Water Storage Tank (Fire Zone 32) provides the normal source of RCS makeup. These tanks are physically separated from each other. Due to the separation and lack of combustibles in the yard area, it is not credible that this tank could be damaged in a fire. Therefore, the RWST will remain available for safe shutdown.

3.7.17.4 Combustibles. No significant combustibles are located in the yard area near the RWST. The fuel oil line to the diesel generators and the hydrogen line from the hydrogen storage tanks emerges from underground and enters the Auxiliary Building near this area. Excluding a fuel oil spill or hydrogen leak in this zone, the hazard classification and expected fire severity in this zone is "negligible".

3.7.17.5 Fire Detection. Due to the lack of combustibles in the area, automatic fire detection is not provided.

3.7.17.6 Fire Suppression. No automatic fire suppression system is provided for the RWST. A yard hydrant is provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.18 Fire Zone 32 - Primary Water Storage Tank

3.7.18.1 General Description. This area includes the Primary Water Storage Tank, located approximately 15 feet north of the Auxiliary Building.

3.7.18.2 Fire Barrier Description. This tank is located outside, separated from other plant areas by distance.

3.7.18.3 Safe Shutdown Equipment. The Primary Water Storage Tank is the normal source of water for RCS makeup. The Refueling Water Storage Tank (Fire Zone 31) provides an alternative shutdown makeup source. Due to the separation and lack of combustibles in the yard area, at least one method of safe shutdown will remain available in case of fire.

3.7.18.4 Combustibles. No significant combustibles are located in the yard area near this tank. Excluding a fuel oil spill or hydrogen leak, the hazard classification and expected fire severity in this zone is "negligible".

3.7.18.5 Fire Detection. Due to the lack of combustibles in the area, automatic fire detection is not provided.

3.7.18.6 Fire Suppression. No automatic fire suppression system is provided for this tank. A yard hydrant is provided for manual fire fighting.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.19 Fire Zone 33 - Condensate Storage Tank

3.7.19.1 General Description. This area includes the Condensate Storage Tank, located approximately 20 feet southwest of the Turbine Building.

3.7.19.2 Fire Barrier Description. This tank is located outside, separated from other plant areas by distance.

3.7.19.3 Safe Shutdown Equipment. The Condensate Storage Tank is the normal source for steam generator makeup. The CST is backed up by the Service Water System for steam generator makeup. Due to the separation and lack of combustibles in the yard area, at least one method of safe shutdown will remain available in case of fire.

3.7.19.4 Combustibles. No significant combustibles are located in the yard area near this tank. The hazard classification and expected fire severity in this zone is "negligible".

3.7.19.5 Fire Detection. Due to the lack of combustibles in the area, automatic fire detection is not provided.

3.7.19.6 Fire Suppression. No automatic fire suppression system is provided for this tank. A yard hydrant, along with hose stations and portable fire extinguishers from the Turbine Building are provided for manual fire fighting in the area.

An exemption from the detection/fixed suppression requirements of Appendix R, Section III.G.3 was received by CP&L for this zone via NRC letter dated September 17, 1986.

3.7.20 Fire Zone 34 - Battery C Enclosure

3.7.20.1 General Description. This zone includes the Battery C enclosure, located on the roof of the Auxiliary Building on Elevation 262 ft., approximately 9 feet north of the Control Room.

3.7.20.2 Fire Barrier Description. This zone is separated from the Auxiliary Building by a reinforced concrete barrier. The zone is separated from other zones in Fire Area G by separation distance and lack of fixed combustibles. The zone is enclosed in a nonrated metal structure. Access is provided by two exterior nonrated metal doors. A wall mounted ventilation unit is provided for this zone.

3.7.20.3 Safe Shutdown Equipment. This area contains no safe shutdown equipment.

3.7.20.4 Combustibles. The fixed combustibles in this zone consist of ordinary Class A combustibles, cables, a battery charger, and a set of auxiliary station batteries. The hazard classification and expected fire severity for this zone is "low".

3.7.20.5 Fire Detection. Fire detection in this area includes two ionization smoke detectors and one manual pull station. These detectors will, through FDAP-A2, actuate the Fire Alarm Console in the Control Room. (Detection Zone 30)

3.7.20.6 Fire Suppression. There is no automatic fire suppression for this zone. A fire hose station on the turbine deck and portable fire extinguishers inside and at the south entrance door are provided for manual fire fighting.

3.7.21 Fire Zone 35 - Radwaste Building

3.7.21.1 General Description. This zone, the Radwaste Building, is located approximately 10 feet east of the Auxiliary Building on 226 ft. elevation. This building is physically separated from the Auxiliary Building.

3.7.21.2 Fire Barrier Description. This area is enclosed by reinforced concrete barriers. Three-hour rated doors are installed in the exterior walls.

3.7.21.3 Safe Shutdown Equipment. This area contains no safe shutdown equipment.

3.7.21.4 Combustibles. The fixed combustibles in this area consist of cables (based on maximum fill of existing cable trays), ordinary Class A combustibles, and 10 gallons of lubricating oil in the overhead crane. The permanent non-fixed combustibles in this area consist of:

1. Clean laundry storage
2. Dirty laundry sorting and storage
3. Contaminated material sorting and storage
4. Contaminated lumber

The hazard classification and expected fire severity of these combustibles in this zone is "low."

3.7.21.5 Fire Detection. Fire detection in this area consists of 41 ionization smoke detectors and 5 manual pull stations, and water flow alarms. These alarms will, through the Radwaste FAP:

1. Actuate the Fire Alarm Console in the Control Room.
2. Sound a local alarm in the Radwaste FAP.
3. Shut down the Radwaste Building HVAC unit.

3.7.21.6 Fire Suppression. Automatic fire suppression for this area consists of a wet-pipe sprinkler system which is actuated by melting the fusible link at the individual sprinkler head. This system may be isolated by manually closing the wall PIV isolation valve just below the alarm check valve. The check valve is located in the north-east corner of the building.

Fire hose stations and portable fire extinguishers are provided for manual fire fighting.

3.7.22 Fire Zone 37 - Radiation Monitoring Room

3.7.22.1 General Description. Zone 37 is the Radiation Monitor Room, which is located on the Auxiliary Building Roof at the 262 ft. Elevation.

3.7.22.2 Fire Barrier Description. This zone is enclosed by unrated metal barriers. Access to this room is obtained from the Auxiliary Building Roof through an unrated door. A wall mounted ventilation unit is provided for this zone.

3.7.22.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.22.4 Combustibles. Combustible materials for this zone include ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.7.22.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.22.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. A fire hose station and portable fire extinguishers located on the turbine deck are provided.

3.7.23 Fire Zone 39 - Purge Inlet Valve Room

3.7.23.1 General Description. Zone 39 is the Purge Inlet Valve Room, which is located in the Yard adjacent to Containment at the 226 ft. Elevation. This zone is considered to be part of Fire Area G, Exterior Area, for analysis purposes. This zone contains the containment purge inlet supply and containment isolation valve.

3.7.23.2 Fire Barrier Description. This zone is enclosed by reinforced concrete fire barriers. Access to this room is obtained from the Yard at El. 226 ft. through an exterior door. No separate ventilation system is provided for this zone.

3.7.23.3 Safe Shutdown Equipment. This zone contains no safe shutdown equipment.

3.7.23.4 Combustibles. Combustible materials for this zone include negligible amounts of ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.7.23.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.23.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. Yard fire hydrants are available for protection of this zone. No portable fire extinguishers are provided for the zone.

3.7.24 Fire Zone 40 - Unit 2 Fuel Oil Unloading/Transfer Area

3.7.24.1 General Description. Zone 40 is the Unit 2 Fuel Oil Unloading/Transfer Area, which is located in the Unit 1 Yard at the 226 ft. Elevation. This zone is considered to be part of Fire Area G, Exterior Area, for analysis purposes. This zone contains the Unit 2 fuel oil transfer pumps and associated valves, and a truck unloading connection.

3.7.24.2 Fire Barrier Description. This zone is an open area on a concrete pad. The pad is bounded by concrete curbing. This zone is spatially separated by a great distance from the Dedicated Shutdown (DS) Diesel Generator.

3.7.24.3 Safe Shutdown Equipment. This zone contains the fuel oil transfer pumps and associated valves. The transfer pumps pump diesel fuel oil from the Unit 1 fuel oil storage tanks to the DS Diesel Generator fuel oil tank storage tank for refilling purposes. A truck unloading connection is also available for direct feed into the piping system to fill the DS Diesel Generator fuel oil storage tank. A fire in this area would have no impact on safe shutdown.

3.7.24.4 Combustibles. There are normally no combustible within this zone. The only hazards are from a fuel oil spill or from ordinary Class A combustibles that may be present in the immediate surrounding area. Excluding the fuel oil, the hazard classification and expected fire severity for this zone and its surrounding area is normally "low".

3.7.24.5 Fire Detection. There is no fixed fire detection system provided for this zone.

3.7.24.6 Fire Suppression. There is no automatic fire suppression system provided for this zone. Yard fire hydrants are available for protection of this zone.

3.8 Appendix R Fire Area H (Fire Zone 27) - RHR Pit

3.8.1 General Information. Floor 27, the RHR Pit, is located immediately west of the Auxiliary Building with a floor elevation of 203 ft.

3.8.2 Fire Barrier Description. This area is enclosed by reinforced concrete fire barriers. Access from outside is provided by an unrated security hatch. A three-hour fire damper is provided in the ventilation duct to FZ 11.

3.8.3 Safe Shutdown Equipment. This area includes the two RHR Pumps. One of these pumps is required for cold shutdown. Due to the low combustible loading and existing separation in this area, one pump will be available to support safe shutdown in the event the other pump is damaged in a fire.

An exemption was received by CP&L from the separation requirements of Appendix R, Section III.G.2 via NRC letter dated November 25, 1983.

3.8.4 Combustibles. Combustibles material located in this area consists of eight gallons of oil and ordinary Class A combustibles. The hazard classification and expected fire severity for this zone is "negligible".

3.8.5 Fire Detection. Fire detection in this area consists of two ionization smoke detectors, two heat detectors, one photoelectric smoke detector, and one manual pull station. These detectors will, through the FDAP-A2 and B2, actuate the Fire Alarm Console in the Control Room.

3.8.6 Fire Suppression. There is no automatic fire suppression system in this area. A fire hose station and portable fire extinguisher are provided in the Yard area above for manual fire fighting.

TABLE 9.5.1A-1
FIRE AREA DESIGNATION CROSS REFERENCE

Description	1977 Fire Zone Designation	Current Fire Zone Designation (Post 1983)	Appendix R Area Designation (Post 1983)
Diesel Generator B	1	1	A
Diesel Generator A	2	2	A
Safety Injection Pump Room	3	3	A
Charging Pump Room	4	4	B
Component Cooling Pump Room	5	5	C
Hot Chem. Lab. Counting Room (Room no Longer Exists)	6	-	-
Auxiliary Feedwater Pump Room	7	6	A
Boron Injection Tank	8	8	A
South Cable Vault	9	10	E
Aux. Bldg. Hallway Near DG	10A	7	A
Aux. Bldg. Hallway With Air Compressors	10B	7	A
Demineralizers, Spent Resin Storage	10D	7	A
Waste Evaporator, Boric Acid Evaporator	10E	7	A
Non-Regenerative Heat Exchanger	10F	4	B
Pipe Alley	10G	11	A
Waste Holdup Tank, RHR Heat Exchangers	10H	12	A
Aux. Bldg. Entrance Area (Renamed as CV Access Area)	11	Part of 25C	G
Roof Deck	12	Yard	--
Solid Waste Handling	13	14	A

TABLE 9.5.1A-1 (Continued)

Description	1977 Fire Zone Designation	Current Fire Zone Designation (Post 1983)	Appendix R Area Designation (Post 1983)
Aux. Bldg. Hallway (second floor)	14A	15	A
Fan HVS-5 and -6 Area	14B	15	A
Non-Regenerative Heat Exchanger, Volume Control Tank	14C	4	B
Chemical Storage Area, Boric Acid Batching Tank	14D	13	A
Spray Additive Tank, Gas Stripper	14E	7	A
HVE-1A and -1B	14F	15	A
HVE-2A, -2B, -5A, and -5B	14G	15	A
RHR Heat Exchangers	14H	12	A
Battery Room	15	16	A
Control Room HVAC	16	17	A
Unit 1 Cable Room	17	18	A
Unit 2 Cable Room	18	19	A
Electrical ELquipment Area	19	20	A
Rod Control Room	20	21	A
Observation Deck	21A	Yard	--
Control Room	21B	22	A
Hagan Room	21C	23	A

TABLE 9.5.1A-1 (Continued)

Description	1977 Fire Zone Designation	Current Fire Zone Designation (Post 1983)	Appendix R Area Designation (Post 1983)
New Fuel Storage	22	28A	G
Spent Fuel Storage	23	28A	G
Hot Machine Shop	24A	28D	G
Equipment Decontamination Area	24B	28B	G
Gas Decay Tank Area	--	28B	G
CVCS Hold-Up Tank Area	--	28C	G
Fuel Handling Bldg. HVE-15 Fan Room	--	28E	G
Fuel Handling Bldg. HVE-14 Fan Room	--	28F	G
Steam Driven AFW Pump	25A	Part of 25B	G
Turbine Oil Reservoir	25B	Part of 25B	G
Oil Storage Tank	25C	Part of 25B	G
H_2 Seal Oil Unit	25D	Part of 25A	G
Turbine Bldg. East Basement	--	25A	G
Turbine Bldg. West Basement	--	25B	G
Turbine Bldg. CV Access & RCA Tool Area	--	25C	G
Dedicated Shutdown Diesel Generator	--	25D	G
Turbine Bldg. East Mezzanine	--	25E	G
Turbine Bldg. West Mezzanine	--	25F	G
Turbine Bldg. Operating Deck	--	25G	G
Main Transformers	26A	26	G
Unit Aux. Transformers	26B	26	G

TABLE 9.5.1A-1 (Continued)

Description	1977 Fire Zone Designation	Current Fire Zone Designation (Post 1983)	Appendix R Area Designation (Post 1983)
Cable Penetration Area	27A	24	F
Reactor Coolant Pumps	27B	24	F
Containment General Area	27C	24	F
RHR Pump Pit	28	27	H
Intake Structure	29	29	G
Diesel Oil Storage	30	30	G
Refueling Water Storage	31	31	G
Primary Water Storage	32	32	G
Condensate Storage	33	33	G
North Cable Vault	34	9	D
Battery C Enclosure	--	34	G
Radwaste Building	--	35	G
Component Cooling Water Surge Tank Rm	--	36	A
Radiation Monitor Room	--	37	G
Waste Evaporator Area	--	38	A
Purge Inlet Valve Room	--	39	G
U2 Fuel Oil Unloading/Transfer Area	--	40	G

H. B. ROBINSON, UNIT 2
APPENDIX 9.5.1B
FIRE PROTECTION PROGRAM DESCRIPTION AND REVIEW
PER APPENDIX A TO BTP APCSB 9.5-1

APPENDIX 9.5.1B
TABLE OF CONTENTS

APPENDIX 9.5.1B
TABLE OF CONTENTS (continued)

A. OVERALL REQUIREMENTS OF NUCLEAR PLANT FIRE PROTECTION PROGRAM

1. Personnel

Overall responsibility for the fire protection program is assigned to the Executive Vice President, Nuclear Generation. Organizational structure and responsibilities are outlined in the Plant Operating Manual. Additional details are contained in Section 6.0 of the HBR2 Technical Specifications.

2. Design Bases

The H. B. Robinson, Unit 2 (HBR2) Nuclear Plant has been evaluated with regard to fire protection to determine that the total fire protection program provides reasonable assurance that a fire will not cause an undue risk to the health and safety of the public, will not prevent the performance of necessary safe shutdown functions, and will not significantly increase the risk of radioactive release to the environment. This review process was documented in an NRC Safety Evaluation Report dated February 28, 1978, with supplements dated September 4, 1979, February 21, 1980 and December 8, 1980. Appendix A to Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1 provides specific guidelines which were used to review the fire protection program for an operating plant. Whenever applicable, those guidelines were addressed, but to provide broader guidelines for the evaluation of the Robinson Plant, the following criteria served as the basis for the overall evaluation:

- General Design Criterion 3 (10CFR50, Appendix A) - Fire Protection - "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the Containment and Control Room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation do not significantly impair the safety capability of these structures, systems, and components."

- Defense in Depth Criterion - For each fire hazard, a suitable combination of fire prevention, fire detection and suppression capability, and ability to withstand safely the effects of a fire shall be provided. Both equipment and procedural aspects of each shall be considered.

- General Design Criteria 19 (10CFR50, Appendix A) - Control Room - "A Control Room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCA).

  Equipment at appropriate locations outside the Control Room shall be provided with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures."

- Single Failure Criterion - A single failure criterion was applied to fire suppression systems which protect systems and equipment important to safety, including equipment required for safe shutdown. The single failure criterion is that no single failure shall result in complete loss of protection of both the primary and backup fire suppression capability.

- Fire Suppression Capacity and Capability - Fire suppression capability shall be provided, with capacity adequate to extinguish any fire which may credibly occur and have adverse effects on equipment and components important to safe shutdown.

- Backup Fire Suppression Capability - For those areas which have an identified fire hazard possibly affecting systems or components important to achieving safe shutdown, total reliance for fire protection shall not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability shall be provided.

- Occurrence of Fire and Other Phenomena - Fire shall not be considered to occur simultaneously with other accidents, events, or phenomena such as a design basis accident. Capability shall be provided (consistent with General Design Criterion 19) to safely shut down the plant during loss of off-site power in the event of any single fire which may credibly occur.

3. <u>Backup</u>

Manual hose stations and portable fire extinguishers are provided as backup for all areas protected by automatic fire suppression systems.

4. <u>Single Failure Criteria</u>

The plant complies with the single failure criterion in all areas except containment by using appropriate piping and valving arrangements to assure that both primary and backup fire suppression systems will not be impaired by a single failure.

A single line in the Auxiliary Building supplies all firefighting water in containment. The fire hose stations and the preaction sprinkler systems in the reactor coolant pump bays are supplied by a single pipe through one containment penetration. The preaction sprinkler system in the cable penetration area is supplied through another containment penetration. Portable fire extinguishers and automatic fire detection are provided in containment. (Described to the NRC in CP&L letter dated June 12, 1980 and accepted in SER dated December 8, 1980.)

A single discharge line from the two fire pumps supplies the main loop. Two backup supplies are available. One backup is from a normally closed connection to the Unit 1 fire loop. The second backup is the capability of an off-site fire pumper to take suction from the lake or discharge canal and supply the fire main. This arrangement was accepted as providing adequate redundancy by the NRC in the Safety Evaluation Report of February 28, 1978.

The effects of lightning strikes have been considered in the plant design by installing lightning rods on the containment and lightning arrestors on power lines.

5. Fire Suppression Systems

The fire water piping inside the containment is seismically designed except for the sprinkler headers in Pump Bays B and C. However, since these headers are not normally charged, a failure of the headers during a seismic event will not cause flooding. Analyses also show that falling header parts will not preclude safe shutdown.

The containment vessel isolation valves for fire water are normally left open and are closed automatically on a Phase A isolation signal. Due to the seismic design and missile protection afforded the fire water piping, a rupture will not occur from a design basis accident. Inadvertent operation of the preaction sprinkler system control valve would not present a flooding or impingement hazard since the sprinkler systems are closed systems. The piping is also supervised with air to detect any leakage before the system actuates.

The fire water system piping in the Auxiliary Building has been analyzed to determine the effect of a pipe rupture on safety-related equipment. A detailed analysis for inadvertent actuation was not considered necessary since the flow through any open sprinkler heads would be bounded by the flow through a pipe rupture. In addition, spurious actuation of the preaction system flow control valve would be alarmed in the Control Room, and total water flow could be limited by operator action. The following description summarizes the effects of various postulated fire water system pipe ruptures on safety-related equipment. The detailed analysis was provided in CP&L letter dated June 12, 1980 and accepted by the NRC in the Safety Evaluation Report supplement dated December 8, 1980.

The pipe rupture analysis was performed by considering separate pipe break scenarios in the Auxiliary Building. These scenarios consistent of a four-inch pipe break in the pipe tunnel (FZ 11) on Elevation 226 feet, and a four-inch pipe break in the hallway (FZ 7) near Motor Control Center (MCC) No. 5 on Elevation 226 feet. The postulated break locations were selected to typify the areas with water-filled pipe in the Auxiliary Building.

The scenario descriptions and analyses show that the floor drain system will prevent flooding of electrical safety-related equipment on the second floor. The four-inch break in the hallway on Elevation 226 is the more severe accident, since it can damage safety-related equipment by direct water impingement. CP&L constructed a spray shield to protect MCC No. 5 from immediate damage by direct water impingement from a pipe rupture. All other breaks could cause equipment damage on Elevation 226 by flooding, but time is available for corrective action to be taken by operators to terminate water flow by closing the appropriate isolation valve. Abnormal operating procedures are in place to address flooding.

Inadvertent operation of the CO_2 or Halon systems (Diesel Generator Rooms (FZs 1 and 2), Cable Vaults (FZs 9 and 10), Cable Spread Room (FZ 19), Emergency Switchgear Room (FZ 20)) will not cause unacceptable damage; the H. B. Robinson, Appendix R, Separation Analysis bounds the loss of electrical equipment in any of these rooms, and demonstrates that safe plant shutdown can still be achieved.

6. <u>Fuel Storage Areas</u>

Not applicable.

7. <u>Fuel Loading</u>

Not applicable.

8. <u>Multiple-Reactor Sites</u>

Not applicable.

9. <u>Simultaneous Fires</u>

Not applicable.

B. <u>ADMINISTRATIVE PROCEDURES, CONTROLS, AND FIRE BRIGADE</u>

1. Administrative procedures have been developed and implemented to maintain the performance of the fire protection systems and personnel responsible for the fire protection program. The referenced NFPA publications, as well as other materials, have been utilized to develop these procedures to assure their practicality and completeness. These procedures are included in the H. B. Robinson Plant Operating Manual.

The plant is committed to meet the requirements of 10CFR50, Appendix R, III.K for administrative controls. To meet this commitment, plant procedures have been established and implemented to:

- Control the use, storage, and disposal of flammable and combustible materials of all types in or exposing safety-related areas.
- Assure that work activities are reviewed by cognizant personnel for potential fire hazards before commencement.
- Govern the use of hot work by a permit system.
- Maintain periodic housekeeping inspections.
- Specify the actions to be taken by various personnel in response to fire emergencies.

In this regard, detailed prefire plans have been prepared for each fire area to define firefighting strategies appropriate to the systems and and hazards present.

2. In addition to the Appendix A requirements, the plant has committed to meet the requirements of 10CFR50, Appendix R, III.I.3, regarding fire brigades, including brigade organization, training, and periodic drills. Plant procedures describe the fire brigade implementation details.

CP&L committed to an administrative program meeting the requirements of 10CFR50 Appendix R, Section III.I.3 for Fire Brigade Training - Drills and Section III.K for Administrative Control of combustibles in a letter dated November 6, 1980. The NRC concluded that these commitments were acceptable in their letter dated December 8, 1980.

C. QUALITY ASSURANCE PROGRAM

The plant has committed to meet the guidelines contained in Attachment 6, "Quality Assurance," of the NRC June 20, 1977 letter titled: Nuclear Plant Fire Protection Functional Responsibilities, Administrative Control and Quality Assurance.

CP&L has a corporate Quality Assurance (QA) program in effect as described in FSAR Section 17. This QA program is applied to the fire protection program as outlined in the CP&L Corporate Quality Assurance Manual. This program provides for periodic QA audits in accordance with NRC I&E Generic Letter 82-21.

D. GENERAL GUIDELINES FOR PLANT OPERATION

1. Building Design

a) Auxiliary, Containment and Fuel Handling Buildings which contain components and systems important to safety are of reinforced concrete construction. This type construction has the advantages of noncombustibility and a high degree of resistance to the effects of fires.

The plant layout subdivides the plant into numerous fire areas which contain safety-related equipment. The barriers (walls, floors, and ceilings) which separate these fire areas are designed to isolate the fire areas from each other. Where redundant items of safety-related equipment or cables are not separated, an appropriate combination of fire retardance coatings for cables, fire detection and alarm, and automatic and/or manual fire suppression is provided. In addition, a dedicated/alternative shutdown system is provided. As a result, the plant can be shut down and maintained in a safe condition in the event of fire in any area.

b) Systems and equipment required for safe shutdown have been identified in the H. B. Robinson, Appendix R, Separation Analysis. Fire hazards have been identified and a fire hazards analysis made. Plant modifications are reviewed to determine the impact upon the existing fire hazards analysis and safe shutdown documentation.

c) The cable spreading room (FZ 19) and cable vaults (FZs 9 and 10) are separated from other areas of the plant and are not shared with another plant.

Additional information relative to the cable spreading room is given in Section F.3.

d) Interior wall and structural components are steel, reinforced concrete, and other noncombustible materials. Thermal insulation and radiation shielding materials are also noncombustible or fire retardant. Interior surfaces are generally painted.

e) Metal deck roof construction is not utilized.

f) Suspended ceilings are noncombustible and exist only in the Control Room (FZ 23), Inside AO Office and RCA Entrance Area (FZ 25A).

The Control Room suspended ceiling is a partial-coverage design, with no ceiling panels installed directly above the control panels (RTGB), to facilitate conduit entry into these panels. As such, the Control Room main area and above-suspended ceiling space communicate through a large opening in the ceiling, which runs approximately the full length and width of the RTGB. To ensure the effectiveness of fire detection in the Control Room, smoke detectors are installed both above and below the partial suspended ceiling. All electrical wiring above the control room partial suspended ceiling is in conduit except for short flexible connectors to lighting fixtures. There is one eight-foot length of eight-inch diameter UL-approved flexible air duct with a flame spread rating of 25 or less.

Combustibles in concealed spaces in the Inside Inside AO Office and the RCA Entrance Area consist only of insulation for small quantities of electrical cables in trays. Neither of the rooms nor the cables are safety-related.

g) No safety-related systems are exposed to flammable oil-filled transformers.

Dedicated Shutdown cables that are routed along the south side of the Turbine Building would be exposed to the yard transformers. However, the normal on-site power distribution system remains available for safe shutdown of the plant in the event these cables are damaged from a transformer fire.

h) Enclosed buildings containing safety-related systems have no openings in exterior walls closer than 50 feet to flammable oil-filled transformers. The open Turbine Building containing Train A safe shutdown equipment is adjacent to transformers in the yard. Safe shutdown can be accomplished by use of equipment located in the Auxiliary Building.

i) Floor drains are provided throughout the plant as are curbs and pedestals for equipment. The diesel generator rooms are the only Auxiliary Building rooms containing significant combustible liquids and are equipped with curbs and separate drain systems which have removable drain plugs. The Diesel Generator Room drain systems are separated from the Auxiliary Building drain system in order to prevent the spread of combustible liquids.

Floor drains in the E&RC Building Chemistry lab are routed to a separate drain tank. Floor drains from oil containing areas in the Turbine Building are routed to settling ponds independent of the liquid radwaste system which serves the Auxiliary Building.

j) The fire hazard in each area has been evaluated to determine barrier requirements. The walls, floors, and ceilings which form barriers to separate fire areas are of heavy reinforced concrete construction. Some barrier sections include fire-rated concrete block. Fire doors, frames and hardware have been provided to meet the fire resistance rating required by the hazard in each area. Ventilation penetrations in rated fire barriers are protected by automatic fire dampers where required or an engineering evaluation performed. Administrative procedures are provided to manually trip the HVAC system fans, where necessary, upon acknowledgement of a significant fire to ensure damper closure. Fire doors are normally kept closed and are inspected daily to verify that they are in the closed position, as accepted in the NRC SER supplement dated December 8, 1980.

In accordance with the requirements of Generic Letter 86-10, engineering evaluations have been prepared to document the acceptability of fire area boundaries where penetrations in floor-to-ceiling or wall-to-wall boundaries are not completely sealed to the fire rating required of the boundaries.

For further discussion of fire barriers and penetrations, refer to the H. B. Robinson Evaluation of Fire Barrier Adequacy (6611-P-300).

2. <u>Control of Combustibles</u>

a) The barriers (walls, floors, ceilings) which separate plant areas isolate the areas from fire hazards in other areas. The use of combustibles in safety-related/safe shutdown areas has been minimized. They consist primarily of lube oil required for certain equipment, diesel generator fuel, insulation on electrical cables and ventilation system charcoal. Limited quantities of ordinary Class A combustibles generally exist throughout the plant to support day to day operations. Where redundant items of safety-related equipment or cables are not separated, an appropriate combination of fire retardance coatings for cables, fire detection and alarm, and automatic and/or manual fire suppression is provided. In addition, instrumentation, controls, power supplies, etc., are provided so that the plant can be shut down and maintained in a safe condition in the event of fire in any area.

b) Bulk gas storage inside structures housing safety-related equipment is not present nor permitted. Hydrogen gas cylinders are maintained in Fire Zone 7 for the Gas Analyzer and Post Accident Sampling Systems.

Bulk hydrogen is stored outside in a high pressure tube trailer located approximately 200 feet northeast of and parallel to the Auxiliary Building. The hydrogen system is also connected to reserve cylinders in the Unit 1 gas shed located approximately 140 ft. east of the Auxiliary Building.

Hydrogen is piped at 120 psig to the generator in the Turbine Building and at 30 psig to the volume control tank in the Auxiliary Building. Double wall pipe is used underground only. Pipe running into the buildings is single wall schedule 40 pipe. The Auxiliary Building pipe is one inch in size and the Turbine Building pipe is 1/2-inch in size. The Auxiliary Building piping is supported by engineered supports designed to withstand the safe shutdown earthquake.

c) Use of plastic materials has generally been minimized whenever practical, except for cable insulation. Flame retardant coatings have been applied to most existing engineered safeguards cables, and detection and automatic suppression are provided in areas of maximum cable concentration.

New plant cable meets the requirements of IEEE-383 to the extent that such cable is available and appropriate for the required function. Nonconforming cable is evaluated or installed in conduit. Communications cable qualified to UL-910 flame test has been evaluated and utilized for specific applications in the plant.

d) Bulk storage of flammable liquids is maintained outside of buildings housing safety-related equipment. Bulk storage of combustible liquids is maintained outside of buildings housing safety-related equipment with the exception of the fuel-oil day tanks for the diesel generators. The oil storage building is separate from all other structures and is located approximately 50 feet from safety-related structures. Storage of small amounts of flammable liquids and hazardous chemicals are stored in specially constructed flammable liquid storage cabinets outside of safety-related areas. These cabinets meet the requirements of National Fire Protection Association (NFPA) 30, Section 4-3, 1976 Edition.

Outdoor oil storage tanks are present for the diesel generators and auxiliary boilers. The diesel fuel oil storage tank is approximately 100 feet north of the Auxiliary Building and is surrounded by a dike of sufficient capacity to hold the entire contents of the tank. The fuel oil tank for the auxiliary boiler is located about 400 feet northeast of the Auxiliary Building. A 250-gallon day tank is provided in the "C" Auxiliary Boiler structure. The diked 5,000-gallon fuel tank for the Dedicated Shutdown Diesel Generator is located about 12 feet south of the diesel enclosure.

Above ground tanks for storing waste oil and solvent are located in the yard about 250 ft. west of containment. There is a 10,000-gallon contaminated oil tank and a 400-gallon contaminated solvent tank within one dike sized to contain the contents of both tanks. Tanks of the same capacity and arrangement are provided for noncontaminated oil and solvent within a second nearby diked area.

3. <u>Electric Cable Construction, Cable Trays, and Cable Penetrations</u>

a) Cable trays are entirely of metal construction and present no combustible hazard.

b) See Item F.3 for fire protection in the cable spread room.

c) Safety-related cable trays outside the cable spread room (FZ19) have been evaluated from a fire protection standpoint. Since safety-related cable runs in the Auxiliary Building did not satisfy the requirements of Regulatory Guide 1.75 and consist primarily of PVC-jacketed cables, application of a flame retardant mastic coating was provided for most trays containing engineered safeguards cable. Cable trays in the south cable vault (FZ 10) are coated up to a point short of the containment penetrations to allow access for utilization of spare cables. Automatic water sprinklers protect safety-related cable in the hallway of the Auxiliary Building ground floor (FZ 7) near the station air compressors and in the containment electrical penetration areas (FZ 24). No critical equipment requiring protection from water damage is in these areas. This and other areas have manual hose stations and fire extinguishers for additional protection. The flame retardant coating and automatic detection provide adequate protection. Based on the fire hazards analysis and alternate methods of fire suppression in specific areas, automatic water sprinkler systems are not warranted for all cable trays outside of the cable spread room.

Existing features provide protection in accordance with the Fire Protection Safety Evaluation Report of February 28, 1978.

d) Cable and cable tray penetrations of fire barriers have been sealed to give adequate fire resistance. Cables which enter the cable spreading room (FZ 19) from the electrical equipment room (FZ 20) do so via trays and conduits. The cable trays pass through openings cast in the wall just large enough to allow tray passage. The air spaces around the trays and cables are sealed to provide an adequate fire barrier. Control wiring enters the Control Room from the Cable Spreading Room through slots in the floor. These penetrations are adequately sealed to qualify as a fire barrier. In other locations where electrical cable trays penetrate the walls and floors, they are sealed with approved fire barrier penetration seals. By letter dated November 25, 1983, NRC

exempted H. B. Robinson from the explicit requirements of 10CFR50, Appendix R, Section III.M, and accepted the described configuration for sealing cable tray penetrations.

e) The necessity for fire breaks in cable runs was considered throughout the plant. Cable trays for electrical distribution have adequate seals at fire barriers. Fire retardant coating was applied to most safety-related cabling in the Auxiliary Building. Possible derating of cable was investigated and found unnecessary due to inherent ampacity safety margins.

f) Prior to the selection of original cabling to be used in the plant, an extensive flame testing program took place which included ASTM vertical flame testing and bonfire tests. Cables were specified on the basis of results from these tests. IEEE-383 testing was not applicable at the time of these tests. Engineered safeguards cable trays containing cable with PVC jackets which do not meet the IEEE-383 flame test requirements are covered with a flame retardant coating as discussed above under Item 2.C.

g) For new cable installations, cable construction that does not give off corrosive gases while burning is considered to the extent practicable in compliance with this guideline.

h) No miscellaneous storage in cable trays or raceways is allowed. All trays are maintained free of debris. Control is maintained administratively.

Cable trenches are used only for cables.

i) No provisions are made for automatic smoke venting in the cable spread room (FZ 19), since a Halon automatic suppression system is installed. Smoke can be vented manually from this area if necessary by opening the door to the exterior and venting with portable exhaust fans.

No provisions are provided for automatic smoke venting in the cable vaults (FZs 9 and 10), since an automatic CO2 suppression system is installed within each room. Smoke can be vented manually from these areas if necessary, with portable exhaust fans and by opening the doors leading to the Containment Access Area (FZ 25C) and the nearby exterior door.

j) In general, the Control Room contains a minimum of cables. All cables entering the Control Room terminate there.

4. <u>Ventilation</u>

a) Ventilation related to handling products of combustion was evaluated based upon the type of fire suppression and potential for radioactive releases. Portable smoke ejection units (fans with flexible ducts) are available to discharge smoke and corrosive gases. Charcoal filters and radioactive monitoring capability are provided in the ventilation system for areas containing radioactive material.

b) Ventilation systems were not specifically designed to exhaust smoke or corrosive gases. Such systems are not compatible with gas suppression systems and have potential for violating controlled areas. The use of ventilation system fire dampers will isolate areas; failure or inadvertent operation of dampers would not compromise controlled areas.

c) Ventilation system actuators are remotely controlled from the Control Room by the operator except for fire dampers and where automatic interlocks are involved. Actuators are designed to fail to the position required for post-accident operation upon loss of electric or pneumatic power. The exhaust ventilation louvers for the emergency diesel generators are maintained in closed position by instrument air pressure and go to open when this pressure is released. Loss of off-site power will result in loss of instrument air; therefore, backup nitrogen cylinders are provided to reclose these louvers if the carbon dioxide fire suppression system is actuated during such an event. Instrumentation in the Control Room will provide information to allow proper remote operation of the system. The Control Room and Cable Room (FZ 19)/Hagan Room (FZ 23) ventilation systems and power supplies are separated from the areas they serve.

d) The power block has a total of eight charcoal filters, none of which have sprinkler systems. The fire protection features for areas containing charcoal filters were accepted in the NRC Safety Evaluation Report of February 28, 1978.

e) Safety-related areas with separate fresh air intakes from the rest of the plant include the Control Room (FZ 22), Relay (Hagan) Room (FZ 23), Battery Room (FZ 16), and Cable Spread Room (FZ 19). These intakes are remote from the exhaust air outlets serving other fire areas. Separation between the exhaust air outlets from the Battery Room to the intake for the Cable Spread Room system is about 25 feet. Most safety-related areas are serviced by the Auxiliary Building system with essentially no influence between supply intake and the exhaust stack.

f) Plant stairways are generally exterior or not enclosed and are not subject to being infiltration paths for smoke. One enclosed stairwell exists for the Auxiliary Building which leads from the ground level to the control level. Doorways at 2 and 3 level landings provide a three-hour fire barrier to building areas.

This stairway was not originally designed to be an interior stair tower. The stairway is provided with a weather protective enclosure which is attached to the west side of the Auxiliary Building. It has a door to the outside at the control (upper) level which could be used for venting smoke.

The elevator for the Turbine Building is exterior to fire areas with door openings at each level to the outside rather than the building. The Containment Building elevator is not used during emergencies and escape routes are established using stairways.

g) Smoke and heat vents do not exist in the plant areas due to incompatibility with the need for control of radioactivity and with existing gas fire suppression systems. As noted above, portable smoke ejector units are available to provide adequate smoke venting.

h) Self-contained Breathing Apparatus (SCBA) are available for use by the fire brigade and Control Room personnel. The SCBAs are rated by NIOSH for 30-minute and 60-minute duration. Extra supply bottles are available. An installed compressor and cascade system are available for refilling.

i) Intake and exhaust ventilation dampers will close upon the same signal from the detection system which initiates the total flooding gas extinguishing system in the cable spread room (FZ 19) and emergency switchgear area (FZ 20)(protected by Halon 1301) and the north (FZ 9) and south (FZ 10) cable vaults (protected by CO_2). The diesel generator room (FZs 1 and 2) dampers will close upon initiation of a single train of the detection system. Therefore, this guideline is met.

5. Lighting and Communication

a) Fixed emergency lighting consisting of sealed beam units with individual 8-hour battery supplies has been provided in areas required to operate safe shutdown equipment and along access and egress routes to these areas with the following exceptions. By letter dated July 30, 1987 CP&L received exemptions from the requirements of Appendix R, Section III.J for fixed emergency lighting in cold shutdown equipment areas and along alternate access routes outside the building. By letter dated June 3, 1996 CP&L received an exemption from the requirements of Appendix R Section III.J for fixed emergency lighting for 3 valves located in outside areas which are illuminated by diesel-backed security lighting.

b) Suitable battery powered, portable hand lights are provided in the fire equipment building for emergency use.

c) Sound-powered and amplified telephones are provided at selected locations throughout the plant.

d) The Operations/Fire Protection radio system utilizes 2-channel portables. One channel has a repeater powered from the DS power supply and the second channel provides a talk-around feature which does not require a repeater.

E. FIRE DETECTION AND SUPPRESSION

1. Fire Detection

a) The fire detection system design criteria include NFPA 72D. The low-voltage fire detection systems are connected to emergency power buses, and is provided with four-hour battery backup.

The following portions of the Fire Detection System are not in accordance with NFPA 72D:

1) The Fire Alarm Console (FAC) audible alarm has been modified to provide alarm of 75 Db, which is 10 Db above the maximum 65 Db background. This will provide an alarm consistent with existing Control Room alarms and loud enough to obtain the proper operator response.

2) The Fire Alarm Console printer has been replaced with a Dectronics printer (DEC LA-100) which is the same type of printer that is being used for other systems in the Control Room. The LA-100 is compatible in performance but is nonsupervised.

3) The Block Acknowledgement option has been evaluated for use with the system. The audible alarm will be silenced with a function key from the keyboard. Subsequent new alarms will not be suppressed and are also required to be silenced in the same manner. After alarms have been reviewed and/or action has been taken, Block Acknowledge will be used to acknowledge alarms.

4) The audible horn circuit in the control room for the MX-202C is unsupervised. However, this circuit is well protected in dedicated conduit and the loss of this line does not affect the FAC CRT and printer operation.

b) The fire detection systems include audible and visual alarms in the Control Room, as well as local alarm devices on the FDAP panels. Control Room operators also utilize the plant public address system to notify personnel of fire emergencies.

c) The fire alarm bells are distinct and unique compared to other plant alarm systems.

d) Fire detection and actuation systems are connected to the emergency power buses as discussed under E.1.a) above.

2. <u>Fire Protection Water Supply Systems</u>

a) The fire protection water supply system design criteria include NFPA 24. Underground piping is lined cast iron, ductile iron, and PVC.

The fire protection system utilizes untreated lake water. Hose stations and hydrants are flushed annually with the exception of containment hose stations (flushed every 3 years). Full system flushing and flow testing is performed every 3 years in accordance with the Technical Specifications.

Valves used to isolate portions of the fire main are post indicator-type, except for three underground valves in pits or curb boxes whose locations are identified in plant procedures.

The fire main system is separate from plant service or sanitary water piping.

b) Not applicable.

c) Two fire pumps are provided, either of which can meet 100% of system pressure and flow requirements.

Both pumps are connected to the yard fire main by a single line with additional water supply available from a normally closed cross-connection to the Unit 1 fire water system.

Each pump has an independent driver and controls; one pump is electric motor-driven and the other diesel engine driven.

The pumps are located in the open with spatial separation from other pumping units.

The system design criteria do not include NFPA 20; however, NFPA 20 was considered as a guide in the design of the system. The electrical fire pump is controlled by a breaker which is not an approved UL/FM fire pump controller. Both fire pumps provide alarms to the Control Room. The arrangement was accepted in SERs dated February 28, 1978 and December 8, 1980.

d) Not applicable.

e) Not applicable.

f) Lake Robinson water is utilized for fire protection.

Individual vertical turbine fire pumps take suction from the circulating water intake system on the clean side of the traveling screens between the screens and the circulating water pumps.

The lake is also the ultimate heat sink with sufficient capacity to provide both this function and fire protection water requirements; failure of the fire protection system will not degrade the function of the ultimate heat sink.

g) Fire hydrants are provided at distances of about 250 feet, except at the east side of the plant where the distance between hydrants is somewhat greater.

The lateral to each hydrant is equipped with a post-indicator isolation valve.

Fire hose houses are located near each hydrant. Each hose house is provided with firefighting equipment with additional equipment available in the fire equipment building. Hose threads are compatible with those used by the local fire department.

3. Water Sprinklers and Hose Standpipe Systems

a) Deluge systems are connected to the main fire water loop independent of hose stations. Preaction sprinkler systems and fire hose station standpipes are fed from branch headers that are connected at one end only to the fire water loop. Several hose stations are connected to each branch header. For water sprinkler systems, piping connections are such that failure will not impair both primary and backup suppression capability except for fire water in containment. Water in containment is supplied by a 6-inch main that divides into two 4-inch supply lines which penetrate the Containment boundary. One line supplies the electric penetration area preaction sprinkler system. The other line supplies eight hose stations in Containment and the three preaction sprinkler systems in Reactor Coolant Pump Bays A, B, and C.

Each sprinkler system is equipped with an OS&Y valve. Hose standpipes in the Auxiliary Building and Containment are equipped with an OS&Y valve; hose standpipes in the Turbine Building, Hot Machine Shop, Spent Fuel Building, and RHR Pit do not have shutoff valves.

Safety-related equipment is not subject to unacceptable spray damage from water sprinkler discharge. Flooding effects of sprinkler discharge are bounded by the effects of a postulated fire water system pipe rupture, as discussed in Section A.5 of this Appendix.

b) Fire water isolation valves are locked open with the exception of 3 curb box valves. Administrative controls and periodic inspections assure that valves are maintained open.

c) The automatic water sprinkler system features are consistent with NFPA 13 and 15.

d) Hose stations with a maximum of 100 feet of 1½-inch fire hose are distributed so that areas of the plant are within 20 feet of a hose nozzle. These hose stations are provided for fire brigade use only.

Individual standpipes are at least 4 inches in diameter for multiple hose connections and at least 2 inches for single hose stations.

System design criteria include NFPA 14.

Hose stations and standpipe shutoff valves are located with due consideration for fire brigade access.

e) Interior hose stations are provided with appropriate nozzles in areas with electrical hazards.

f) Fixed foam suppression systems have not been selected for use in any plant areas since other adequate suppression systems are available. Portable foam suppression capability is provided for fire brigade use on flammable/combustible liquid fires. Foam fire extinguishers are also available where appropriate (e.g., diesel generator rooms).

4. Halon Suppression Systems

Halon 1301 systems protect the Cable Spreading Room (FZ 19) and the Emergency Switchgear Room (FZ 20). System design criteria include NFPA 12A.

Testing and maintenance of the system is provided which includes determining halon quantities. The system selection and design has given due consideration to required halon concentration, soak time, toxicity, and the effects of thermal decomposition products.

5. Carbon Dioxide Suppression Systems

Carbon dioxide systems protect the Diesel Generator Rooms (FZs 1 and 2) and North and South Cable Vaults (FZs 9 and 10).

System design criteria utilized NFPA 12 as a general guide.

6. Portable Extinguishers

The plant portable fire extinguisher utilization is consistent with NFPA 10.

Due consideration has been given to the cleanup problems associated with the use of dry chemical extinguishers. Halon 1211 fire extinguishers have been provided near electrical equipment.

F. GUIDELINES FOR SPECIFIC PLANT AREAS

1. Primary and Secondary Containment (FZ 24)

The reactor containment system is designed to maintain the capability in case of fire to safely shut down and isolate the reactor. The reactor containment completely encloses the entire reactor and reactor coolant system and ensures that an acceptable upper limit for leakage of radioactive materials to the environment will not be exceeded even if gross failure of the reactor coolant system were to occur. The containment structure is provided with access during operation by means of a personnel air lock, which is leak-testable at containment design

pressure between doors, and an equipment access hatch with a double-gasketed cover. The open and closed status of the personnel lock door is indicated in the Control Room.

The containment system structure is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication, and inspection governing the above features conform to the applicable provisions of recognized codes and good nuclear practice.

Fire protection for the containment interior has been considered, taking into account the factors of type and location of combustible materials, potential effects of fire in containment, accessibility of various areas of containment during operation and during outages, and potential effects of inadvertent operation of extinguishing systems. Major combustibles include reactor coolant pump lube oil and cable insulation. Additional combustibles (plastics, paper, etc.) are brought in during refueling and maintenance under administrative controls.

The three reactor coolant pumps, the steam generators, and the piping associated with each reactor coolant loop are partitioned from each other at various levels by reinforced concrete walls. The pressure boundary of the reactor coolant system is heavily insulated and the bearing oil systems for the pumps are self-contained. The Fire Hazards Analysis shows that combustion of the total amount of lubricating oil from a reactor coolant pump would result in a low fire severity. A fire of this severity could be withstood without unacceptable consequences. The support structures and members for the reactor coolant loop components consist of massive members. Electrical cables, instruments, and other light components in one pump bay might be damaged by such a fire, but safe shutdown capability would not be lost.

Automatic detection and fixed suppression are provided for reactor coolant pumps as discussed below. By letter dated March 7, 1985, CP&L received an exemption from the requirements of 10CFR50, Appendix R, Section III.O, for a reactor coolant pump lube oil collection system.

Cabling inside containment is flame-resistant, silicon rubber jacketed, unless otherwise evaluated. For a cable fire in containment, installed detectors would give early warning to allow manual firefighting measures to be taken. Time exists for an orderly shutdown and access for manual firefighting, if necessary.

Because of the redundancy and separation provided for the limited amount of safe shutdown equipment in containment, a cable fire would not prevent safe shutdown.

To provide prompt indication of a fire condition inside containment, specific fire detection systems are installed. Three separate systems are provided based on the evaluation of fire hazards. One system is provided for the cable penetration area where critical cabling is concentrated and prompt response could mitigate fire damage. A detection system is also provided for the reactor coolant pumps which have a potential oil fire hazard. Prompt fire indication in pump areas would allow action by the operators to trip the reactor coolant pump and shut off the oil supply pump. Additional detection is also provided to indicate fire conditions in the remaining areas of containment as well as supplying backup detection capability for the cable penetration area and coolant pumps. This system consists of smoke and heat detection on the containment operating deck.

In addition to the detection systems, additional protection is provided by manual and automatic fire suppression capability. The manual capability includes fire hose stations and portable Halon 1211 and dry chemical fire extinguishers. Automatic preaction sprinkler systems are provided in the cable penetration area and in each of the three reactor coolant pump bays.

1) As described above, the design features of the containment detection and suppression systems provide a limited probability of fire and prompt response for firefighting in case fire occurs. With these features, the plant can be brought to a safe shutdown condition.

2) The fire protection features described above also provide adequate protection during refueling or maintenance outages.

2. <u>Control Room</u> (FZ 22)

The Robinson Plant Control Room is located on the third level of the Auxiliary Building, separated from the remainder of the plant. To restrict the possibility of fire originating in the Control Room, noncombustible materials were used in its construction.

Electrical circuits are limited to those associated with lighting, instrumentation, and control. Lighting circuits are 120 volt; instrumentation and control circuits are either 120 volts AC or 125 volts DC, or at the millivolt level. All 120- and 125-volt circuits are protected against both overload and short circuits by either fuses or circuit breakers. The millivolt instrumentation circuits are addressed in the H. B. Robinson Associated Circuits Analysis.

Most lighting wiring is either in steel conduits or enclosed in metal wireways built into the lighting fixtures. All instrumentation and control wiring is inside the panels for control boards in which the wires are terminated.

Because of the overload and short circuit protection provided for the circuits in the Control Room, and because most electrical wiring and devices are surrounded by or mounted in metal enclosures, the fire hazard presented by the electrical equipment due to either electrical faults, or an externally applied flame, is considered minimal.

Carpet installed in the control room has a critical radiant flux rating of greater than 0.45 W/cm^2.

Safety-related cabinets in the Control Room have smoke detectors placed inside the cabinets for prompt detection of fire. Six smoke detectors are placed in the cabinets. Other cabinets do not require detectors since they are either not related to safe shutdown or redundancy precludes the requirement.

In the event a fire occurs in the Control Room, the operator has available Halon 1211 fire extinguishers sized and located in accordance with NFPA 10. Hose Station 52 in the Hagan Room is provided for Control Room fires. Hose Station 31 on the Turbine Building mezzanine could also be used if required to suppress a fire in the Control Room. By letter dated November 13, 1981, CP&L received an exemption from the requirements of Appendix R, Section III.G.3, concerning fixed suppression in the Control Room.

A fire requiring abandoning of the Control Room is not considered credible due to the noncombustible and flame resistant nature of the building and electrical system. However, should such a situation arise and the operators were forced to leave the Control Room, individual controls (local and at the motor control centers) are available for safely shutting down the plant, if required. Also, a dedicated/alternative shutdown system exists which will bring the plant to a safe shutdown condition in the event of a fire in the Control Room or other key areas.

Design features also exist for protection against the spread of fire into the Control Room from other areas. Control wiring entering the Control Room does so via slots in the Control Room floor. Some slots are located beneath the control or instrumentation panels in which the wires are terminated. Some slots are located beneath the Control Room raised floor. To prevent flames and products of combustion from a cable spread room fire entering the Control Room, these penetrations are adequately sealed to qualify as a fire barrier. A limited amount of wiring enters the control room via other penetrations and runs in rigid steel conduit to the top of the panels in which the wires terminate. Conduit penetrations have been sealed to provide a three-hour fire rating. To provide additional separation from the Hagan Room on the control level, a three-hour rated fire door is provided.

The Control Room is air conditioned by its own air-conditioning unit located in the equipment room below. The air intake is ducted from a louver in the exterior wall. If a remotely located fire causes smoke to be drawn into the Control Room, the HVAC can be isolated by motor-

operated dampers. Smoke may be vented by use of motor-operated dampers, or by use of portable ventilation fans. Self-contained breathing units are also available in the Control Room locker and the fire equipment building.

3. Cable Spreading Room (FZ 19)

The Unit 2 Cable Spread Room is an area with significant concentrations of cabling for safety-related equipment and systems including those required for safe shutdown. All cables entering the Unit 2 Cable Spread Room do so via trays and conduits which penetrate the wall between the Cable Spread Room and the Electrical Equipment Room (FZ 20). The tray penetrations are through windows cast in the wall just large enough to allow passage of the trays. The air spaces around the trays and cables are sealed as adequate fire barriers. In both the Electrical Equipment Room and Cable Spreading Room, cables for mutually redundant safety feature systems are run in separate trays. These separate trays run with as much lateral space between them as is physically possible to prevent any single fire or other hazard from disabling all systems.

Cabling in the Cable Spread Room is of PVC construction and divisional cable separation does not meet the guidelines of Regulatory Guide 1.75. To provide additional fire protection and to alleviate the deficiencies of cable construction and separation, most cable trays are coated with a fire retardant coating. This coating reduces the likelihood of cable fires and the effect of noncable related fires on safety-related cables.

The Cable Spread Room is ventilated by an air circulating system separate from the Auxiliary Building system. In the event of a fire in this area, the operator has control of the supply fan from the Control Room so that the circulating air can be cut off. The presence of fire in the Cable Spread Room is alarmed in the Control Room by the detection system which will also actuate the Halon total flooding system. The room is constructed without the use of combustible materials. Manual hose stations are available nearby from the Electrical Equipment Room and Turbine Building mezzanine.

The Cable Spread Room is adequately isolated from the remainder of the plant by its present design. Reinforced concrete walls, ceiling, and floor provided the primary barriers. Additionally, three-hour rated fire doors are provided at the exterior and interior entrances to the room. Cable trays are generally overhead, which provide adequate provision for access also. Electrical penetrations as discussed above are also of adequate design.

An automatic, total flooding Halon suppression system is provided for the Cable Spread Room. The ventilation system fire dampers automatically close on initiation of the Halon system. A fixed-water suppression system was not considered appropriate due to the presence of important electrical relay racks, difficulty of arranging a system that would wet all cable tray runs, and possible drainage problems. To provide additional capability for safe shutdown, alternate cable routings independent of this area are

provided. This alternative/dedicated safe shutdown capability is discussed in more detail in the H. B. Robinson, Appendix R Separation Analysis which is summarized in Appendix 9.5.1C.

4. Plant Computer

The Emergency Response Facility Information System (ERFIS) is a computer-based data gathering, analysis, and display system. ERFIS is strictly a plant monitoring system with no control functions. The ERFIS computer is a dual redundantly configured computer system designed to operate in primary and backup modes to allow failover to the backup system in the event of failure of the primary system. The computer system hardware are mounted in the ERFIS computer room in the EOF/TSC Building. This computer room is cut off from other areas, and a fire detection system which actuates a Halon gas suppression system with local alarms and annunciation to the control room is provided. Automatic sprinkler protection is also provided in this room.

5. Emergency Switchgear Rooms (FZ 20)

Safety-related switchgear, inverters, and relay racks are located in the Auxiliary Building adjacent to the Cable Spreading Room (FZ 19). The portion of this area containing the seal water injection tank is fenced off from the remainder of the area for access control. Three-hour rated fire doors are installed to provide separation from the remainder of the plant. An automatic fire detection system is installed in this area as are portable extinguishers and a manual hose station.

Cabling in this area is of PVC construction. To provide additional fire protection, most cable trays are coated with a fire-retardant coating. This reduces possible spread of fire along cable trays or to redundant divisions. A total flooding Halon suppression system is installed for this area which contains critical emergency buses. Ventilation system fire dampers are automatically actuated to close upon initiation of the Halon system. To provide additional capability for safe shutdown, alternate cable routings and power supplies independent and separate from this area are provided. Capability for power transfer to an alternative supply outside this area, as described in the H. B. Robinson Appendix R Separation Analysis, will assure safe shutdown even in the event of loss of this area.

6. Remote Safety-Related Panels

The remote safety-related panels presently installed at the H. B. Robinson Plant consist of the following:

a. Waste disposal boron recycle panel (FZ 7)
b. Waste evaporator panel (FZ 7)
c. Remote shutdown equipment panels (FZs 4, 5, 21, 25E & 25F)
d. Diesel generator local control panels (FZs 1 and 2)

The first two panels are located in the lower hallway of the Auxiliary Building (Fire Zone 7). Fire detection is provided for this area due to the presence of safety-related cabling.

The remote shutdown panels are located throughout the plant and are normally in the same room as the equipment controlled by them. The Electrical Equipment Room (FZ 20) and Rod Control Room (FZ 21) each contain a group of remote shutdown panels that control equipment that is not located within these rooms.

The Diesel Generator local control panels are located within their respective diesel generator room and are protected by automatic fire detection and suppression systems.

The fire detection and suppression systems protecting the rooms containing these safety-related control panels are discussed in greater detail in the Fire Hazards Analysis.

Manual hose stations and portable fire extinguishers are available for fire protection in all areas containing remote safety-related panels. Even in the event of fire and loss of the waste disposal boron recycle panel or waste evaporator panel, safe shutdown is not compromised nor will unacceptable radioactive release result.

7. Station Battery Rooms (FZs 16 and 34)

The redundant safety-related station batteries are located in the same room (FZ 16). The layout of these batteries is in accordance with IEEE-279 standards for physical separation. To assure proper ventilation for the prevention of fire or explosion caused by hydrogen accumulation, the battery room is provided with redundant exhaust fans powered from an emergency power supply, one of which runs continuously. The operation of the fans are indicated in the Control Room. In the unlikely event that a hydrogen explosion occurs, an additional physical barrier is provided between the batteries to limit the damage to the battery area in which the explosion occurs. The physical barrier is a steel wall approximately five feet high and consists of heavy steel grating on either side of a solid steel plate with openings above and below the wall and at either end to facilitate proper room ventilation. This barrier provides personnel access and maintenance accessibility to the battery system. The opening below this barrier is small enough and is positioned so as to preclude a fire from propagating under the wall, but still allows free air circulation.

The battery chargers and load distribution system exists in this room with local alarm and alarm and annunciation in the Control Room. Reinforced concrete walls separate the room from the remainder of the plant; three-hour fire rated doors provide further isolation.

Fusible link ventilation system fire dampers are installed to provide additional isolation from adjacent areas in the event of fire. With the indication of a fire condition by the detection system, charging current can be turned off by manual trip at MCC-5 and MCC-6.

Nonsafety-related station battery "C" (FZ 34) and its associated charger are located in a separate enclosure on the roof of the Auxiliary Building. The roof is reinforced concrete construction with a three-hour fire rating. The battery enclosure itself is an unrated metal enclosure. A ventilation system is provided for the enclosure. Automatic fire detection is provided within the enclosure. Manual fire suppression equipment is available for the enclosure. The existing configuration provides adequate separation from safety-related systems, including the safety-related batteries.

8. Turbine Lubrication and Control Oil Storage and Use Areas

Combustibles associated with the turbine generator include both hydrogen (used for generator cooling) and oils, used in the turbine generator. The turbine generator is of the outdoor type. It is mounted on an open concrete structure which provides a large, open outdoor operating floor area. Underneath this floor are the condenser, feedwater heaters, condensate and feedwater pumps, and other power-generating equipment. This area is not enclosed. The turbine oil storage tanks and oil conditioning and handling equipment are located underneath the turbine floor at grade level on the side of the turbine area away from the Containment and Auxiliary Building. Hydrogen (which is used for generator cooling) is piped into the Turbine Building from storage in the yard northeast of the Auxiliary Building. The separation afforded by location of these areas, together with the fire-resistant construction, assures that a fire in these areas would not prevent safe shutdown.

Turbine oil storage is located in the southwest area of the Turbine Building. The nearest safety-related equipment approximately 50 feet away (steam-driven auxiliary feedwater pump). The auxiliary boiler is located near the steam-driven auxiliary feedwater pump. However, this hazard area is remote and separated from the motor driven auxiliary feedwater pumps located in the Auxiliary Building. An automatic open head deluge water system is installed to protect the turbine oil storage area as well as the hydrogen seal oil unit.

9. Diesel Generator Areas (FZs 1, 2 and 25D)

The emergency diesel generators (A and B) (FZs 1 and 2) are enclosed in separate rooms on the ground floor of the Auxiliary Building, separated from the remainder of the plant by reinforced concrete walls, ventilation system fire dampers, and three-hour rated fire doors. Automatic fire detection is provided in each room. Drainage and smoke venting capability is available. An automatic, total flooding CO_2 suppression system provides fire protection for each room. Day tanks with a capacity of 275 gallons are provided for each diesel in each respective room.

The dedicated shutdown (DS) diesel generator (FZ 25D) is located in a separate enclosure west of the Turbine Building. A day tank containing 150 gallons of fuel oil is located in the enclosure, and a 5,000 gallon diked storage tank is located nearby. Portable dry chemical and foam extinguishers are provided for the enclosure, and portable carts and hose stations are available. Drainage is provided in the yard area. The existing configuration provides adequate separation from safety-related systems, including the emergency diesel generator in the Auxiliary Building.

10. Diesel Fuel Oil Storage Area (FZ 30)

A 25,000-gallon diesel fuel oil storage tank is provided at the Robinson Plant approximately 100 feet north of the Auxiliary Building. The tank is surrounded by a dike to prevent runoff of fuel oil should tank rupture occur. The tank is also more than 50 feet away from safety-related tanks adjacent to the Auxiliary Building. This area complies with NFPA 30 criteria.

11. Safety-Related Pumps

Rooms containing safety-related pumps in the Auxiliary Building consist of the Charging Pump Room (FZ 4), Safety Injection Pump Room (FZ 3), Component Cooling Equipment Room (FZ 5), Auxiliary Feedwater Pump Room (FZ 6), and Residual Heat Removal Pump Pit (FZ 27). Automatic fire detection systems are provided for each of these rooms to allow prompt detection. Automatic partial water sprinkler protection is provided for the component cooling pumps. Additional safety-related pump areas include the steam-driven auxiliary feedwater pump in the Turbine Building (FZ 25B), the service water pumps at the intake structure (FZ 29), and the spent fuel pit pumps (FZ 28A). With the presence of alternate systems for backup, safe shutdown capability is not jeopardized by a fire in these areas. Local hose stations and portable extinguishers are also available in or near these areas as discussed in the HBR Fire Hazards Analysis.

The Unit 2 Fuel Oil Unloading/Transfer Area (FZ 40) is an outdoor area containing the transfer pumps needed to transfer diesel fuel from the Unit 1 fuel oil storage tank to the dedicated shutdown diesel fuel oil storage tank. Yard fire hydrants are available for protection of this area.

12. New Fuel Area (FZ 28A)

The new fuel storage area contains a minimal amount of combustibles and is under strict access control. This area contains fuel for only short periods of time. The racks are designed such that a maximum K_{eff} of 0.90 would exist if the fuel were to be covered with clean unborated water. This area drains to the Fuel Handling Building sump. Due to the negligible combustibles in this area, no detection or suppression systems are installed. Manual firefighting equipment is available from portable fire extinguisher or yard hydrant.

13. Spent Fuel Pool Area (FZ 28A)

The quantity of combustible material in the spent fuel storage area is also minimal and the equipment is de-energized from its respective power panels when not in use. A portable extinguisher and a manual hose station are provided. Strict access control is carried out for this area. Due to the small quantity of combustibles, no additional fire detection or suppression system is necessary for this area.

14. Radwaste Building (FZ 35)

The Radwaste Building (FZ 35) is separated from the rest of the plant by reinforced concrete walls. Three-hour rated fire doors are provided. Fire detection and a wet-pipe sprinkler system are installed in the building; portable fire extinguishers and fire hose stations are provided for fire fighting. Being in a detached structure, the ventilation system is independent and isolated from the rest of the plant; a radiation monitor is provided at the exhaust duct to monitor any release. Water from this building drains into the building sumps; samples are taken before water is discharged from the building. Sorting, frisking, and rebagging of contaminated and potentially contaminated trash and other materials is performed in this building. The building is also used for the decontamination of contaminated equipment, storage of contaminated materials, anti-c clothing, air sampling equipment, and health physics supplies. The building also contains concrete bunkers with shielded lids for storing highly radioactive materials, such as spent filters, spent resins, and other materials. Spent resin is sluiced from the Spent Resin Storage Tank or from the Waste Water Demineralization System to a High Integrity Container (HIC) located inside the shielded bunker. Spent resins and spent filters are dewatered in the shielded bunkers prior to being shipped offsite for burial.

Building 230 of all metal construction is used to store miscellaneous contaminated equipment. No automatic fire suppression, fire detection, or ventilation system isolation capability is installed in this structure. Portable fire extinguishers are provided and yard fire hydrants with hose houses are located in the area for manual firefighting. This does not comply with the guidelines of BTP APCSP 9.5-1. This structure has been designated as a "temporary facility." An evaluation was presented in the regularly scheduled PNSC meeting Number 1277 on May 18, 1988 assessing the consequences of a fire assuming that the fire would result in the release of 100% of all radwaste materials involved. This evaluation concluded that the whole body off-site dose from such a fire would be less than 1 millirem. This was considered to be insignificant.

There is also a solid radwaste drumming room (FZ 14) in the Auxiliary Building; however, the room is no longer routinely used for this purpose. This room is separated from the remainder of the plant by reinforced concrete walls and a three-hour rated fire door is provided for the hallway entrance. Ventilation system fire dampers are also provided to increase isolation of this area. Radwaste may be stored or processed in the room as needed. Fire detection and a preaction sprinkler system are installed in this area; portable fire extinguishers and fire hose stations are available for manual firefighting.

In the waste evaporator area (FZ 38) of the Auxiliary Building, a filtration and demineralization process is used to remove radioactive ions

and particles from waste water. When wet spent resin is removed, it is temporarily stored in a high integrity container in the room and then transferred to a transportation high integrity container outside. This area is separated from the rest of the Auxiliary Building by three-hour rated fire barriers. No automatic fire suppression or detection is provided or required because of the negligible combustible loading in the zone. This zone does not contain safety-related or safe shutdown systems. A fire hose station and portable fire extinguisher are provided for manual firefighting.

There is a 10,000-gallon contaminated oil storage tank and a 400-gallon contaminated solvent storage tank located in the radiation controlled area yard Southwest of Building 375. These tanks and their associated pumps are enclosed by a concrete dike sized to contain the entire contents of the storage tanks. (There are also tanks of the same sizes for noncontaminated waste oil and solvent nearby in a separate diked area.) In the event of a spill and fire consuming all of the contaminated oil and solvent, the amount of radioactivity released would be approximately 642 μ Ci, based on release of Co^{60}. In the event of this extremely unlikely occurence, the total off-site release would be 0.1 percent of the 15 mRem/year allowable off-site release limit.

Contaminated material is occasionally stored in the RCA yard under the control of Health Physics. Such material is usually in metal drums, boxes, or containers. Because of intervening distance and barriers, these yard facilities do not present a significant exposure to safe shutdown or safety-related/safe shutdown equipment. Yard fire hydrants with hose houses and portable fire extinguishers are available for manual firefighting.

Liquid and gaseous radwastes are processed in other compartments of the Auxiliary Building. Although these areas contain little or no combustible materials, detection capability is provided in or near these areas, as is manual firefighting equipment.

Waste storage tanks are located in a separate area in the Fuel Handling Building (FZ 28B). Because access is strictly limited and there are negligible combustibles, no additional protection is required.

15. Decontamination Area (FZ 28B)

No flammable liquids are stored in decontamination areas, so this guideline is not strictly applicable. The large equipment decontamination area is made entirely of concrete, is seldom utilized, and is remote from safety-related/safe shutdown equipment. Manual hose stations and portable extinguishers are available from the nearby hot machine shop (FZ 28D) and Yard for this zone. No additional fire detection or suppression features are necessary.

16. Safety-Related Water Tanks (FZs 31, 32 and 33)

Safety-related water tanks consist of the refueling water storage (FZ-31) and primary water storage tanks (FZ 32), located north of the Auxiliary Building, and the condensate storage tank (FZ 33) near the southwest corner of the Turbine Building.

The water storage tanks are separated from safety-related systems by the walls of the Auxiliary Building and are greater than 50 feet from the diesel oil storage tank (FZ 30), also north of the building. Yard hydrants are available for fire protection of these tanks.

The condensate storage tank is about 30 feet from the turbine oil storage area, but that hazard is protected by an automatic deluge system. The condensate storage tank is also adequately separated from the Dedicated Shutdown Diesel Generator fuel oil storage tank. Yard hydrants and firefighting equipment from the Turbine Building are available for fire protection.

17. Cooling Towers

Cooling towers are no longer utilized for the waste evaporator and are located in the north yard. These towers are of noncombustible construction.

18. Miscellaneous Areas

The records storage area for the Robinson Plant is located in the Records Storage Vault, remote from Unit 2. Fire protection for this area is being addressed along guidelines particular to that type area (ANSI N45.2.9, NFPA 232). The hot machine shop (FZ 28D) is located within the Unit 2 area but remote from safety-related/safe shutdown areas. Other shops and warehouses are located between Units 1 and 2 and west of Unit 2 in the Yard separated from safety-related/safe shutdown areas. Fuel oil storage for the auxiliary boiler is located about 400 feet northeast of the Auxiliary Building. Due to the remote separation of these miscellaneous areas, existing protection is adequate.

G. SPECIAL PROTECTION GUIDELINES

1. Welding and Cutting, Acetylene-Oxygen Fuel Gas Systems

Welding and cutting equipment is stored in shop storage areas. These areas are remote from safety-related systems and equipment of Unit 2 and were not considered in the fire hazards analysis. A permit system for use of such equipment is in effect. Local hose stations and portable equipment are readily available to these areas.

2. Storage Areas for Dry Ion Exchange Resin

No resins are presently stored near safety-related areas in the Auxiliary Building. A dedicated storage area for dry resin is provided, removed from safety-related areas with appropriate protective features.

3. Hazardous Chemicals

The plant controls for the storage and use of hazardous chemicals are based on the CP&L program for chemical safety and health management. Plant procedures implement this corporate program.

The various chemicals used at the site are stored in suitable facilities, including the Chemical Storage Warehouse (located outside the protected area) and the E&RC Building chemistry laboratory chemical storage vault. These two primary chemical storage facilities are in buildings detached from the power block and protected by automatic sprinklers.

Concentrated sulphuric acid and 50% sodium hydroxide solution used in the makeup water treatment and condensate polishing systems are stored in tanks of about 8,000 gallons each, located west of the Turbine Building. The sodium hydroxide tank is housed in a metal building and has a spill containment dike. In the chemical feed room at the southwest corner of the Turbine Building, both 35% hydrazine and 30% ammonium hydroxide are utilized for water treatment. There is a 350-gallon feed tank for the hydrazine and a 250-gallon feed tank for the ammonium hydroxide. Up to five drums of each chemical may also be present for feed tank refill.

There is a system for injecting a combustible liquid dispersant (Flash Point > 200°F) and a noncombustible solution of 14% sodium hypochlorite in water into the service water headers. Tanks containing the solution and dispersant and associated pumps are located at the Unit 1 intake structure with piping extending to the Unit 2 intake structure.

There are also small quantities of chemicals used in the secondary sampling room in analysis. There are several small cylinders of various laboratory gases located outside the E&RC Building chemistry laboratory on the north wall.

A leak or fire involving chemicals in these storage locations could present a localized respiratory or skin contact exposure to personnel. However, because of the separation distances and barriers provided, such an occurrence would have no effect on safe shutdown or safety-related equipment.

4. <u>Materials Containing Radioactivity</u>

Spent resin storage is provided by a metal tank in an area free of combustibles. Solid materials containing radioactive material are processed in the Radwaste Building with minimal temporary storage. Materials are ultimately drummed and removed from the site.

2.2.3 Safe-Shutdown Function/System Descriptions

The safe shutdown functions necessary to operate the plant during the cooldown from normal plant power operation to a cold shutdown status are identified as follows:

2.2.3.1 Reactor Coolant Inventory and Pressure Control. The reactor coolant system provides core cooling by maintaining sufficient reactor water inventory once the reactor vessel is no longer passing heat to the steam generators by means of the forced circulation provided by the reactor coolant pumps. Loss of offsite power disables the reactor coolant pumps, leaving only natural circulation flow as the means of heat transport from the reactor core to the steam generators. Hot and cold leg temperature sensors provide the monitoring of this heat flow, while pressurizer level and pressure sensors provide indication of system inventory and pressure conditions. Loss of reactor coolant inventory is to be limited to the reactor coolant pump seal leakage by removing power from the letdown isolation valves thereby causing their closure. The pressurizer PORVs will be immediately deactivated to the closed position and only the mechanically-operated relief valves to the pressurizer relief tank will be available for primary system pressure relief. The excess letdown line is also blocked by the deenergization of the isolation valve, thereby causing it to close. Following a reactor trip, the secondary system will be employed to remove decay heat and, therefore, cause shrinkage of the RCS inventory; RCP seal leakage will cause a further reduction in the primary system inventory. Additional borated water from the RWST is added to the system by means of charging pump A for shutdown Alternate A; charging pump C for the Alternate B1, or one of the safety injection pumps in the event that none of the charging pumps are available (Alternate B2). The feasibility and operational acceptability of the use of the safety injection pumps for RCS makeup service under post-fire operating conditions has been evaluated and documented.

Reactor coolant makeup by use of the charging pumps will utilize the normal charging flow paths to Loops 1 and 2 via the regenerative heat exchanger. In addition, some of the charging water is utilized to maintain the reactor coolant pump seal flow. Alternate B reactor coolant makeup utilizes a safety injection pump with water from the RWST added to the RCS cold legs during hot standby and the RCS hot legs during plant cooldown. RCS vent paths such as the reactor head and pressurizer vents are blocked closed by the deenergization of the system isolation valves. System hot and cold leg temperatures are monitored to control the rate of cooldown.

2.2.3.2 Secondary System Cooling. The secondary shutdown system consists of the equipment necessary to provide for decay heat removal from the primary system during hot standby and additional heat removal for cooldown operation.

Components for this system have been identified to enable the controlled release of steam to the atmosphere and the supply of feedwater to the steam generators. Steam generator feedwater makeup and steam release to the atmosphere is the primary means of removing heat from the RCS during hot standby. To effectively utilize the secondary system for decay heat removal, at least one steam generator must be fed to maintain Hot Shutdown. Two will be needed to proceed to cold shutdown. Level instrumentation for all three steam generators has been provided at both local shutdown panels.

In Alternate A, the steam-driven feedwater pump is employed to pump feedwater from the condensate storage tank to the steam generators. In Alternate B, feedwater is supplied via the motor-driven auxiliary feedwater pumps. Control valves can be operated locally, as required, for Alternate A and from the control room for Alternate B to allow the feeding of one steam generator at a time during plant cooldown. The power-operated steam relief valves are operated after completion of repair procedure to release steam from each steam generator during the time feedwater is added. Alternate A utilizes local control of the steam generator power-operated relief valves from the secondary control panel and Alternate B operates the PORVs remotely in the control room. Other valve operations such as the trip of the steam supply valves to the main turbine-generator occur when the reactor trip occurs. Valves to supply service water to the SDAFW Pump are operated by local manual action if the condensate storage tank reaches a minimum useable level of inventory.

2.2.3.3 Shutdown Cooling/Residual Heat Removal. The residual heat removal system consists of two pumps, two heat exchangers, and 2 trains of valves to interconnect the system to the RCS. This system provides for the removal of the decay heat from the RCS after the RCS has cooled to 350°F and the pressure is less than or equal to 375 psig. The system provides the heat removal capability required to maintain the plant in a cold shutdown condition.

The RHR system is placed in service by operating one RHR pump; these pumps are normally powered from the emergency buses, but in the event of a fire in Fire Zone A or H, a repair procedure is available to energize and operate either pump from the DS Bus/DS generator. The system valves can be manually positioned (Alternate A shutdown) to provide coolant flow through both heat exchangers. The coolant loop is operated utilizing its miniflow recirculation loop until the temperature matches the RCS loop temperature. The isolation valves which interconnect the RHR and RCS systems are opened either remotely for Alternate B or manually for Alternate A. The flow and temperature instrumentation and the HX outlet and bypass line flow control valves are provided with repair procedures should normal operation not be available due to fire-induced cable damage. The repair procedures provide for local control and ensure the cooldown rate is controllable. The RHR pumps and heat exchangers utilize component cooling water as their coolant. The flow control through the heat exchangers is controlled by flow control valve operation powered from instrument air, if available, (Alternate B) or local nitrogen bottles via repair procedures for Alternate A shutdown (Alternate B without instrument air).

2.2.3.4 Component Cooling Water System. This system is a support system to the previously discussed plant operating systems. The function of this system is to transfer heat from the RCS or RHR systems to the service water system. The system consists of at least one pump for circulating the coolant, two heat exchangers, an expansion tank, and miscellaneous valves for equipment isolation or flow control. Component cooling water is supplied via the component cooling heat exchanger (cold shutdown), and seal water heat exchangers for cooling of process equipment. Safe shutdown loads which are cooled by component cooling water include the charging pump (s) (Alternate A shutdown mode and Alternate B Method 1), the reactor coolant pumps thermal barrier, and the high-head safety injection pumps (Alternate B Method 2 shutdown mode).

2.3 SHUTDOWN ASSUMPTIONS AND POSITIONS

2.3.1 Introduction

The safe-shutdown analysis considers the effects of fire on plant equipment and identifies methods for achieving safe shutdown. The fundamental assumption made in the analysis is that a single fire occurs in any plant area coincident with a complete 72-hour loss of offsite power. However, offsite power is assumed to present for those situations where availability of offsite power could adversely impact safe shutdown. All equipment normally present in the plant is assumed to be functional at design capability and may be lost only as a result of fire damage. No other external events, accidents, or equipment failures are assumed to occur in connection with either the postulated fire or through achieving a stable cold shutdown condition. Other assumptions were made in the course of the analysis to ensure that the study closely reflects the impact of a fire. These assumptions consist of the following major categories:

(1) Fire damage to plant equipment

(2) Smoke and Toxic Gases

(3) Fire duration and brigade activity

(4) Manpower availability and manual operations

(5) Repairs

Each category is discussed in the subsection that follows.

2.3.2 Fire Damage To Plant Equipment

This subsection describes the basic assumptions made with regard to fire damage.

2.3.2.1 Electrical Cable Fire Damage. The integrity of insulation and external jacket material for electrical cables is susceptible to fire damage. Damage may assume several forms including deformity, loss of structure, cracking, and ignition. The relationship between exposure of electrical cable insulation to fire conditions, the failure mode, and time to failure may vary with the configuration and cable type. To accommodate these uncertainties in a consistent and conservative manner, the analysis, except where fire protection features exist, assumes that the functional integrity of electrical cables is immediately lost when exposed to a postulated fire in an area. Electrical cable failures are limited by the following considerations:

(1) The fire damage occurs throughout the area under consideration.

(2) The fire damage results in an unreliable cable with regard to proper safe shutdown function.

(3) The fire-damaged cable conductors will either short to other conductors in the same cable or conductors in other cables located in the same enclosure; or short to ground through the enclosure; or the conductor will separate causing an open circuit.

The analysis reflects the NRC position concerning hot shorts as expressed by the Staff in a memorandum to CP&L dated December 21, 1983. This position excludes the following combinations of cable-to-cable hot shorts based on the low probability of occurrence:

(1) 3-phase AC power circuit cable 4.16 kv and 480 V voltage levels;

(2) Deenergized 2-wire double fused ungrounded DC power cable (1235 V or 250 V voltage level);

(3) Deenergized 2-wire double fused ungrounded DC control circuit cable (125 V voltage level); and

(4) Deenergized 2-wire ungrounded AC power or control circuits (120 V AC).

2.3.2.2 Mechanical Component Damage. Fire damage to valves, piping, and noncombustible tubing is not assumed to adversely impact their ability to function as pressure boundaries or as safe shutdown components. Therefore, a fire is not assumed to cause a valve or other mechanical component to change position unless the fire also affects the electrical equipment or circuit associated with the component. In addition, it was assumed that exposure to a fire will not prevent the manual stroking of the valve following fire extinguishment.
The assumption reflects the fact that nuclear power plant fires are sufficiently limited in magnitude and duration to preclude the potential of significant damage to mechanical equipment. Damage which is assumed to occur as a result of a fire would involve discoloration and other such superficial manifestations of exposure to a high temperature oxidizing environment. Since these effects would be localized and of short duration, mechanical and overall structural integrity is considered not impaired.

2.3.2.3 Instrument Damage. Instruments (e.g., resistance temperature detectors (RTDs), thermocouples, pressure transmitters and flow transmitters) are assumed to suffer damage in a manner similar to electrical cables. If these devices are exposed to a fire, only associated cables are damaged. The instrument fluid boundary remains undamaged. Sight-glasses and mechanically linked tank-level indicators are assumed to be unaffected by fire.

2.3.3 Smoke and Toxic Gases

The analysis recognizes that smoke and corrosive gases generated by burning materials such as those containing polyvinylchlorides may pose a threat to personnel safety. However, the relatively short burn duration of the postulated fire is assumed to preclude the buildup of sufficient concentrations of such gases to cause failure of electrical and mechanical components. Consequently, concentrations of such gases within fire areas and deposition of chlorides on plant components are not considered in the analysis.

The postulated corrosive gas buildup from a fire in a small area and chloride deposition within a general plant area would not be sufficient to adversely affect plant equipment while safe shutdown is achieved and maintained. This conclusion is further supported by the NRC in their analysis of the Browns Ferry fire as documented in NUREG-0050.

2.3.4 Fire Duration and Fire Brigade Activity

The total fire brigade commitment to a fire is one hour. This hour is broken down as follows:

(1) 30 minutes to respond and extinguish the fire after its discovery

(2) 30 minutes to assess the fire damage and restore suppression equipment following fire extinguishment

2.3.5 Manpower Availability and Manual Operation

The analysis assumes the manual operation of some safe shutdown equipment as a part of the alternative shutdown process for specific fire areas. Any manual operation so credited is incorporated in the HBR safe shutdown procedures for use by the operating shift personnel. All operators and fire brigade members are drawn from onsite personnel based on the minimum staffing level specified by technical specifications and applicable plant procedures. Although a recall procedure can be credited for increasing the number of operators available for manual operations after a fire, the analysis does not take credit for a recall procedure.

The activities requiring operations personnel intervention in the event of a fire include fire fighting and plant operation. To plan the allocation of personnel, the basic fire scenario is combined with the shutdown scenario to ensure the proper coordination of activities. A time-line/manpower concept is utilized in the analysis to establish that sufficient time is available for achievement of the safe shutdown system function.

2.3.6 Repairs

The analysis further assumes that offsite power would be restored 72 hours following fire initiation. The repair of cables or controls for cold-shutdown-related equipment which may be affected by a fire, would be accomplished during this extended time period, using post-fire emergency repair procedures (Dedicated Shutdown Procedures) as required.

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

TABLE OF CONTENTS

1

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

TABLE OF CONTENTS (Cont'd)

CHAPTER 10
STEAM AND POWER CONVERSION SYSTEM

LIST OF TABLES

10.2 TURBINE GENERATOR

10.2.1 DESIGN BASIS

All of the equipment in the turbine generator systems is designed to produce a maximum calculated gross output of 780,000 kW at a condenser vacuum of 2.0 in. Hg. 7

The design parameters for the turbine generator are provided in Table 10.2.1-1.

TABLE 10.2.1-1

DESIGN PARAMETERS-TURBINE GENERATOR

Turbine Type	Three-element, tandem-compound four-flow exhaust
Turbine Capacity (kW)	
Maximum calculated (at 4.0 in. Hg)	727,000
Maximum calculated (at 2.1 in. Hg)	780,000
Generated Rating (kVa)	854,000
Turbine Speed (rpm)	1800

7

10.2.2 DESCRIPTION

The turbine is a three-element, tandem-compound, four-flow exhaust, 1800 rpm unit with 45 in. last row blades, and has moisture separation and live steam reheat between the high pressure (HP) and low pressure (LP) elements. The AC generator and rotating rectifier exciter are direct-connected to the turbine shaft. |7

The turbine consists of one double-flow, HP element in tandem with two double-flow, LP elements. Four combination moisture-separator, live-steam reheater assemblies are located alongside the LP turbine.

The turbine has a maximum guaranteed gross rating of 702,125 kW when operating with inlet steam conditions of 745 psia 510°F, exhausting at 4.0 in. of Hg absolute, zero percent makeup, and with six stages of feedwater heating in service.

The hydrogen inner-cooled generator is rated at 854,000 kVa at 75 psig hydrogen gas pressure. The generator has sufficient capability to accept gross kW output of the steam turbine with its control valves wide open at rated steam conditions.

The turbine oil system is of a conventional design. It consists of three parts: a HP oil system, a lubrication system, and an electro-hydraulic control system. The electro-hydraulic control system is completely separate from the other two parts. Lube oil is also used to seal the generator glands to prevent hydrogen leakage from the machine. The oil used for the control system is a fire resistant synthetic. The maximum available steam temperature is not capable of initiating a fire in the lubrication oil system.

The turbine has low speed, motor driven, spindle turning gear equipment which is side mounted on the outboard bearing of the LP turbine nearest the generator.

Turbine Controls

High Pressure steam enters the turbine through two stop valves and four governing control valves. An electro-hydraulic, servo-actuator controls each stop valve so that it is either in the wide-open or closed position. The control signal for this servo-actuator comes from the mechanical-hydraulic overspeed trip portion of the electro-hydraulic control system. The major function of these stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the protective devices function. The control valves are positioned by a similar electro-hydraulic servo-actuator acting in response to an electrical signal from the main governor portion of the electro-hydraulic control system. Upon loss of load resulting in a high rate of acceleration, the auxiliary governor portion of the electro-hydraulic control will act to close the control valve rapidly.

As shown in Figure 10.1.0-2, the steam, after passing through the stop and control valves, passes through the HP turbine, then through the moisture separator and reheater. The reheat stop valves and reheat intercept valves are located between the reheater and the LP turbine inlet. Their purpose is to control the steam flow to the LP turbines in the event of turbine overspeed.

The reheat stop valve is an open-closed type valve, closed upon operation of the overspeed trip in a manner similar to the operation described above for the main stop valves. The reheat intercept valve is a positioned valve controlled from the auxiliary governor portion of the electro-hydraulic control system. The use of intercept valves provides the capability for the turbine generator to accept a full loss of external electrical load without turbine trip, thus maintaining electrical power to plant auxiliaries.

The electro-hydraulic turbine control system combines a solid state electronic controller with a HP fire resistant fluid supply system which is independent of the lubricating oil.

The electro-hydraulic control system includes the following features:

a) Governor valve controller
b) Intercept valve controller
c) Load limit controller
d) Auxiliary governor
e) Speed controller
f) Load controller
g) Operators panel to provide for a centralized turbine control station
h) High pressure hydraulic fluid pumping unit
i) Turbine protective devices

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft, which is balanced in position by a spring until the speed reaches approximately 110 percent of rated speed. Its centrifugal force then overcomes the spring and the weight flies out striking a trigger which trips the overspeed trip valve and releases the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure, closing the main stop and governing control valves and the reheat stop and intercept valves.

In the steam admission system any steam path has two valves in series which are controlled by completely independent systems. Furthermore, the high pressure oil system that actuates the steam valves is completely independent of the LP lubrication oil. The turbine control and protection system is fail-safe. Any loss of oil pressure or voltage causes closure of the steam valves.

The autostop valve is also tripped when any one of the protective turbine trip devices is actuated. The protective devices are all included in a separate assembly but are connected hydraulically to the overspeed trip relay.

The following malfunctions or faults will cause an automatic turbine generator trip.

a) Generator/electrical faults
b) Low condenser vacuum
c) Thrust bearing failure
d) Low lubricating oil pressure
e) Turbine overspeed
f) Reactor trip
g) Manual trip
7 h) AMSAC trip

10.2.3 TURBINE DISK INTEGRITY

The advanced status of the art of rotor forging and inspection techniques guarantees practically defect-free turbine rotors. Further, Westinghouse conservative design eliminates any harmful stress concentration point.

Due to the redundancy and reliability of the turbine control protection system and of the steam system, the probability occurrency of a unit overspeeding above the design value, i.e., 120 percent, is very remote.

Due to conservative design, very careful rotor forging procurement and rigid inspection, Westinghouse turbine generator units had, at the time HBR 2 was licensed, never experienced a massive failure.

A survey of the available literature on turbine generator unit failure shows that the last massive failure of a turbine generator occurred about eight years prior to the submittal of the original HBR FSAR in November, 1968. The causes of failure were identified at that time, and provisions were adopted to prevent the recurrence of massive failures. The record since that time demonstrates the soundness of these provisions and correct design.

The no-failure record of Westinghouse turbine generator units, plus the experience gained from the referenced incidents, together with the improvement in the design and inspection techniques in the past, indicated the likelihood of massive turbine generator failure to be extremely remote.

With regard to design and inspection techniques, it is worthwhile to mention that a technical committee of forging suppliers and equipment manufacturers was formed about ten years prior to the submittal of the original HBR FSAR under ASTM to study turbine and generator rotor failures. This group developed the high toughness NiCrMoV material, now used in all turbine rotors and disks. This Task Force was very active in making additional improvements in quality and soundness of large forgings. (Reference 10.2.3-1)

The survey of the literature on massive turbine failures in the 20 years prior to the original FSAR indicates that all of them occurred between 1953 and 1958.

This survey has pointed out that the rate events of a catastrophic failure of turbines fell into one of two categories:

a) Failure by overstressing arising from accidental and excessive overspeed

b) Failure, due to defects in the material, occurring at about normal speed

No failure falling in the first category had occurred in the United States during this period. The only two documented examples occurred in the United Kingdom. Both accidents were caused by the main steam admission valves sticking in the open position after full load rejection, because of impurities in the turbine control and lubrication oil. The probability of this occurrence in this plant is very remote as previously pointed out.

Besides the provisions in the design of the turbine control and protection system during plant operation, valves are exercised on a periodic basis, to further preclude the possibility of a valve stem sticking. Analysis of oil samples are performed as required.

The turbine is periodically overspeeded to check the tripping speed. The remaining tripping devices are periodically checked.

Westinghouse specified the quality and method of manufacturing of the purchased forgings. Written specifications covered the manufacturing process, the chemical and mechanical properties, the tests performed, etc. Specifically, the tests performed were both destructive and nondestructive in nature. The destructive tests included tension tests, impact tests, and transition temperature measurement tests. The tension specimens were taken in a radial and/or longitudinal direction. The tensile properties were determined in accordance with ASTM A-370 on a Standard Round 1/2 in. Diameter 2 in. Gage Length Test specimen. The yield strength was taken as the load per unit of original cross section at which the material exhibits an offset of 0.2 percent of the original length. The Charpy impact specimens were taken in a radial direction and the minimum impact strength at room temperature measured. The transition temperature was determined from 6 specimens tested at different temperatures in accordance with ASTM A-443. The specimens were taken in a radial direction and machined in such a manner that the V-notch was parallel to the forging axis. Two specimens were machined from each test bar. All specimens were taken following all heat treatment. Curves of impact strength and percent brittle failure versus test temperature were drawn.

The nondestructive tests included bore inspection, sulfur printing, magnetic particle test, thermal stability test, and ultrasonic tests.

The bores were visually inspected and the walls of the finished bores were free from cracks, pipe shrinkage, gas cavities, nonmetallic inclusions, injurious scratches, tool marks, and similar defects.

A magnetic particle test was made on each forging to demonstrate the freedom from surface discontinuities. The end faces of the main body over and beyond the fillets joining the main body to the shaft portions were magnetic particle tested. The bore was also magnetic particle tested at a high sensitivity level in accordance with ASTM A-275. These inspections were done by Westinghouse inspectors prior to Westinghouse accepting these forgings. After final machining by Westinghouse, rotors were again magnetic particle inspected on the external surfaces by Westinghouse.

The face of the test prolongations at each end of the rotor body or an area on the end faces of the rotor body equivalent to the test prolongations was sulfur printed to determine the freedom from undue ingot corner segregation and excessive sulfide inclusions.

A thermal stability test was performed on the forging at the place of manufacture after all heat treatment was completed.

The forgings were ultrasonically inspected at the place of manufacture by Westinghouse inspectors.

Based on conservative design, reliable turbine control system, careful rotor forging procurement, and rigid inspection, the probability of a combination of excessive overspeed, new-born large forging defects, and operating temperature below the transition temperature is considered practically zero.

Further information on turbine disk integrity and generic questions and answers on Westinghouse nuclear LP turbines is contained in Reference 10.2.3-2.

10.2.3.1 Materials Section

10.2.3.1.1 High Pressure Turbine

The high pressure turbine element, shown in Figure 10.2.3-1, is of a double flow design; therefore, it is inherently thrust-balanced. Steam from the four control valves enters at the center of the turbine element through four inlet pipes, two in the base and two in the cover. These pipes feed four double flow nozzle chambers flexibly connected to the turbine casing. Each nozzle chamber is free to expand and contract relative to the adjacent chambers.

Steam leaving the nozzle chambers passes through the rateau control stages and then flows through the reaction blading. The reaction blading is mounted in blade rings shown in Figure 10.2.3-2, which in turn are mounted in the turbine casing. The blade rings are centerline supported to ensure center alignment while allowing for differential expansion between the blade ring and the casing. The design reduces casing thermal distortion and, thus, seal clearances are more readily maintained.

Steam exhausts from the HP turbine base, through cross-under piping, to the two combined moisture separator live steam reheater assemblies.

The HP rotor is made of NiCrMoV alloy steel. The specified minimum mechanical properties are given in Table 10.2.3-1.

The main body of the rotor weight is approximately 100,000 lb. The approximate values of the transverse centerline diameter, the maximum diameter, and the main body length are 36 in., 66 in., and 138 in., respectively.

The blade rings and the casing cover and base are made of carbon steel casings. The specified mechanical properties are given in Table 10.2.3-2.

The bend test specimen shall be capable of being bent cold through an angle of 90 degrees and around a pin one inch in diameter without cracking on the outside of the bent portion.

The approximate weight of the four blade rings, the casing cover, and the casing base is 80,000 lb, 140,000 lb, and 160,000 lb, respectively.

The casing cover and base are tied together by means of more than 100 studs. The stud material is an alloy steel having the mechanical properties given in Table 10.2.3-3.

The studs have length ranging from 18 to 66 in. and diameter ranging from 2.75 in. to 4.5 in. About 90 percent of them have diameter ranging between 2.5 and 4 in. The total stud cross-sectional area is about 900 in.^{2} and the total stud free-length volume is about 36,000 in.^{3}.

10.2.3.1.2 Low Pressure Turbine

The double flow LP turbine, shown in Figures 10.2.3-3 and 10.2.3-4, incorporates high efficiency blading diffuser type exhaust and liberal exhaust hood design. The LP turbine cylinders are fabricated from steel plate to provide uniform wall thickness, thus reducing thermal distortion to a minimum. The entire outer casing is subjected to low temperature exhaust steam.

The temperature drop from the cross-under steam temperature to the exhaust steam temperature is taken across three walls; an inner cylinder number 1, a thermal shield, and an inner cylinder number 2. This precludes a large temperature drop across any one wall except the thermal shield which is not a structural element, thereby virtually eliminating thermal distortion. The fabricated inner cylinder number 2 is supported by the outer casing at the horizontal centerline and is fixed transversely at the top and bottom and axially at the centerline of the steam inlet, thus allowing freedom of expansion independent of the outer casing. Inner cylinder number 1 is, in turn, supported by inner cylinder number 2 at the horizontal centerline and fixed transversely at the top and bottom and axially at the centerline of the steam inlets, thus allowing freedom of expansion independent of inner cylinder number 2. Inner cylinder number 1 is surrounded by the thermal shield.

The steam leaving the last row of blades flows into the diffuser where the velocity energy is converted to pressure energy, thus improving efficiency and reducing the excitation forces on the last rotating row of blades.

The LP rotors are made of NiCrMoV alloy steel. The specified minimum mechanical properties are given in Table 10.2.3-4. The fully integrated rotors consist of one-piece forgings of monoblock design to each of which are attached nine rows of rotating blades. The rotating blades are machined or drop forged and the nine rows are attached to the rotor by a serrated root type of fastening. The rotor shaft and fitted blades make up each LP turbine
7 rotor assembly.

The outer cylinder and the two inner cylinders are mainly made of ASTM A-285 Grade C material. The minimum specified properties are given in Table 10.2.3-6.

10.2.4 EVALUATION

This unit's contribution to system load requirements is controlled by the automatic load dispatch system which is described in Chapter 7. The power conversion system, under nominal operating conditions, is capable of accepting load changes up to generation load increases of 15 percent of full load per minute and accepting step load increases or decreases of 20 percent of full load, within the load range of 15 to 95 percent load. These limits are based on full load rating of 2300 Mwt.

REFERENCES: SECTION 10.2

10.2.3-1 Curran, R. M., "History of the Special ASTM Task Force on Large Turbine and Generator Rotors," ASTM Meeting, Purdue University, 1965. 7

10.3.2 SYSTEM DESCRIPTION

The main steam supply system is shown on Figures 10.1.0-1 through 10.1.0-3. Steam from each of the three steam generators is supplied to the turbine, where the steam expands through the high pressure (HP) turbine, and then flows 5
through a moisture preseparator system, reheaters and intercept values to two, double-flow, low-pressure (LP) turbines, all in tandem. Six stages of extraction are provided, two from the HP turbine, one of which is the exhaust, and four stages from each of the LP turbines. The feedwater heaters for the lowest two stages are located in the condenser neck. All feedwater heaters are horizontal, half-size units (two strings). The feedwater string is the closed type with deaeration accomplished in the condenser hotwell to less than 0.005 cc per liter of residual oxygen. The moisture preseparator system consists of four Moisture Preseparator/Special Crossunder Pipe Separator (MOPS/SCRUPS) devices. MOPS are concentric chambers in the crossunder line directly at the HP outlet. The moisture is removed from the crossunder line through a gap at the upper end of the chamber and is enhanced since the extraction steam is also removed through this same concentric gap. SCRUPS is 5
a specially designed elbow with turning vanes that are designed to remove moisture from the steam path. An outer shell is provided as a separating chamber from which the extraction steam is vented and condensate is drained.

There are four, horizontal-axis, cylindrical-shell, combined moisture-separator, live-steam reheater assemblies. Steam from the exhaust of the HP turbine element enters each assembly at one end. Internal manifolds in the lower section distribute the wet steam. The steam then passes through a chevron moisture separator where the moisture is removed. Live steam from the steam generators enters at the other end of each assembly, passes through the tubes and leaves as condensate. The lower pressure steam leaving the chevron separator flows over the tube bundle where it is reheated. This reheated steam leaves through openings in the top of the assemblies and flows through individual stop and intercept valves to the LP turbines.

10.3.2.1 Main Steam Isolation Valves

Steam from each of the steam generators flows through a 26 in. swing disc type isolation valve and a swing disc check valve to a 72 in. common header. The main steam line isolation valve bodies are cast carbon steel with stainless steel trim. The valves each pass 3.37×10^6 lb of steam/hr at 785 psig and 518.2°F with 0.25 percent moisture. The design pressure and temperature of the valves are 1085 psig and 600°F, respectively. The isolation valves are equipped with three top mounted air cylinders and stay in the open position in the event of loss of air pressure. A bypass valve is provided around each isolation valve to equalize pressure across the valve and for steamline warmup. The valve design has been analyzed in Reference 10.3.2-1 to confirm the integrity of the MSIVs under the dynamic loads associated with postulated steam line breaks.

10.3.2.2 Main Steam Safety Valves

The steam generator safety valves provide emergency pressure relief for the steam generators as a result of imbalance between steam generation and steam

consumption. These valves have a total flow capacity equal to steam generator flow at maximum calculated plant operation at the pressure setting established by the applicable ASME code.

There are four safety valves located on each of the three 26 in. main steam lines outside the reactor containment and upstream of the nonreturn valves and the swing disc isolation valves. Discharge from each of the safety valves is carried to atmosphere. The lowest safety valve set pressure is 1085 psia.
5 The twelve main steam safety valves have a total combined rated capacity of 1.022×10^7 lbs/hr.

10.3.2.3 Main Steam Power-Operated Relief Valves

Three power operated relief valves (PORV) are provided which are capable of releasing heat to the atmosphere. These valves are automatically controlled by pressure or may be manually operated from the control board. In addition, in the event of a load rejection of greater than 70 percent, the steam dump controls can take over the operation of these valves. The PORVs together have a designed capacity to release 1,740,000 pounds per hour of steam at 790 psia. One power operated relief valve, located on each main steam line upstream of the nonreturn valve and the swing disc isolation valve, is provided for each steam generator. Discharge from each of the three power operated relief valves is carried to the atmosphere.

The steam generator power operated relief valves provide the means for plant cooldown by steam discharge to the atmosphere if the condenser steam dump is not available. The relief valves are of the modulating type, remote pressure controlled with remote adjusted relief pressure setting.

10.3.3 EVALUATION

Pressure relief is required at the system design pressure of 1085 psig, and the first safety valve is set to relieve at this pressure. Additional safety valves are set at pressures up to 1139 psig, as allowed by the ASME Code. In addition to the safety valves, one modulated pressure relief valve is installed for each steam generator which can be manually operated from the control room.

The pressure relieving capacity of the safety valves is at least equal to the steam generation rate at maximum calculated conditions.

The evaluation of the capability to isolate a steam generator to limit the loss of radioactivity and the steam break accident analysis are presented in Section 15.1.5.

10.3.5 WATER CHEMISTRY

10.3.5.1 Chemistry Control Basis

Feedwater chemistry is maintained within the following limits during power operation:

pH	8.8 - 9.6	3
Cation Conductivity, Micro Siemens/cm @ 25°C	$\leq$ 0.2	
Hydrazine, ppm	$\geq$ 3 times condensate oxygen concentration	
Oxygen, ppm	$\leq$ 0.005	

These limits are maintained by the addition of ammonium hydroxide, a pH additive, which is injected into the condensate at the discharge of the condensate polisher. In addition, hydrazine, an oxygen scavenger is injected into the system at the discharge of the condensate polisher and/or the moisture crossovers to the LP turbines.

The steam generators are operated with blowdown to maintain the steam
generator chemistry within specification. The blowdown rate is adjusted as
required to remove dissolved and suspended solids. 3

Also provided to maintain steam generator chemistry within specification, is a condensate polisher located downstream of the condensate pumps and upstream of the gland steam condenser. The polisher removes suspended solids and ionic constituents and is designed to operate in both the hydrogen and ammonia cycles without effecting effluent concentrations. Resins from the polisher vessels are regenerated with an external regeneration unit.

A review of feedwater chemistry data has shown that during power operations
all feedwater chemistry is maintained within specification. Condensate oxygen 3
levels occasionally rise above their specification due to air leakage to the
condensers but are returned to normal levels by hydrazine addition and repair
of leakage.

The All Volatile Treatment (AVT) chemistry specifications for the feedwater
makeup, condensate storage, and steam generators during periods of operation 3
or wet layup are in accordance with the EPRI Guidelines.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

10.4.2.1 Design Basis

The main condenser evacuation system is designed to establish and maintain condenser vacuum during plant startup and shutdown and to remove air and noncondensable gases during plant operations. The design parameters for the condenser evacuation system are shown on Table 10.4.2.-1.

10.4.2.2 System Description

The mechanical vacuum pumps for the turbine condenser discharge to the plant vent. The exhausted air passes by a shielded radiation monitor before going to the plant vent.

The plant vent is located in the northeast quadrant adjacent to and just outside of the reactor containment.

The flow diagram for the condenser air evacuation system is shown on Figures 10.1.0-4 and 10.1.0-6.

10.4.2.3 Safety Evaluation

Under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. In this event, monitoring the vacuum pump off-gas will detect any contamination. Refer to Section 11.5 for the radiation monitoring system description.

TABLE 10.4.2-1

DESIGN PARAMETERS

MAIN CONDENSER EVACUATION SYSTEM

Condenser Vacuum Pumps

Number Provided	2
Type	Nash, Single Jet
Model	CL-3005
Capacity	20 cfm
Motor HP	150 HP
Power Supply	A - 480 V Bus 1
	B - 480 V Bus 3

10.4.4 STEAM DUMP SYSTEM

10.4.4.1 Design Basis

The automatic steam dump system has been included to increase the transient capability of the plant to provide a means for an orderly reactor power reduction in the event the unit is suddenly disconnected from the distribution network. The time for a return to full power operation is therefore minimized.

The steam dump controls operate the five main condenser dump valves, and when required, the three atmospheric discharge power operated relief valves (PORV) located upstream of the main steam isolation valves, one on each steam generator line. Following a secondary load rejection or turbine runback, the system reduces the Reactor Coolant System (RCS) average temperature, T_{avg}, to within a preset temperature value of the programmed T_{ref} at the new load condition. After a turbine trip, the system reduces T_{avg} to a preset value. During a unit cooldown, it cools the reactor coolant system until the Residual Heat Removal System (RHRS) can take over. 3

10.4.4.2 System Description

Dump is initiated by coincidence of a large rapid load change together with a large error signal between T_{avg} and the desired reference T_{avg} at the new load condition. For very large reductions, e.g., loss of load to the auxiliary power level, both PORV and condenser dumps are actuated to serve as a short term artificial load. As the control group is inserted by the T_{avg} reactor control system reactor power is reduced, thereby reducing T_{avg}. The steam dump is modulated proportional to the same T_{avg} measurement and is thus reduced as rapidly as the rods are able to reduce core power. PORV is closed first, followed by closure of the condenser dump. In this manner the minimum amount of steam is lost from the system. The transient is terminated with the plant at equilibrium conditions at auxiliary load and there is no further steam dump to the condenser.

10.4.4.3 Safety Evaluation

The steam dump to the condenser and the PORV can handle a 50 percent load rejection without lifting the main safety valves.

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of reactor coolant system sensible heat and core decay heat, is discharged to the atmosphere.

If the control valves should fail to dump steam, the result is a loss of load transient. If they operate to dump steam inadvertently, the result would be a load increase equivalent to a small steamline break. In either case, the reactor control and protection system precludes unsafe operation. These protection systems are provided to trip the reactor in the event of a sustained load mismatch between the reactor and turbine. Normal turbine overspeed protection and the steam generator safety valves provide protection for these systems completely independent of any steam dump valve operation.

10.4.6 Condensate and Feedwater System

10.4.6.1 Design Basis. The feedwater system is designed to supply water to the steam generators under all operating conditions. During normal power operation the main feedwater pumps are utilized to supply the needed water. During periods of shutdown or abnormal conditions, one steam driven and two motor operated auxiliary feedwater pumps may be used.

Feedwater control valves in the feedwater line to each steam generator maintain the proper water level in the steam generators for all load conditions.

The design parameters for the condensate and feedwater systems are shown on Table 10.4.6-1.

10.4.6.2 System Description. The feedwater train is the closed type with deaeration accomplished in the condenser. Condensate is taken from the condenser hotwell through the condensate pumps, condensate polisher, gland steam condenser, and low pressure (LP) heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high pressure (HP) heaters to the steam generators. Also, feedwater can be recirculated from the condenser hotwell through the condensate polishing system, low pressure heaters 1, 2, 3, 4, and 5, high pressure heaters 6A and 6B, and returned to the Main Condenser B.

The flow diagram for the condensate and feedwater system is shown in Figures 10.1.0-4, 10.1.0-5, and 10.1.0-6. The flow diagram for the heater drain and vent system is shown on Figure 10.1.0-7.

There are two multi-stage, vertical, pit-type, centrifugal condensate pumps with vertical motor drives. Each pump delivers 35 percent of the feedwater flow that the steam system requires for normal operation. The remaining 30 percent feedwater requirement is delivered by the two heater drain pumps.

Two barrel-type, motor driven feedwater pumps are provided and each is equipped with minimum flow protective devices. The design discharge pressure is the required steam generator pressure plus feedwater system losses. There is an alarm on low pressure at the feedwater pump suction.

Drains from the reheaters and extraction steam flow to the HP heaters, 6A and 6B, drains from the HP heaters flow to the heater drain tanks. The last stage LP heaters, 5A and 5B, and the moisture separators, also drain to these tanks. The heater drain pumps take suction from the drain tanks and discharge to the feedwater pumps suction. Drains from the four lower pressure heaters, 4 through 1, cascade to the condenser.

10.4.6.3 Safety Evaluation. A reactor trip from power requires subsequent removal of core decay heat. Immediate decay heat removal requirements are normally satisfied by the steam dump system. Therefore, core decay heat can be continuously dissipated via the steam bypass to the

condenser as feedwater in the steam generator is converted to steam by heat absorption. Normally, the capability to return feedwater flow to the steam generators is provided by operation of the turbine cycle feedwater system.

As noted in paragraph 10.4.7.2, under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. The condensate polisher wastewater monitor will provide delayed indication of such leaks.

A high activity signal initiates closure of air piston operated valve RCV-10549, isolating the polisher waste from the circulating water system. Refer to Chapter 11 for additional information about the polisher wastewater radiation monitor.

A sampling system, consisting of a flowmeter and an automatic sampling module, is provided to allow identification of radionuclides in the polisher waste.

TABLE 10.4.6-1

DESIGN PARAMETERS

CONDENSATE AND FEEDWATER SYSTEM

Condensate Pumps

Type	Multi-stage, vertical, pit-type, centrifugal
Number	2
Design Capacity (each-gpm)	8,000
Total Head in ft of H_2O	1,130
Motor Type	Vertical
Motor Rating (HP)	3,000

Feedwater Pumps

Type	High Speed, barrel-type, horizontal single stage, centrifugal
Number	2
Design Capacity (each-gpm)	12,700
Total Head in ft of H_2O	3,000
Motor Type	Horizontal
Motor Rating (HP)	6,000

TABLE 10.4.6-1 (Cont'd)

LP 3A and 3B	Shell	Tube
Design Temp., °F	290	290
Design Press., psig	60	600
Test Press., psig	90	900
FW Temp. Increase Through Heater, °F	-	53.4
Number of Passes		2
Tubes:		
Number	744 U's	
Material	Stainless Steel	
Size	3/4 in. O.D.	

2

LP 4A and 4B	Shell	Tube
Design Temp., °F	325	330
Design Press., psig	100	600
Test Press., psig	150	900
FW Temp Increase Through Heater, °F	-	51.8
Number of Passes		2
Tubes:		
Number	746 U's	
Material	Stainless Steel	
Size	3/4 in. O.D.	

TABLE 10.4.6-1 (Cont'd)

LP 5A and 5B	Shell	Tube	
Design Temp., °F	400	400	
Design Press., psig	225	600	
Test Press., psig	340	900	
FW Temp. Increase Through Heater, °F	-	60.2	
Number of Passes		2	
Tubes:			
Number	776 U's		
Material	Stainless Steel		2
Size	3/4 in. O.D.		

HP 6A and 6B	Shell	Tube	
Design Temp., °F	475	465	
Design Press., psig	460	1,525	
Test Press., psig	690	2,290	
FW Temp. Increase Through Heater, °F	-	67.1	
Number of Passes		2	
Tubes:			
Number	1,730 U's		
Material	Stainless Steel		2
Size	5/8 in. O.D.		

10.4.7 Steam Generator Blowdown and Wet Layup System

10.4.7.1 System Description.

10.4.7.1.1 Steam generator blowdown. A blowdown line is routed from each of the three (3) steam generators and out of the containment through penetrations to the steam generator drain tank. The steam generator drain tank is located adjacent to the north side of the Turbine Building. Each blowdown line is provided with:

1. A flow restriction orifice sized for 130,000 lbs./hr. located proximate to the respective steam generator,

2. Two air operated containment isolation valves which permit stream sampling to a continuous radiation monitor and to a sample station,

3. Two air operated shutdown (containment isolation) valves which are located proximate to the respective penetration outside containment,

4. Provision for heat recovery of 20,030 lbs./hr. of blowdown through a heat exchanger to the main condenser,

5. An air operated flow control valve which is located at the inlet of the steam generator drain tank is used for controlling high flow blowdowns. A manual control valve for blowdown rates below 50 gpm is located near the heat exchanger,

6. Provision for pumped draindown of the steam generators while bypassing the steam generator drain tank,

7. Provisions for circulation during wet layup operation, and

8. Branch connections for future addition of more heat exchangers.

Blowdown flow is normally diverted through the blowdown heat exchangers (tube side) where heat is lost to the condensate feed to the LP heaters in lieu of flashing to steam in the drain tank or condenser. The heat exchanger shells are provided with drain connections which are routed to the drain tank to allow complete drainage of the exchangers. Regulation of condensate flow is through orfices designed for maximum heat recovery. Condensate for heat recovery is tapped from the condensate system downstream of the condensate pumps and in parallel with condensate flow to the gland steam condenser. Isolation valves are provided such that the blowdown heat exchangers may be bypassed if necessary.

The blowdown fluid accumulated in the steam generator drain tank is adjusted by using any one or a combination of three (3) steam generator drain/wet layup pumps. Level is maintained within the drain tank by a level controller which positions an air operated control valve in the discharge of the pumps. The pumps may discharge the fluid to the catch basin, the waste disposal system, or the condensate storage system.

The flow diagram for the steam generator blowdown system is shown on Figure 10.1.0-8.

10.4.7.1.2 Steam Generator Wet Layup

Each steam generator has its own means of recirculating the internal water mass in either upward or downward flow directions utilizing the respective steam generator drain/wet layup pump for circulation through portions of the feedwater and blowdown piping. Each of the steam generator wet layup circulation loops is provided with:

a) Bi-directional flow capability,

b) Branch connections for addition of a filtration unit,

c) Nitrogen sparging/purging,

d) Provisions for addition of chemicals,

e) Stream sampling to a continuous radiation monitor and to a sample station,

f) An air operated flow control valve, and

g) Provision for pumped draindown of the steam generators.

The flow diagram from the steam generator blowdown and wet layup system is shown on Figure 10.1.0-8.

10.4.7.2 Safety Evaluation

Under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. In this event, monitoring of the steam generator blowdown will detect any contamination.

A radioactivity monitor is provided for steam generator blowdown. Blowdown is taken from each steam generator, with each stream passing through it's
6 separate sample cooler and then into a radiation monitor which detects total activity present in the blowdown. A high activity signal initiates closure of the remote operated blowdown stop valves, the blowdown rate control valve, and
6 blowdown sample valves of the affected steam generator. The circulating water discharge valve will shut if all three radiation monitors go into alarm.

Refer to Section 11.5 for the Radiation Monitoring System description for the steam generator.

10.4.8 Auxiliary Feedwater System

10.4.8.1 Design Basis. The design parameters for the auxiliary feedwater system components are shown on Table 10.4.8-1. The auxiliary feedwater system is designed and constructed in accordance with the Seismic Class I requirements presented in Section 3.2.

10.4.8.2 System Description. The flow diagram for the auxiliary feedwater system is included with the condensate and feedwater flow diagram Figures 10.1.0-4, 10.1.0-5, and 10.1.0-6.

The auxiliary feedwater system can provide feedwater to the steam generators from any one or combination of three auxiliary feedwater (AFW) pumps, two are motor driven pumps and the third is steam driven.

Two motor driven auxiliary feedwater pumps are supplied power from the emergency busses E-1 and E-2. The emergency busses also supply power to the motor driven auxiliary feedwater pump's discharge isolation valves and the steam driven auxiliary feedwater pump's steam supply and feedwater discharge isolation valves. The emergency busses are supplied power either from offsite or plant diesel generators. The steam driven auxiliary feedwater pump can be operated independent of electrical power where steam produced from decay heat drives the turbine. The auxiliary feedwater pumps supply feedwater to the steam generators for decay heat removal if main feedwater is not available or steam generator level is not adequate, as described below. The auxiliary feedwater pumps can be used to fill the steam generators under any plant condition, except the steam driven auxiliary feedwater pump which requires the plant to be heated up above 350°F.

Upon receipt of an auto start signal to the steam driven auxiliary feedwater pump, the steam supply valves will open supplying steam to drive the turbine-pump. At the same time, the feedwater discharge valves open to the steam generators. The turbine-pump builds up speed and supplies feedwater to the steam generators.

A cavitating venturi is located in the discharge piping of the steam driven auxiliary feedwater pump. Its function is to prevent excess flow from the pump into a low pressure steam generator in the case of a failed discharge flow control valve. This prevents excess mass/flow into containment during a main steamline break and prevents steam driven auxiliary feedwater pump runout.

Upon receipt of an auto start signal to the motor driven auxiliary feedwater pumps, the feedwater discharge valves open while the motor is accelerating up to speed and supplies feedwater to the steam generators.

The auxiliary feedwater pumps and turbine are supplied with bearing cooling water from the service water system.

The capacity of the steam driven auxiliary feedwater pump is based on preventing the water level in the steam generators from receding below the lowest level within the indicated level range in the event of a loss of offsite power. This will prevent the tube sheet from being uncovered. A signal indicating a low low steam generator water level in any two steam generators or a direct signal of undervoltage on 4160 buses 1 and 4 will automatically start the steam driven AFW pump by opening steam admission valves and auxiliary feedwater discharge valves to individual steam generators. The initiating signals for starting the motor driven AFW pumps

are: both main feedwater pump breakers open, low low water level in any steam generator, initiation of a safety injection signal, or blackout (loss of offsite power) condition on the pump's respective emergency bus. No operator action is required since flow control valves maintain the required flow into the steam generators under varying backpressures. At some time, it may be desirable to manually isolate the flow to the individual steam generators. Provision is made in the control room for isolation of the individual steam generator flow. The AFW Flow Indication System continuously monitors the flow to the steam generators through the AFW piping and presents this information to the operator by meters mounted on the RTGB. Similarly, control is provided to modulate the total AFW flow. Key switches are provided for the purpose of blocking selected auxiliary feedwater pump auto start signals and steam generator blowdown valve closure signals during plant outages.

The steam supply to the steam driven AFW pump is taken off upstream from the main steam isolation valves, thereby assuring a source of steam to the pump. Main steam nonreturn valves (power operated stop-checks) are provided in each steam generator steam line. In the unlikely event of a steam line break the action of the nonreturn valve on the broken line prevents steam from the other two steam generators from discharging through the break. Feedwater to the unit with the ruptured line is isolated and the unit allowed to boil dry. The auxiliary feedwater pumps operation is automatic.

Should a steam line break occur in the header between the main steam isolation valves and the turbine, all main steam isolation valves are closed automatically. With the coincident loss of auxiliary power, emergency cooldown procedures are followed. If one main steam isolation valve fails to close, the feedwater line to the affected unit is isolated and the unit allowed to boil dry. Plant cooldown is then effected using the remaining two steam generators. Alternative shutdown control capability is discussed in
6 Section 7.4.

10.4.8.3 Safety Evaluation

In the unlikely event of complete loss of offsite electrical power to the station, decay heat removal would continue to be assured by the availability of one steam driven, and two motor driven auxiliary feedwater pumps, and steam discharge to atmosphere via the main steam safety valves and power operated relief valves. In this case, feedwater is available from the condensate storage tank by gravity feed to the auxiliary feedwater pumps. The 132,000 gallons of water normally maintained in the condensate storage tank are adequate for decay heat removal for a period of at least twelve hours. Alternate sources of water are available from the lake via either leg of the plant service water system for an indefinite time period, and from the deep wells if offsite power is available.

If an auxiliary feedwater pump failed to start following a loss of main feedwater, sufficient redundance of feedwater pumps is available to provide the required feedwater. The steam driven AFW pump has twice the capacity of a motor driven emergency feedwater pump. One motor driven pump has sufficient capacity to prevent relief of fluid through the primary side relief valves.

The maximum starting time requirement for the motor driven auxiliary feedwater pumps is one minute. This allows sufficient time for the diesels to be started and auxiliary systems of higher priority to be loaded on the diesels. The motor driven auxiliary feedwater pumps are sized assuming the pumps are started within one minute including the allowance for starting the diesels and the loading sequence.

The maximum starting time requirement for the steam driven auxiliary feedwater pump is at most equal to that of the motor driven auxiliary feedwater pumps. This allows for starting delays and bringing the steam driven AFW pump to full load.

The adequacy of the auxiliary feedwater pump capacities is demonstrated in the Loss of Normal Feedwater Accident of Section 15.2.7.

The analysis of the effects of loss of full or partial load on the reactor coolant system is discussed in Section 15.2.2.

In the event of a failure of Lake Robinson Dam, shutdown would be accomplished in an orderly manner using the condensate storage tank. When the condensate storage tank reaches a low level limit, auxiliary feedwater pump suction would be changed to the deepwell pump discharge. This source would provide the required feedwater indefinitely or until such time some other source of feedwater can be established. It is assumed that emergency power is not required for this accident.

TABLE 10.4.8-1

DESIGN PARAMETERS
AUXILIARY FEEDWATER SYSTEM

Motor Driven Auxiliary Feedwater Pumps	
Number	2
Stages	10
Type	JTCH
Capacity	300 gpm
Total Head in ft of H_2O	3,000
Motor HP	350
Steam Driven Auxiliary Feedwater Pump	
Number	1
Type	TBA-16
Capacity	600 gpm*
Total Head in ft H_2O	3000
Steam Supply Pressure	Range 120 to 1005
Steam Supply Temperature	Range 350°F to 547°F
Speed (running)	9,400 RPM
Speed (trip)	10,800 RPM
Turbine HP	387
Emergency Feedwater Source	35,000 gallons available in the condensate storage tank. Alternate supply from the service water system and deep well pumps.

---

* This was the original design flow for the Steam Driven AFW Pump. The flow from the SDAFW pump is controlled by FCV-6416 and a cavitating venturi and may be less than the pump design flow. The maximum flow to a faulted steam generator will be less than 630 gpm, limited by the cavitating venturi. The setpoint for FIC-6416, the controller for FCV-6416, is 500 gpm.

CHAPTER 11
RADIOACTIVE WASTE MANAGEMENT

TABLE OF CONTENTS

CHAPTER 11
RADIOACTIVE WASTE MANAGEMENT

TABLE OF CONTENTS (Cont'd)

11.2 LIQUID WASTE MANAGEMENT SYSTEMS

Liquid waste disposal facilities are designed so that discharge of effluents and offsite shipments are in accordance with applicable governmental regulations. The ODCM provides the methodologies to be used by the plant to comply with technical specifications for release of liquid and gaseous 5
radioactive effluent.

Radioactive fluids entering the Waste Disposal System (WDS) are collected in sumps and tanks until determination of subsequent treatment can be made. They are sampled and analyzed to determine the quantity of radioactivity. Before 5
discharge, radioactive fluids are processed as required and then released under controlled conditions. The system design and operation are characteristically directed toward minimizing releases to unrestricted areas. Discharge streams are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10CFR20.

The bulk of the radioactive liquids discharged from the Reactor Coolant System (RCS) are processed and retained inside the plant by the Chemical and Volume Control System (CVCS) recycle train. Processed wastes are stored until shipped for offsite disposal.

11.2.1 DESIGN BASIS

The facility design shall include those means necessary to maintain control over the plant liquid radioactive effluents. Appropriate holdup capacity shall be provided for retention of liquid effluents, particularly where unfavorable environmental conditions are expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified:

a) On the basis of 10CFR20 requirements, for normal operations and for any transient situation that might reasonably be anticipated to occur.

b) On the basis of 10CFR100 dosage level guidelines, for potential reactor accidents of exceedingly low probability of occurrence.

The system is capable of processing all wastes generated during continuous operation of the primary system assuming that fission products escape from one percent of the fuel into the reactor coolant.

The Liquid Waste Disposal components with their associated design parameters are presented in Table 11.2.1-1 and the applicable code requirements for these components are presented in Table 3.2.2-5.

At least two valves must be manually opened to permit discharge of liquid waste from the WDS. One of these valves is normally locked closed. The control valve will trip closed on a high effluent radioactivity level signal.

TABLE 11.2.1-1

LIQUID WASTE MANAGEMENT SYSTEM, COMPONENTS, AND DESIGN PARAMETERS

COMPONENTS

REACTOR COOLANT DRAIN TANK

Number	1
Volume	350 gal
Design pressure, internal	25 psig
Design pressure, external	60 psig
Design temperature, internal	267°F
Design temperature, external	120°F
Normal operating pressure range	0.5 - 2.0 psig
Normal operating temperature range	80 - 200°F
Material of construction	Austenitic SS

LAUNDRY AND HOT SHOWER TANKS

Number	2
Volume, each	600 gal
Design pressure	Atmospheric
Design temperature	180°F
Normal operating pressure	Atmospheric
Normal operating temperature	80 - 160°F
Material of construction	Austenitic SS

CHEMICAL DRAIN TANK

Number	1
Volume	600 gal
Design pressure	Atmospheric
Design temperature	180°F
Normal operating pressure	Atmospheric
Normal operating temperature	80 - 140°F
Material of construction	Austenitic SS

WASTE HOLDUP TANK

Number	1
Volume	3242 ft^3/24,250 gal
Design pressure	Atmospheric
Design temperature	150°F
Normal operating pressure	Atmospheric
Normal operating temperature	80 - 140°F
Material of construction	Austenitic SS

TABLE 11.2.1-1 (Cont'd)

LIQUID WASTE MANAGEMENT SYSTEM, COMPONENTS, AND DESIGN PARAMETERS

REACTOR COOLANT DRAIN TANK PUMPS

Number	2
Type	Canned
Design flow rate, Pump A	50 gpm
Pump B	150 gpm
Design head	175 ft
Design pressure	150 psig
Design temperature	267^{o}F
Required NPSH at design flow, Pump A	10 ft
Pump B	12 ft
Material of construction, wetted surfaces	Austenitic SS

CHEMICAL DRAIN TANK PUMP

Number	1
Type	Horiz. Cent.
Design flow rate	20 gpm
Design head	100 ft
Design pressure	150 psig
Design temperature	180^{o}F
Required NPSH at design flow	10 ft
Material of construction, wetted surfaces	Austenitic SS

LAUNDRY AND HOT SHOWER TANK PUMP

Number	1
Type	Horiz. Cent.
Design flow rate	20 gpm
Design head	100 ft
Design pressure	150 psig
Design temperature	180^{o}F
Required NPSH at design flow	10 ft
Material of construction, wetted surfaces	Austenitic SS

AUXILIARY BUILDING SUMP TANK PUMPS

Number	4
Type	Horiz. Cent.
Design flow rate	20 gpm
Design head	100 ft
Design pressure	150 psig
Design temperature	180^{o}F
Required NPSH at design flow	10 ft
Material of construction, wetted surfaces	Austenitic SS

TABLE 11.2.1-1 (Cont'd)

LIQUID WASTE MANAGEMENT SYSTEM, COMPONENTS, AND DESIGN PARAMETERS

RADWASTE PUMPS	
Number	2
Type	Horiz. Cent.
Design Flow Rate	150 gpm at 3500 rpm
Design Head	150 ft
Material of construction, wetted surfaces	Austenitic SS
WASTE CONDENSATE PUMPS A AND B	
Type	Horiz. Cent.
Design flow rate	20 gpm at 3500 rpm
Design head	100 ft
Material of construction, wetted surfaces	Austenitic SS
WASTE CONDENSATE PUMPS C AND D	
Type	Horiz. Cent.
Design flow rate	55 gpm at 3500 rpm
Design head	160 ft
Material of construction, wetted surfaces	Austenitic SS
WASTE CONDENSATE TANK RECIRC. PUMP	
Number	1
Type	Horiz. Cent.
Design flow rate	275 gpm at 1750 rpm
Design head	110 ft
Material of construction, wetted surfaces	Austenitic SS
CONCENTRATES HOLDING TANK PUMP	
Number	1
Type	Rotary screw
Design flow rate	Variable
Design head	Variable
Material of construction, wetted surfaces	Austenitic SS
CONCENTRATES HOLDING TANK ELECTRIC HEATER	
Number	1
Heat transfer rate	3.0 kW
Material of construction	Austenitic SS

TABLE 11.2.1-1 (Cont'd)

LIQUID WASTE MANAGEMENT SYSTEM, COMPONENTS, AND DESIGN PARAMETERS

CONCENTRATES FILTER

Number	1
Type	Disposable cartridge
Design pressure	100 psig
Design temperature	250°F
Design flow rate	20 gpm
Pressure drop at 20 gpm, clean	5 psi
Retention for 25 micron particles	98%
Maximum pressure drop at 20 gpm	20 psi
Material of construction (vessel)	Austenitic SS

LAUNDRY TANK BASKET STRAINER

Number	1
Design temperature	180°F
Design pressure	150 psig
Design flow	20 gpm
Material in contact with fluid	Stainless steel

WASTE FILTER

Number	1
Design temperature	180°F
Design pressure	150 psig
Design flow	20 gpm
Material	Stainless steel
Type	Replaceable cartridge

"A" WASTE EVAPORATOR

Number	1
Type	Vacuum
Design process rate	2 gpm
Feed composition, dissolved solids	Variable
activity	Variable
Bottoms composition, dissolved solids	Variable
activity	40 μCi/cc max
Condensate composition, dissolved solids	Variable
activity	4×10^{-5} μCi/cc max
Decontamination factor: $\frac{\text{Bottoms activity}}{\text{Condensate activity}}$	10^6
Steam supply, flow rate	1200 lb/hr
pressure (saturated)	15 psig
Cooling water, flow rate	90 gpm
inlet temperature	105°F
outlet temperature	128°F
Basic material of construction	Austenitic SS

TABLE 11.2.1-1 (Cont'd)

LIQUID WASTE MANAGEMENT SYSTEM, COMPONENTS, AND DESIGN PARAMETERS

CONTAINMENT WASTE OIL STORAGE TANK

Volume	10,000 gal.
Design Pressure	Atmospheric (Static)
Design Temperature	150°F
Normal Operating Temperature	Ambient
Normal Operating Pressure	Atmospheric
Material of Construction	304 SS

CONTAMINATED WASTE SOLVENT TANK

Volume	400 gal.
Design Pressure	Atmospheric
Design Temperature	350°F
Normal Operating Temperature	Ambient
Normal Operating Pressure	Atmospheric
Material of Construction	304 SS

CONTAMINATED WASTE OIL FILL TANK

Volume	75 gal.
Design Pressure	Atmospheric (Static) 5
Design Temperature	150°F
Normal Operating Temperature	Ambient
Normal Operating Pressure	Atmospheric
Material of Construction	304 SS

CONTAMINATED WASTE OIL FILL PUMP

Number	1
Type	Rotary Gear
Design Flow Rate	20 gpm
Design Discharge Pressure	70 psi
Material of Construction, Wetted Surfaces	Ductile Iron

CONTAMINATED WASTE OIL TRANSFER/RECIRCULATION PUMP

Number	1
Type	Rotary Gear
Design Flow Rate	150 gpm
Design Discharge Pressure	50 psi
Material of Construction, Wetted Surfaces	Cast Iron

CONTAMINATED WASTE SOLVENT TRANSFER/RECIRCULATION PUMP

Number	1
Type	Centrifugal
Design Flow Rate	40 gpm
Design Head	88'
Material of Construction, Wetted Surfaces	316 SS

11.2.2 System Description

11.2.2.1 Liquid Radioactive Waste Processing. During normal plant operation the WDS processes liquids from the following sources:

1. Equipment drains and leakoffs
2. Radioactive chemical laboratory drains
3. Radioactive shower drains
4. Decontamination area drains
5. Demineralizer regeneration

As shown in the flow diagrams, Figures 11.2.2-1 through 11.2.2-4, the system also collects and transfers liquids from the following sources to the WHUT or CVCS for processing:

1. Reactor coolant loop drains
2. Pressurizer relief tank
3. Reactor coolant pump secondary seals
4. Excess letdown during startup
5. Accumulators
6. Reactor vessel flange leakoffs

These liquids flow to the reactor coolant drain tank and are discharged to the WHUT or the CVCS holdup tanks by the reactor coolant drain pumps which are operated automatically by a level controller in the tank. These pumps also return water from the refueling canal and cavity to the refueling water storage tank.

Where possible, waste liquids drain to the waste holdup tank by gravity flow. Other waste liquids drain to the sump tank and are discharged to the waste holdup tank by pumps operated automatically by a level controller in the tank.

Since the radioactivity level of waste liquid from the hot shower area will usually be low enough to permit discharge from the site without processing, two tanks are provided to permit one tank to be filled and isolated for sampling and analysis while the second is in service. If preliminary analysis indicates that the liquid is suitable for discharge, it is pumped to one of the waste condensate tanks where its radioactivity can be determined for record before it is discharged through a radiation monitor to the condenser circulating water. Otherwise, the liquid is pumped to the waste holdup tank. Although the waste holdup tank cannot be isolated while the preliminary analysis is made, the final analysis for record is done in the waste condensate tanks which can be isolated to ensure no added contamination during sampling, analysis, and release.

Liquids from the waste holdup tank and CVCS holdup tanks are processed using the Waste Water Demineralization System (WWDS) and Boron Recycle System (BRS). The WWDS and BRS consist of filters and demineralizers with various capabilities selected depending on process conditions. Processed liquids are routed to one of the Waste Condensate Tanks or Monitor Tanks. When the tank is filled, it is isolated and sampled for analysis while an alternate tank is in service. If analysis confirms the activity level is suitable for discharge, the condensate is pumped through a flow meter and a radiation monitor to the condensor circulating water discharge. Otherwise, it is returned to the waste holdup tank for reprocessing. Although the radiochemical analysis forms the basis for recording activity releases, the radiation monitor provides surveillance over the operation by closing the discharge valve if the liquid activity level exceeds a preset value.

Liquids in the Radwaste Building sump are to be discharged into the storm sewer if analysis confirms the activity level is suitable for discharge. Otherwise, it is required to be pumped to a radwaste drain.

<u>11.2.2.2 Components</u>. Codes applying to components of the WDS are shown in Table 3.2.2-5. Components summary data are shown in Table 11.2.1-1.

<u>Laundry and Hot Shower Tanks</u> - Two stainless steel tanks collect liquid wastes originating from the hot shower. When a tank has been filled, its contents are analyzed for gross β-γ activity. The tank contents may be drained to the waste condensate tanks or to the waste holdup tanks for waste evaporator processing.

<u>Chemical Drain Tank</u> - The stainless steel chemical drain tank is provided to collect drainage from the hot area of the chemistry laboratory. After analysis, the tank contents are pumped to the waste holdup tanks or to the waste condensate tanks.

<u>Reactor Coolant Drain Tank</u> - The reactor coolant drain tank is all-welded austenitic stainless steel. This tank serves as a drain collecting point for the RCS and other equipment located inside the reactor containment.

<u>Waste Holdup Tank</u> - The waste holdup tank retains radioactive liquids from the CVCS, sump tank, chemical drain tank, reactor coolant drain tank, and laundry and hot shower tanks. The tank is stainless steel of welded construction.

<u>Sump Tanks and Pumps</u> - The sump tanks serve as collecting points for waste discharged to the basement level drain header. They are located at the lowest point in the Auxiliary Building. All floor drains entering these tanks contain loop seals to prevent gas from leaving the pressure vent system. Two horizontal centrifugal sump pumps drain these tanks. All wetted parts of the pumps are stainless steel. The tanks are all welded austenitic stainless steel.

<u>E&RC Lab/Waste Sump Tank</u> - This tank serves as a collection point for liquid waste discharged from the E&RC laboratory. It is located east of the E&RC Building and is below grade. It is connected to the "B" sump tank in the Auxiliary Building by a 2" stainless steel line (A-312, Type 316). One 30 gpm vertical sump pump pumps liquid waste to the "B" Radwaste Sump in the Auxiliary Building. The E&RC Lab/Waste Sump Tank is constructed of reinforced concrete.

Radwaste Building Sumps - The sumps serve as a collection point for liquid waste originating from the Radwaste Building. The truck bay sump liquid is pumped to the main building sump. The main building sump will be either pumped to the storm sewer or a radwaste drain depending on radioactivity level. The Radwaste Building sumps are constructed of reinforced concrete, and the main sump has a stainless steel liner.

Spent Resin Storage Tank - The spent resin storage tank retains spent resin normally discharged from the mixed bed, spent fuel pit, base removal, and cation and polishing demineralizers. The deborating demineralizers and evaporator condensate demineralizers are regenerated and therefore will be discharged less frequently. Normally, the tank is filled over a long period of time, the contents are allowed to decay, and then emptied prior to receiving any additional resin. However, the contents can be removed at any time, if sufficient shielding is provided for the spent resin shipping vessel. A layer of water is maintained over the resin surface to prevent resin degradation due to heat generation from decaying fission products. Resin is removed from the tank by first backflushing to loosen the resin bed and then flushing the resin to the radwaste facility with nitrogen entering the top of the tank. The tank is all welded austenitic stainless steel.

Waste Evaporator Package - Not Used.

The evaporator concentrates dissolved and suspended solids in the liquid waste. It consists of a batch tank (feed), concentrator, distillate tank, hot water converter, batch tank pump, hot water circulating pump, distillate pump, and control panel.

The length of an evaporator operating cycle is determined either by solids content or activity concentration of the solution. The entire evaporator is austenitic stainless steel of welded construction except for the heat transfer surfaces which are admiralty metal.

"A" and "B" waste condensate tanks are located in the Auxiliary Building in the hallway just outside the pipe alley entrance. These two tanks receive distillate from "A" waste evaporator and provide a temporary storage for this distillate water until it can be released to the environment.

"C", "D", and "E" waste condensate tanks receive distillate from "B" waste evaporator and they are located just north of the Auxiliary Building. When a waste condensate tank gets to approximately 90 percent level, the distillate from the evaporator is aligned to go to an alternate tank. The "full" tank can then be recirculated and sampled for release.

Waste Water Demineralization System Filters - WWDS Filter Vessels contain either replaceable cartridges or a replaceable bag. Cartridge and bag filters are available with various micron ratings. The filter vessel header system provides for isolation and by-pass and has influent and effluent pressure gauges. Each filter vessel has a vent and a low point drain.

Waste Water Demineralizers - Demineralizer Pressure Vessels, designed for down flow application, have cylindrical bar screens located on both the influent and effluent lines to prevent media migration. Media is sluiced into the vessel at the top and sluiced out of the vessel at the bottom. Each vessel has an inspection port located on the top of the vessel, an influent pressure gauge and a sample point.

The medias selected for use may vary depending on process conditions. The process vessel design is compatible with gel ion exchange medias, activated carbon, natural ion exchangers, and silicate based exchangers, which have 60 mesh or larger particle size.

Pumps - Pumps used throughout the system for draining tanks and transferring liquids are shown in Figures 11.2.2-1 and 11.2.2-2. The pumps are either canned motor or mechanically sealed types to minimize leakage.

The wetted surfaces of all pumps are stainless steel or other materials of equivalent corrosion resistance.

Piping - The piping which carries liquid wastes is stainless steel and flexible plastic hose. All gas piping is carbon steel. Piping connections are welded except where flanged or clamped connections are necessary to facilitate equipment maintenance or where taper thread connections and compression fittings are used in the area of the gas analyzer.

Valves - All valves exposed to gases are carbon steel. All other valves are stainless steel. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage.

Stop valves are provided to isolate equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction.

Concentrates Holding Tank - The concentrates holding tank is sized to hold the production of concentrates from one batch of evaporator operation. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless steel.

11.2.2.3 Contaminated Waste Oil Storage System. The purpose of the waste oil storage system is to transfer and store radioactively contaminated waste petroleum products. The system, located inside the RCA, consists of a set of three tanks, three transfer pumps, and three strainers--with associated piping and instrumentation. The waste oil storage system is surrounded by a seismically designed dike capable of holding the contents of the storage tank, solvent tank, and fill tank in case of a spill or tank rupture.

Contaminated Waste Oil Storage Tank - The contaminated waste oil storage tank is sized to hold up to 10,000 gallons (accumulation of contaminated waste oil for an estimated 10 years).

Contaminated Waste Solvent Tank - The contaminated waste solvent tank is designed to hold up to 400 gallons of contaminated solvents. The solvent tank is located within the seismically designed diked area containing the waste oil storage tank and waste oil fill tank.

Contaminated Waste Oil Fill Tank - The contaminated waste oil fill tank will hold up to 75 gallons of oil. This tank is not a storage tank. The contents of this tank are to be transferred to the contaminated waste oil storage tank.

Valves - All valves exposed to gases are carbon steel. All other valves are stainless steel. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage.

Stop valves are provided to isolate equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction.

Concentrates Holding Tank - The concentrates holding tank is sized to hold the production of concentrates from one batch of evaporator operation. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless steel.

11.2.2.3 Contaminated Waste Oil Storage System

The purpose of the waste oil storage system is to transfer and store radioactively contaminated waste petroleum products. The system, located inside the RCA, consists of a set of three tanks, three transfer pumps, and three strainers--with associated piping and instrumentation. The waste oil storage system is surrounded by a seismically designed dike capable of holding the contents of the storage tank, solvent tank, and fill tank in case of a spill or tank rupture.

Contaminated Waste Oil Storage Tank

5

The contaminated waste oil storage tank is sized to hold up to 10,000 gallons (accumulation of contaminated waste oil for an estimated 10 years).

Contaminated Waste Solvent Tank

The contaminated waste solvent tank is designed to hold up to 400 gallons of contaminated solvents. The solvent tank is located within the seismically designed diked area containing the waste oil storage tank and waste oil fill tank.

Contaminated Waste Oil Fill Tank

The contaminated waste oil fill tank will hold up to 75 gallons of oil. This tank is not a storage tank. The contents of this tank are to be transferred to the contaminated waste oil storage tank.

11.2.3 RADIOACTIVE RELEASES

11.2.3.1 Liquid Effluent Source Terms

Liquid effluents from HBR 2 can occur both continuously and on a batch basis. The following sections discuss the methodology which is utilized to show compliance with 10CFR20.

Continuous Releases - Steam generator (SG) blowdown and condensate polisher waste are continuously released from HBR during normal operation. A daily grab sample is taken of SG blowdown. This sample is composited and analyzed weekly for I-131 and various other fission and activation products. Condensate polisher (CP) waste is composited automatically. CP samples are collected weekly and analyzed for radioactive fission and activation products. Compliance with 10CFR20 during actual release is established through respective effluent monitor alarm setpoint. However, if a continuous release should occur in which the effluent monitor alarm setpoint is exceeded, then actual compliance with 10CFR20 may be determined utilizing the actual radionuclide mix.

Batch Releases - Batch releases occur during normal operation. The radioactivity content of each batch and compliance with 10CFR20 will be determined prior to release.

For HBR, the liquid radwaste system discharges to the circulating water system. Therefore, the dilution flow rate (DFR) is a function of the number of circulating water pumps operating. HBR 2 has 3 circulating water pumps. Pump curves show that with 3 pumps operating, the circulating water flow rate is 400,000 gpm, with 2 pumps operating the flow rate is 250,000 gpm, and with 1 pump, the flow rate is 160,700 gpm.

During outages in which the Unit 2 circulating water system is out of service the HBR Unit 1 circulating water pumps will be used as a source for dilution flow. The Unit 1 and Unit 2 circulating water systems share a common discharge canal. In any given situation regarding a liquid waste release, the ratio of release rate to dilution flow will be maintained within regulatory limits.

Releases from the HBR liquid radwaste system may occur from the waste condensate tanks, the monitor tanks, the condensate polisher, and the steam generator (SG). The maximum release rate is 250 gpm from each steam generator and 60 gpm from the monitor and waste condensate tanks and 390 gpm from the condensate polisher waste.

As discussed in Section 11.5, the Steam Generator Liquid Sample Monitors (R-19A, B and C), WDS Liquid Effluent Monitor (R-18), and the Condensate Polisher Waste Monitor (R-37) setpoints will be limited to 10 CFR 20, Appendix B, Table II, Column 2 using the methodology described in the Offsite Dose Calculation Manual (ODCM).

Liquid wastes are generated primarily by plant maintenance and service operations. Considerable operational margin exists between the estimated load on the waste disposal system and the design capability.

11.2.3.2 Doses from Liquid Effluents

1

The sum of the cumulative doses from all batch and continuous releases for a quarter are compared to one half the design objective doses for total body and any organ. The sum of the cumulative doses from all batch and continuous releases for a calendar year are compared to the design objective doses.

For the calendar quarter,

$$D_{\tau} \leq 1.5 \text{ mrem total body} \quad (1)$$

$$D_{\tau} \leq 5 \text{ mrem any organ} \quad (2)$$

For the calendar year,

$$D_{\tau} \leq 3 \text{ mrem total body} \quad (3)$$

$$D_{\tau} \leq 10 \text{ mrem any organ} \quad (4)$$

where: D_{τ} = cumulative total dose to any organ τ or to the total body from continuous and batch releases, mrem

$$= D_{\tau b} + D_{\tau c}$$

The quarterly limits given above represent one-half the annual design objective of Section II.A of Appendix I of 10CFR50. If any of the limits are exceeded, a special report pursuant to Section IV.A of Appendix I of 10CFR50 must be filed with the NRC.

A summation of all liquid releases, along with offsite dose calculation results, is documented in the Effluent and Waste Disposal Semi-Annual Report submitted to the NRC semi-annually.

11.3 GASEOUS WASTE MANAGEMENT SYSTEMS

This section describes the capabilities of the plant to control, collect, process, store, and dispose of gaseous radioactive wastes generated as a result of normal operation including anticipated operational occurrences. The section discusses the design and operating features of the Gaseous Waste Processing System (GWPS) and the performance of other gas treatment and ventilation systems.

11.3.1 DESIGN BASIS

The system was designed to meet proposed General Design Criterion (GDC) 70. See Section 3.1 for a discussion of the GDC.

The design of the GWPS is based on continuous operation of the Unit assuming that one percent of the rated core power is generated by fuel rods containing cladding defects. This condition is assumed to exist over the life of the plant.

11.3.2 SYSTEM DESCRIPTION

11.3.2.1 Gaseous Radioactive Waste Processing

During plant operations, gaseous wastes will originate from:

a) Degassing reactor coolant discharged to the Chemical and Volume Control System (CVCS)

b) Displacement of cover gases as liquids accumulate in various tanks

c) Miscellaneous equipment vents and relief valves

d) Sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases

The flow diagrams for the system are shown in Figures 11.3.2-1 and 11.3.2-2.

Radioactive gases are collected at a slight positive pressure in a vent header. From there, they are pumped by compressors through a manifold to one of the gas decay tanks where they are held a suitable period of time for decay. Cover gases in the nitrogen blanketing system are reused to minimize gaseous wastes. During normal operation, gases are discharged intermittently at a controlled rate from these tanks through the monitored plant vent. The system is provided with holdup capacity and discharge controls for gaseous wastes such that plant operations will not be limited by environmental conditions.

During normal operation the Waste Disposal System supplies nitrogen and hydrogen from standard cylinders to primary plant components. This operation is identical for both the nitrogen supply and the hydrogen supply. For each, two headers are provided, one for operation and one for backup. The pressure regulator in the operating header is set for 100 psig discharge and that in the backup header for 90 psig discharge. When the operating header is exhausted, its discharge pressure will fall below 100 psig and an alarm will alert the operator. The second bank will come into service automatically at 90 psig to ensure a continuous supply of gas. After the exhausted header has been recharged, the operator manually sets the operating pressure back to 100 psig and the backup pressure at 90 psig.

Most of the gas received by the Waste Disposal System during normal operation is cover gas displaced from the CVCS holdup tanks as they fill with liquid. The pressure of cover gases are maintained within a narrow range. As the tanks are filled displacing cover gas, the pressure rises. When the upper limit of the range is approached, the waste gas compressors pump the displaced gas to the gas decay tanks. As the tanks are emptied, the cover gas pressure approaches the lower limit of the range and additional gas is supplied. Since the gas displaced during filling must be replaced when the tanks are emptied, facilities are provided to return gas from the decay tanks to the holdup tanks. A backup supply from the nitrogen header is provided for makeup if return flow from the gas decay tanks is not available. To prevent hydrogen concentration from exceeding the combustible limit during this type of operation, components discharging to the vent header system are restricted to those containing no air or aerated liquids and the vent header itself is

designed to operate at a slight positive pressure (0.5 psig minimum to 2.0 psig maximum) to prevent in-leakage. On the other hand, out-leakage from the system is minimized by using Saunders patent diaphragm valves, bellows seals, self contained pressure regulators and soft-seated packless valves throughout the radioactive portions of the system.

Gases vented to the vent header flow to the waste gas compressor suction header. Both compressors are in a standby mode and start on a pressure signal sensed in the suction line, or, if system load requires, one (1) compressor is placed in run and the other is in a standby mode. From the compressors, gas flows to one of the gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one tank in service and to select one tank for backup if the tank in operation becomes fully pressurized. When the tank in service becomes pressurized to 110 psig, a pressure transmitter automatically closes the inlet valve to that tank, opens the inlet valve to the backup tank and sounds an alarm to alert the operator of this event so that he may select a new backup tank. Pressure indicators are supplied to aid the operator in selecting the backup tank.

Gas held in the decay tanks can either be returned to the CVCS holdup tanks, or discharged to the atmosphere if it has decayed sufficiently for release. Generally, the last tank to receive gas will be the first tank emptied back to the holdup tanks in order to permit the maximum decay time before releasing gas to the environment. However, the header arrangement at the tank inlet gives the operator freedom to fill, reuse or discharge gas to the environment simultaneously without restricting operation of the other tanks. During degassing of the reactor coolant prior to a refueling shutdown, it may be desirable to pump the gas purged from the volume control tank into a particular tank and isolate that tank for decay rather than reuse the gas in it. This is done by aligning the control to open the inlet valve to the desired tank and closing the outlet valve to the reuse header. However, one of the other tanks can be opened to the reuse header at this time if desired, while still another might be discharged to atmosphere.

Before a tank can be emptied to the environment, it must be sampled and analyzed to determine and record the activity to be released, and only then discharged to the plant vent at a controlled rate. The effluent is continuously sampled by a radiation monitor. Grab samples are taken manually at the WGDT local sampling station or by opening the isolation valve to the plant vent discharge line and permitting gas to flow to the gas analyzer where it can be collected in one of the sampling system gas sample vessels. In the event of a gas analyzer failure, the gas analyzer grab sample line can be used to obtain grab samples for laboratory analysis. After sampling, the isolation valve is closed until the tank contents are released. During release a trip valve in the discharge line is closed automatically by a high activity level indication in the plant vent.

When waste gases are being released to the environment, the release is automatically terminated if the radioactivity level exceeds a predetermined level (the radiological monitoring and control instrumentation is described in Section 11.5).

During operation, gas samples are drawn periodically from tanks discharging to the waste gas vent header as well as from the particular gas

decay tank being filled at the time, and automatically analyzed to determine their hydrogen and oxygen content. The hydrogen analysis is for surveillance since the concentration range will vary considerably from tank to tank. There should be no significant oxygen content in any of the tanks, and an alarm will warn the operator if any sample shows 2 percent by volume of oxygen. This allows time to take the required action before the combustible limit is reached. Another tank is placed in service while the operator locates and eliminates the source of oxygen.

11.3.2.2 Components. Component data are given in Table 11.3.2-1.

Nitrogen Manifold

A dual manifold supplies nitrogen to purge the vapor space of various components to reduce the hydrogen concentration or to replace fluid that has been removed. A pressure controller, which automatically switches from one manifold to the other, assures a continuous supply of gas.

Hydrogen Manifold

A dual manifold supplies hydrogen to the volume control tank to maintain the hydrogen partial pressure as hydrogen dissolves in the reactor coolant. A pressure controller, which automatically switches from one manifold to the other, assures a continuous supply of gas.

Gas Analyzer

An automatic gas analyzer is provided to monitor the concentrations of oxygen and hydrogen in the cover gas of the Waste Disposal System, CVCS tanks, boric acid evaporators and gas stripper. The gas analyzer grab sample line can be used as an alternative method of obtaining gas samples for analysis. Upon indication of a high oxygen level, provisions are made to purge the equipment to the gaseous waste system with an inert gas.

Piping

All gas piping is carbon steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance. No threaded fittings are used in waste piping.

Valves

All valves exposed to gases are carbon or stainless steel. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage.

Gas Compressors

Two compressors are provided for removal of gases to the gas decay tanks from all equipment that contains or can contain radioactive gases. These compressors are of the water sealed centrifugal displacement type. The operation of the compressors is automatically controlled by the gas manifold

pressure. While one unit is in operation, the other serves as a standby for unusually high flows or failure of the first unit.

Gas Decay Tanks

Four welded carbon steel tanks are provided to contain compressed waste gases (hydrogen, nitrogen, oxygen and fission gases). After a period for radioactive decay, these gases may be released at a controlled rate to the atmosphere through the plant vent. All discharges to the atmosphere will be monitored.

11.3.3 RADIOACTIVE RELEASES

The criteria for the release of gaseous wastes from the GWPS are predetermined using the methodologies of the Offsite Dose Calculation Manual (ODCM). The ODCM provides the methodologies to be used by the plant to comply with the Technical Specifications for liquid and gaseous radiological effluents. The ODCM utilizes X/Q and D/Q values derived from the 1978 meteorological study prepared by Dames and Moore to demonstrate compliance with 10CFR50, 5
Appendix I. Setpoints for monitor alarms and automatic cutoff valves are determined so as to limit the release rate of gaseous wastes to less than the allowable values prescribed in 10CFR20.

Airborne releases from HBR 2 are determined by continuous monitors, periodic grab samples and radionuclide analyses. A summation of these releases is documented in a semi-annual report of effluent and waste disposal activity. This report presents total release, average release rate, and percent of 5
Technical Specification Limit. The report data substantiates the fact that plant performance meets the criteria of 10CFR20, Appendix B, Table II, Column I, and the design objectives of Appendix I to 10CFR50.

11.4 SOLID WASTE PROCESSING SYSTEM

Solid wastes consist of liquid waste concentrates, spent resins and miscellaneous materials, such as paper and glassware. Solid wastes are packaged in approved containers such as 55-gallon drums, liners, and boxes, for removal to a burial facility. The Solid Waste Processing System (SWPS) is designed so that all radioactive solid waste is processed, packaged, and stored, to keep the discharge of effluents and offsite shipments in accordance with appropriate federal and state standards and in compliance with 49CFR170-179, 10CFR20, and 10CFR50. | 5

11.4.1 DESIGN BASIS

The objective of the SWPS is to convert radioactive solid wastes into acceptable packaged forms for offsite disposal. In addition, the SWPS is to provide a reliable means for processing the material while minimizing radioactive exposures to plant personnel and the general public in compliance with the guidelines of 10CFR20 and 10CFR50.

The SWPS collects, controls, processes, packages, handles, and temporarily stores radioactive solid waste generated as a result of the normal operations of the plant, including anticipated operational occurrences. The SWPS receives concentrated wastes from Liquid Waste Processing System (LWPS), spent resins, and solid radioactive waste such as contaminated paper, cloth, construction materials, laboratory supplies, and other non-retrievable items.

The specific design basis primary coolant source terms are presented in Section 11.1.

11.4.2 SYSTEM DESCRIPTION

The SWPS solidifies and packages radioactive wastes generated during normal plant operations for offsite burial. It is designed to provide for processing, packaging, and storage of solid wastes resulting from normal plant operations without limiting the operation or availability of the plant.

Typical data on types of wastes, quantities, activities, and radionuclide distributions are given in Table 11.4.2-1. The seismic criteria and the quality group classification for the solid waste components and piping are given in Section 3.2 of the FSAR.

The piping and instrumentation associated with the SWPS appear in Figures 11.2.2-1 and 11.2.2-4.

11.4.2.1 Components and Inputs

The SWPS input sources are spent resins, filter cartridges, evaporator concentrates, and compacted and noncompacted dry active wastes.

All waste collection, processing, packaging, storing and shipping for offsite burial conforms to the guidelines of 49CFR170-179, 10CFR20, and 10CFR50.

11.4.2.2 Solid Waste Processing

The SWPS processes waste from several sources:

a) Waste evaporator concentrates
b) Spent resins
c) Filter cartridges
d) Dry radioactive wastes
e) Laboratory wastes

The Solid Waste Solidification Subsystem packages solid wastes in approved containers for removal to burial facilities. Concentrates from the waste evaporator are pumped into approved containers which are subsequently filled with cement. The cement solidifies the excess water into a solid matrix. After filling, the approved containers are moved to a storage area until a sufficient number have accumulated for shipment. A separate crane is then used to place the approved containers on the carrier for removal off site.

Depleted radioactive resins are sluiced from their respective ion exchange vessels into the spent resin storage tank for temporary storage. To dispose of the resins, the system is lined up from the spent resin storage tank to the spent resin fill connection in the radwaste facility. A flexible hose is connected to this fill connection at one end and the other is placed into a high integrity container (HIC). The spent resin storage tank is then pressurized with low pressure nitrogen and the resins are forced to the radwaste facility, via installed piping, and down through the flexible hose into the HIC. Once full, the HIC can be transported in a shipping cask overland to a radwaste burial facility for ultimate disposal.

Cartridge filters consist of cellulose type elements placed within a stainless
steel cage assembly. Exhausted cartridge filters are removed from their
5 vessel, placed in a container, and transferred to a container in a storage
shield. The filters are stored in a shield until they are transferred to a
shipping cask for shipment to a licensed disposal site.

Dry radioactive wastes consists of air filters, miscellaneous paper, rags,
etc., from contaminated areas and contaminated clothing, tools and equipment
parts which cannot be effectively decontaminated, and solid laboratory
wastes. These wastes are collected in containers located in designated zones
5 (areas) around the plant.

Because of their low radioactivity content, dry radioactive wastes can be
stored until enough waste has accumulated to permit economical transportation
to an offsite burial facility for final disposal.

5 The filled containers are removed for segregation and the contents are placed
in the appropriate container and stored for ultimate offsite removal.

Remote indication and annunciation for this channel are also provided on the Waste Disposal System Control Board. The channel provides assurance that gaseous releases from the Waste Disposal System are below the 10 CFR 20 limits using the methodology of the ODCM. If the channel countrate exceeds the release setpoint, for 10 CFR 20 compliance, a channel high alarm occurs. The alarm automatically closes valve RCV-014 in the Waste Gas System. Technical Specifications provide the lower limit of detection requirements for R-14 C.

During accident conditions, if the channel countrate exceeds a preset valve in its top decade, the monitor automatically switches flow from the low range shield to the high range shield. This causes both the R-14 C High and Fail alarms in the control room to stay lit until the monitor switches back to the low range shield. The control room display for R-14 C will also default to a reading of 1.0 E 6 CPM.

11.5.2.2.3.5 High Range Particulate and Iodine Sampling

Once sample flow has switched over to the heated High Range Shield Assembly, the sample enters the shielded filter holder chamber. The sample passes through a particulate filter and a silver zeolite cartridge held together in one assembly. During an accident, the filter and cartridge may be removed and placed in a portable shield for transport to a shielded work area in a laboratory hood, prior to analysis.

11.5.2.2.3.6 Intermediate Range Noble Gas Channel, R-14 D

After leaving the first chamber, the filtered sample enters the next shielded chamber and is monitored for noble gases by a beta-scintillation detector. This detector, and the high range detector, operate in a current integrating mode. The intermediate channel is designed to overlap both the normal noble gas channel and the high range noble gas channel by at least one decade. If the channel countrate drops below a preset value in its bottom decade, the monitor automatically switches flow back to the low range shield.

11.4.2.2.3.7 High Range Noble Gas Channel, R-14 E

After the sample leaves the intermediate range chamber, it flows into the high range chamber where it is monitored by a high range beta-scintillation detector similar to R-14 D. This detector meets the high range requirements of NUREG 0737 and Reg. Guide 1.97.

11.5.2.2.4 Condenser Air Ejector Gas Monitor (R-15)

This channel continuously monitors the gaseous effluent from the air ejector exhaust header of the condensers. Radioactivity in this effluent stream indicates primary to secondary system leakage. The air ejector effluent flows into the plant vent where particulate, iodine and noble gas activity is monitored by the plant vent monitoring system.

The detector output is transmitted to the RMS cabinets in the Control Room. The activity is indicated on a digital ratemeter and recorded by a multipoint recorder. High-activity and channel fail alarm indications are displayed on the ratemeter and on the control board annunciator.

A beta-gamma sensitive GM tube is used to monitor the gaseous radiation level. The detector is inserted into an in-line fixed volume container which includes adequate shielding to reduce the background radiation to a value consistent with the detector's maximum sensitivity.

11.5.2.2.5 Containment HVH Units Fan and Motor Cooling Water Monitor (R-16)

This channel monitors the containment fan and motor coolers service water for radiation indicative of a leak from the containment atmosphere into the cooling water. A small bypass flow from each of the heat exchangers is mixed in a common header and monitored by a sodium iodide scintillation detector mounted in a shielded assembly. Upon indication of a high radiation level, each heat exchanger can be individually sampled to determine which unit is leaking. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 1 min).

The particulate and noble gas detectors are beta scintillation detectors (phosphor). The iodine detector is a gamma scintillation detector (sodium iodine). The detectors are housed in lead and steel shield assemblies. The electronics of the R-22 have a 5-decade range, 10 to 10^6 cpm.

The operator may perform detector checks. Each detector has an associated radioactive check source which may be used to generate a quick functional test of the detector and post-detector electronics. The R-22 has a self diagnostic check and alarm system for detector or electronics failure.

11.5.2.2.12 Radwaste Building Exhaust Monitor (R-23)

This unit continuously monitors the exhaust from the radwaste building. The monitor is similar to R-22 and R-38, but is an older analog model without digital circuitry. An isokinetic probe in the exhaust plenum removes the sample from the final filtered exhaust stream and sends it through a heat traced sample line to the monitor. The sample pump flowrate is maintained at 2.0 cfm. The maximum building exhaust flow rate is 15,000 scfm. Particulate, iodine and noble gas activity is monitored by three shielded detectors identical to those used in R-14, R-22 and R-23. Countrates are displayed at the monitor on analog meters and recorded on a strip chart recorder. Channel high, alert and fail alarms are indicated by local and remote colored lights and bells. The remote alarm station is on the first floor in a frequently occupied area of the building.

11.5.2.2.13 Fuel Handling Building Basement Exhaust High Range Radioactive Gas Monitor (R-30)

This channel continuously monitors the ventilation exhaust air (HVE-14) from the Fuel Handling Building basement and Hot Machine Shop for gaseous radioactivity. The system consists of a GM type detector mounted on the exterior of the exhaust duct in a lead collimator. The monitor overlaps the upper end of R-20's range by a factor of 10, and also meets the upper end of the range required by NUREG 0737 and Reg. Guide 1.97.

11.5.2.2.14 Main Steamline Radiation Gas Monitors (R-31A, B, and C)

These three channels continuously monitor the main steam lines. The GM tube detectors are externally mounted next to the steam line between the containment and the steam line PORV. The detectors are located in collimated lead shields designed to reduce background from design based levels. Calculations were made to account for the low energy gamma rays being attenuated by the approximately one inch steel steam line wall. Noble gas resulting from a primary to secondary leak has the potential of escaping to the atmosphere through an open main steam line PORV.

11.5.2.2.15 Condensate Polisher Waste Monitor (R-37)

This channel continually monitors condensate polisher waste from the neutralization tank and sump pumps. Annunciation of this monitor would be indicative of a past primary-to-secondary system leak. Sump effluent and neutralized waste, which are independent of each other and intermittent, are mixed in a common header and are monitored by R-37 before discharging into the circulating water system. Upon indication of a high-radiation level, an air piston operated butterfly valve, located downstream of the monitor, isolates the waste from the circulating water system. A manual globe valve can be opened to direct the flow to the liquid waste disposal system.

A remote display module and single pen stripchart recorder are located on the condensate polisher control panel.

The detector is a photomultiplier tube - gamma scintillation counter (NaI crystal), cast lead shielded. A solenoid-actuated CS-137 checksource verifies detector operation. Signal processing is achieved with a digital microprocessor. Monitor has a sensitivity of 7.81×10^{-8} μCi/cc and a range of 10^1 to 10^7 cpm.

R-37 has high and alert radiation level alarms which annunciate on the RM-80, RM-23, and condensate polisher control panel. If not acknowledged, high radiation will annunciate the RTGB as "Condensate Polisher Trouble." On circuit trouble, the green "OPERATE" status light extinguishes.

Both the alert and high radiation level alarm circuits are bistable for R-37. Setpoint is adjustable over the range of the instrument.

A remotely operated long half-life radiation check source is furnished for the operable channel. The energy emission ranges are similar to the radiation energy-spectra being monitored.

11.5.2.2.16 <u>TSC/EOF Accident Monitor, R-38</u>

R-38 continuously monitors the air in the TSC/EOF Building. An isokinetic probe in the intake vent samples the air flow which is directed to the monitor at a flow rate of 2.5 cfm. This monitor has the capability of sampling the air stream for particulate, iodine, and noble gas activity. These results are displayed on a CRT screen in scientific notation as counts per minute. High alert and low alarms (bell and colored lights) will register both locally and at a remote box. Upon high alarm, an emergency fan system will be activated in the TSC/EOF and will process contaminated air through a HEPA filtering system with particulate and charcoal filters. Green lamps on both the monitor and the remote box will light to indicate system activation. The monitor also possesses a recorder for each of the channels and a printer that is activated by alarm conditions.

The particulate and gas channels both are beta scintillation detectors and the iodine channel utilizes a sodium iodide detector. All three detectors are lead and steel shielded. All three channels utilize internal check sources to verify monitor operability.

CHAPTER 12
RADIATION PROTECTION

TABLE OF CONTENTS (Cont'd)

CHAPTER 12
RADIATION PROTECTION

TABLE OF CONTENTS (Cont'd)

CHAPTER 12
RADIATION PROTECTION

LIST OF FIGURES

12.0 RADIATION PROTECTION

12.1 Ensuring that Occupational Radiation Exposures are as Low as Reasonably Achievable (ALARA)

12.1.1 Policy Considerations

12.1.1.1 Corporate Health Physics Policy. It is the policy of the Carolina Power & Light Company to develop, implement, and maintain sound health physics programs at each Company facility where radiation-producing equipment and/or radioactive materials are used or stored. The health physics programs shall be structured to ensure that radiation doses to Company personnel, contractor personnel, and the general public are maintained at levels which are as low as reasonably achievable (ALARA) and consistent with the United States Nuclear Regulatory Commission Regulations in Title 10 of the United States Code of Federal Regulations and with applicable state regulations.

The line management at each of these Company facilities is responsible and accountable for implementing and enforcing the facility's health physics program. Radiation control personnel shall be assigned to these Company facilities to assist line management in carrying out their responsibility to protect workers and the general public. Radiation control personnel shall have sufficient independence from the line management which they assist to assure that proper health physics practices are not compromised by operational pressures. Furthermore, radiation control personnel shall have access to higher levels of management for the resolution of health physics concerns which cannot be resolved at a lower management level.

All Company and contractor employees working in a facility where exposure to radiation might occur are personally responsible for maintaining radiation doses and releases of radioactive materials to unrestricted areas as far below specified limits as reasonably achievable, to minimize the creation of radwaste, and to support the requirements of the health physics programs consistent with the proper discharge of their duties. Personnel who habitually or willfully disregard or violate health physics procedures and practices will be subject to disciplinary action.

A manual shall be developed and maintained as the controlling document for the Company's health physics programs and shall set forth policies and standards for the Company's health physics programs. The health physics programs at the Company's nuclear generating plants shall comply with the manual and meet the intent of the Institute of Nuclear Power Operations' "Guidelines for Radiological Protection at Nuclear Power Stations."

The goal of the Company is to maintain the annual integrated occupational dose at nuclear plants and dose to members of the public from Company activities among the lowest in the country. The design, maintenance, and operation of nuclear facilities shall be consistent with this goal. Modifications to existing nuclear facilities shall be designed and implemented in compliance with the health physics programs to meet the ALARA objective.

To support this goal and to allow management to conduct effective health physics programs, the Company will commit sufficient resources in the form of facilities, equipment, and personnel to the programs. Personnel involved in the conduct of the health physics programs, including general employees and contractors, shall be given adequate training and instruction to allow them to contribute to the programs.

The Director - Corporate Health Physics of the Nuclear Services and Environmental Support Department shall monitor the Company's health physics programs on a continuous basis to assure they are being carried out in an effective manner. He shall be expected to communicate directly with corporate management up to and including the Executive Vice President to resolve any concern in the area of health physics if the concern cannot be resolved satisfactorily at a lower management level.

12.1.1.2 Facility Management Policy. Carolina Power & Light Company is committed to a program of keeping occupational radiation exposure as low as reasonably achievable (ALARA). The Operating License, issued by the Nuclear Regulatory Commission, carries with it an obligation to both workers and the general public to maintain exposures as low as is reasonably achievable, considering costs and expected benefits. Carolina Power & Light Company follows the general guidance of Regulatory Guides 1.8., 8.8, 8.10, and publications which deal with ALARA concepts and practices, including Title 10, Code of Federal Regulations, Part 20. As discussed in Section 12.1.1.1, corporate management has formally committed itself to this concept by issuing and endorsing the Corporate Health Physics Policy, which ensures compliance with all state and federal regulations that pertain to the safe operation of nuclear power plants.

The implementation of the Corporate Health Physics Policy is accomplished through a number of mechanisms and procedures in all phases of plant operation. The Radiation Control and Protection Manual provides the direction necessary for implementing corporate policy.

The Radiation Control and Protection Manual sets forth the basic philosophy and general radiation protection standards and procedures that are essential to the safe operation of CP&L's nuclear facilities. The Site Vice President of each nuclear facility is responsible for ensuring the requirements of this manual are included in the Radiation Control and Protection Program at that facility. The procedures which implement the requirements of the Radiation Control and Protection Program are a volume of the Robinson Nuclear Project Operating Manual.

The primary purpose of the Radiation Control and Protection Program is to provide personnel with a safe environment in which to work, to protect the general public and the off-site environs, and to establish procedures and a system of records to meet all the requirements of applicable regulations.

Effective control of radiation exposure involves the following major considerations:

1. Management commitment to, and support of, the Radiation Control and Protection Program

2. Careful design of facilities and equipment to minimize radiation exposure during operation and maintenance

3. Good radiation protection practices, including good planning and the proper use of appropriate equipment by qualified, well-trained personnel

The management of CP&L is firmly committed to performing all reasonable actions for ensuring that radiation exposures are maintained ALARA.

12.1.1.3 Facility Management Responsibilities. Management's commitment to the Corporate Health Physics Policy is reflected in the careful preparation of plant operating and maintenance procedures, the provision for review of these procedures and for review of equipment design to consider the results of operating experience, and most importantly, the establishment of an on-going training program. Training is provided for personnel, so that each individual will be capable of carrying out his responsibility for maintaining his own radiation exposure, as well as that of others, ALARA consistent with discharging his duties. The development of a proper attitude and an awareness of the potential problems in the area of health physics is accomplished through proper training of all plant personnel.

The responsibility for implementation of the ALARA program resides with the Site Vice President, with primary support from all facility Section and Unit heads. The Manager, Environmental and Radiation Control reports to the General Manager - Robinson Plant and makes recommendations to plant management concerning the most effective radiation exposure reduction methods. He is assisted in this task by the Senior Analyst - ALARA who includes, as a major portion of his assignment, an analysis of plant operations and maintenance with respect to maintaining an ALARA approach to personnel radiation exposure. Figure 12.1.1-1 shows the reporting relationship in the Environmental and Radiation Control organization.

The success of the program depends upon cooperation between many plant operating groups. The Senior Analyst - ALARA acts as liaison between the groups while maintaining a high degree of organizational freedom. An ALARA Committee, composed of all major plant operating groups and chaired by the Site Vice President - Robinson Plant or designee, handles plant workers' suggestions for reducing radiation exposure, ensures interface with various plant groups, and provides a mechanism for the review of outages and maintenance activities. Data and experience compiled from the operation of HBR 2 and similar nuclear plants are used as a basis for the review of plant operations, features, and proposed modifications.

The Superintendent - Radiation Control reports to the Environmental and Radiation Control Manager, who reports directly to the Plant General Manager, assuring an open line of communication with appropriate management. The overall effectiveness of the program is reviewed periodically by appropriate plant and corporate management personnel, including the Director - Corporate Health Physics. Formal guidance is provided in the Radiation Control and Protection Manual (discussed in Section 12.1.1.2) and a written ALARA program. The Health Physics Section of the Nuclear Services Department provides formal support for the plant's ALARA program through the efforts of the Superintendent - Radiation Control, who is responsible for ensuring that the direction provided in the Radiation Control and Protection Manual is implemented and that the health physics programs comply with the Corporate Health Physics Policy.

12.1.1.4 Policy Implementation. The management's ALARA policy is implemented at HBR 2 by the Radiation Control Staff under the direction of the Superintendent - Radiation Control, Radiation Control Supervisors, and Senior Analyst - ALARA. It is formalized by incorporating ALARA philosophy and considerations into permanent plant procedures which deal specifically with ALARA concerns. The operational ALARA considerations identified in Sections 12.1.3. and 12.5.3.2 have been implemented according to plant procedures.

A training program has been established to give appropriate plant personnel the knowledge necessary to understand why and how they should maintain their occupational radiation exposure ALARA.

12.1.1.5 ALARA Program Implementation Components. The Plant Management's responsibilities for implementation of corporate policy include:

1. Ensuring that an effective measurement system is established and used to determine the degree of success achieved by plant operations with regard to the ALARA goals and objectives.

2. Ensuring that the measurement system results are reviewed on a periodic basis, and that corrective action is taken when attainment of the specific objectives appears to be jeopardized.

3. Ensuring that the authority for providing procedures and practices, by which the specific goals and objectives are achieved, is delegated.

4. Ensuring that the resources needed to achieve ALARA goals and objectives are made available.

The health physics program is based on regulations and experience including or considering the following:

1. Detailed procedures have been prepared and approved for radiation protection and are a part of HBR's health physics program.

2. Radiological incidents are thoroughly investigated and documented in order to minimize the potential for recurrence. Reports are made to the NRC, in accordance with 10CFR20.2202 and 10CFR20.2203, 10CFR20.2204 and the Technical Specifications.

3. Periodic radiation, contamination, and airborne activity surveys are performed and recorded to document radiological conditions. Records of surveys are maintained in accordance with 10CFR20.2103.

4. Radiation areas, high radiation areas, and very high radiation areas are segregated and identified in accordance with 10CFR20.1003, 10CRF20.1501, 10CFR20.1601, 10CFR20.1602, 10CFR20.1901, 10CFR20.1902, and the Technical Specifications. Airborne radioactivity is determined and posted in accordance with 10CFR20.1003, 10CFR20.1501, 10CFR20.1901, and 10CFR20.1902.

12.1.3 Operational Considerations

Operational considerations at HBR that promote the ALARA philosophy include the determination of the origins of radiation exposures, the proper training of personnel, the preparation of radiation protection procedures, the development of conditions for implementing these procedures, and the formation of a review system to assess the effectiveness of the ALARA philosophy.

Operational radiation protection objectives deal with access to radiation areas, exposure to personnel, and decontamination. Working at or near highly radioactive components requires planning, special methods, and criteria directed toward keeping occupational radiation exposure ALARA. Job training and debriefing following selected high exposure jobs contribute toward reduced exposures. Decontamination also helps to reduce exposure. Procedures and techniques are based upon operational criteria and experience that have worked to keep radiation exposure ALARA.

12.1.3.1 Plant Organization. As described in Section 12.5.1, the plant organization provides both the Radiation Control Supervisors and Superintendent - Radiation Control access to the Plant General Manager through the Manager, Environmental and Radiation Control. This organization allows the Plant General Manager to be involved in the review and approval of specific ALARA goals and objectives as well as review of data and dissemination of information related to the ALARA program.

The organization also provides the Senior Analyst - ALARA through the Superintendent - Radiation Control, who is normally free from routine health physics activities, to implement the plant's ALARA program. This individual is primarily responsible for coordination of plant ALARA activities and routinely interfaces with first line supervision in radiation work planning and post-job review.

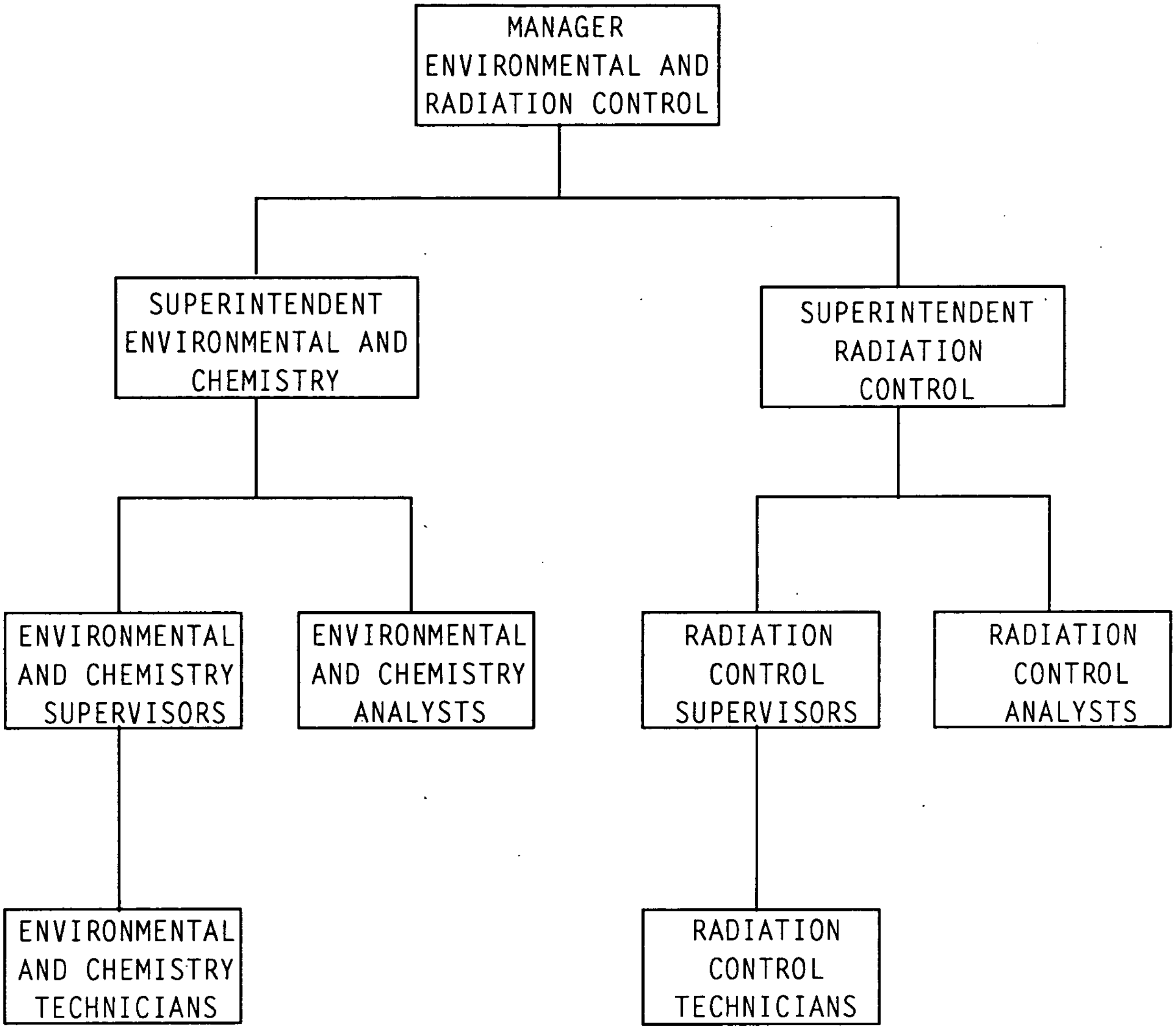
12.1.3.2 Operating Experience. The Radiation Work Permit process described in Section 12.5.3 provides a mechanism for collection and evaluation of data relating to personnel radiation exposure. Information, collated by systems and/or components and job function, assists in evaluating design or procedure changes intended to minimize future radiation exposures.

The Radiation Control Supervisors and the Senior Analyst - ALARA, through the Superintendent - Radiation Control, are responsible for the review of radiation exposure records, investigating not only the individual exposures, but the exposures as classified by job description and job location.

12.1.3.3 Exposure Reduction. Specific radiation exposure reduction techniques that are used at HBR are described in Section 12.5.3. Procedures assure that: applicable plant activities are completed with adequate preparation and planning; work is performed with appropriate health physics recommendations and support; and, results of post-job data evaluation are applied to implement improvements.

In addition, the radiation control staff is, at all times, vigilant for ways to reduce radiation exposures by soliciting employee suggestions, evaluating origins of plant exposures, investigating unusual exposures, and assuring that adequate supplies and instrumentation are available.

The Health Physics Section of the Nuclear Services Department provides support and review services to plant management in accordance with the plant's needs.



Revision No. 13

H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	ENVIRONMENTAL AND RADIATION CONTROL ORGANIZATION	FIGURE 12.1.1-1

12.3.3 AREA RADIATION AND AIRBORNE RADIOACTIVITY MONITORING INSTRUMENTATION

The Radiation Monitoring System (RMS) consists of the following:

a) Area Radiation Monitoring System

b) Process and Effluent Radiological Monitoring and Sampling System

The Area Radiation Monitoring System is described below, while the Process and Effluent Monitoring and Sampling System (which includes Airborne Radiation Monitoring) is described in Section 11.5.

12.3.3.1 Area Radiation Monitoring System

12.3.3.1.1 Design Basis

The Radiation Monitoring System is designed to perform two basic functions:

a) Warn of any radiation health hazard which might develop

b) Give early warning of a plant malfunction which might lead to a health hazard or plant damage

Instruments are located at selected points in and around the plant to detect, compute, and record the radiation levels. In the event the radiation level should rise above a desired setpoint, an alarm is initiated in the Control Room. The automatic Radiation Monitoring System operates in conjunction with regular and special radiation surveys and with chemical and radiochemical analyses performed by the plant staff. Adequate information and warning are thereby provided for the continued safe operation of the plant and assurance that personnel exposure does not exceed 10CFR20 limits.

The only components of these systems which are located in the containment are the detectors for certain area monitoring channels. The low range channels would not be expected to operate following a major loss-of-coolant accident and are not designed for this purpose. Components of all other area monitoring channels are designed for post-accident operation. Area monitors are of a nonsaturating design so that they "peg" full scale if exposed to radiation levels above full scale indications.

The components of the Radiation Monitoring System in the control room are designed according to the following normal environmental conditions:

a) Temperature - an ambient temperature range of 70° to 77°F

b) Humidity - 20 to 80 percent relative humidity

c) Pressure - normal atmospheric pressure (components inside the containment are designed to withstand test pressure).

d) Radiation - Negligible

12.3.3.1.2 General system description. The Area Radiation Monitoring System consists of twelve channels which monitor radiation levels in various areas of the plant. These areas are as follows:

CHANNEL	AREA MONITOR
R-1	Control Room
R-2	Containment
R-3	Pass Panel Area
R-4	Charging Pump Room
R-5	Spent Fuel Building
R-6	Sampling Room
R-7	In-Core Instrumentation Cubicle
R-8	Drumming Station
R-9	Failed Fuel
R-32A	Containment
R-32B	Containment
R-33	Monitor Building

All of the Control Room system equipment is centralized in three cabinets. High reliability and ease of maintenance are emphasized in the design of this system. Sliding channel drawers are used for rapid replacement of units, assemblies, and entire channels. It is possible to completely remove the various chassis from the cabinet, after disconnecting the cables from the rear of these units.

A 32-point strip chart recorder is provided in the Radiation Monitoring System cabinets in the Control Room. Each monitoring channel is sequentially recorded.

Table 12.3.3-1 indicates the detector medium and temperature conditions during normal operation.

The relation of the radiation monitoring channels to the systems with which they are associated is given in the sections describing those systems. Routine test and recalibrations will ensure that the channels operate properly.

12.3.3.1.2.1 Channel R1, 2, 3, 4, 5, 6, 7, 8, 9 and 33

Each channel has a fixed position gamma sensitive GM tube detector assembly located remotely in the plant. Each detector contains a source check mechanism and a preamplifier in addition to the GM tube. Each detector is connected to a ratemeter in the control room which provides power to operate the detector and provides outputs to the control room recorder, the local readout, the ERFIS computer and, upon alarm, to the RTGB annunciator panel and the local display. The remote meter and alarm assembly at the detector contains a red indicator light and a buzzer type alarm annunciator actuated on high alarm. R-1 also provides a signal to operate control room ventilation equipment on an alarm signal.

The pulse rate from each detector is averaged by the ratemeter, converted to a reading in Mr/hr and displayed digitally at the ratemeter. Local readouts are on analog meters. The range of R-1 through R-8 is 0.1 mR/hr to 10,000 mR/hr. The range of R-9 and R-33 is 1.0 mR/hr to 100,000 mR/hr.

Each ratemeter front panel has the following function buttons and lights:

A Circuit Test button to test the electronics, microprocessor, and alarms;

An Alarm/Reset button which lights on high alarm and, when depressed, displays the setpoint and resets any fail or high alarms;

A Check Source button which operates the remote detector check source solenoid. Performing this remote Source Check provides a quick operational check of the entire ratemeter/detector system;

A High Voltage Off button to test the detector fail alarm;

A Fail alarm light;

And a Power On light.

12.3.3.1.2.2 Channel 32A and 32B

The Post Accident Containment Radiation Monitoring System is designed to provide measurement of containment radiation exposure levels during an accident to help assess the severity of the accident.

The system consists of two, independent monitors with a measurement range of 1R/hr to 10^7R/hr. The monitors and associated equipment are qualified for continuous post-accident operation. The monitors are mounted on opposite sides of the containment building and are powered by independent vital power supplies. Readout and recording for each monitor are provided in the control room.

TABLE 12.3.3-1

AREA RADIATION MONITORING SYSTEM

DETECTING MEDIUM CONDITIONS

CHANNEL	MEDIUM	TEMPERATURE RANGE (°C)
R-1	Air	10-50
R-2	Air	10-50
R-3	Air	10-50
R-4	Air	10-50
R-5	Air	10-50
R-6	Air	10-50
R-7	Air	10-50
R-8	Air	10-50
R-9	Air	10-50
R-32A	Air	-18-177
R-32B	Air	-18-177
R-33	Air	10-50

12.5 Health Physics Program

12.5.1 Organization

12.5.1.1 Introduction. The HBR health physics program has been established to provide an effective means of radiation protection for plant personnel, visitors, and the general public. To provide this radiation protection, the health physics program incorporates a dedicated philosophy from management, qualified personnel to direct and to implement the health physics program, the appropriate equipment and facilities, and written procedures based upon acceptable radiation protection practices and guidance.

The health physics program at HBR is developed and implemented to evaluate and document plant radiological conditions and to ensure that every reasonable effort is made to maintain occupational radiation exposure (ORE) as low as reasonably achievable (ALARA). The organization of the health physics program provides a flexible, responsive, and comprehensive structure for attaining these goals. The structural organization is shown on Figure 12.1.1-1. The qualifications of all plant personnel are provided in Sections 13.1.3 and 1.8.

12.5.1.2 Responsibilities. The Radiation Control Supervisors are under the supervision of the Manager - Environmental and Radiation Control, and are responsible for providing the information necessary to establish compliance with regulations pertaining to radiation safety, for uniformly enforcing plant health physics requirements, and for ensuring every reasonable effort to minimize personnel exposures. In addition, they are responsible for ensuring that the staff members who implement the health physics program are trained and retrained in operational health physics principles. They are assisted by a staff which includes a number of RC Technicians. The ALARA program is implemented and evaluated under the technical direction of a Senior Analyst - ALARA who reports to the Superintendent - Radiation Control. The Senior Analyst - ALARA provides technical direction and expertise to the RC subunit and ensures compliance with the corporate commitment to ALARA expressed in the Corporate Health Physics Policy.

The E&RC unit coordinates with the operations, maintenance, and engineering units and provides health physics coverage for all activities that involve radiation or radioactive material. In addition, RC provides various other services, including the following:

1. Preparing health physics procedures for routine and non-routine activities that may be encountered in operating, maintaining, inspecting, and testing the plant.

2. Ensuring that the provisions and standards of 10CFR20 for permissible dose limits and potential release levels are not exceeded.

3. Providing a personnel radiation dosimetry program and maintaining dosimetry records

4. Providing radiation surveys of plant areas and maintaining survey records

5. Assisting in plant training programs by consulting with the plant training organization

6. Providing and calibrating radiation detection instruments and equipment for assessing the radiation environment at HBR

7. Providing, maintaining, and issuing protective clothing and equipment

8. Assisting in the shipping and receiving of all radioactive material to ensure compliance with regulatory requirements

9. Preparing, maintaining, and issuing reports of the required regulatory, plant, and personnel records that involve radiological aspects at HBR

10. Assisting in the decontamination of personnel, equipment, and facilities at HBR

11. Preparing, maintaining, and implementing the HBR respiratory protection program

The responsibilities of the Superintendent - Radiation Control and the Radiation Control Supervisors are to provide the day-to-day execution of the health physics program through supervision of the routine and special surveys and the programs required by applicable regulations and procedures. The Radiation Control Technicians implement the health physics program by performing routine and special surveys and by providing health physics surveillance in accordance with plant health physics procedures.

It is the responsibility of each individual to obey all radiation control procedures and to report to either the Radiation Control Supervisors or the Superintendent - Radiation Control or their designees any circumstances where procedures may be incorrect or unsafe activities may be occurring.

The Director - Corporate Health Physics is available to provide expertise to ensure that the HBR health physics program conforms to the Corporate Health Physics Policy. The Director - Corporate Health Physics reports to the Manager of Nuclear Plant Support who reports to the Vice President Nuclear Services and Environmental Support Department. The Director - Corporate Health Physics has the organizational freedom to communicate directly with the Chief Executive Officer to resolve any concern in the area of corporate health physics should the concern not be resolved satisfactorily at a lower management level. The Director - Corporate Health Physics is responsible for the overview and upgrading of all company health physics related activities through formulating corporate level health physics policies, routinely evaluating all company health physics programs, functioning as corporate spokesman on health physics matters, and participating in the observation of various activities which impact the area of health physics.

12.5.1.3 Authority. The plant General Manager, who is ultimately responsible for all plant activities including radiation safety, receives direct reports from the Manager - Environmental and Radiation Control concerning the status of the health physics program. To ensure uniform enforcement of health physics requirements, the Plant General Manager delegates his authority to the Environmental and Radiation Control Manager who delegates authority to the Superintendent - Radiation Control and the Radiation Control Supervisors. The Superintendent - Radiation Control and the Radiation Control Supervisors have the authority to cease any work activity when, in their judgment, worker safety is jeopardized, or in the event of unnecessary personnel radiation exposures.

The Radiation Control Supervisors delegate authority to responsible RC Technicians to cease any work activity which is not being performed in accordance with health physics requirements. The Radiation Control Technicians have the authority to ensure that jobs are conducted in accordance with health physics requirements.

In the absence of Radiation Control supervision, the authority associated with the above positions may be delegated, in accordance with the plant's health physics procedures, to the most senior health physics individual on shift.

12.5.1.4 Experience and Qualification. The radiation control staff, which is responsible for the health physics program at HBR, meet minimum experience and qualification requirements as described in Section 1.8.

12.5.2 Equipment, Instrumentation, and Facilities

12.5.2.1 Personnel Protective Equipment. Personnel entering the Radiation Control Area may be required to wear protective clothing. The nature of the work to be done is the governing factor in the selection of protective clothing to be worn by individuals. Some of the protective apparel available are shoe covers, head covers, gloves, coveralls, etc. Additional items of specialized apparel such as plastic or rubber suits, and respirators are available for operations involving wet surfaces or airborne radioactivity. In all cases, health physics-trained personnel shall evaluate the radiological conditions and specify the required items of protective clothing to be worn.

Respiratory protective devices may be required in situations arising from plant operations in which an airborne radioactive area exists or is expected. Airborne concentrations are monitored by health physics personnel and the necessary personnel protective devices are specified according to the concentration and type of airborne contaminants present while maintaining the total effective dose equivalent ALARA.

Respiratory devices which may be available for use include:

1. Full-face air purifying respirator

2. Air supplied full-face respirators or hoods

3. Self-contained breathing apparatus.

Respirators are maintained by checking for mechanical defects, contamination, and cleanliness by qualified health physics personnel.

12.5.2.2 Radiation Instrumentation. Facilities are provided for the Environmental & Chemistry and Radiation Control Group. These facilities include both laboratory and health physics work areas. These facilities are equipped to analyze routine air samples and contamination smear surveys. These facilities also serve as a central location for portable radiation survey instruments, respiratory protection equipment, and contamination control supplies.

Survey instruments are calibrated periodically.

12.5.2.3 Personnel Monitoring. All individuals, except casual visitors, who enter the Radiation Control Area are monitored for external whole body radiation exposure using an appropriate individual monitoring device. Individual monitoring devices used at HBR include (but are not limited to) thermoluminescent dosimeters (TLDs), electronic pocket dosimeters, and self-reading pocket ionization chambers.

Individuals subject to monitoring for occupational radiation exposure are issued individual monitoring devices and are required to wear them at all times while in the Radiation Control Area.

Special or additional individual monitoring devices are issued as may be required at the discretion of health physics personnel.

Individual monitoring devices capable of measuring neutron dose equivalent are issued as required. The neutron dose equivalent may be determined initially by using survey data and stay times to calculate exposure.

Casual visitors are not subject to monitoring, recordkeeping, and reporting requirements of 10CFR19 and 10CFR20. However, they are issued a self-reading dosimeter (e.g. pocket ionization chamber or electronic pocket dosimeter) for verification purposes.

12.5.2.4 Facilities and Access Provisions. The plant site is divided into two categories, the Clean Area and the Radiation Control Area for radiation protection purposes as shown on Figures 12.5.2-1 and 12.5.2-2.

Entry to and exit from the primary Radiation Control Area is through the four designated Access Control Points. There are four access control points: 1) RCA Processing; 2) Turbine Building Ground Floor; 3) E&RC Building Ground Floor, West Entrance and 4) RCA Access Facility.

Satellite Radiation Control Areas exist in other areas on plant site and access to these areas is administratively controlled by the Environmental and Radiation Control Organization.

Radiation Control Areas are surveyed, classified, and conspicuously posted in accordance with 10CFR20 regulations.

The general arrangement of the service facilities is designed to provide personnel decontamination and change areas (see Figure 12.5.2-1). Clean locker rooms in the RCA Access Facility are used to store individuals' clothing when they must dress out to perform work in the Radiation Control Area. A dress out area is provided in the Radiation Control Area. A supply of clean protective clothing for personnel is maintained in this area. Appropriate personnel contamination survey devices are located at the exit point of the Radiation Control Area so that personnel can survey themselves upon leaving the Radiation Control Area. A decontamination shower and washroom is located in the Radiation Control Area.

The spent fuel shipping cask decontamination facility has facilities to handle the decontamination of large items of equipment. (Note: The facility has been abandoned in-place. A portable hydrolazer/steam jenny is presently being used to aid in the decontamination process.)

Decontamination areas are also provided in the Reactor Auxiliary Building and within the machine shop for the decontamination of hand tools and small equipment.

12.5.3 Procedures

The health physics procedures developed for HBR are an integral part of the ALARA policy, as discussed in Section 12.1. These procedures, developed through careful planning and preparation and utilized by well-trained and qualified personnel, contribute significantly to the overall reduction of the occupational radiation exposures. The health physics procedures cover the appropriate administrative, operating, and ALARA-related operations and conditions at HBR. As indicated in Section 12.1, ALARA considerations have been embodied in applicable procedures.

12.5.3.1 Control of Access and Stay Time in Radiation Areas. As specified in Section 12.1, physical and administrative controls are instituted at HBR to ensure that the philosophy of maintaining personnel exposures as low as reasonably achievable (ALARA) is implemented.

12.5.3.1.1 Physical controls

12.5.3.1.1.1 Security check point and access control. The plant's security checkpoints are continuously manned. Assigned personnel dosimetry devices and identification badges are stored at designated entry locations when not in use. The security force ensures that all personnel who enter the plant possess appropriate badges and dosimetry in accordance with plant procedures. A restricted area access list is maintained at the security entrance. Any individual not authorized access must be accompanied by a person who is an authorized escort for restricted areas. The training, retraining, and testing requirements for unescorted access are described in the HBR Plant Access Training Procedures.

12.5.3.1.1.2 Door and area posting and locking. Physical control is provided by the posting and locking, as appropriate, of Radiation Areas, High Radiation Areas, and very High Radiation Areas. These areas, as defined in 10CFR20.1003, are posted in accordance with 10CFR20.1902. Plant areas that are routinely accessible are surveyed in accordance with plant procedures to determine radiation and contamination levels. The surveys are performed on a frequency that is appropriate with the potential hazard present. In addition to recording the results of these surveys in accordance with 10CFR20.2103, the radiological postings are updated to reflect operating conditions.

12.5.3.1.1.3 Health physics surveillance. When appropriate, health physics surveillance of work activities is provided to assure a positive control of access and stay time in radiation areas. Surveillance may also be provided for tasks in areas where conditions may warrant timely instructions to workers (e.g., on jobs where the radiological conditions can fluctuate greatly).

12.5.3.1.2 Administrative controls.

12.5.3.1.2.1 Training. As specified in Section 12.5.3.7, personnel allowed unescorted restricted area access receive health physics and related training in accordance with 10CFR19.12.

12.5.3.1.2.2 Radiation work permits. The Radiation Work Permit (RWP) system described in Section 12.5.3.2 is implemented to administratively control access and stay time in radiation areas. For personnel or groups who must routinely enter specific areas as a necessary part of work duties, a General Radiation Work Permit (GRWP) may be issued in accordance with plant procedures.

12.5.3.2 Assuring Occupational Radiation Exposures are ALARA. To effectively implement the corporate ALARA commitment as discussed in Section 12.1.1, an ALARA program is utilized at HBR to assure that activities are performed with ALARA personnel exposure. Carolina Power & Light Company considers it necessary to apply the basic concepts of ALARA to both internal and external exposure to assure proper emphasis on both modes of potential radiation exposure. Procedures employed to implement the program described are subject to review and revision to ensure that the ALARA program is responsive to plant needs and conditions.

12.5.3.2.1 ALARA procedures common to external and internal exposure.

12.5.3.2.1.1 Training. Individuals allowed unescorted restricted area access receive health physics training as described in Section 12.5.3.7. The individual's responsibility to avoid unnecessary exposure is emphasized during health physics training sessions.

As appropriate, individuals involved in potentially high occupational radiation exposure jobs receive pre-job training in exposure reduction techniques and controls applicable to the specific job. Post-job reviews are held, as appropriate, to provide a positive feedback on improved job performance.

12.5.3.2.1.2 Radiation work permit (RWP). For entry into the Radiation Control Area (RCA), an RWP is initiated and approved prior to commencement of scheduled work. Plant procedures specify that an RWP will be completed for work that is performed involving the following situations:

1. Entry into any area where whole body radiation levels are in excess of 100 mrem/hr.

2. Any maintenance work which involves opening of any system which contains, or could potentially contain, radioactive material in excess of limits established by plant procedures

3. Any maintenance of contaminated or potentially contaminated equipment using methods involving abrasion, cutting, machining, or welding

Radiation control personnel evaluate the radiological conditions associated with the work to be performed and specify appropriate protective clothing/devices, respiratory protective equipment, dosimetry, special samples, surveys, procedures, precautions to be taken, and the expiration date.

The RWP is evaluated to ensure that the work will be performed utilizing good health physics practices and an ALARA approach.

The RWP is approved and signed by a Radiation Control Supervisor or his designee. The RWP implementation process is detailed in plant procedures.

12.5.3.2.1.3 Work scheduling. Use of the RWP System establishes a data base from which supervisory staff are able to efficiently schedule workers.

12.5.3.2.1.4 Job pre-planning and exposure goals. Filing out a RWP is a form of job pre-planning. The responsible supervisor ensures that individuals selected to perform the task are familiar with the appropriate procedures to be employed.

On major dose accumulating job functions, total man-rem exposure goals are established prior to commencement of scheduled work. Significant deviations above established goals are investigated by ALARA staff. Methods to improve performance on future jobs will be investigated and implemented, if appropriate.

12.5.3.2.1.5 ALARA program reviews. In an effort to provide more efficient methods of control, evaluation, and reporting, the Senior Analyst - ALARA and radiation control supervisory personnel periodically conduct reviews of the RWP program and procedures utilized to minimize personnel radiation exposure. Results of internal reviews are reported to appropriate levels of plant management. In addition, the radiation protection group performs special reviews or studies requested by corporate committees to assist management in assuring that all aspects of the ALARA program are implemented.

12.5.3.2.2 External ALARA

12.5.3.2.2.1 Administrative limits. Administrative limits are implemented by plant procedures to maintain personnel exposures ALARA with respect to federal regulations. Plant radiation exposure limits may be exceeded only after approval of plant management. Unapproved radiation exposures exceeding plant limits are investigated by radiation control personnel to identify causes and establish methods to prevent recurrence.

12.5.3.2.2.2 Temporary shielding and special tools. During the planning phase of RWP work, qualified radiation control personnel and the ALARA staff evaluate the use of temporary shielding. Care is taken to ensure that installation and removal of shielding does not cause larger man-rem total exposures than expected without its use.

Every reasonable effort is expended to ensure that any necessary, special, or modified tools are available for specific tasks.

12.5.3.2.3 Internal ALARA. To minimize potential intake of radioactive material in excess of federal limits, plant limits are established. Airborne radioactivity concentrations in excess of these limits may require work restriction, engineering controls, use of respiratory protection, and/or special in-vivo or bioassay studies.

When RWP requests indicate that work is required in areas containing potential airborne radioactive material, appropriate air samples are taken. These data samples are normally of short-term, low-volume nature in order to obtain representative of normal breathing rates. Any area that is posted as an airborne radioactivity area is sampled and analyzed prior to commencement of scheduled work.

12.5.3.2.3.1 Control of absorption. When work is scheduled on equipment or systems that contained or may contain radioactive liquids, every reasonable effort to prevent skin contact with radioactive solutions is made.

12.5.3.2.3.2 Control of area and equipment contamination levels. Contaminated areas and equipment are decontaminated to as low a level as reasonably achievable in accordance with plant procedures.

12.5.3.2.3.3 Airborne exposure evaluation. Exposure to airborne radioactive material is evaluated in accordance with 10CFR20.1201(d) and Subpart H - Respiratory Protection and Controls to Restrict Internal Exposure in Restricted Areas to aid in work planning and to demonstrate the effectiveness of the internal ALARA program.

12.5.3.3 Radiation Surveys. The health physics program utilizes a comprehensive system of radiation surveys to document plant radiological conditions and identify sources of radiation that contribute to occupational radiation exposure. Radiation control personnel normally perform radiation and contamination surveys of all accessible areas in the plant. The surveys are performed on an appropriate frequency, depending on the probability of radiation and contamination levels changing, and the frequency with which the areas are visited. Surveys related to specific operations and maintenance activities may be performed prior to, during, and/or after the activity, based on information required to keep radiation exposures ALARA.

Radiation level surveys may be performed for alpha, gamma, beta, and/or neutron exposure rates. Contamination surveys are normally performed to establish gross beta-gamma contamination level, but may be processed for specific types of radiation (beta-alpha-gamma) or specific radionuclides (via gamma spectroscopy). Availability of current survey information aids in keeping exposures ALARA.

The radiation survey program is subject to evaluation by radiation control supervision to ensure that necessary data are collected while exposures to surveyors are ALARA.

12.5.3.4 Contamination Survey Procedures. A system of periodic contamination evaluations is utilized to minimize the spread of radioactive material. Evaluation of personnel, equipment and surface contamination is also made to demonstrate the effectiveness of engineering and procedural controls. In addition, the contamination survey programs are evaluated to assure that survey personnel exposures are ALARA.

12.5.3.4.1 Personnel contamination surveys. Evaluation of exposures due to personnel contamination is conducted in accordance with Section 12.5.3.6.

Instrumentation designed for contamination monitoring is strategically located within the Restricted Area. Every effort is made to locate these instruments in as low a radiation background area as possible in order to maximize sensitivity. Personnel are trained in the use of the instruments and interpretation of the readings.

Personnel contamination causing an alarm requires notification of radiation control personnel. Radiation control personnel take appropriate actions to minimize further spread of contamination, and direct appropriate decontamination of affected areas and personnel.

12.5.3.4.2 Equipment contamination surveys. Movement of equipment from the Radiation Control Area requires the assistance of RC personnel. Fixed and removable contamination levels are evaluated as appropriate and a clearance for removal is issued in accordance with plant procedures.

Reusable protective clothing and shoe covers used in contamination zones are collected in receptacles at access areas and sent for laundering/decontamination.

Change-out procedures require that individuals leaving the Radiation Control Area have to perform surveys of personal items that may have become contaminated during work.

Radioactive material is shipped in accordance with U. S. Department of Transportation and NRC Regulations. Plant procedures implement the applicable regulations with regard to proper packaging and labeling requirements. Appropriate removable contamination and dose rate surveys are taken, records completed, and shipment labeled accordingly.

12.5.3.4.3 Surface contamination surveys. A smear survey program is utilized to assure that a representative number of routinely accessible surface areas within the Radiation Control Area are checked for removable contamination. Emphasis is placed on survey of the clean side of established contamination area access areas.

Occupied plant areas outside the Radiation Control Area are surveyed to assure that a representative number of floor surfaces are checked for removable contamination. The exit areas from the Radiation Control Area receive emphasis to minimize the spread of contamination.

Lunch room facilities and vending machine areas frequented by Radiation Control Area workers are checked for removable contamination. Stoves, benches, table tops, and floor surfaces are representatively smeared to assure minimal contamination in eating areas.

<u>12.5.3.5 Airborne Radioactive Material</u>. Accessible areas containing concentrations of airborne radioactive materials as specified in 10CFR20.1003 are posted in accordance with 10CFR20.1902(d) and applicable plant procedures.

12.5.3.5.1 Airborne concentration sampling. Routine sampling in selected areas of potential airborne radioactivity is accomplished with portable air monitors. Special air samples are taken, as required. The majority of special air samples are taken as a result of RWP requests and pertinent results are recorded thereon.

12.5.3.5.2 Respiratory protection. The respiratory protection program assures that personnel intake of radioactive material is minimized. The respiratory protection program is not used in place of practical engineering controls and prudent radiation control practices. Every reasonable effort is made to prevent potential, and minimize existing, airborne concentrations. When controls are not practicable, or conditions unpredictable, respiratory protective devices may be utilized to minimize potential intake of airborne radioactive material.

The RNPD Respiratory Protection Program ensures that the following minimum criteria are met: written standard operating procedures; proper selection of equipment, based on the hazard; proper training and instruction of users; proper fitting, use, cleaning, storage, inspection, quality assurance, and maintenance of equipment; appropriate surveillance of work area conditions; consideration of the degree of employee exposure to stress; regular inspection and evaluation to determine the continued program effectiveness; program responsibility vested in one qualified individual and an adequate medical surveillance program for respirator users.

12.5.3.5.3 Handling of radioactive material. Recognized methods for the safe handling of radioactive materials are incorporated into procedures to ensure proper usage. Procedures specify handling techniques, storage, and other safety considerations, as listed below:

1. Minimizing distances that large radioactive sources are transported

2. Use of shielded transporters

3. Storage of sources in appropriately shielded containers

4. Proper labeling of radioactive material containers in accordance with 10CFR20

5. Inventorying of all radioactive sources in accordance with plant procedures

6. Leak testing of sources at six-month intervals in accordance with license conditions

7. Monitoring of all packages received containing radioactive material in accordance with 10CFR20.1906.

12.5.3.6 Personnel Monitoring.

12.5.3.6.1 External radiation exposure assessment. Individual monitoring devices are used at HBR to evaluate external occupational exposure to radiation sources. The appropriate individual monitoring devices are issued in accordance with plant procedures implementing 10CFR20.1502(a).

Individuals who are issued individual monitoring devices are instructed in the purpose and use of the devices, plant administrative exposure limits, and interpretation of the self-reading monitoring device data.

Administrative exposure limits are established and implemented by health physics procedures to ensure the limits of 10CFR20.1201 are not exceeded and personnel occupational exposures are maintained ALARA.

12.5.3.6.2 Internal radiation exposure assessment. To demonstrate the effectiveness of engineering controls and the respiratory protection program, personnel are periodically monitored for internal radioactivity. The following methods for assessing internal exposure are used to ensure compliance with occupational dose equivalent limits:

1. Air sampling to determine the concentrations of airborne radioactive materials in the work area; or

2. Whole body counting techniques to determine the quantities of radioactive material in the body; or

3. Bioassay techniques to determine the quantities of radioactive material excreted from the body; or

4. Any combination of the above listed methods.

12.5.3.6.3 Methods of recording and reporting. Updates of exposure totals are compiled from self-reading pocket dosimeter readings. Unapproved exposures exceeding plant limits will be reported to the Plant General Manager and appropriate supervision, and investigated by radiation control personnel to identify causes and establish methods to prevent recurrence.

Occupational radiation exposure received during previous employment is used in preparation of individuals' Forms NRC-4, or equivalent in accordance with 10CFR20.2104. Records used in preparing Form NRC-4, or equivalent, are retained and preserved until the NRC authorizes disposition.

Records of the radiation exposure of personnel who are issued individual monitoring devices in accordance with 10CFR20.1502 are maintained on Form NRC-5, or equivalent. Records of radiation exposures of individuals receiving exposure under the provisions of 10CFR20.1206 are documented in accordance with 10CFR20.2105 and maintained on Form NRC-5 or equivalent.

Reports of exposure to radiation or radioactive materials are made to individuals as specified in 10CFR19.13. When reports of individual exposure to radiation or radioactive material are made to the NRC, the individual concerned is also notified. This notice is forwarded to the individual at a time no later than the transmittal to the NRC and complies with 10CFR19.13.

Reports of individual monitoring are submitted in accordance with 10CFR20.2206 on or before April 30 of each calendar year. As part of a routine annual operating report, personnel exposure information is submitted within the first quarter of each calendar year. It includes a tabulation of the number of plant, utility, and other personnel (including contractors) for whom monitoring was required or provided, the exposures then received, and associated man-rem exposure according to work and job functions.

Reports of overexposures at HBR are submitted to the NRC and the individual(s) involved in accordance with 10CFR19.13 and 10CFR20.2203. Reports are also forwarded to appropriate committees for review and recommendation for follow-up action.

12.5.3.7 Health Physics Training Programs. Health physics training programs assure that personnel, who have unescorted access to the restricted area, possess an adequate understanding of radiation protection to maintain occupational radiation exposures ALARA. Special training/retraining is administered upon recommendation of the Training Supervisor or Radiation Control Supervisor. Record-keeping and training scheduling is performed by the Manager - Training or designated alternate. This program covers the following:

1. General employee health physics
2. General employee respiratory protection
3. Contractor health physics
4. Contractor respiratory protection
5. General employee retraining
6. Radiation control technician training
7. Radiation control technician retraining

12.5.3.7.1 Health physics training. Persons allowed unescorted access to Radiologically Controlled areas must demonstrate proficiency in the following areas as evidenced by passing a written examination:

1. Requirements of 10CFR19.12
2. Radiation/Contamination (examples and control)
3. ALARA (Corporate commitments, meaning, and individual responsibility)
4. Personnel Monitoring and Self-Survey Requirements
5. Radiological Control Signs and Posting Requirements
6. Radiation Exposure Control and Limits
7. Radiation Emergency Plan and Applicable Procedures
8. Prenatal Radiation Exposure

Training is administered to provide radiation workers with an adequate knowledge to effectively cope with job situations while maintaining radiation exposures as low as reasonably achievable.

To assure individual proficiency in radiation protection practices, retraining/retesting should be performed annually ±25% (maximum 15 months). Scheduling, records and test results are maintained by the Manager - Training or designated alternate. Individuals changing job classification receive training of the level required by their new job classification.

12.5.3.7.2 Respiratory protection training program. Individuals and their supervisors requiring access to areas where respiratory protection is utilized are required to complete the Respiratory Protection Training Program. The instructor is a qualified individual with a thorough knowledge regarding the application and use of respiratory protective equipment and the hazards associated with radioactive airborne contaminants.

Training includes lectures, demonstrations, discussions of pertinent plant procedures, and actual wearing of respirators to become familiar with the various devices utilized at HBR.

13.0 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.1 Management and Technical Support Organization

13.1.1.1 Organizational Arrangements. Carolina Power & Light Company is engaged in the production, transmission, distribution, and sale of electric energy to residential, commercial, and industrial customers spread over a service area of 30,000 sq. mi. in North and South Carolina. The Company has extensive experience in the design, construction, startup, testing, operating, and staffing of modern generating facilities.

The corporate organization, which provides line responsibility for operation of the Company, is shown in Figure 13.1.1-1. Ultimate responsibility for operation of HBR2 rests with the President/Chief Operating Officer reporting to the Chief Executive Officer/Chairman. The Executive Vice President - Nuclear Generation, the Senior Vice President - Power Operations and the Senior Vice President - Customer and Operating Services report to the President/Chief Operating Officer.

1. Nuclear Generation Group. The Executive Vice President-Nuclear Generation Group reports to the President/Chief Operating Officer. He is responsible for managing the company's nuclear plants and assuring they are in compliance with applicable regulations, codes, and other requirements. There are five departments in the Nuclear Generation Group: (a) the Brunswick Nuclear Plant Department, (b) the Harris Nuclear Plant Department, (c) the Robinson Nuclear Plant Department, (d) the Nuclear Engineering Department, and (e) the Nuclear Services and Environmental Support Department. Their responsibilities are summarized below:

a. The Brunswick Nuclear Plant Department - The Vice President, Brunswick Nuclear Plant Department reports to the Executive Vice President - Nuclear Generation and is responsible for managing all aspects of modification installation, outage management, direct plant support functions, operation, and maintenance of the Brunswick Nuclear Plant. The Department consists of: (1) Director of Site Operations, (2) Plant General Manager, (3) Manager - Site Support Services, (4) Manager - Regulatory Affairs, (5) Manager - Training, (6) Manager - Nuclear Assessment, and (7) Plant Controller.

b. The Harris Nuclear Plant Department - The Vice President, Harris Nuclear Plant Department reports to the Executive Vice President - Nuclear Generation and is responsible for managing all aspects of modification installation, outage management, direct plant support functions, operation, and maintenance of the Harris Nuclear Plant. The Department consists of: (1) Plant General Manager, (2) Manager - Plant Support Services, (3) Manager - Regulatory Affairs, (4) Manager - Training, (5) Manager - Nuclear Assessment, and (6) Plant Controller.

c. The Robinson Nuclear Plant Department - The Vice President, Robinson Nuclear Plant Department reports to the Executive Vice President - Nuclear Generation and is responsible for managing all aspects of modification installation, outage management, direct plant support functions, operation, and maintenance of the Robinson Nuclear Plant. The department consists of: (1) Director of Site Operators, (2) Plant General Manager, (3) Manager - Plant Support Services, (4) Manager - Regulatory Affairs, (5) Manager - Training, (6) Plant Controller, and (7) Manager - Nuclear Assessment.

d. The Nuclear Engineering Department - The Vice President, Nuclear Engineering Department reports to the Executive Vice President - Nuclear Generation and is responsible for the engineering support of the Company's nuclear generating facilities. Reporting to the Vice President - Nuclear Engineering Department are: (1) Manager - Brunswick Engineering Support Section, (2) Manager - Harris Engineering Support Section, (3) Manager - Robinson Engineering Support Section, (4) Manager - Business Planning and Budgeting, (5) Chief Engineer, and (6) Manager - Nuclear Fuel Management and Safety Analysis.

The Nuclear Fuel Management and Safety Analysis Section provides services associated with the procurement, design, engineering and fabrication of nuclear fuel. The Section also provides probabilistic risk assessment (PRA) and spent fuel management services to the nuclear plants.

The Chief's Engineer Section (CES) is comprised of mechanical/materials/civil and electrical/instrumentation & control engineering staff. The CES provides nuclear engineering discipline technical support to the respective Plant Engineering Support organizations.

Reporting to the Robinson Engineering Support Section Manager are Superintendents for Design Control, Electrical/I&C Systems, and Mechanical Systems.

The Manager of Robinson Engineering Support Services is responsible for ensuring programs and processes are developed and maintained to ensure that configuration control of HBR2 design basis is maintained. He is the direct line of communication with the Vice President - Robinson Nuclear Plant for resolution of engineering related issues to support the safe and efficient operation of the HBR2. This responsibility is executed through the Superintendents of Design Control, Electrical/I&C Systems, and Mechanical Systems.

The Electrical/I&C Systems and Mechanical Systems Units provide the front line engineering leadership to the overall goals of safe, reliable and cost-efficient plant operations of world class standards.

The Units provide an in-house multi-discipline design engineering force to maintain quality, cost-effective design expertise and methods that will be available to meet present as well as future needs. The units are also a resource for the performance of special technical studies of plant design related topics.

e. The Nuclear Services and Environmental Support Department is responsible for matters related to nuclear plant maintenance services and technical support; generic licensing; nuclear plant support in numerous areas such as Health Physics, Chemistry, Training, Radwaste, Environmental Radiation Exposure control and Vendor and Equipment Quality; provides independent oversight of the plants' nuclear assessment sections; and administrative services for the Nuclear Generation Group. Additionally, Nuclear Services and

Environmental Support coordinates the Nuclear Generation Group's Peer Group activities and provides interface with various industry organizations including the company's activities associated with environmental services.

The Department Manager operates through the Manager - Nuclear Licensing and Regulatory Affairs; the Manager - Nuclear Plant Support, the Manager - Performance Evaluation; the Manager - Environmental Services, the Manager - Nuclear Information Technology; the Manager - Nuclear Purchasing, Contracts & Materials; the Manager - Performance Planning & Analysis; the Manager - Laboratory and Facility Services; and the NGG Controller. The responsibilities of the Performance Evaluation Section are further described in Section 17.3, and additional organization descriptions are contained in the CP&L Corporate QA Program Manual.

2. Power Operations - The Senior Vice President, Power Operations, reports to the President/Chief Operating Officer and is responsible for the planning, engineering, modification, operation, and maintenance of the fossil generating, transmission, and associated facilities, and for the fuel and materials management of the fossil facilities. There are four departments and one section reporting to the Senior Vice President, Power Operations: (a) Fossil Generation Department, (b) System Planning and Operations Department, (c) Transmission Department, (d) Fossil Fuel Department, and (e) Business Services Section. The responsibilities of each of these are described below:

a. <u>Fossil Generation Department</u>. The Vice President - Fossil Generation reports to the Senior Vice President - Power Operations and is responsible for managing the Company's eight fossil steam and associated IC turbine facilities, and four hydro-generating facilities. He is also responsible for providing craft traveling maintenance support, operations support, efficiency and analysis support, turbine generator technical support, engineering support, installation support, licensing support for hydro, and project management for clean air act compliance.

b. <u>Systems Planning and Operations Department</u>. The Vice President - Systems Planning and Operations Department reports to the Senior Vice President - Power Operations and has the primary responsibility to develop the company plans for generation and transmission resources; to negotiate, coordinate, and administer bulk power agreements, and agreements for joint ownership and utilization of Company facilities; and to schedule, control, and deliver electric energy through the bulk power system.

c. <u>Transmission Department</u>. The Vice President - Transmission Department reports directly to the Senior Vice President of Power Operations Group. It is the responsibility of the department to design, construct, operate and maintain the transmission system.

d. <u>Fossil Fuel Department</u>. The Manager - Fuel Department reports to the Senior Vice President - Power Operations and is responsible for managing the fuel for eight fossil steam plants and associated IC turbine facilities. This includes short-term and long-term fuel contracts, railroad negotiations for shipping coal, spot coal purchases, payment of fuel including freight charges, and negotiations for management of emission allowances.

e. Business Services Section. The Manager - Business Services Section reports to the Senior Vice President - Power Operations. The Business Services Section has responsibility for providing business planning, cost reporting, information system coordinator, and benchmarking support for the group.

13.1.1.2 Qualifications. The CP&L Corporate Organization is fully qualified to support the operation of the HBR2 as documented by the issuance of the Facility Operating License.

13.1.2 Operating Organization

13.1.2.1 Plant Organization. The facility organization is shown on Figure 13.1.2-1.

13.1.2.2 Plant Personnel Functions, Responsibilities, and Authorities. The Vice President - Robinson Nuclear Plant reports to the Executive Vice President and is responsible for managing all aspects of engineering, construction, operation, and maintenance at the Robinson Nuclear Plant. These activities are conducted in a manner which will protect the health and safety of the public, will be in compliance with applicable governmental regulations, and will be within the policies and guidelines of the Company. The Vice President - Robinson Nuclear Plant is supported in these responsibilities by the following: (1) the Director - Site Operations, (2) Manager - Plant Support Services, (3) the Manager - Regulatory Affairs, (4) the Plant Controller, (5) the Manager - Nuclear Assessment Section. In the absence of the Vice President - Robinson Nuclear Plant, these Managers may be designated "Acting Plant Vice President" for the purpose of approving documentation. The following offsite reporting section managers are located on plant site and provide support to the Vice President - Robinson Nuclear Plant: Manager - Robinson Engineering Support Section, Manager - Human Resources, and the Manager - Communications.

1. The Director - Site Operations reports to the Vice President Robinson Nuclear Plant and is responsible for providing direction necessary to ensure the safety of the public, plant personnel, and plant equipment; obtain high availability of plant generating capacity; assist in the selection and training of qualified personnel; produce economic operation consistent with sound operating practices; and conduct formal and informal relations with official bodies and the general public consistent with company policies and practices. The Director - Site Operations will provide general direction and guidance to managers in the selection of personnel for positions on the plant staff. The Director - Site Operations shall also provide direction and guidance to the training and requalification training programs.

a. The Plant General Manager is directly responsible for the safe, reliable, and efficient operation of H. B. Robinson Unit 2 and the Independent Spent Fuel Storage Installation, including operation, maintenance, and technical supervision. This Manager is responsible for adherence to all requirements in the Operating License and Technical Specifications. The Plant General Manager is supported in these responsibilities by the Manager - Operations, Manager - Maintenance, Manager - Environmental and Radiation Control, Manager - Outage Management, and the Manager - Work Control. In the absence of the Plant General Manager, the On-Call Management Designee will assume the Plant General Manager's duties and responsibilities.

1) The Manager - Operations is responsible for optimizing operation of the nuclear generating unit within Technical Specifications and operating procedures to meet system load requirements during all shifts of operation. Major considerations include maximizing efficiency, reliability, availability, safety, and economic generation while ensuring that plant operation is in compliance with NRC, other regulatory requirements associated with nuclear safety, Quality Assurance Program, and health physics, and that

minimum impact on the environment is achieved. These responsibilities are accomplished through those reporting to the Manager - Operations, including the Assistant Unit Manager - Operations, and Superintendent - Operations Support.

The Superintendent - Operations Support is responsible for providing technical and engineering support to the Operations Unit which contributes to operating in a safe, efficient, and reliable manner in compliance of all regulatory requirements. This Superintendent is also responsible for the development and maintenance status of the Unit's goals and standards, and ensuring that the operating procedures are accurate and reflect the last Management guidance and operating experience with respect to the safe, efficient, and reliable operation of the Plant.

The Assistant Manager - Operations is responsible for providing coordination between the activities of the on-shift operating crews and the day-to-day activities of the Plant. This Manager assists the Manager - Operations in making decisions about unit evolutions and plans and provides the interface with other onsite groups to execute these activities. These responsibilities are accomplished through the Superintendent - Shift Operations, Superintendent - Work Coordination, and the remainder of the operating crews.

Superintendent - Shift Operations - A Superintendent - Operations is responsible for supervising each operating crew to ensure safe, reliable and efficient generation of power, consistent with industrial and nuclear safety measures and in strict compliance with Technical Specifications, CP&L operating procedures and criteria, and with the licenses and regulations issued by the NRC.

Superintendent - Work Coordination - This Superintendent also maintains operational control of the work Control Center.

Senior Reactor Operators (Control Room) - are accountable for administratively and technically supporting the monitoring, evaluation, and control of the instrumentation and equipment of the generating unit to ensure safe, reliable, and economic operations consistent with industrial and nuclear safety measures and in strict compliance with Technical Specifications, CP&L operating procedures and criteria, and the licenses and regulations issued by the NRC. The Senior Reactor Operators directly supervise the manipulations of the reactor controls and are qualified to serve as the Control Room Supervisor.

Senior Reactor Operator (Work Control Center) is responsible for the proper functioning of the work management process.

Shift Technical Advisor (STA) - This position is responsible for providing operating experience/accident assessment technical advice and is dedicated to concern for the safety of the plant; maintaining/broadening knowledge of normal and off-normal operations; diagnosing off-normal events; maintaining cognizance of current operating experience; ensuring capability of response to an emergency situation within ten minutes of being alerted; and effectively carrying out assigned non-accident duties related to plant safety. This position provides continual on-shift engineering assistance as described in Technical Specifications to the Superintendent - Shift Operations.

<u>Control Room Supervisor</u> - This position is responsible for supervising the operations of a nuclear generating unit to ensure safe, reliable, and efficient generation of power consistent with industrial and nuclear safety measures and in strict compliance with Technical Specifications, CP&L operating procedures and criteria and with the licenses and regulations issued by the NRC. This position is responsible to maintain/increase knowledge and skills to retain an SRO license and to effectively provide technical and administrative supervision to the operating shift; ensure shift operations activities are in compliance with Technical Specifications, regulatory requirements, and department and corporate policies and procedures; ensure adequate and appropriate documentation and accounting for the operation of the nuclear unit as required by the NRC and company or plant programs; maintain a competent, qualified shift operations staff and a high level of productivity and morale; contribute to cost-effective, improved plant operations and effective communications; support achievement of department, section, and unit goals through effective teamwork and working relationships; ensure that work is conducted with appropriate emphasis on employee safety, radiation protection, security and other programs designed to protect the welfare of employees and the public.

<u>Control Operators</u> - This position is accountable for monitoring and controlling the controls, instrumentation, and equipment required to run the generating unit in a safe, efficient, and reliable manner. The Control Operators are expected to maintain the knowledge and skill to be able to function effectively in critical situations to assure the safety of the public and the plant. The Control Operators must operate in an environment that is subject to strict NRC, procedural, safety, and other regulatory agency controls.

<u>Auxiliary Operators</u> - The Auxiliary Operators are responsible for assisting in the performance of assignments associated with shift operations and refueling, including operation of auxiliary systems and equipment outside of the control room.

2) <u>Manager - Environmental and Radiation Control</u> - is responsible for providing the environmental, chemistry, and radiation control programs necessary for the operations of the plant within technical specifications and applicable state and federal regulations. These responsibilities are accomplished through those reporting to this Manager, including the Supervisor - Radiation Control, Superintendent - Environmental and Chemistry, and the Superintendent - Radiation Protection.

<u>Supervisor - Radiation Control</u> - The Supervisor - Radiation Control is responsible for providing: 1) the radiation safety of employees, plant workers, visitors, and the general public; 2) radiation control within the plant; and 3) shipment of radioactive material in compliance with Technical Specifications and plant and regulatory compliance.

Superintendent - Environmental and Chemistry - The Superintendent - Environmental and Chemistry is responsible for providing for the evaluation, authorization, and reporting of plant radioactive effluents in conformance with federal and state regulations and licenses. This Superintendent is also responsible for the chemistry control within the plant as specified in the Technical Specifications and fuel warranty and in accordance with recommended operating practice.

Superintendent - Radiation Protection - The Superintendent - Radiation Protection is responsible for providing the Radiation Control support necessary for the operation of the plant within Technical Specifications and applicable state and federal regulations. The Superintendent is also responsible for the Plant's ALARA Program.

3) Manager - Maintenance - The Manager - Maintenance is responsible for ensuring the plant mechanical, Instrumentation & Control (I&C), and electrical equipment/systems are economically maintained at optimum dependability, safety, and operating efficiency in a manner to ensure compliance with plant technical specifications, Quality Assurance Program, health physics, and other requirements. This Manager is also responsible for ensuring that maintenance work is scheduled and performed per the Work Management Process. These responsibilities are accomplished through those reporting to the Manager - Maintenance including the Superintendent - Mechanical Maintenance, Superintendent - Electrical/I&C Maintenance, Fix-It-Now (FIN) Team Supervisor, and Supervisor - Maintenance Programs.

Superintendent - Mechanical Maintenance - The Superintendent - Mechanical Maintenance is responsible for maintaining plant mechanical systems at optimum dependability, safety, and operating efficiency in a manner to ensure Technical Specifications and plant and regulatory requirements are met. These responsibilities are accomplished through those reporting to the Superintendent - Mechanical Maintenance including the Mechanical (Shop) Supervisors and the Paint and Pipe Covering Supervisor.

Superintendent - Electrical/I&C Maintenance - The Superintendent - Electrical/I&C Maintenance is responsible for surveillance testing and maintenance of plant electrical and instrumentation and control systems at optimum dependability, safety, and operating efficiency to ensure compliance with Technical Specifications and plant and regulatory requirements. These responsibilities are accomplished through those reporting to the Superintendent - Electrical/I&C Maintenance including the I&C (Shop) Supervisors.

Fix-It-Now (FIN) Supervisor - The Fix-It-Now Supervisor is responsible for maintaining plant mechanical and electrical/I&C systems at optimum dependability, safety and operation efficiency to ensure compliance with Technical Specifications and plant and regulatory requirements. These responsibilities are accomplished through those reporting to the Fix-It-Now Supervisor.

Supervisor - Maintenance Programs - The Supervisor - Maintenance Programs is responsible for ensuring that procedures are accurate and reflect the latest Management guidance and industry experience with respect to safe and efficient maintenance of plant equipment.

4) Manager - Work Control - The Manager - Work Control is responsible for the planning of maintenance work activities, scheduling of outage and non-outage activities, and managing the Work Control Process. This Manager is also responsible for the Plant's Long Range Plan. These responsibilities are accomplished through those reporting to this Manager including the Schedulers and the Supervisor - Planning.

Schedulers - The Schedulers are responsible for the schedules which control work activities related to the maintenance, inspection, testing, and modification of plant equipment. These schedules cover both outage and on-line activities. These schedulers also maintain the Plant's Long Range Plan and develop/maintain the performance indicators that provide effective monitoring of the work management process.

Supervisor - Planning - The Supervisor - Planning is responsible for the planning of work packages associated with both on-line and outage maintenance activities. This responsibility is accomplished by those reporting to this supervisor including the Mechanical and Electrical/I&C Planners.

5) Manager - Outage Management - The Manager - Outage Management is responsible for establishing milestones and schedules to help ensure a safe timely completion of refueling and planned/forced outages. This Manager is also responsible for the management of outage activities to ensure schedule adherence or, if necessary, revisions to the schedule based on changes in outage scope. These responsibilities are accomplished through those reporting to this Manager including the Shift Outage Directors and Coordinators.

Shift Outage Coordinator - The Shift Outage Coordinator is responsible for schedule development and review associated with Plant outages. This review includes the Shutdown Risk Management requirements. During the outage, the Shift Outage Coordinator is responsible for ensuring that work gets accomplished as scheduled, consulting with management and outage coordinators to ensure appropriate response to emergent work and problems with scheduled activities, and to keep the Manager - Outage Management aware of work status and difficulties.

b. The Manager - Training provides technical training and is responsible for the accredited training programs (licensed and non-licensed operator initial and continuing, STA, Maintenance, Chemistry, Radiological Controls, Shift Supervisor, and Maintenance Supervisor). Additionally, the Manager - Training is responsible for providing regulatory based training including but not limited to General Employee Training and Requalification Training, Fitness for Duty, Respirator, and Emergency Preparedness.

These responsibilities are accomplished through those reporting to this Manager including the Superintendent - Operations Training, Supervisor - Technical Training and, the Instructional Technologists for Accredited Training Programs.

Management and supervisory development programs and other non-accredited and non-technical training is normally provided by the Human Resources Department.

2. The Manager - Plant Support Services - is responsible for the Plant's record management and document control systems and associated procedures which ensure compliance with corporate and regulatory requirements.

This Manager is also responsible for: 1) the Plant's computer hardware and software and associated personnel training, 2) the Plant's Security Program including the security system, staff, and associated procedures, and 3) the repairs and general cleaning of the Plant's facilities including decon activities, maintenance of Plant vehicles, and upkeep of grounds.

These responsibilities are accomplished through those reporting to the Manager - Plant Support Services including the Superintendent - Document Services, Superintendent - Information Systems, Superintendent - Security, and Supervisor - Facility Services.

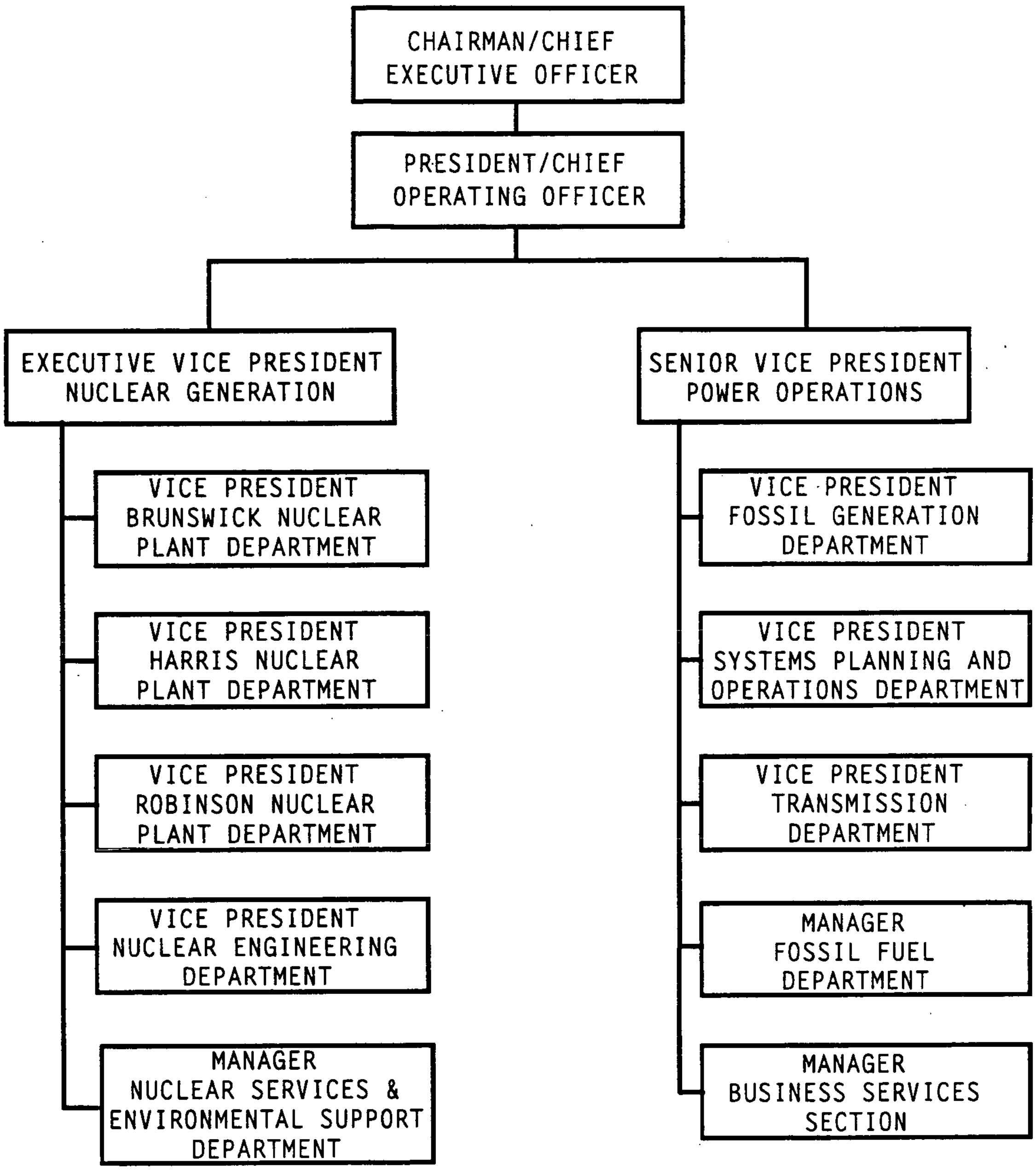
3. The Manager - Regulatory Affairs - is responsible for providing regulatory support for plant efforts to comply with regulatory (NRC), state, environmental, insurance, and Institute of Nuclear Power Operations (INPO) requirements and guidelines. This is accomplished by establishing regulatory interpretations, coordinating onsite NRC, Nuclear Assessment Section (NAS), Licensing, South Carolina Department of Health & Environmental Control, insurance, and INPO activities; inspections, commitments, responses, and resolution of concerns. This Manager ensures that commitments are met, responses which accurately depict the plant's position are submitted, reportable occurrences are detected and reported (e.g., Licensee Event Reports), documentation is maintained, and support is provided for preparing and implementing revisions to Technical Specifications and to the Updated Final Safety Analysis Report.

This Manager is also responsible for the Plant's Emergency Preparedness activities and facilities, the Plant's Corrective Action Program, the Operating Experience Program, and oversight of self-assessment activities.

These responsibilities are accomplished through those reporting to the Manager - Regulatory Affairs including the Manager - Operating Experience Assessment, Manager -Licensing/Regulatory Programs, and the Manager - Emergency Preparedness.

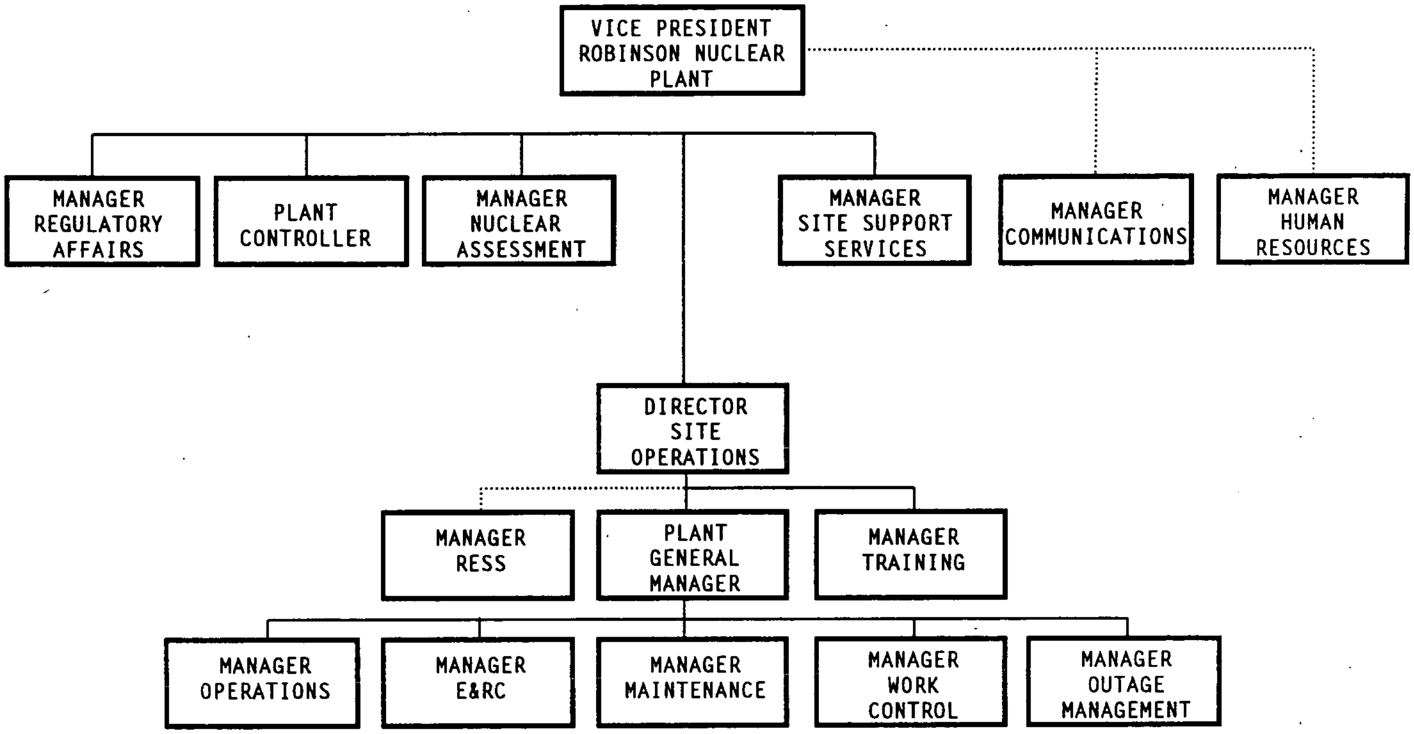
4. The Plant Controller - is responsible for managing and directing the financial activities of the Plant including budget preparation, cost control and analysis, cash flow projections, accounting, and business planning relative to the Plant and Corporate strategic goals. These responsibilities are accomplished through those reporting to the Plant Controller.

5. The Manager - Nuclear Assessment Section (NAS) is responsible for overall management of Independent Assessment, Independent Safety Review and Quality Control programs. In this capacity, the Manager shall: manage performance-based assessment activities in a manner that facilitates achievement of world-class performance by the line organizations in the areas of nuclear safety, production and cost; identify issues and weaknesses in the area of nuclear performance to plant and senior management; promote self-assessment within the line organization by on-the-job training and example; facilitate rotation by managing assigned resources in a manner that accomplishes personnel development in both assessment skills and line functional area expertise; management quality control functions to ensure plant activities are conducted in accordance with appropriate regulatory and design commitments; manage the independent safety review program.



REVISION NO. 13

H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	CP&L'S NUCLEAR GENERATION AND POWER OPERATIONS GROUPS	FIGURE 13.1.1-1



REVISION NO. 13

H.B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	PLANT ORGANIZATION	FIGURE 13.1.2-1

13.2 Training

13.2.1 Accredited Training Programs

The H. B. Robinson Steam Electric Plant, (HBRSEP) Unit No. 2 programs have been developed in accordance with the Systems Approach to Training as prescribed by the Institute of Nuclear Power Operations (INPO). The National Academy for Nuclear Training, through a formal accreditation process, verifies that HBRSEP training programs meet the established criteria. HBRSEP is a branch of the National Academy and has achieved accreditation of the following programs.

Nonlicensed Operator
Reactor Operator
Senior Reactor Operator
Continuing Training for Licensed Personnel
Shift Supervisor
Shift Technical Advisor
Instrument and Control Technician
Electrical Maintenance Personnel
Mechanical Maintenance Personnel and Supervisor
Radiological Protection Technician
Chemistry Technician
Engineering Support Personnel

The training programs are periodically evaluated and reviewed by management for effectiveness. Revisions are made as appropriate. Records are retained as necessary to support management information needs and to provide historical data.

13.2.2 General Employee and Fitness for Duty Training Programs

All persons regularly employees at HBRSEP are trained in the following areas commensurate with their job duties.

Fitness for Duty
General Plant Description
Job related Procedures and Instructions
Radiological Protection
Emergency Preparedness
Industrial Safety
Fire Protection
Security
Quality Assurance

13.2.3 Other Training Programs

Responsible managers ensure that personnel performing quality-related activities receive indoctrination and training to ensure that adequate proficiency is achieved and maintained.

13.3 Emergency Planning

The description of plans for coping with emergencies at the H. B. Robinson Steam Electric Plant is contained in the latest revision of the H. B. Robinson Steam Electric Plant Radiological Emergency Response Plan, Volume 1, Part 2 of the Plant Operating Manual (Reference 13.3-1).

Revisions to the Emergency Plan and Plant Emergency Procedures are transmitted to NRC in accordance with 10 CFR 50.54(q). Additionally, the South Carolina Operational Radiological Emergency Response Plan and the South Carolina Technical Radiological Emergency Response Plan have been transmitted to the NRC (Reference 13.3-3).

The NRC approved the H. B. Robinson Emergency Plan on May 11, 1983 (Reference 13.3-4).

13.4 Review and Audit

The description of plans for conducting reviews and assessments of operating phase activities that are important to safety is contained in Section 6.5, "Review and Audit" of Plant Technical Specifications and UFSAR Section 17.3.3, respectively.

13.5 PLANT PROCEDURES

The administrative and operating procedures used by the HBR plant staff to ensure that routine operating, off-normal, and emergency activities are conducted in a safe manner are described in the H. B. Robinson Plant Operating Manual (POM) (Reference 13.2.2-1).

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

TABLE OF CONTENTS (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

LIST OF FIGURES

LIST OF FIGURES (Cont'd)

CHAPTER 15
ACCIDENT ANALYSIS

LIST OF FIGURES (Cont'd)

LIST OF FIGURES (Cont'd)

15.0 ACCIDENT ANALYSIS

15.0.1 CLASSIFICATION OF PLANT CONDITIONS

Plant operations are established to be in one of four categories. These are categorized in accordance with the nomenclature adopted by the American Nuclear Society. The categories are:

a) CONDITION I - Normal Operation and Operational Transient - Events which are expected to occur frequently in the course of power operation, refueling, maintenance, or plant maneuvering.

b) CONDITION II - Faults of Moderate Frequency - Events which are expected to occur on a frequency of once per year during plant operation.

c) CONDITION III - Infrequent Faults - Events which are expected to occur once during the lifetime of the plant.

d) CONDITION IV - Limiting Faults - Events which are not expected to occur but which are evaluated to demonstrate the adequacy of the design.

15.0.1.1 Acceptance Criteria

Condition I - This condition describes the normal operational modes of the reactor. As such, occurrences in this category must maintain margin between operating conditions and the plant trip setpoints. The setpoints are established to assure maintenance of margin to design limits. The set of operating conditions, together with conservative operational uncertainties for the variables, establish the set of initial conditions for the other event categories.

Condition II

a) The pressures in reactor coolant and main steam systems should be less than 110% of design values.

b) The fuel cladding integrity should be maintained by ensuring that fuel design limits are not exceeded by assuring that the minimum calculated departure from nucleate boiling ratio does not exceed the applicable limits of the DNBR correlation being used (see Sections 4.4 and 15.0.10).

c) The radiological consequences should be less than 10 CFR 20 guidelines.

d) The event should not generate a more serious plant condition without other faults occurring independently.

Condition III

a) The pressures in reactor coolant and main steam systems should be less than 110% of design values.

b) A small fraction of fuel failures may occur, but these failures should not hinder the core coolability.

c) The radiological consequences should be a small fraction of 10 CFR 100 guidelines (generally < 10%).

d) The event should not generate a limiting fault or result in the consequential loss of the reactor coolant or containment barriers.

Condition IV

a) Radiological consequences should not exceed 10 CFR 100 guidelines.

b) The event should not cause a consequential loss of the required functions of systems needed to cope with the reactor coolant and containment systems.

c) Additional criteria to be satisfied by specific events are:

1) LOCA - 10 CFR 50.46 and Appendix K.

2) Rod Ejection - Radially averaged fuel enthalpy < 280 cal/gm.

15.0.1.2 Classification of Accident Events by Category

Table 15.0.1-1 presents the event classification by category used in evaluating the acceptability of results of the analysis.

15.0.2 Plant Characteristics and Initial Conditions Used in the Accident Analyses

Five operational modes have been considered in the analysis.

1.	Refueling	Shutdown margin ≥ 6% Δk/k
2.	Cold Shutdown	Subcritical Primary coolant temperature ≤ 200°F Shutdown margin ≥ 1% Δk/k
3.	Hot Shutdown	Subcritical Primary coolant temperature > 200°F Shutdown margin as defined in Plant Technical Specifications
4.	Startup	Subcritical, to < 2% rated power
5.	Power Operation	Power ≥ 2% rated power (no automatic control rod withdrawal considered)

These operational modes have been considered in establishing the subevents associated with each event initiator. A set of initial conditions is established for the events necessary to be analyzed with the conditions for each mode of operation.

The normal plant rated operating conditions are presented in Table 15.0.2-1 and principal fuel design characteristics in Table 15.0.2-2. The uncertainties used in the accident analysis applicable to the operating conditions are:

1.	Core Power	± 2%
2.	Primary Coolant Pressure	± 30 psi[a]

[a]The primary coolant pressure uncertainty listed here is applied to the system transient analysis pressure which is used in the hot subchannel analysis to calculate the minimum DNB ratio. It is not applied to the system transient analysis initial-condition pressure. This is in accordance with the applicable non-LOCA transient analysis methodology (see page 203 of Reference 15.0-3).

TABLE 15.0.2-1

NOMINAL PLANT RATED OPERATING CONDITIONS

Core Thermal Power	2300 MWt
Vessel Average Coolant Temperature	575.4°F
Vessel Coolant Flow*	97.3 * 10^6 lb/hr
Active Core Flow*	92.9 * 10^6 lb/hr
Steam Generator Pressure (Dome)	800 psia
Feedwater Temperature	441.5°F
Pressurizer Pressure	2250 psia
Pressurizer Level	53.3% of span
Steam Generator Level	52% of span
Steam Generator Total Fluid Inventory	91,000 lbs. (per steam generator)
Steam Generator Circulation Ratio	4.13

* Coolant flow reflects 6% steam generator tube plugging for rebuilt steam generators and is a lower bound value (based on the Technical Specification minimum), rather than a nominal value.

15.0.3 Power Distribution

The radial and axial power peaking used in the analysis is presented in Table 15.0.3-1. The reference axial power distribution used for DNB events which do not experience power redistribution (fast non-LOCA transients not challenging the OTΔT trip function) is presented in Figure 15.0.3-1. The limiting axial power distributions used for DNB events which may experience power redistribution (slow non-LOCA transients challenging the OTΔT trip function--events 15.2.2, 15.4.2, and 15.4.3c) are presented in Figure 15.0.3-2. The limiting axial power distributions used for analysis of other limiting faults which do not experience power redistribution are presented in Reference 15.0-1 (Large-Break LOCA) and Reference 15.0-6 (Small-Break LOCA).

The Technical Specification (Reference 15.0-2) operating limits and reactor protection system setpoints assure that the power distribution is maintained within these power distribution limits. For example, the margin to trip setpoint is automatically reduced for DNB and fuel temperature limiting events, when the difference between top and bottom power flux detectors would indicate an axial flux offset which would degrade conditions to less than those established with the allowable operating power distributions. This reduction for the OTΔT and OPΔT trips was confirmed using statistical setpoint analysis (Reference 15.0-10).*

*The OTΔT trip function and statistical setpoint analysis are described in Section 15.0.7.

TABLE 15.0.3-1

REACTOR POWER DISTRIBUTION USED IN THE ANALYSIS

Fraction of power deposited in fuel	.974
Nuclear enthalpy rise hot channel factor ($F_{\Delta H}$)	1.80
Heat flux hot channel factor (F_Q)	2.50

15.0.4 Range of Plant Operating Parameters and States Used in the Analysis

Table 15.0.4-1 presents the range of key plant operating parameters considered in the analysis. A broader range of power, vessel average coolant temperature, and primary pressure is considered in establishing the trip setpoints verified by the analysis results presented in this document. The broader range is consistent with that indicated on page 2.1-4 of Reference 15.0-2.

Operating states of the reactor are also considered in the analysis. The operating states include the exposure of the fuel as impacts fuel thermal performance and neutronics parameters. State values are selected for the event analyzed to provide the greatest challenge to the acceptance criteria for an event. Several analyses may be required to bound the range of the state variable. For example, a range of neutronic parameters is used in the analysis of rod withdrawal events in order to verify the range of protection of the challenged trip setpoints.

The range of initiating events is also considered in formulating the analysis conditions for an event. The initiating conditions are examined to identify the set which most challenge the acceptance criteria. Where not obvious, sensitivity analysis or several analyses are performed. For example, analyses are performed for uncontrolled rod withdrawal events throughout the range of reactivity insertion rate possible from shim dilution to maximum withdrawal rate of the most worthy control banks. Since the most challenging initial power level is not obvious, the range of power level as permitted by the reactor protection system is analyzed.

A further example of state variation is the impact of protective systems such as the pressurizer spray and power operated relief valves. These are assumed to be in a state which most challenges the acceptance criteria under consideration.

The various operating modes of the reactor are also considered. The modes for this analysis are as described in 15.0.2. The startup mode, for example, is relevant to the uncontrolled rod withdrawal from subcritical or low power event. All modes of operation are relevant to the CVCS malfunction event which can result in dilution of primary boron concentration.

In this manner, the permitted operating modes, states and range of plant operating variables are considered in the safety analysis. Thus, the plant may be operated within these bounds and be expected to meet the acceptance criteria as cited for each event.

Sensitivity studies performed by Siemens Power Corporation indicated that it was not necessary to bias the initial pressure in the ANF-RELAP system analysis of the NSSS transient response. However, to be conservative in the core subchannel calculation of DNBR, it is necessary to bias the pressure based on the plant measurement uncertainty.

The sensitivity calculations indicate that the maximum pressure calculated in the system analysis for events with rapidly increasing pressures were controlled not by the initial pressure value but by the biased PORV, and safety valve setpoints. For events with little or no change in pressure or

decreasing pressures, the initial system pressure was again found to have little impact on the calculated pressures. The calculated pressures simply varied throughout the event by approximately the applied pressure bias.

Thus, the Siemens Power Corporation transient methodology is to:

- initiate the calculation of the NSSS transient response (using the ANF-RELAP computer code) at nominal pressure

  and

- reduce the core inlet pressure calculated by the ANF-RELAP computer code for use as input data in estimating the Minimum DNB Ratio with the XCOBRA-IIIC computer code.

TABLE 15.0.4-1

INITIAL CONDITION RANGE OF KEY PLANT OPERATING PARAMETERS CONSIDERED IN THE ANALYSIS

Core thermal power	Subcritical to 2346 MWT**
Vessel average coolant temperature	547°F to 575.4°F*
Pressurizer water level	22.2% to 53.3% of span (programmed)
Steam generator level	39% to 52% of span (programmed)
Nominal Reactor Coolant System pressure	2250 psia***

*Lower temperature operation during startup is bounded by the higher temperature listed here (see Reference 15.0-7).

**1.02*2300.

***See discussion in text Section 15.0.4-1.

15.0.5 Reactivity Coefficients Used in the Safety Analysis

Table 15.0.5-1 presents the reactivity coefficients used in the analysis. As discussed in 15.0.4, the set of these parameters which most challenges the event acceptance criteria is used in each analysis. Conservative values for the moderator temperature and Doppler coefficients are used in the safety analysis to bound operating conditions. The conservatism factor (20% or greater) is applied in a sense to most challenge the event acceptance criteria.

The table shows that a positive moderator coefficient was assumed in the analysis of events most challenged by BOC neutronic parameters. The assumption demonstrates safety of the system under an extreme set of initial conditions, and allows a single analysis to cover both high-power operation (for which the moderator temperature coefficient is actually a negative value) and low-power operation (for which the moderator temperature coefficient is a small positive value). Although the results of the analyses support a moderator temperature coefficient of up to +5 pcm/°F, the plant operates with a moderator temperature coefficient of ≤ 0 pcm/°F at rated power.

TABLE 15.0.5-1

NOMINAL REACTIVITY COEFFICIENTS USED IN THE ANALYSIS

Item	BOC	EOC
Moderator Temperature Coefficient	+5.0 pcm/°F	-40 pcm/°F
Doppler Coefficient	-1.0 pcm/°F	-2.0 pcm/°F
Scram Worth, (N-1)* .9	3600 pcm	3600 pcm

15.0.7 Trip Setpoints and Time Delays

Table 15.0.7-1 presents the trip setpoints and time delays used in the analysis. Additional trips are available, i.e., overpower ΔT, feedwater steam flow mismatch, and turbine trip. If credit were taken in the analysis for such trips the results of the events would be further mitigated with less challenging results. It is, therefore, conservative not to credit the additional trips.

The overtemperature ΔT trip function is designed to preclude bulk boiling in the hot legs and to protect the DNBR safety limit over the range of allowable primary coolant pressures (Reference 15.0-10). Avoidance of bulk boiling assures that proper trip compensation is made for the DNB-influencing parameters (hot leg coolant temperatures and pressures). The trip function is set to protect against bulk boiling and DNB, with allowance for appropriate uncertainties in plant operation, temperature and pressure measurements, and trip channel performance.

The overtemperature ΔT trip function was evaluated statistically using the methodology described in Reference 15.0-10. This evaluation confirmed, on a static basis, that the trip function described in Table 15.0.7-2 provides protection against bulk boiling in the hot leg and against DNB at a 95% probability with a 95% confidence level. The transient analysis confirmed that the lead/lag compensation on the measured T_{avg} is sufficient to make the static analysis conservative.

The statistical setpoint analysis uncertainties which were combined with local peaking uncertainties for measurement and for fuel pellet geometry were an overall trip channel uncertainty of ±10.35% and a ΔI uncertainty of ±3%. Both of these uncertainties were treated as two-sided 95% probability limits.

TABLE 15.0.7-1

TRIP SETPOINTS AND TIME DELAYS USED IN THE SAFETY ANALYSIS

Trip	Nominal Trip Setpoint	Biased Trip Setpoint Assumed in the Analysis	Nominal Time Delay (sec)
Power range high neutron flux, high setting	109%	118%	.5
Power range high neutron flux, low setting	25%	35%	.5
Overtemperature $\Delta T^{(1)}$	1.1365	1.24	$0.75^{(2)}$
High pressurizer pressure	2400 psia	2430 psia	1.0
Low pressurizer pressure	1850 psia	1800 psia	$1.0^{(3)}$
Low reactor coolant flow (from loop flow detectors)	90%	87%	1.0
Low-low steam generator	14% span	0% span	1.0

(1) A description of the overtemperature ΔT trip function is presented in Table 15.0.7-2.

(2) 0.75 sec. for electronic time delay. In addition, the thermal transient transport through the thermowell and the RTD response time are represented by a first order lag with a time constant of 4.0 seconds (nominal) or 5.0 seconds (in the analysis).

(3) 1.0 sec. for electronic delay. Also, the pressure signal for the low pressurizer pressure trip is compensated by a lead-lag controller with time constants of τ_{lead} = 10 seconds and τ_{lag} = 1 second.

TABLE 15.0.7-2

DESCRIPTION OF OVER TEMPERATURE ΔT TRIP FUNCTION

$$\Delta T \leq \Delta T_0 \ [K_1 - K_2 \frac{(1 + t_1 S)}{(1 + t_2 S)} \ (T - T') + K_3 (P - P') - f(\Delta I)]$$

where:

ΔT	=	Indicated ΔT
ΔT_0	=	Indicated ΔT at rated thermal power;*
T	=	Average temperature, °F;
P	=	Pressurizer pressure, psig;
K_1	<	1.1365, nominal; 1.24, analysis;
K_2	=	0.01228;
K_3	=	0.00089;
$\frac{1 + t_1 S}{1 + t_2 S}$	=	The function generated by the lead-lag controller for T_{avg} dynamic compensation;
t_1 & t_2	=	Time constants utilized in the lead-lag controller for T_{avg}, t_1 = 20 seconds, t_2 = 3 seconds;
T'	=	575.4°F Reference T_{avg} at rated thermal power;
P'	=	2235 psig (Nominal RCS Operating Pressure);
S	=	Laplace transform operator, sec^{-1};

and f(ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant start-up tests such that:

(1) For (q_t - q_b) within +12% and -17%, where q_t and q_b are percent power in the top and bottom halves of the core, respectively, and q_t + q_b is total core power in percent of rated power (2300 Mwt), f(ΔI) = 0.

For every 2.4% below rated power (2300 Mwt) level, the permissible positive flux difference range is extended by +1%. For every 2.4% below rated power (2300 Mwt) level, the permissible negative flux difference range is extended by -1%.

*In the instrumentation, ΔT_0 is set to 57.5°F as the indicated temperature difference at full power. In the plant transient analysis calculation model, ΔT_0 is set to the temperature difference for the initial conditions of 102% of rated thermal power and the minimum RCS flow allowed by Technical Specifications. In the statistical setpoint calculations, ΔT_0 is set to 57.5°F and the RCS flow is adjusted to obtain a temperature difference of 57.5°F for the "nominal" case.

TABLE 15.0.7-2 (Continued)

(2) For each percent that the magnitude of $(q_t - q_b)$ exceeds +12% in a positive direction, the ΔT trip setpoint shall be automatically reduced by 2.4% of the value of ΔT at rated power (2300 Mwt). 3

(3) For each percent that the magnitude of $(q_t - q_b)$ exceeds -17%, the ΔT trip setpoint shall be automatically reduced by 2.4% of the value of ΔT at rated power (2300 Mwt).

TABLE 15.0.8-1

COMPONENT CAPACITIES AND SETPOINTS USED IN THE SAFETY ANALYSIS

COMPONENT	RESPONSE TIME	NOMINAL SETPOINT	ANALYSIS SETPOINT	CAPACITY
Pressurizer Safety valves	0.7 s to 1.0 s[a]	2485 psig to 2560 psig	(1.02)(2485 psig) to (1.04)(2560 psig)[b]	864,000 lb/hr[c] @(1.06)(2560 psig)
Steam line safety valves	-	1085 psig to 1140 psig	(1.03)(1085 psig) to (1.03)(1140 psig)	10,220,000 lb/hr @(1.10)(1140 psig)
Turbine stop and governor valves	0.1 s	-	-	-
Main steam isolation valves	10 s	-	-	-
Feedwater isolation valves	1.0 s[d]	-	-	-
Auxiliary feedwater	67 s	-	-	240 gpm[e](2 SGs/ 120 gpm ea.)
Pressurizer PORVs	0.1 s	2335 psig (open) 2327 psig (close)	2331 psig (open) 2323 psig (close)	(1.06)(511,200 lb/hr)@2477 psig

(a) The loop seal purge delay to the opening of the pressurizer safety valves ranges from 0.7 seconds (used for DNB-challenge cases) to 1.0 seconds (used for pressurization-challenge cases), based on the procedure and uncertainties given in Reference 15.0-11 and a 0.458 ft^3 loop seal liquid volume.

(b) The pressurizer safety valve setpoint used for DNB-challenge cases is based on the lower-bound rated setpoint, with 3% added for liquid-loop-seal setpoint shift and 1% subtracted for setpoint uncertainty. The setpoint used for pressurization-challenge cases is based on the upper-bound rated setpoint, with 3% added for liquid-loop-seal setpoint shift and 1% added for setpoint uncertainty.

(c) The analysis assumes that the pressurizer safety valves reach their rated capacity at a pressure 6% above the upper-bound rated pressure (based on 3% liquid-loop-seal setpoint shift and 3% accumulation).

(d) Steam Line Break analysis used a conservatively large value of 30 seconds.

(e) A single motor-driven auxiliary feedwater pump delivering 240 gpm is credited in the Chapter 15 analysis. The steam-driven auxiliary feedwater pump, which is credited for plant shutdown after a fire or loss of all AC power, has a cavitating venturi in its discharge which limits flow during low steam generator pressure conditions. This limit may be less than 240 gpm during very low pressure periods such as startup and cooldown below 375°F reactor coolant temperature. A capacity greater than that shown above is used in Steam Line Break analysis, because the higher flow contributes to the severity of that event.

15.0.10 Effects of Fuel Assembly Hydraulic Design and Fuel Rod Bowing

H. B. Robinson used the same fuel assembly hydraulic design from the time Siemens Power Corporation (formerly known as Advanced Nuclear Fuel and/or Exxon Nuclear) became the fuel supplier in the mid-1970's until the 1990 refueling outage. Siemens Power Corporation's High Thermal Performance (HTP) fuel was first introduced at the 1990 refueling outage. From a thermal-hydraulic standpoint, the major difference between the old Standard Mixing Vane (SMV) design and the new HTP design is an improved spacer or grid strap design and an increased number of them to improve mixing of coolant within the core. For the new HTP fuel, the ANFP correlation has a DNBR safety limit of 1.154 (Reference 15.0-8).

The effects of rod bow for SMV fuel in the H. B. Robinson 2 Cycle 10 and subsequent cores of similar fuel types have been evaluated (Reference 15.0-5). A rod bow evaluation of the HTP fuel assemblies for burnups to 52,500 MWd/MTU showed that there is no reduction in DNB or LOCA-ECCS limits to an average assembly burnup of 47,000 MWd/MTU (Reference 15.0-9). Fuel assemblies with burnups greater than approximately 30,000 MWd/MTU cannot reach sufficiently high power densities that, even with a penalty from rod bow applied, they can be limiting with regard to DNB or to LOCA-ECCS peaking limits when compared to fuel assemblies with burnups below 30,000 MWd/MTU.

REFERENCES: SECTION 15.0

15.0-1 H. B. Robinson Unit 2 Large Break LOCA Analysis
EMF-96-060, Siemens Power Corporation, Richland, WA, May 1996.

15.0-2 Technical Specifications and Bases for H. B. Robinson Unit 2, Appendix A to the Facility Operating License DPR-23, Docket No. 50-261, Carolina Power and Light, Hartsville, SC.

15.0-3 ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events, ANF-89-151(P)(A), Advanced Nuclear Fuels Corporation, Richland, WA, May 1992.

15.0-4 Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations, XN-NF-82-21(P)(A), Revision 1, Exxon Nuclear Company, Richland, WA, September 1983.

15.0-5 Computational Procedure for Evaluating Fuel Rod Bowing, XN-NF-75-32(P)(A), Supplements 1, 2, 3, & 4, Exxon Nuclear Company, Richland, WA, October 1983.

15.0-6 H. B. Robinson Unit 2 Small Break LOCA Analysis, EMF-94-203(P), Siemens Power Corporation, Richland, WA, October 1994.

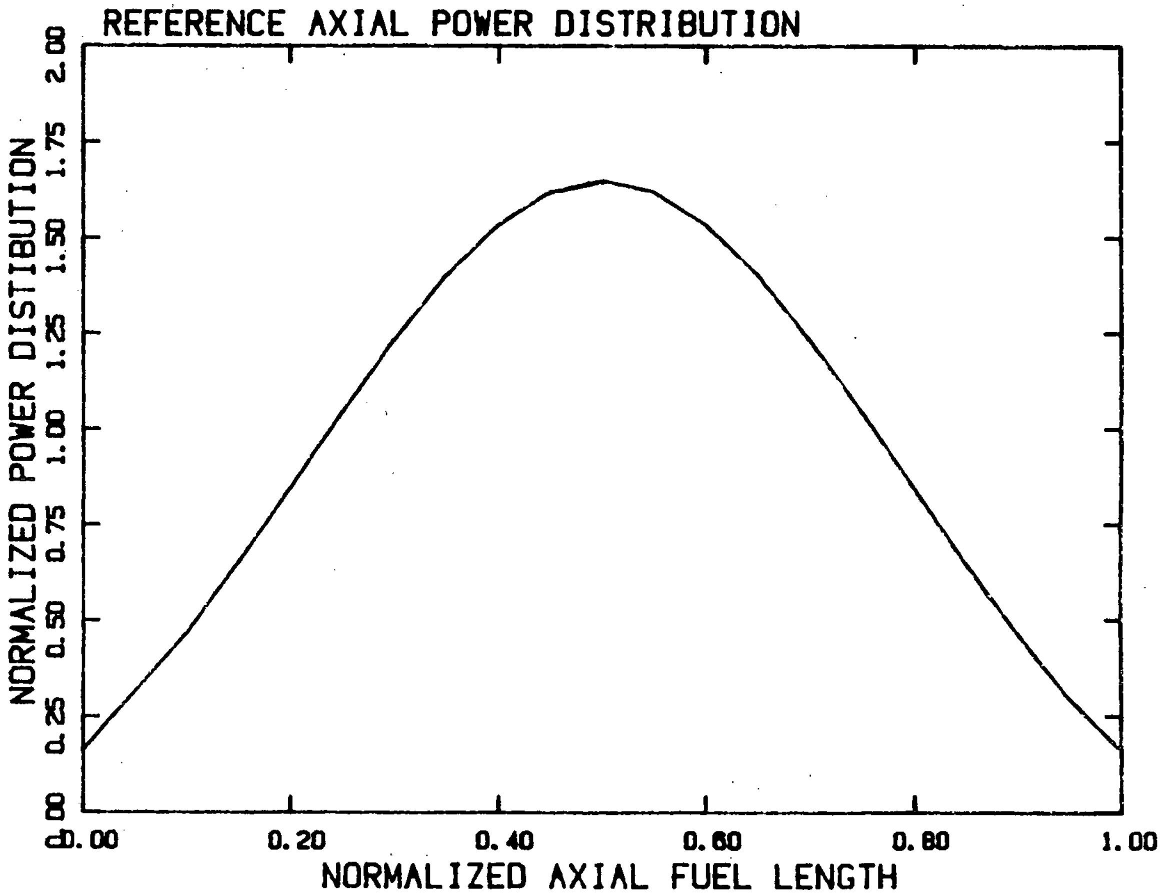
15.0-7 Letter from H. G. Shaw (SPC) to B. A. Morgan (CP&L), "Minimum Temperature for Criticality for H. B. Robinson Unit 2," HGS:94:472, December 22, 1994.

15.0-8 Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel, ANF-1224(P)(A), Advanced Nuclear Fuels Corporation, Richland, WA, May 1989.

15.0-9 H. B. Robinson Unit 2, Cycle 17 Safety Analysis Report, EMF-95-031, Siemens Power Corporation, Richland, WA, April 1995.

15.0-10 Statistical Setpoint/Transient Methodology for Westinghouse Type Reactors, EMF-92-081(P)(A), Siemens Power Corporation, Richland, WA, February 1994.

15.0-11 Pressurizer Safety Valve Set Pressure Shift, WCAP-12910, Westinghouse Electric Corporation, Pittsburgh, PA, March 1991.



AMENDMENT 3

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	REFERENCE AXIAL POWER DISTRIBUTION	FIGURE 15.0.3 - 1

15.1.3 Increase in Steam Flow (Excess Load)

15.1.3.1 Identification of Causes and Event Description. The increase in steam flow event is initiated by an increase in steam demand. The increased steam demand may be initiated by the operator, system demand, or regulating valve malfunction. The step increase in steam flow used bounds the maximum capacity of the turbine steam regulating valves.

The event initiator is a step increase in steam flow. The feedwater regulating valves open to increase the feedwater flow to match the new steam demand and maintain steam generator water level. In response to the increased steam flow, the secondary system pressure decreases, resulting in an increase in the primary-to-secondary heat transfer rate. The primary side steam generator outlet temperature decreases due to the enhanced heat removal. As a consequence, the primary system core average temperature decreases and the primary system fluid contracts, resulting in an outsurge of fluid from the pressurizer. The pressurizer level and pressure decrease as fluid is expelled from the pressurizer.

The effect of this cooldown on the core power level will depend upon the sign of the moderator temperature coefficient and the state of the Rod Control System. If automatic control rod withdrawal is blocked[a], negative moderator feedback will increase the core power as the coolant temperature decreases, and the reactor system will reach a new steady-state condition at a power level which is consistent with the increased heat removal rate. (Positive moderator feedback, on the other hand, would decrease the core power level and not challenge the acceptance criterion.)

This event is classified as a Condition II event (Table 15.0.1-1). The relevant acceptance criteria are described in 15.0.1.1. As cited in Table 15.0.11-1, no single failure in the ESF will affect the analysis for this event.

15.1.3.2 Analysis Method. The analysis was performed using the ANF-RELAP and XCOBRA-IIIC codes. The ANF-RELAP code (Reference 15.0-3) was used to model the salient system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). A DNBR calculation was performed to estimate the approximate time at which the DNBR was a minimum. The core fluid boundary conditions and average rod surface heat flux at this time were then used as input to the XCOBRA-IIIC code (Reference 15.0-4), which was used to evaluate the MDNBR.

15.1.3.3 Definition of Events Analyzed and Bounding Input. This event is predominantly a depressurization event, so the primary concern for this event is the challenge to the specified acceptable fuel design limits (SAFDLs). Therefore, the cases identified for analysis for this event are selected on the basis of bounding the largest challenge to the SAFDLs.

---

[a] Automatic control rod withdrawal was not considered in the analysis.

This event is analyzed at full power conditions because at full power the margin to the SAFDLs is the smallest. Thus, full power conditions bound operation at lower power levels.

The core burnup (beginning of cycle or end of cycle) was selected to maximize the challenge to the SAFDLs. The time in the cycle will determine the value of the moderator reactivity temperature coefficient. If the moderator reactivity temperature coefficient is negative, there will be a positive reactivity insertion as the core average temperature decreases. The magnitude of this positive insertion is dependent on how negative the moderator reactivity temperature coefficient is. If the moderator temperature coefficient is positive, then negative reactivity will be inserted as the coolant temperature decreases, causing the power to decrease with less challenge.

The following conditions were used:

Initial power	102% of rated
Moderator temperature coefficient	-42.0% pcm/°F
Doppler coefficient	-2.5 pcm/°F
Increase in steam flow	10% step increase
Core inlet temperature	Nominal
Initial RCS pressure	Nominal
Core outlet pressure used in subchannel analysis	Nominal -30 psi
Pressurizer level	Nominal
Pressurizer heater	Disable
Pressurizer level control	Disable

15.1.3.4 Analysis of Results. The event is initiated by a 10 percent step increase in turbine steam flow. The steam dome pressures drop about 74 psi, resulting in lower steam generator temperatures, increased primary to secondary heat transfer, and hence a reduction in primary side temperature. Vessel average temperature drops about 5°F. This temperature reduction results in a depressurization of the primary system about 68 psia, lowers the pressurizer level about 6.5%, and provides a positive reactivity insertion which peaks at about 0.02 dollars.

The positive reactivity insertion increases core power until the increased load demand is balanced.

Eventually, a new steady state operating condition is reached. This occurs at about 120 sec. The challenge to the DNBR limit results from the combination of rising power and decreasing pressure.

The transient response is shown in Figures 15.1.3-1 to 15.1.3-7. The event sequence is summarized in Table 15.1.3-1. The minimum DNBR computed for the event is 1.65, which is significantly greater than the DNBR limit of 1.154.

15.1.3.5 Conclusion. The results of the analysis demonstrate that the event acceptance criteria is met since the minimum DNBR predicted is greater than the limit. The limit assures that with 95 percent probability and confidence limits, DNB is not expected to occur; therefore, no fuel is expected to fail.

TABLE 15.1.3-1

INCREASE IN STEAM FLOW EVENT SUMMARY

TIME	EVENT	VALUE
0.0 sec.	10% Step increase in turbine flow	
10 sec.	Maximum reactivity	0.02 dollars
120 sec.	New quasi-steady-state operating condition	
	Core power	113% of rated
	Pressurizer pressure	2182 psia
	Minimum DNBR	1.65

15.1.5 Main Steamline Break Event

15.1.5.1 Introduction. The Main Steamline Break event analyzed is the most severe case of an uncontrolled steam release from a steam generator. The break would result in a large initial steam flow, decreasing during the accident as the steam pressure falls. The energy removal from the RCS would cause a reduction of coolant temperature and pressure. With a negative moderator temperature coefficient, the cooldown would result in a reduction of core shutdown margin. If the most reactive control rod assembly is assumed stuck in its fully withdrawn position, there is a possibility that the core will become critical and return to power even with the remaining control rods inserted. A return to power following a steam pipe rupture is a potential problem only because of the high hot channel factors which may exist when the most reactive rod is assumed stuck in its fully withdrawn position. Assuming the most pessimistic combination of circumstances which could lead to power generation following a steam line break, the core power transient is stabilized by Doppler feedback and by the decrease in moderator density in the core. With time, the increasing boron concentration in the reactor causes the power to continuously reduce. When the operator secures auxiliary feedwater, the temperature of the RCS increases and the event is terminated.

15.1.5.2 Analysis Basis. This event was analyzed from hot full power and hot zero power with and without offsite power available (Reference 15.1.5-1). The greatest challenge to fuel centerline melt and to DNB corresponds to a case initiated from hot zero power (HZP) with the offsite power available. For this case, the steam generator secondary side water inventory is greatest, which maximizes the duration and severity of the primary system cooldown, and the moderator temperature in the core is lowest. The bases for this analysis are listed in Tables 15.1.5-1 and 15.1.5-2. For conservatism, the most reactive control rod was assumed to be stuck out of the core. The worst single failure assumed in the analysis is the loss of one of three High Head Safety Injection (HHSI) pumps. In addition, one HHSI pump is assumed to be out of service. The remaining HHSI pump is assumed to take suction from the refueling water storage tank at 45°F and discharge into the BIT. The initial inventories of the BIT and of the injection lines between the RCS cold legs and the BIT were assumed to be unborated water. The initial inventory of the BIT was assumed to flow to the cold leg of the primary ahead of and unmixed with the borated water from the refueling water storage tank. Flow in the lines between the BIT and the cold leg injection locations was conservatively assumed to have no axial mixing. Initial boron concentration in these lines was assumed to be zero. Flow at the cold leg injection point was controlled by the injection delivery curve illustrated in Figure 15.1.5-1. The HHSI pump can provide safety injection as soon as the primary system pressure at the injection point drops below the HHSI pump shut-off head (1435 psia). Safety injection by the HHSI pump was delayed for 12 seconds after the SI actuation trip setpoint was reached to account for the time required for the HHSI pump to come up to speed.

The limiting break location is downstream of the steamline flow nozzle (i.e., flow meter) of the affected steam generator. The break flow area for the affected steam generator is at the integral flow restrictor of that steam generator.

No credit was taken for the steam line check valves until the Main Steam Isolation Valves (MSIVs) close: Instead of preventing initial reverse flow from the intact loops out the break, the intact loops make a significant contribution to the blowdown until MSIV closure is complete. This basis bounds the case for a (different) break location outside the Reactor Containment Building between the steam line check valves and the steam line header (for a break inside the Reactor Containment Building, check valve operability is necessary to prevent continued blowdown of an intact steam line if one MSIV fails to close as an alternative single active failure). Although in actuality a break located inside containment gives a High Steam Line Differential Pressure signal because of immediate check valve closure, only a High Steam Line Flow Coincident with Low Steam Line Pressure or Low Tav signal (see Table 15.1.5-2) was used in the analysis.

The main and auxiliary feedwater flows are assumed at a temperature of 40°F. The main feedwater flow is based on the operation of one of two feedwater trains since this is the maximum number of trains that would be operable under hot zero power conditions. Flow as a function of steam generator pressure is given in Figure 15.1.5-2 and is based on the combined head/flow characteristics of one condensate pump and one feedwater pump connected in series and a conservative treatment of the hydraulic characteristics in the feedwater train including the control valve. The auxiliary feedwater flow is held constant over the transient at a conservative upper bound value.

Trips for the SIS, main feedwater valves, and main steam isolation valves (MSIVs) are given in Table 15.1.5-2. Uncertainty biases are included in the trip setpoints as shown. Delay times given are between the time the trip setpoint is reached and completion of the safety action.

The reactor kinetics were calculated using a point kinetics model. The minimum bounding value for the end-of-cycle (EOC) Moderator Temperature Coefficient at full power, -40 pcm/°F, was used in this analysis. The minimum shutdown margin of 1770 pcm was used.

The parameters in the steamline break analysis that have a direct impact on core return to power have been biased or modeled to conservatively maximize the return to power. Specifically, biases or models were utilized which: (1) delay injection of boron into the core; (2) delay closure of the MSIVs; (3) increase the flow rate and decrease the temperature of the feedwater; (4) limit mixing between loops; and, (5) increase positive reactivity feedback and decrease negative reactivity feedback. Other parameters in the analysis such as plant geometric parameters and plant thermal hydraulic initial conditions have been taken at their nominal values.

15.1.5.3 Calculation Results. These calculations were performed in accordance with Siemens Power Corporation's steamline break methodology (Reference 15.1.5-2). NSSS response is computed with ANF-RELAP, detailed core neutronics characteristics are computed with XTGPWR, and the detailed core flow distribution is computed with XCOBRA-IIIC.

15.1.5.3.1 Relaps NSSS simulation. The ANF-RELAP simulation of the NSSS response during a steamline break is illustrated in Figures 15.1.5-3 through 15.1.5-10. A tabulation of the limiting steamline break event sequence of events is presented in Table 15.1.5-3.

15.1.5.3.1.1 Secondary system thermal hydraulic parameters. Steam flow out the break is the source of the NSSS cooldown. Break flow rates from both sides of the break are plotted in Figure 15.1.5-3. The break flow from the unaffected steam generators (MSIV side) was terminated when the MSIVs closed approximately 29 seconds after the break was initiated. Steam generator pressures and steam generator masses for the affected and unaffected steam generators are plotted in Figure 15.1.5-4 and 15.1.5-5, respectively. The pressures in these intact steam generators recovered as the intact steam generators equilibrated with the primary system and then experienced a slow decrease in as the intact steam generators began to act as heat sinks for the primary system.

The affected steam generator continued to blow down through the break throughout the transient except for a short period about 8 minutes into the transient when the steam generator tubes experienced DNB. The pressure and mass flow rate dropped rapidly for the first 50 seconds, after which they reached a quasi-steady state with the affected steam generator boiling off its inventory. The main feedwater flow terminated approximately 45 seconds after the break. The auxiliary feedwater was assumed to continue feeding the affected steam generator at the maximum achievable rate. Termination of auxiliary feedwater would have made the event less severe.

15.1.5.3.1.2 Primary system thermal hydraulic parameters. The primary system pressure and core coolant temperature responses resulting from the break flow are illustrated in Figures 15.1.5-6 through 15.1.5-10. The primary system pressure decays rapidly as the coolant contracts due to cooldown and the pressurizer empties. After the pressurizer empties of liquid, the pressure continues to drop as steam flows from the pressurizer and is condensed in the hot leg. Continued pressure reduction in the primary system due to expansion of steam in the pressurizer ultimately causes the relatively hot stagnant liquid in the head of the reactor pressure vessel to flash. This retards the pressure decay from that point forward in time. This acts to limit the delivery of boron into the core due to the pressure versus flow characteristics of the SIS.

A comparison of cold leg temperatures indicates significant differences between loops.

15.1.5.3.1.3 Reactivity and core power. The system response for the core is shown in Figures 15.1.5-11 and 15.1.5-12.

The reactivity transient calculated by ANF-RELAP is illustrated in Figure 15.1.5-13. Initially the core is assumed to be subcritical at hot zero power. All control rods, except the most reactive one, are assumed to be in the core at initiation of the steamline break and the reactor is initially subcritical by 1770 pcm.

Cooldown of both the coolant and fuel brings the core critical due to moderator and doppler reactivity feedback. After reaching criticality, the power spikes, fuel temperature rises and doppler feedback effects rapidly reduce core reactivity and power. Shortly thereafter power and moderator temperature begin to level out and core reactivity is essentially zero. The HHSI pump reaches full speed at above 27 seconds. The first wave of low boric acid concentration water has passed through the core by about 237 seconds. Entry of low boric acid concentration water into the core initiates a slow power descent as the concentration of boric acid builds with each pass of primary coolant through the core. When the steam generator tubes experienced DNB on the secondary side, the relatively minor change in inlet temperature resulted in a significant, but temporary, power reduction. When the secondary side re-wetted, the power returned. Ultimately, the transient was assumed to be terminated by operator intervention at 10 minutes.

The transient experienced by the core power is illustrated in Figure 15.1.5-14. Peak power is calculated to occur at about 50 seconds, The maximum power level is 739 Mwt or 32 percent of rated power. The ANF-RELAP core power calculation is conservative as demonstrated by a comparison to XTGPWR.

15.1.5.3.2 Core analysis. The reference reactivity and both the axial and radial power distributions for subcritical HZP conditions were calculated with XTGPWR. The axial distribution is skewed to the top of the core and is essentially independent of the radial location within the core. As the reactor comes to power during the steamline break event, the axial power distribution in the region of the stuck control rod will redistribute from a top core skewed profile, to a more uniform profile, and finally to a bottom core skewed profile as power is increased further. The radial power profile will tend to become more uniform as power is raised.

The input data taken from ANF-RELAP for input to XTGPWR is listed in Table 15.1.5-4. The radial and axial power distributions computed by XTG at MDNBR form the basis for the subsequent XCOBRA-IIIC core flow distribution calculation and also for the DNBR calculation.

The XTGPWR reactivity calculation indicates that the core at this point in time would be subcritical, whereas the ANF-RELAP calculation indicates that the core would be critical, thus indicating that the ANF-RELAP power calculation is conservative.

An XCOBRA-IIIC core analysis was conducted to define the axial and radial flow distribution within the high power assembly. The calculation was based on the core power and boundary conditions from ANF-RELAP and the power distributions from XTGPWR at the MDNBR point in time. Specifically the calculation was based on the data listed in Table 15.1.5-4. The resultant mass flux and enthalpy axial distributions in the hot assembly are shown in Figures 15.1.5-16 and 15.1.5-17.

15.1.5.3.3 DNBR analysis. The calculated minimum DNB ratio is 1.89, occurring at 48 seconds. No fuel rods would be expected to fail.

15.1.5.3.4 Fuel centerline melt analysis. The fuel centerline melt criterion was also used to determine the extent of fuel failure. Maximum post-scram LHGR values were determined. The maximum LHGR was calculated as follows:

$$LHGR_{max} = LHGR_{avg} \times F_Q^N \times f_e \times f_Q$$

Where $LHGR_{avg}$ is the LHGR at the time of maximum post-scram core average LHGR (based on the core power) from ANF-RELAP, F_Q^N is the nuclear heat flux hot channel factor from XTGPWR, f_e is the engineering factor uncertainty and f_Q is the calculational uncertainty associated with F_Q^N.

The maximum post-scram LHGR values, along with the core average LHGR and F_Q^N values, are tabulated in Table 15.1.5-5. The peak LHGR value was below the limit of 20.2 kW/ft, therefore, no fuel failures were predicted to occur.

15.1.5.4 Radiological Consequences. In the event of a steam pipe rupture, the water boiled off in the affected steam generator, plus the steam released from the two unaffected steam generators during plant cooldown are the sources for activity release. Therefore, the released activity sources are divided into two parts:

1. The part released from the affected steam generator, consisting of a fraction of the equilibrium activity in the water and steam in the steam generator and associated piping, plus the activity in the primary coolant that leaks into the secondary side.

2. The part released from the two nonaffected steam generators during plant cooldown.

For the purpose of radiological assessment, it has been conservatively assumed that the affected steam generator pressure drops almost instantaneously to atmospheric pressure and the primary coolant pressure remains essentially 2250 psia for the first two hours. From two to six hours, it is assumed that the primary system pressure decreased linearly to 350 psia from 2250 psia. After six hours, the Residual Heat Removal System (RHRS) is placed in operation to continue heat removal from the primary system, and, at this time, the release of activity to the atmosphere is terminated.

The leakage to the affected steam generator has been assumed proportional to the square root to the primary to secondary pressure differential.

For the purposes of analysis, intial leak rates of 0.1 gpm and 3 gpm were assumed with primary activity associated with 1 percent fuel defects.

Following the postulated accident for the 0.1 gpm case, the leakage to the secondary side of the affected steam generator amounts to approximately 2.5 ft^3 and, for 3 gpm, approximately 75 ft^3. The activities of equivalent I-131 carried over to the steam generator are about 0.18 Ci for the entire period of the accident for the 0.1 gpm case, and about 4 Ci for the 3 gpm case.

The total equivalent I-131 activity released for the 6 hr. period is approximately 0.7 Ci for the 0.1 gpm case, and approximately 14 Ci for the 3 gpm case.

The offsite doses were calculated to be 0.2 rem thyroid, .001 rem whole body and 5 rem thyroid, .01 rem whole body for the 0.1 gpm case and the 3 gpm case, respectively. A $\frac{X}{Q}$ at the site boundary, of 7 x 10^{-4} sec/m^3 was assumed for the entire six hour period.

The equilibrium iodine concentrations were calculated using the "PREL" Code for the Primary and Secondary Systems and with a total Primary-To-Secondary leak rate in the three steam generators of 0.1 gpm for one case and 3 gpm for another case, with activity associated with 1 percent fuel defects. These numbers are based on the assumption of a total blowdown rate of 9 gpm from the three steam generators.

The equilibrium iodine concentrations in the primary and the secondary systems prior to the steam line rupture accident are given in Table 15.1.5-7.

15.1.5.5 Conclusions. In a conservative estimation of the consequences, the shutdown margin is lost and the core returns to power. When the auxiliary feedwater flow is terminated, heatup of the primary with resulting negative moderator and doppler feedback effects will augment the negative reactivity inserted from the boron to terminate the power excursion. Evaluation of the peak fuel Linear Heat Generation Rate shows that fuel centerline melting does not occur and core subchannel calculations show that DNB does not occur. The equilibrium activity in the steam generator shell results in an offsite exposure that is a small fraction of the allowable dose.

TABLE 15.1.5-2

ACTUATION SIGNALS AND DELAYS FOR MSIV, SIS AND FEEDWATER SAFETY ACTIONS

PARAMETER SETPOINTS		Setpoint	Uncertainty	Analysis Value
1.	High Steam Line Flow - HFP	3,707,000 lbm/hr	+240,000 lbm/hr	3,947,000 lbm/hr
	- HZP	1,348,000 lbm/hr	+876,200 lbm/hr	2,224,200 lbm/hr
2.	Low Steam Line Pressure	614.7 psia	-42 psi	572.7 psia
3.	Low Pressurizer Pressure	1714.7 psia	-30 psi	1684.7 psia

MSIV CLOSURE

Required Actuation Signal

A. (1) in two of three lines coincident with
(2) in two of three lines.

Delay - 10 seconds

SIS ACTUATION

Required Actuation Signal

A. (1) in two of three lines coincident with
(2) in two of three lines

B. (3)

Delay - 12 seconds with offsite power available, 32.5 seconds for a loss of offsite power

MAIN FEEDWATER VALVE CLOSURE

Required Actuation Signal

A. Any SIS actuation signal

Delay - 30 seconds[1]

---

(1) From Reference 15.1.5-6, containment analysis shows acceptable results with this response time extended to 82 seconds. This will allow credit for feedwater block valve closure, in case of feedwater regulating valve's failure to close.

TABLE 15.1.5-3

LIMITING STEAMLINE BREAK EVENT SEQUENCE

Time		Event
t = 0.0	A.	Reactor at hot zero power. All control rods inserted except the most reactive one.
t = 0.0+	B.	Double ended guillotine break located downstream of the flow meter in the affected steamline. Steam generator auxiliary feedwater at maximum flow to affected steam generator. Steam generator main feedwater at maximum flow available from one feedwater train to affected steam generator.
t = 14.7	C.	First safety injection system actuation signal--low pressurizer pressure.
t = 15.0	D.	Reactor becomes critical.
t = 18.6	E.	High steamline flow and low steamline pressure SI signals occur for unaffected steam generators.
t = 26.7	F.	HHSI pumps reach rated speed.
t = 28.7	G.	MSIVs close 10 seconds after high steamline flow and low steamline pressure.
t = 44.7	H.	Main Feed Water flow terminates 30 seconds after first SI signal.
t = 48.0	I.	MDNBR occurs.
t = 50.0	J.	Thermal power reaches maximum level at 32% of rated power.
t = 236.7	K.	HHSI line purged, borated water enters RCS.
t = 600.0	L.	AFW terminated by operator intervention.
t = 600.0+	M.	Transient terminated by primary system heatup as affected steam generator dries out and boron concentration increases in the RCS.

TABLE 15.1.5-4

XTGPWR INPUT AND ANF-RELAP OUTPUT AT MDNBR POINT

Time of MDNBR	48 seconds
Core Parameters	
Power	728.8 MW_t
Exit Pressure	866.2 psia
Average Mass Flux	2.44 $Mlb/hr\text{-}ft^2$
Unaffected Core Sector	
Inlet Temperature	478.3°F
Mass Flux	2.38 $Mlb/hr\text{-}ft^2$
Affected Core Sector	
Inlet Temperature	395.3°F
Mass Flux	2.58 $Mlb/hr\text{-}ft^2$
Stuck Rod Sector	
Inlet Temperature	395.3°F
Mass Flux	2.56 $Mlb/hr\text{-}ft^2$

TABLE 15.1.5-5

PEAK LHGR AND FUEL FAILURE RESULTS

Time of Peak LHGR	49 seconds
Core Average LHGR	1.9183 kW/ft
F_Q	9.636
Maximum LHGR	19.99 kW/ft

REFERENCES: SECTION 15.1

15.1.3-1	Deleted by Revision No. 14
15.1.3-2	Deleted by Revision No. 14
15.1.3-3	Deleted by Revision No. 14
15.1.3-4	Deleted by Revision No. 14
15.1.3-5	Deleted by Revision No. 14
15.1.5-1	EMF-95-032(P), "Main Steamline Break Analysis for H. B. Robinson Unit 2," Siemens Power Corporation - Nuclear Division, Richland, WA, March 1995.
15.1.5-2	ANF-84-93(P)(A) and Supplement 1, "Steamline Break Methodology for PWRs," Siemens Power Corporation, Richland, WA, March 1989.
15.1.5-3	Deleted by Revision No. 13.
15.1.5-4	Deleted by Revision No. 13.
15.1.5-5	Deleted by Revision No. 13.
15.1.5-6	CP&L Nuclear Fuel Section Design Activity 87-0074.
15.1.5-7	Deleted by Revision No. 14

15.2.2 Loss of External Electrical Load

15.2.2.1 Identification of Causes and Event Description. A major load loss on the generator can result from the loss of external electrical load due to an electrical system disturbance. Offsite electrical power is available to operate the reactor coolant system pumps and other station auxiliaries. Following the loss of generator load, the turbine stop valve closes, terminating the steam flow and causing the secondary system temperature and pressure to increase. The primary-to-secondary heat transfer decreases as the secondary system temperature increases.

If the reactor is not tripped when the turbine is tripped, the primary system temperature continues to rise. The primary liquid will expand and the pressurizer steam space is compressed, causing the pressurizer pressure to rise. If this continues, the reactor will trip on high pressurizer pressure, reducing the primary heat source. As the heat load into the primary system decreases, the primary system pressurization will begin to diminish. If the setpoint for opening the primary system code safety valves is exceeded during the initial system overpressurization, these valves will open to relieve pressure and to mitigate the pressure transient. The mitigative features of the pressurizer spray, pressurizer relief valves, and the steam bypass system are assumed not to function, so as to exacerbate the overpressurization of the primary system. For the minimum DNBR case, the mitigative features of the pressurizer spray and pressurizer relief valves are assumed to function. This minimizes the pressurization of the primary system, resulting in a conservative evaluation of the MDNBR for this event. Energy is removed during the early phase of the transient through the steam generator safety valves when the steam generator pressure exceeds the safety valve opening setpoint.

The primary challenge of this transient is to the primary and secondary system overpressurization acceptance criterion (peak pressure less than 110 percent of the design value). The challenge to the specified acceptable fuel design limit is also evaluated because of the increasing core inlet temperature and the potential for the reactor core power to increase prior to reactor trip. Reactor control is assumed to be in the manual mode, so the reactor power will not be reduced when the primary system average temperature begins to increase.

This event is a moderate frequency (Condition II) event (Table 15.0.1-1). The acceptance criteria for this event are listed in Section 15.0.1.1. As cited in Table 15.0.11-1, no single failure in the ESF will affect the analysis for this event.

15.2.2.2 Analysis Method. The analysis was performed using the ANF-RELAP and XCOBRA-IIIC codes. The ANF-RELAP code (Reference 15.0-3) was used to model the salient system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). A DNBR calculation was performed to estimate the approximate time at which the DNBR was a minimum. The core fluid boundary conditions and average rod surface heat flux at this time were then used as input to the XCOBRA-IIIC code (Reference 15.0-4), which was used to evaluate the MDNBR.

15.2.2.3 Definition of Events Analyzed and Bounding Input. The purpose of analyzing this event is to demonstrate that the primary and secondary

pressure relief capability is sufficient to limit the pressures to less than 110 percent of their respective design pressure limits. This event is also analyzed to ensure that reactor protection systems are properly set to prevent penetration of the SAFDLs under the limiting assumptions of no credit for a direct reactor trip on turbine trip and the unavailability of the secondary system relief capacity of the turbine bypass system.

Two cases are analyzed for this event: one challenging the overpressurization criterion, and one challenging to the fuel design limits. In both cases, the input parameters are biased to maximize the increase in reactor power during the transient. However, in the first case, the parameters and the equipment operational states are selected to maximize the system overpressurization, and in the second case the parameters and equipment states have been selected to reduce the primary system pressurization to provide a conservative estimation of the minimum DNBR during the transient.

The bounding operating mode for this event is full power initial conditions with the reactor control system in the manual mode.

Conservative conditions are established for analysis of each subevent as follows:

	Maximum Pressurization	Minimum DNBR.
Rod Control	Manual	Manual
Initial Power	Rated +2%	Rated +2%
Moderator temperature coefficient	5.0 pcm/°F	5.0 pcm/°F
Doppler coefficient	-0.8 pcm/°F	-0.8 pcm/°F
Core inlet temperature	Nominal	Nominal
Initial RCS pressure	Nominal	Nominal
Core outlet pressure used in subchannel analysis	_____	Nom. -30 psi
Pressurizer level	Nominal	Nominal
Pressurizer spray	Disable	Available
Pressurizer PORVs	Disable	Available
Steam bypass	Disable	Disable
Steam PORVs	Disable	Disable
Safety Valve setpoints	Nom. +3%	Nom. +3%
Reactor trip on turbine trip	Disable	Disable
High pressurizer pressure trip	Available	Disable

	Maximum Pressurization	Minimum DNBR.
Overtemperature ΔT trip	Disable	Available

15.2.2.4 Analysis of Results. The maximum RCS pressurization case initiates with a turbine control valve closure. Steam line pressure increases until the safety valves open at 13.2 sec. The pressurization of the secondary side results in decreased primary to secondary heat transfer, and a substantial rise in cold leg temperature.

The average primary temperature increases about 12°F peaking at 9.1 sec. This results in a large insurge into the pressurizer, compressing the steam space and pressurizing the primary system. The reactor trips on high pressure with rods beginning to insert at 6.7 sec. The pressurizer safety valves do not open because the pressure does not reach the valve setpoint value. The increase in coolant temperature also causes the core power to rise to about 105 percent due to positive moderator feedback. The transient is terminated when the reactor scrams, decreasing temperature and hence pressure.

The minimum DNBR and maximum SG pressurization case is initiated in the same manner. Steam line pressure increases until the secondary side safety valves open at 12.9 sec. The pressurization of the secondary side results in decreased primary-to-secondary heat transfer and a substantial rise in cold leg temperature. The average primary temperature increased about 28°F, peaking at 16.0 seconds.

The rapid increase in primary side temperatures result in a large insurge into the pressurizer, compressing the steam space and pressurizing the primary system. The pressurizer compensated and uncompensated PORV's opened at 3.8 and 4.9 seconds, respectively.

Limiting the pressure rise prevents the reactor scram on high pressure. Therefore, in this case the reactor power reaches about 118 percent, scramming on overtemperature ΔT with rod insertion commencing at 13.9 sec. The DNBR challenge results from the core power and primary coolant temperature increase. The challenge is further exacerbated by the limitation on primary pressure rise.

The transient response to the maximum RCS pressurization case is shown in Figures 15.2.2-1 to 15.2.2-5. An event summary is shown in Table 15.2.2-1. The maximum reactor coolant system boundary pressure computed for this case is 2689 psia in the vessel lower head. This is below the 110 percent design allowable of 2750 psia. The response to the minimum DNBR case is given in Figures 15.2.2-6 to 15.2.2-12, with an event summary shown in Table 15.2.2-1. A minimum DNB ratio of 1.25 was calculated.

This is greater than the DNB limit of 1.154. The maximum secondary side pressure predicted is 1205 psia, at the bottom of the steam generators. This is below the 110% design allowable pressure of 1210 psia.

15.2.2.5 Conclusion. The maximum pressure is less than the acceptance limit of 110 percent of design pressure and the minimum DNBR is greater than the approved safety limit. Therefore, acceptance criteria is met.

TABLE 15.2.2-1

LOSS OF EXTERNAL LOAD EVENT SUMMARY

RCS Pressurization Case

Time	Event	Value
0.0 s	Turbine tripped	-
5.7 s	Pressurizer pressure reached high-pressure trip setpoint (see Figure 15.2.2-3)	2430 psia
6.7 s	Scram rod insertion began	-
6.7 s	Core power peaked (see Figure 15.2.2-1)	105% of rated
9.1 s	Vessel average temperature peaked (see Figure 15.2.2-2)	588°F
10.0 s	RCS pressure peaked (vessel lower head)	2689 psia
13.2 s	Steam line safety valves opened	1132 psia

Secondary Pressurization and Minimum DNBR Case

Time	Event	Value
0.0 s	Turbine tripped	-
3.8 s	Compensated pressurizer PORV opened	+96 psi error
4.9 s	Uncompensated pressurizer PORV opened (see Figure 15.2.2-9)	2346 psia
12.9 s	Steam line safety valves opened	1132 psia
13.2 s	Indicated vessel temperature rise reached OTΔT trip setpoint (see Figure 15.2.2-8)	54°F
13.9 s	Scram rod insertion began	-
13.9 s	Core power peaked (see Figure 15.2.2-6)	118% of rated
14.4 s	Minimum DNBR occurred (see Figure 15.2.2-12)	1.25
16.0 s	Vessel average temperature peaked (see Figure 15.2.2-7)	603°F
19.7 s	Secondary pressure peaked (bottom of steam generator)	1205 psia

15.2.7 Loss of Normal Feedwater Flow

15.2.7.1 Identification of Causes and Event Description. The loss of normal feedwater event could result from loss of feedwater pumps, isolation of the feedwater regulating valves, or loss of offsite AC power. This results in reduction of heat removal capacity from the reactor system. An alternative supply of feedwater from the condensate storage tank is available with the steam-driven auxiliary or diesel engine generator motor-driven auxiliary feedwater pumps. This supply assures long-term and orderly recovery of the unit. The initial inventory in the steam generators assures a short-term controllable response.

The reactor trips early, due to either high pressurizer pressure or the steam generator low-low level reactor trip. Sufficient heat rejection capacity remains at this steam generator water level to avoid approach to DNB. The DNB aspects of the event are bounded by those of the loss of flow event, since the trip is delayed in the loss of flow event until loop flow coasts down to the low flow trip setpoint with consequent lower primary flow.

The objective of this analysis is to demonstrate the adequacy of relief capacity and setpoint of the steam generator safety valves, auxiliary feedwater capacity, and steam generator inventory to maintain primary system pressure below the 110 percent pressure vessel design rating and to avoid the expelling of liquid from the primary pressurizer safety valves. The latter assures long-term cooling capability to a safe shutdown condition and precludes pressure surge related to packing.

This event is classified as a Condition II event (Table 15.0.1-1). The acceptance criteria are as described in Section 15.0.1.1. As noted in Tables 15.0.8-1 and 15.0.11-1, minimum Auxiliary Feedwater flow is used as a conservative basis for the analysis; one motor driven pump delivering flow to two steam generators. The event is analyzed with and without primary coolant pump coastdown in order to bound results of all causative events.

15.2.7.2 Analysis Method. The analysis was performed using the ANF-RELAP thermal-hydraulic code (Reference 15.0-3) to simulate the system response. The ANF-RELAP code includes relevant aspects of the primary and secondary systems. Minimum auxiliary feedwater flow was used as a conservative basis for the analysis: one motor-driven pump delivering flow to two steam generators. The event was analyzed with and without offsite power available. The following assumptions were made:

1. The main feedwater valves are ramped closed at the initiation of the event.

2. The reactor trips on high pressurizer pressure or steam generator low-low level.

3. Depending on the case to be analyzed, all reactor coolant pumps may be tripped at the time of reactor trip and coast down.

4. The starting sequence for the auxiliary feedwater pump diesel generators (which includes a time delay) is initiated when the ESF steam generator low-low level signal is issued.

15.2.7.3 Definition of Events Analyzed and Bounding Input.

Two cases were analyzed:

1. Reactor coolant pumps trip at reactor scram (loss of offsite power).

2. Reactor coolant pumps operate throughout transient (offsite power available).

These cases bound all operational modes for this event. Conservative conditions were used:

Initial power	102% of rated
Moderator temperature coefficient	+5.0 pcm/°F
Doppler coefficient	-0.8 pcm/°F
Condensate storage tank temperature	Maximum [115°F]
Steam-driven auxiliary feedwater pump	Disabled
Diesel generator-driven auxiliary feedwater pump	One available[a]

[a] Delivering a total of 240 gpm to two steam generators.

15.2.7.4 Analysis of Results. The event was initiated by shutting off the main feedwater flow to all steam generators, using a conservatively short 1.0 second rampdown. Steam generator pressures rose slowly due to the cessation of feedwater flow. This resulted in a reduction of reactor system heat removal, which caused a primary temperature rise and an increase in reactor power, as well as pressurizer level and pressure. The pressurizer pressure reached the high-pressure trip setpoint of 2430 psia at 40.0 seconds. The reactor scrammed at 41.0 seconds. The turbine tripped at reactor scram, which caused a rapid increase in the secondary pressure, primary pressure, pressurizer level, and primary coolant temperature. The steam generator level reached the low-low setpoint at 41.9 seconds. Auxiliary feedwater flow began 67 seconds after the steam generator low-low level setpoint was reached, delivering a total of 240 gpm to two steam generators.

For the PUMPS OFF case (see Figures 15.2.7-1 through 15.2.7-7 and Table 15.2.7-1), the reactor coolant pumps were tripped and began to coast down at reactor scram (41.0 seconds). The maximum vessel average coolant temperature was calculated to be 584°F (at 43.5 seconds), and the maximum primary coolant system pressure (at the bottom of the reactor vessel) was calculated to be 2543 psia (at 44.0 seconds). The maximum pressurizer level was calculated to be 59.0% of span (at 44.5 seconds). The maximum secondary

TABLE 15.2.7-1

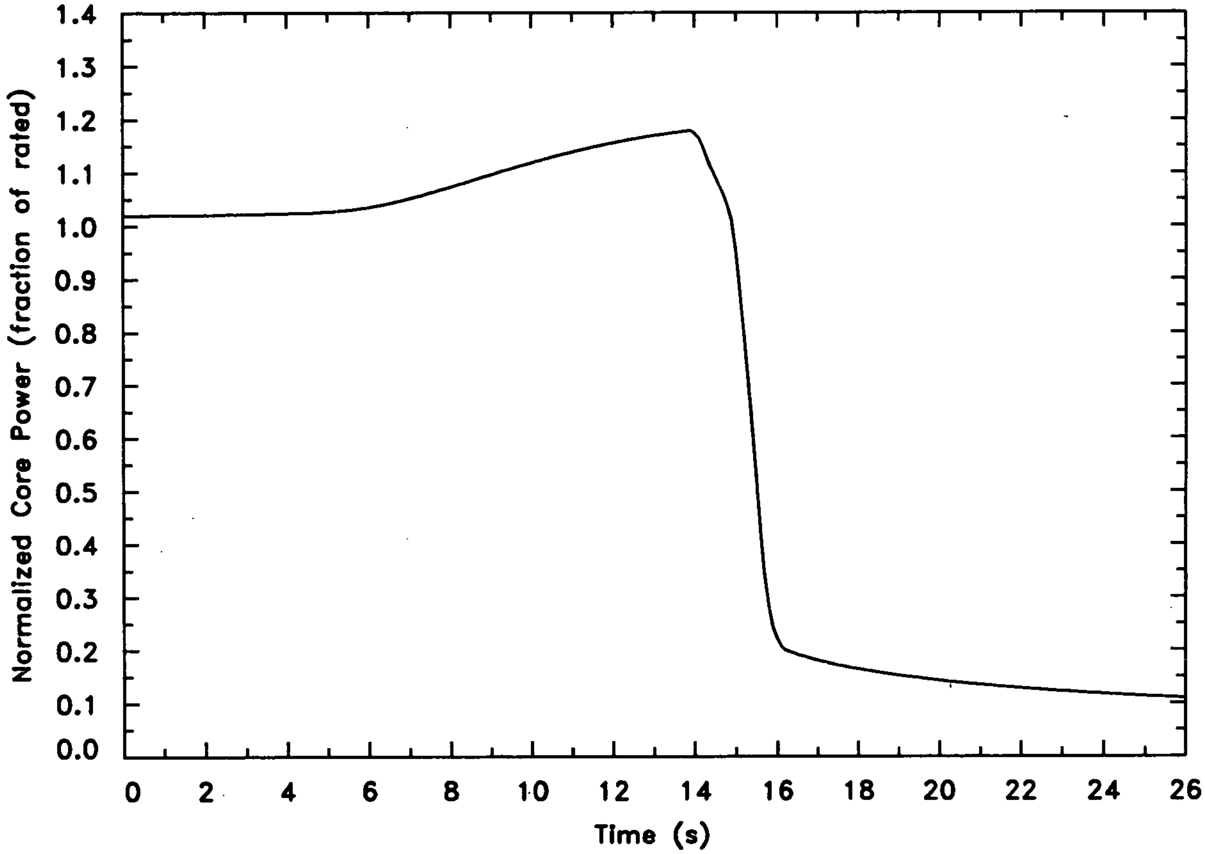
LOSS OF NORMAL FEEDWATER
EVENT SUMMARY FOR PUMPS OFF CASE

Time	Event	Value
0.0 s	Main feedwater flow was shut off	-
40.0 s	Pressurizer pressure reached high-pressure trip setpoint (see Figure 15.2.7-4)	2430 psia
41.0 s	Scram rod insertion began	-
41.0 s	Reactor coolant pumps were tripped	-
41.9 s	Steam generator level reached low-low level ESF setpoint	0.0% of span
44.0 s	Primary pressure peaked (vessel lower head)	2543 psia
44.5 s	Pressurizer liquid level peaked	59.0% of span
61.0 s	Secondary pressure peaked (bottom of steam generators)	1180 psia
108.9 s	Auxiliary feedwater began feeding steam generators C and A	-
672.0 s	Liquid inventory of steam generators C and A reached minimum (see Figure 15.2.7-7)	32,348 lb (SG C)
1690.0 s	Steam generator B dried out	-

TABLE 15.2.7-2

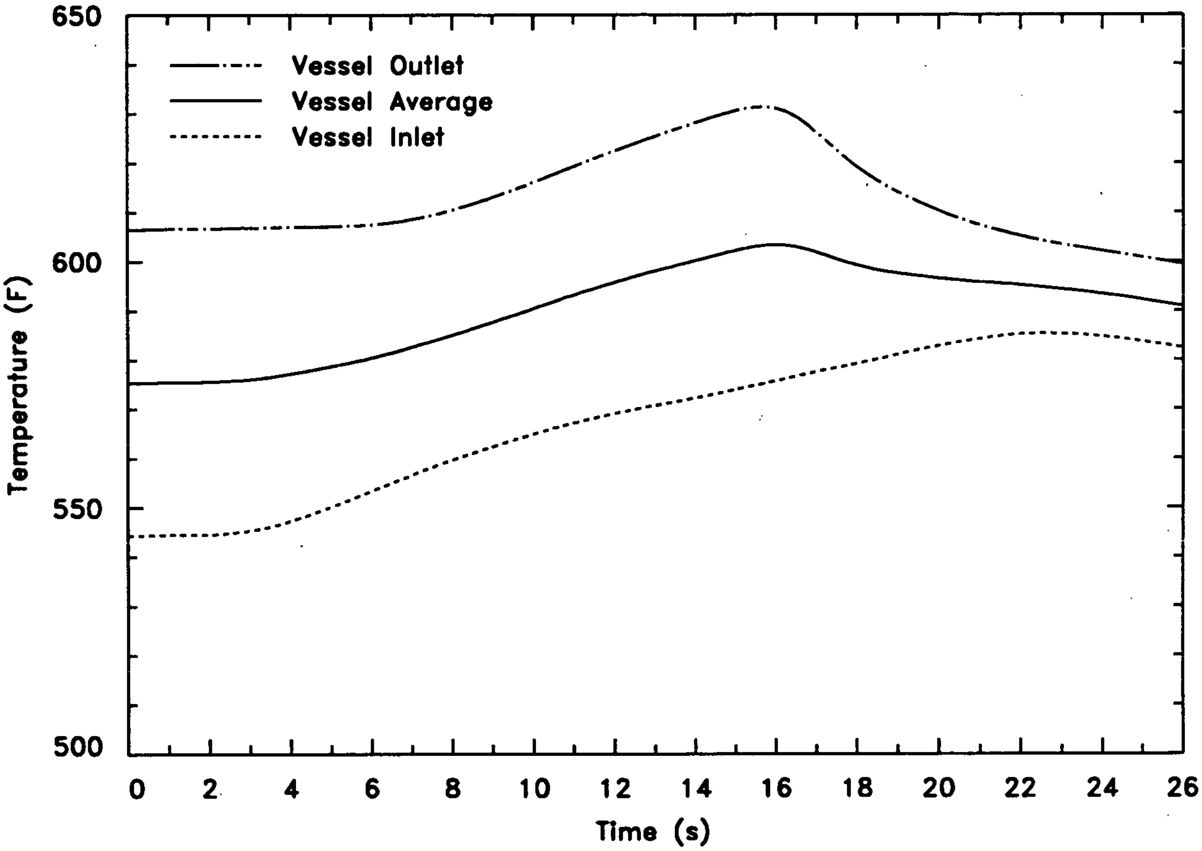
LOSS OF NORMAL FEEDWATER
EVENT SUMMARY FOR PUMPS ON CASE

Time	Event	Value
0.0 s	Main feedwater flow was shut off	-
40.0 s	Pressurizer pressure reached high-pressure trip setpoint (see Figure 15.2.7-11)	2430 psia
41.0 s	Scram rod insertion began	-
41.9 s	Steam generator level reached low-low level ESF setpoint	0.0% of span
42.5 s	Primary pressure peaked (vessel lower head)	2535 psia
43.5 s	Pressurizer liquid level peaked	58.6% of span
61.5 s	Secondary pressure peaked (bottom of steam generators)	1185 psia
108.9 s	Auxiliary feedwater began feeding steam generators C and A	-
1825.0 s	Steam generator B dried out	-
4325.0 s	Liquid inventory of steam generators C and A reached minimum (see Figure 15.2.7-14)	13,251 lb (SG C or SG A)



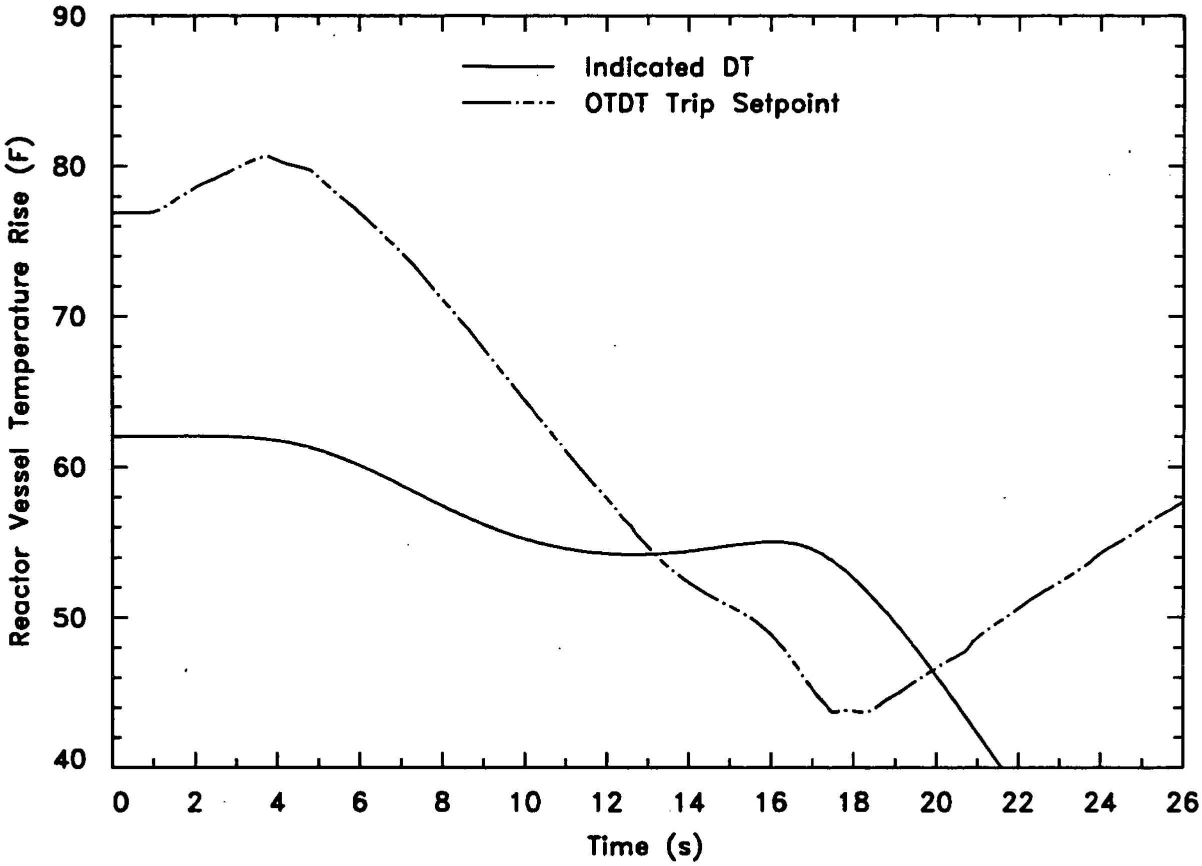
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Core Power	FIGURE 15.2.2-6



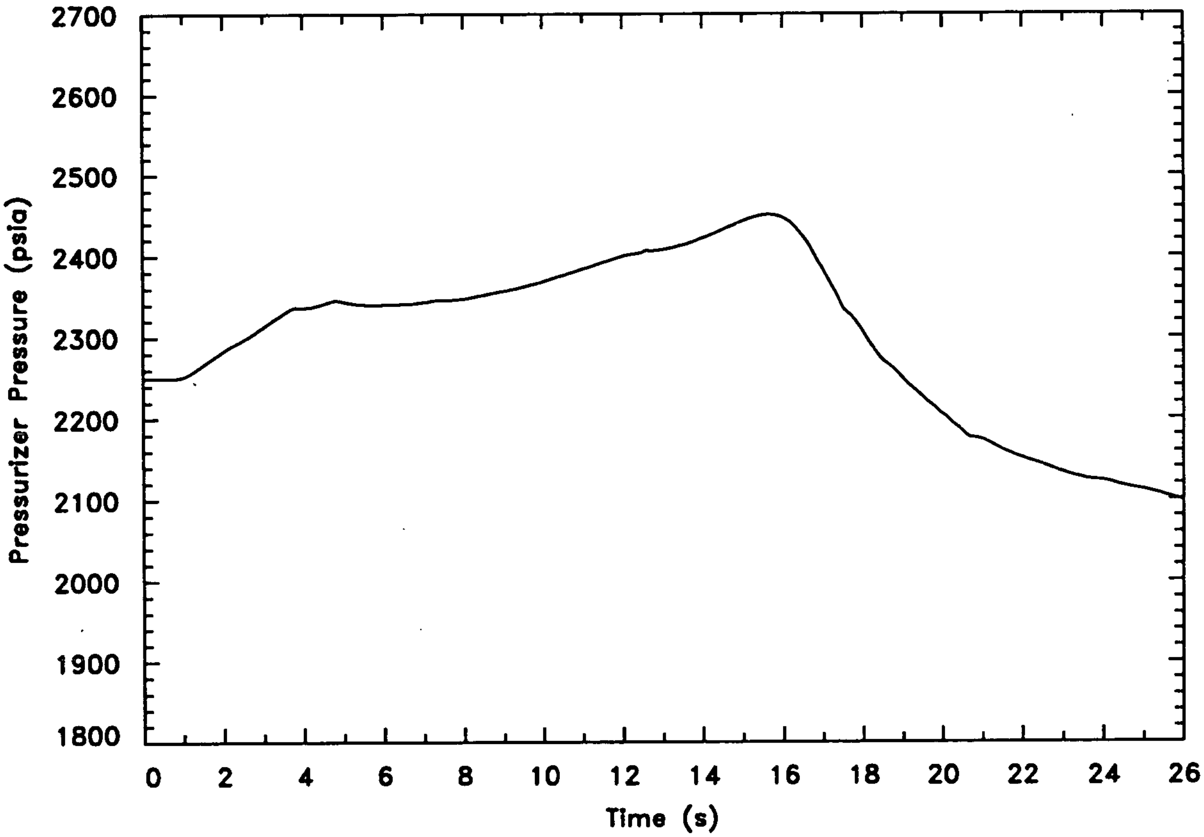
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Reactor Coolant Temperatures	FIGURE 15.2.2-7



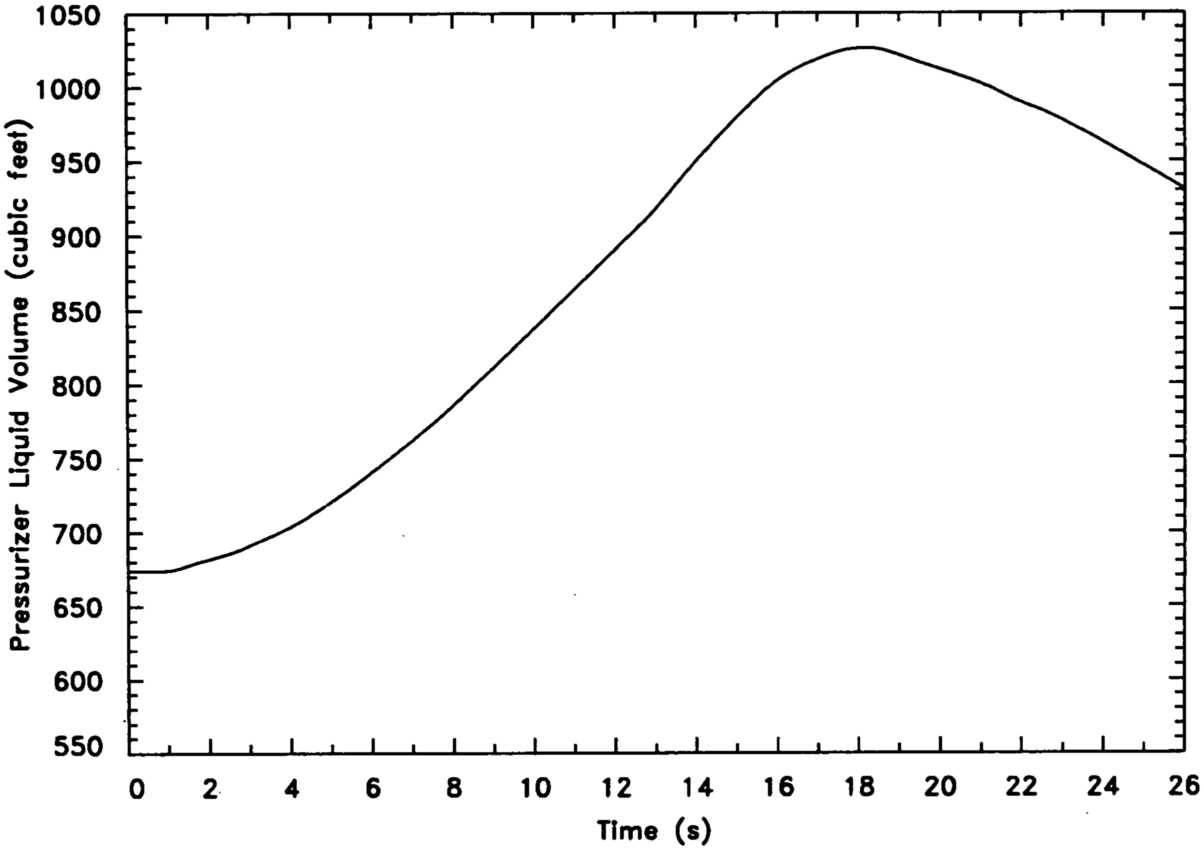
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Reactor Vessel Temperature Rise and OTΔT Setpoint	FIGURE 15.2.2-8



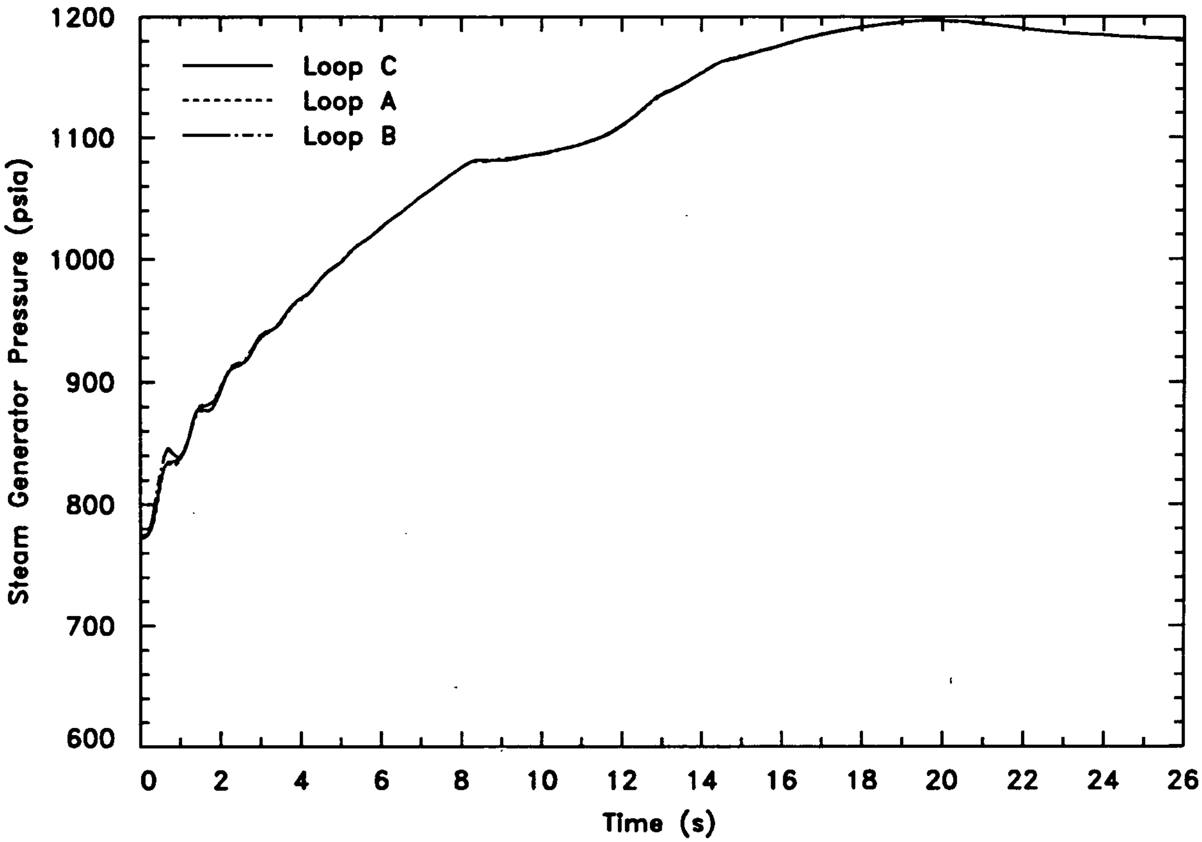
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Pressurizer Pressure	FIGURE 15.2.2-9



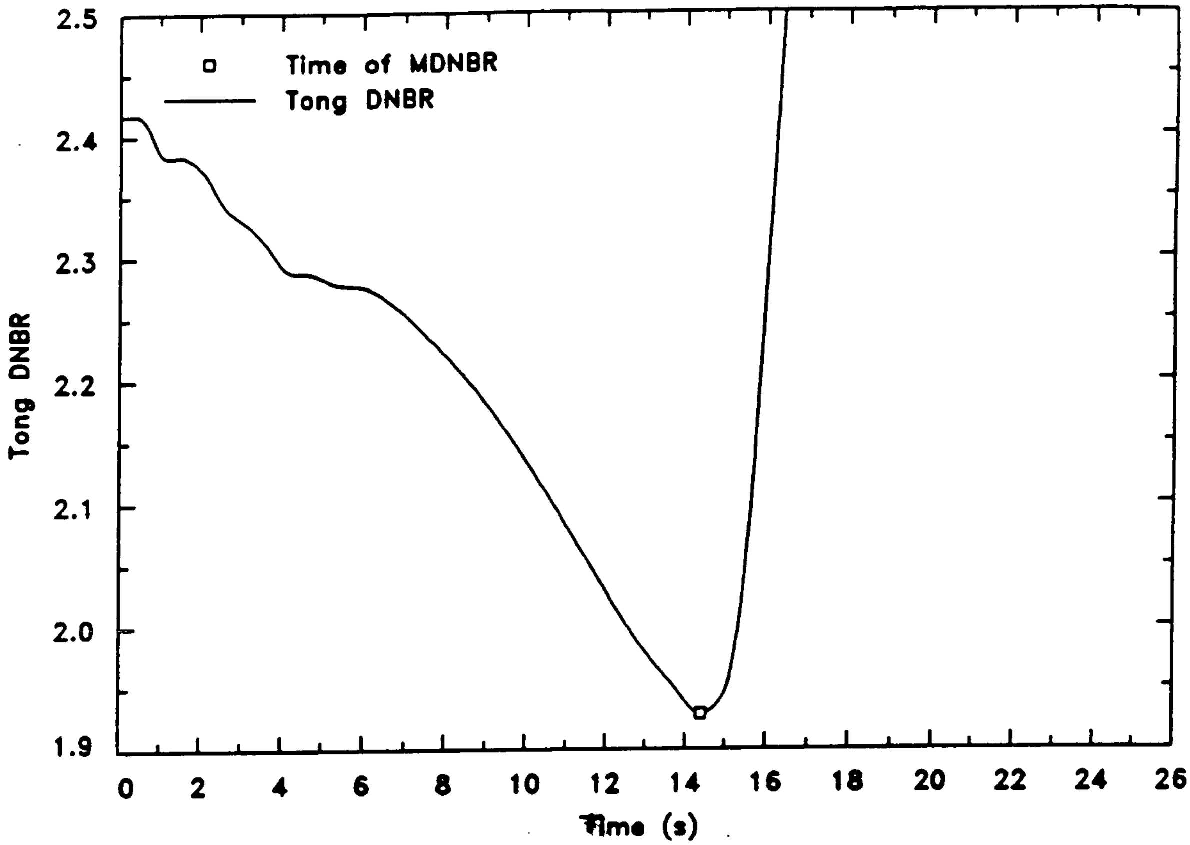
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Pressurizer Liquid Volume	FIGURE 15.2.2-10



REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Loss of External Load, Secondary Pressurization and MDNBR Case: Steam Generator Pressures	FIGURE 15.2.2-11



Note: Tong DNBR value is a RELAP calculated core-wide DNBR trend used to estimate approximate time of minimum DNBR to establish core parameters for input into the XCOBRA IIIC code to evaluate MDNBR.

REVISION NO. 14

H. B. ROBINSON UNIT NO. 2 Carolina Power & Light Company **UPDATED FINAL SAFETY ANALYSIS REPORT**	Loss of External Load, Secondary Pressurization and MDNBR Case: DNBR	FIGURE 15.2.2-12

15.3.1.4 Analysis of Results. The transient is initiated by tripping all three primary coolant pumps. As the pumps coast down, the core flow is reduced, causing a reactor scram with rod insertion beginning at 2.7 sec.

As the flow coasts down, primary temperatures increase. The average core temperature increases about 7°F before being turned around due to the power decrease following reactor scram. This increase in temperature causes subsequent power rise due to moderator reactivity feedback as a result of the coefficient. The power peaks at about 107 percent of rated.

The temperature increase also causes an insurge into the pressurizer and resultant pressurization of the reactor coolant system. The pressurizer PORVs are allowed to open to minimize pressure and maximize the DNB challenge. This occurs at 4.6 sec and prevented the pressure from exceeding 2338 psia. This peak pressure occurred at 4.7 seconds. The pressure then decreased as the core power level continued to drop. The principal DNB challenge was caused by the decrease in flowrate and resultant increase in coolant temperatures.

The transient response is shown in Figure 15.3.1-1 through 15.3.1-6. An event summary is given in Table 15.3.1-1. The minimum DNBR was calculated to be 1.42.

15.3.1.5 Conclusion. Experience has shown that this event is not the most severe challenge to the maximum pressure criterion. Substantial margin to Departure from Nucleate Boiling is calculated. Therefore, event acceptance criteria are met.

TABLE 15.3.1-1

LOSS OF FORCED COOLANT FLOW EVENT SUMMARY

Time	Event	Value
0.0 s	Three-pump coastdown was initiated	-
1.7 s	Primary loop flowrate reached low-flow trip setpoint	87% of TS min.
2.7 s	Scram rod insertion began	-
2.7 s	Core power peaked (see Figure 15.3.1-1)	107% of rated
3.7 s	Minimum DNBR occurred (see Figure 15.3.1-6)	1.42
4.6 s	Compensated pressurizer PORV opened	+96 psi error
4.7 s	Pressurizer pressure peaked (see Figure 15.3.1-4)	2338 psia
5.0 s	Average vessel coolant temperature peaked (see Figure 15.3.1-2)	582°F

15.3.2 Reactor Coolant Pump Shaft Seizure (Locked Rotor)

15.3.2.1 Identification of Causes and Event Description. This event is caused by an instantaneous seizure of a primary reactor coolant pump rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal.

Following reactor trip, the heat stored in the fuel rods continues to be transfered to the reactor coolant. Because of the reduced core flow, the coolant temperatures will begin to rise. This will cause the coolant to expand and force fluid in to the pressurizer. The insurging fluid will compress the pressurizer steam space causing the pressurizer pressure to rise rapidly. Simultaneously, the reduced primary coolant flow rate will cause a reduction in the primary to secondary heat transfer which will cause the primary side steam generator outlet temperature to increase. The reduction in primary to secondary heat transfer will be further degraded as the steam generator pressures and temperatures increase following termination of steam flow on turbine trip. This overall reduction in primary to secondary heat transfer will further increase the rise in primary system temperatures and pressures. As the primary system pressure increases, the pressurizer spray and power operated relief valves would actuate to mitigate the overpressurization transient. For conservatism in evaluating the overpressurization challenge of the event, no credit is taken for the pressure relief capacity of these components. The pressurizer code safety valves will lift to relieve the primary system pressure. Eventually the primary system pressure will decrease due to the reduced core power following reactor trip.

On the secondary side, the rise in shell side steam generator pressure would normally be controlled by the operation of the steam bypass system or steam generator PORVs following closure of the turbine stop valves. However, no credit is taken for these two systems; the mechanism for removing energy from the steam generator following closure of the turbine stop valves is through the steam generator code safety valves. Energy removal through these valves will help to mitigate the primary pressure transient.

The rapid rise in primary system temperatures during the initial phase of the transient results in a reduction in the initial DNB margin. This event causes a challenge to both the specified acceptable fuel design limits and system overpressurization. The system pressurization is less severe than the Loss of External Load event presented in Section 15.2.2, so only the DNB case is presented.

This event is a Condition IV (Limiting Fault) event (Table 15.0.1-1). The acceptance criteria for this event is presented in Section 15.0.1.1. This event represents the bounding decrease in reactor coolant flow rate event for the Condition IV events. As cited in Table 15.0.11-1, no single failure in the ESF affects the analysis for this event. However, it was conservatively assumed that a loss of offsite power trips the pumps in the two unaffected loops at the time of shaft seizure.

15.3.2.2 Analysis Method. The transient response of the primary and secondary systems is calculated using the ANF-RELAP computer code (Reference 15.0-3). The MDNBR is calculated using the ANF-RELAP conditions at time of MDNBR as input to the XCOBRA-IIIC methodology (Reference 15.0-4).

15.3.2.3 Definition of Events Analyzed and Bounding Input. The bounding operating mode for this event is full power. Conservative conditions were used:

Rod Control	Manual
Initial Power	102% of rated
Pump flywheel inertia	90% of rated
Moderator temperature coefficient	+5.0 pcm/°F
Doppler coefficient	-1.0 pcm/°F
Core inlet temperature	Nominal
Initial RCS pressure	Nominal
Core outlet pressure used in subchannel analysis	Nominal -30 psi
Pressurizer level	Nominal
Pressurizer heater	Disable
Pressurizer PORVs	Available
Reactor trip setpoint	Low flow -3%

15.3.2.4 Analysis of Results. The pump in one loop seizes at initiation and the flow in the loop is abruptly reduced. This generates a low flow scram signal which results in rod insertion beginning at 1.08 sec. The flows in the other two loops decreased slowly, as the unaffected pumps began coasting down (following the loss of offsite power at initiation). The relatively high flows in the unaffected loops maintained a substantial reactor vessel inlet-to-outlet pressure drop, which caused the flow in the affected loop to reverse at about 1.65 seconds. By 2.00 seconds, the core flowrate was about 60% of nominal. The flow reduction caused the core average coolant temperature to rise, which resulted in a power increase to about 107% of rated power (due to positive moderator feedback). The increasing temperatures and decreasing flowrate resulted in MDNBR occurring shortly after scram, at 2.25 seconds. The reactor pressures and temperatures were eventually reduced by heat transfer to the steam generators (mostly to the two unaffected-loop steam generators).

The transient response is shown in Figures 15.3.2-1 to 15.3.2-6. An event summary is given in Table 15.3.2-1.

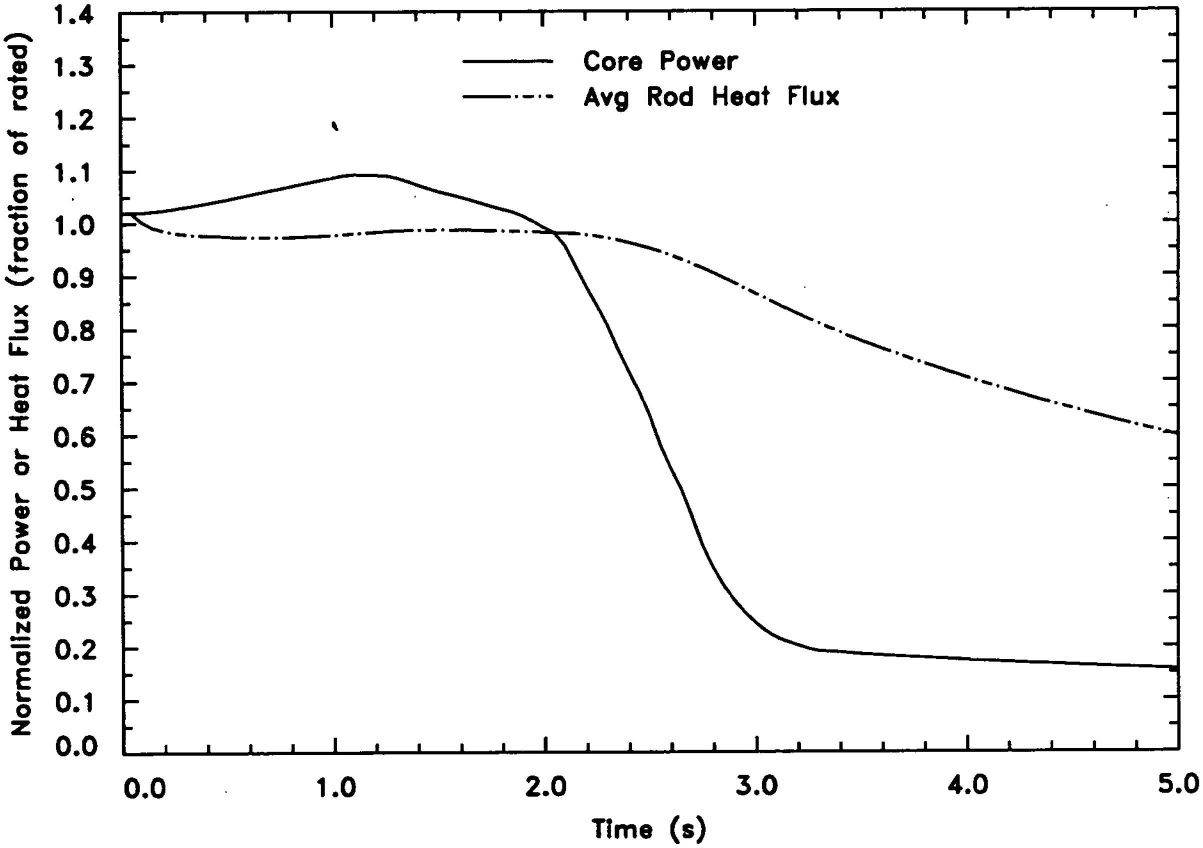
The minimum DNBR for this transient is calculated to be 0.90, below the safety limit. Less than full core was calculated to experience Departure from Nucleate Boiling. The radiological consequences evaluation (Reference 15.3.2-1) for the Design Basis LOCA event assumed all fuel assemblies in the core failed. Acceptable results were obtained for the LOCA, i.e., less than 10 percent of the 10 CFR 100 limits. Both events are a Condition IV event. Using the conservative assumption that DNBR causes fuel failure, less than full core exhibited DNB and integrity of the primary is maintained; therefore, the radiological results of the Locked Rotor event are bounded by those of the LOCA event.

15.3.2.5 Conclusion. Only a small fraction of the core was calculated to experience DNB. The radiological consequences are bounded by those of 15.6.5 and are a small fraction of the 10 CFR 100 requirements. Therefore, results of the analysis are acceptable.

TABLE 15.3.2-1

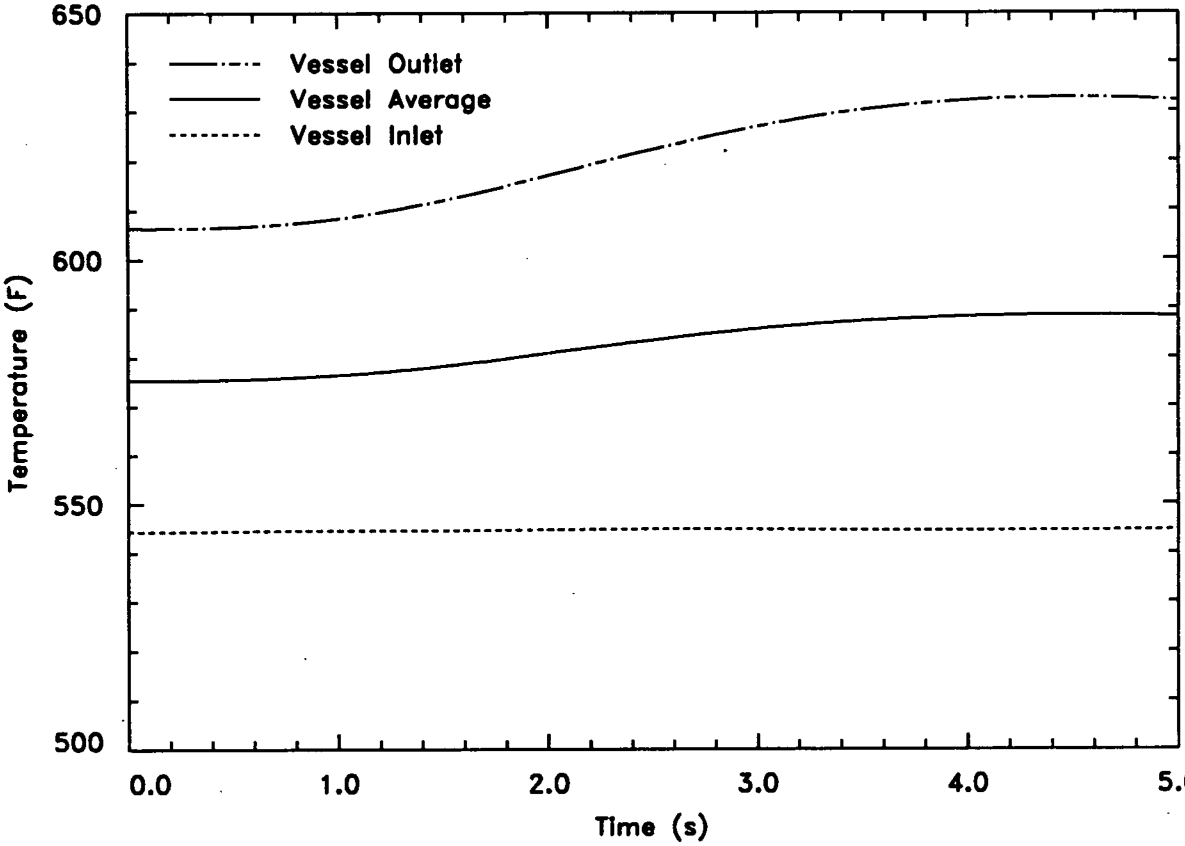
COOLANT PUMP SHAFT SEIZURE EVENT SUMMARY

Time	Event	Value
0.00 s	Single primary coolant pump seized	-
0.00 s	Other primary coolant pumps were tripped	-
0.05 s	Affected-loop flow reached low-flow trip setpoint	87% of TS min.
1.08 s	Scram rod insertion began	-
1.10 s	Core power peaked (see Figure 15.3.2-1)	107% of rated
1.65 s	Affected-loop flow reversed	-
2.25 s	Minimum DNBR occurred (see Figure 15.3.2-6)	0.90



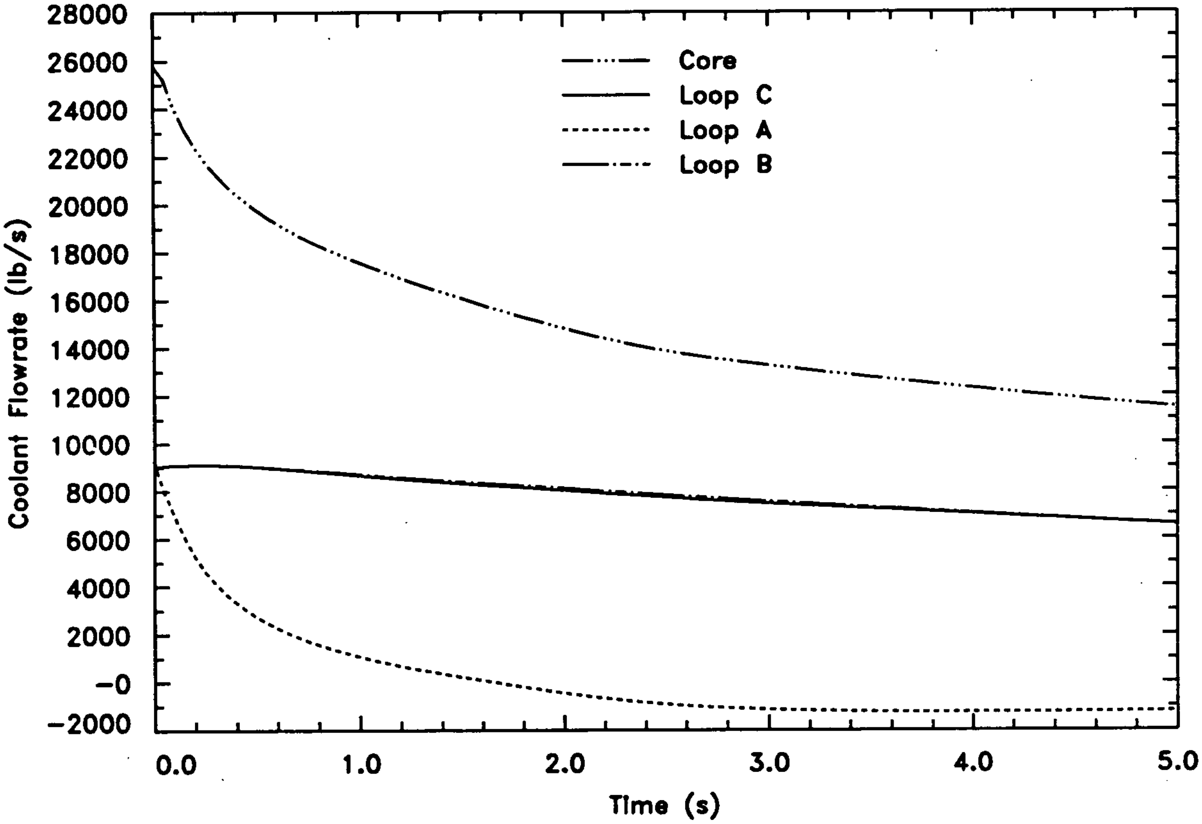
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Coolant Pump Shaft Seizure: Core Power and Average Rod Heat Flux	FIGURE 15.3.2-1



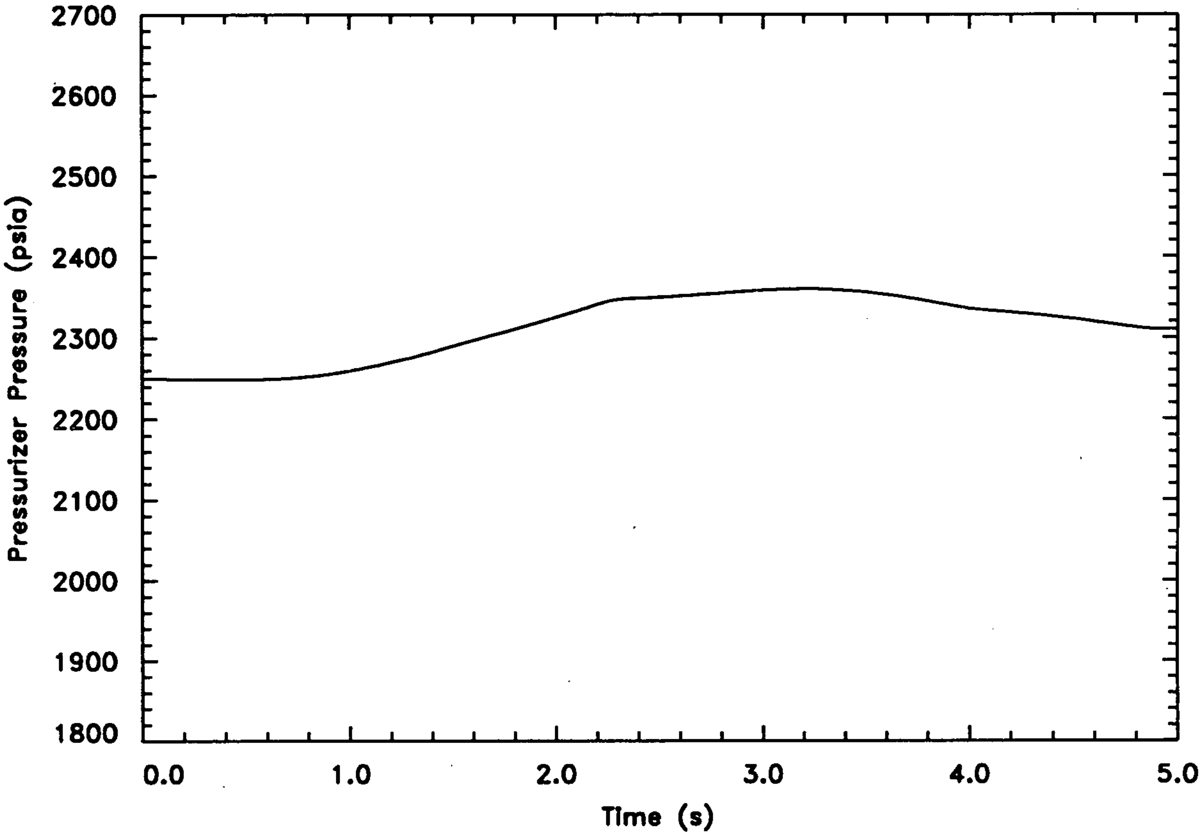
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Coolant Pump Shaft Seizure: Reactor Coolant Temperatures	FIGURE 15.3.2-2



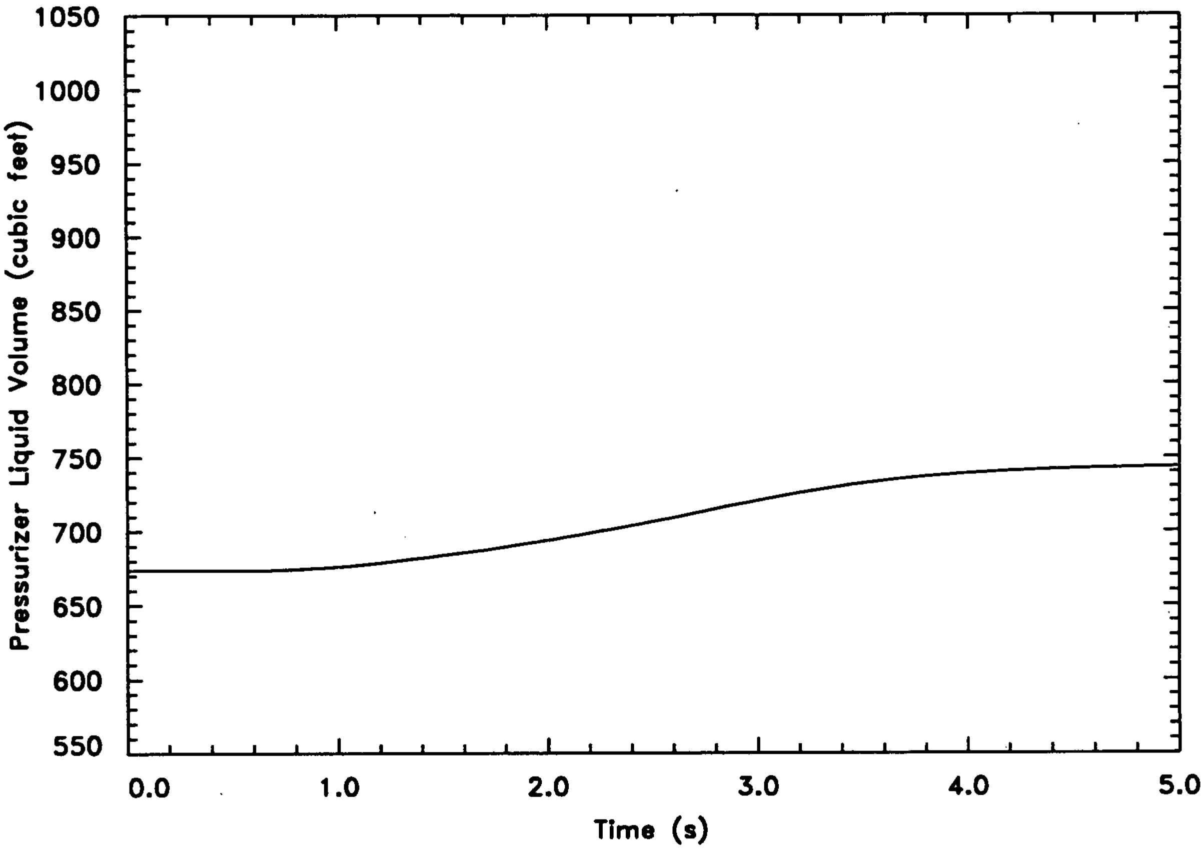
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Coolant Pump Shaft Seizure: Core and Primary Loop Coolant Flowrates	FIGURE 15.3.2-3



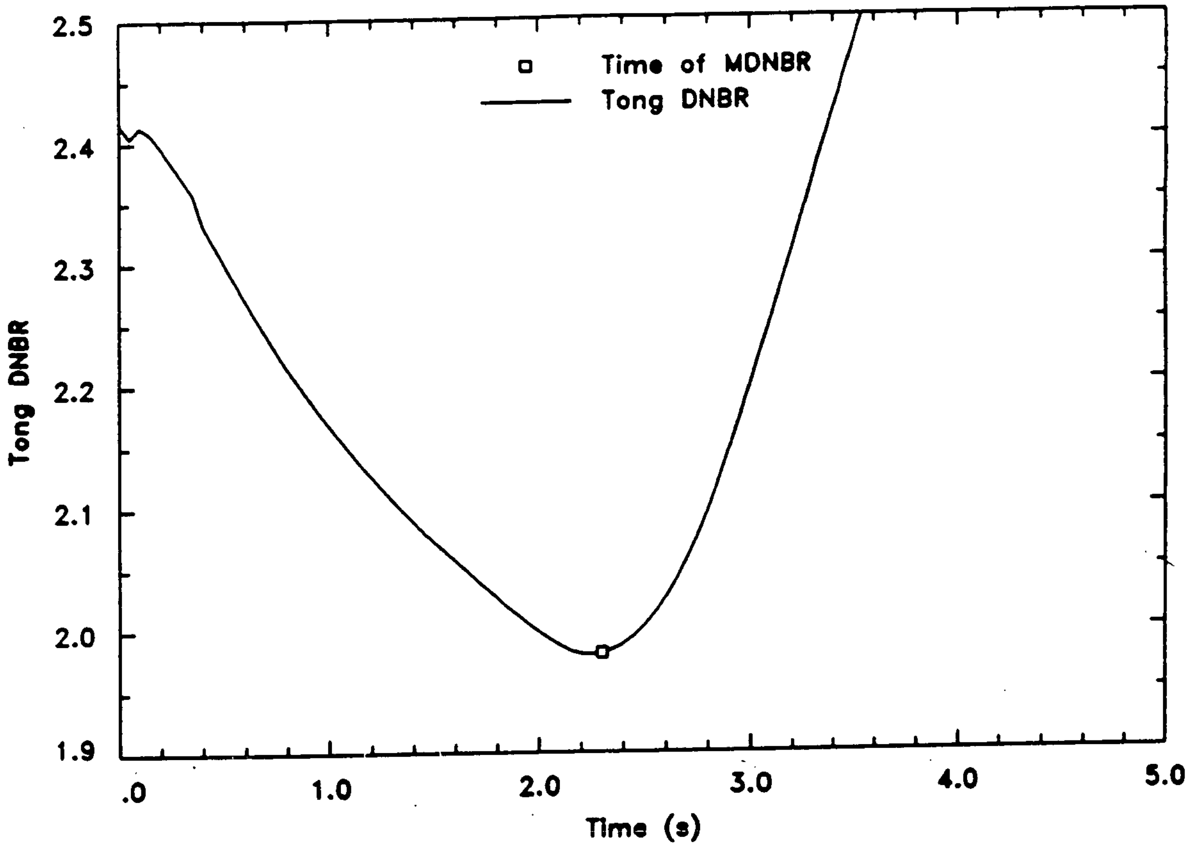
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Coolant Pump Shaft Seizure: Pressurizer Pressure	FIGURE 15.3.2-4



REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Coolant Pump Shaft Seizure: Pressurizer Liquid Volume	FIGURE 15.3.2-5



Note: Tong DNBR value is a RELAP calculated core-wide DNBR trend used to estimate approximate time of minimum DNBR to establish core parameters for input into the XCOBRA IIIC code to evaluate MDNBR.

REVISION NO. 14

H. B. ROBINSON **UNIT NO. 2** Carolina Power & Light Company **UPDATED FINAL** **SAFETY ANALYSIS REPORT**	Coolant Pump Shaft Seizure: DNBR	FIGURE 15.3.2-6

15.4 Reactivity and Power Distribution Anomalies

15.4.1 Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From Subcritical or Low Power

15.4.1.1 Identification of Causes and Event Description. This event is defined to result from an uncontrolled control rod bank withdrawal from subcritical or low power. The event could be caused by a control system malfunction. The malfunction could result in a rapid and large reactivity insertion, which is terminated by the low range setting of the power range flux trip. The maximum insertion rate is determined from the bounding worth of rod banks which are wired in common together with a bounding control rod withdrawal rate.

The reactivity insertion rate is rapid enough that very high neutron powers are calculated, but of short enough duration that excessive energy deposition does not occur. Rod surface heat flux approaches a significant fraction of full power. As the event can be very rapid, primary coolant temperature lags behind power. The reactivity insertion rate is initially countered by the fuel Doppler followed by trip and rod insertion.

There are four safety mechanisms which limit this event. These are:

1. Source range flux trip
2. Intermediate range flux trip
3. Intermediate range rod stop
4. Power range trip (low setting)

The source and intermediate range trips are bypassed when permissives are reached before reaching the respective trip setpoints. The power range (low setting) trip is set at 25% of rated power.

Initial power levels ranging up to 2% of rated power were considered for this event. Higher initial powers ranging to rated power are analyzed in Section 15.4.2.

The objective of this analysis is to bound plant operational modes below approximately 2 percent rated power to where the operational state (shutdown margin greater than or equal to 1.77% at end of cycle, 1% at beginning of cycle) precludes return to power in an anticipated operational occurrence. The analysis examined the possible operational modes and state conditions between these two limits to develop a bounding case.

The event is classified as a Condition II event (Table 15.0.1-1). The acceptance criteria is as described in Table 15.0.1-1 with the addition of fuel centerline melt criterion. For this analysis, the systems challenged in this event are redundant; no single active failure will adversely affect the consequences of the event.

15.4.1.2 Analysis Method. The analysis is performed using the ANF-RELAP code and XCOBRA-IIIC. The ANF-RELAP code models the salient system components and calculates neutron power, fuel thermal response, surface heat transport and fluid conditions, including coolant flow rate, temperature and

primary pressure. An approximate DNB calculation is performed to identify the time and parametrically the fluid conditions for which DNBR is minimum. The fluid boundary conditions and rod surface heat flux at the time of MDNBR are then transposed to the XCOBRA-IIIC methodology (Reference 15.0-4).

15.4.1.3 <u>Definition of Events Analyzed and Bounding Input</u>. One case was analyzed. The case input and initial conditions bound hot shutdown and startup modes. The lowest initial power yields the maximum margin to trip, and hence maximum time for withdrawal to trip. This yields the largest prompt multiplication which maximizes overshoot past trip. The initial power conservatively bounds the initial power possible in hot shutdown and startup operation. Maximum coolant temperature for the mode of operation minimizes DNBR and is, therefore, appropriate. The bias selection for the pellet to cladding heat transfer coefficient minimizes Doppler feedback.

Maximization of power peaking and minimization of core flow rate reduce DNBR. The use of two primary coolant pumps appropriately represents the operational mode and results will bound those with 3 pump operation.

Consistent beginning of cycle parameters are used as this minimizes Doppler and provides maximum positive moderator coefficient which provides positive feedback for an increasing coolant temperature.

Conservative conditions are established for the analysis:

Initial Power	10^{-9} rated
Primary Coolant Pumps Operating	2
Reactivity Insertion Rate	> Max. worth and rate banks wired in common
Radial Power Distribution	Hot Zero Power
Moderator Temp. Coefficient	+5.0 pcm/°F
Doppler	-0.8 pcm/°F
Pellet to Clad HTC	Maximum core-average BOC value

15.4.1.4 <u>Analysis of Results</u>. The event is initiated with control bank withdrawal. At approximately 15.7 sec reactor power reached 1% of rated. The peak nuclear power of 292% of rated is reached at 16.3 seconds. The rapid power increase results in a fuel temperature increase which produces negative Doppler reactivity which first reduces power. The trip signal occurs at 16.0 sec on the high flux (low setting) trip with rod insertion beginning at 16.5 seconds. A peak core-average surface heat flux equivalent to 82 percent of rated power occurs at 17.8 seconds. This results in a maximum LHGR less than that for fuel centerline melt. The minimum DNB ratio calculated for this event was 1.19. A summary of sequence of events is presented in Table 15.4.1-1. Neutron power, rod surface heat flux and fuel rod temperature as a function of time are presented in Figures 15.4.1-2 and 15.4.1-3.

15.4.1.5 <u>Conclusions</u>. The analysis demonstrated that the SAFDLs are not penetrated and, therefore, event acceptance criteria is met.

TABLE 15.4.1-1

BANK WITHDRAWAL FROM SUBCRITICAL EVENT SUMMARY

TIME	EVENT	VALUE
0.0 s	Bank withdrawal began	-
16.0 s	Core power reached high-flux trip setpoint (see Figure 15.4.1-2)	35% of rated
16.3 s	Core power peaked (see Figure 15.4.1-2)	292% of rated
16.5 s	Scram rod insertion began	-
17.8 s	Core-average rod surface heat flux peaked (see Figure 15.4.1-2)	82% of rated
17.8 s	Minimum DNBR occurred (see Figure 15.4.1-4)	1.19
18.0 s	Core-average fuel temperature peaked (see Figure 15.4.1-3)	1078°F
18.2 s	Hot rod centerline temperature peaked	3780°F
20.0 s	Average vessel coolant temperature peaked (see Figure 15.4.1-3)	574°F

15.4.2 Uncontrolled Control Rod Assembly Bank Withdrawal at Power

15.4.2.1 Identification of Causes and Event Description. This event is defined to result from an uncontrolled control bank withdrawal at power. The power range to be considered is from 2 percent rated power to rated power. The event could be caused by misoperation of the most reactive control rod banks wired in common withdrawing at up to the maximum rate.

The reactor protection trip system is designed and set to preclude penetration of the SAFDLs. Because of the design of this analysis, the overtemperature ΔT and power range (high setting) high flux trips are principally challenged. Both trip setpoints include allowance for process variable measurement, processing channel drift, and operating variances from that indicated.

The overtemperature ΔT function is designed and set to protect against DNB. Principal DNB parameters such as power (measured as core coolant temperature rise), core coolant temperature, primary pressure and core power distribution are measured, and the function decreases margin to trip setpoint when process variables indicate a decrease in operating margin. This function is established based on the core protection boundaries, operation within which assures protection of the SAFDLs.

For the maximum possible reactivity insertion rates, the core temperature rise lags behind nuclear power. The power range reactor trip protects the system from these events.

A broad range of reactivity insertion rates and initial operating conditions are possible. The range of reactivity insertion is from very slow, as would be associated with a gradual boron dilution, and bounded on the fast end of the range by bank withdrawal.

The objective of the analysis is to demonstrate the adequacy of the trip setpoints to assure meeting the acceptance criteria. To assure this objective, the analysis is performed for a spectrum of reactivity insertion rates and initial powers. Since neutronic feedback is a function of cycle exposure and design, these effects are also included in the analysis.

Each transient in the spectrum of cases analyzed is characterized by the following sequence of events:

1. Reactivity is inserted.
2. Core power ascends.
3. Clad heat flux increases, lagging behind the core power ascent.
4. Primary coolant temperatures increase.
5. The reactor trips on core temperature rise or high neutron flux.

This event is classified as a Condition II event (Table 15.0.1-1).

The acceptance criteria are as described in Section 15.0.1.1 with the added condition of fuel centerline melt criteria. The systems challenged in this event are redundant and no single active failure will adversely affect the consequences of the event.

Maximum RCS pressure is bounded by Loss of External Load in Section 15.2.2 because the secondary system is isolated.

15.4.2.2 Analysis Method. The analysis is performed using the ANF-RELAP code and XCOBRA-IIIC. The ANF-RELAP code models the salient system components and calculates neutron power, fuel thermal response, and fluid conditions. The fluid conditions and rod surface heat transport at the time of MDNBR are transposed to be XCOBRA-IIIC methodology (Reference 15.0-4) for calculation of the MDNBR.

Systems which minimize DNBR are enabled in the analysis. These include (e.g.) pressurizer spray and PORVs.

15.4.2.3 Definition of Events Analyzed and Bounding Input. The analysis bounds power operation. Two case series are analyzed: one for negative and the other for positive neutronic feedback.

Case Series	Initial Power	Reactivity Rate	Neutronics
1	102% of rated	Low to high	Neg. Feedback
	60% Rated	Low to high	Neg. Feedback
2	102% of rated	Low to high	Pos. Feedback
	60% Rated	Low to high	Pos. Feedback

Conservative conditions are established for analysis of each subevent.

Control	Manual
Core power	Nom. +2% Rated
Core coolant inlet temperature	Nominal
Initial RCS pressure	Nominal
Core outlet pressure used in subchannel analysis	Nom. -30 psi
Pressurizer spray	Available
Reactor coolant system flow rate	Minimum allowed by Technical Specifications
Pressurizer PORVs	Available
Pressurizer level	Nominal
Steam bypass	Disable
Steamline PORVs	Disable

Reactor Trips	OT-ΔT Power Range high flux (high) OP-ΔT-Disable	
Reactivity insertion rate	Maximum to very low	
	Max. Pos.	Max. Neg.
Moderator temperature coefficient	+5 pcm/°F	-42 pcm/°F
Doppler coefficient	-0.8 pcm/°F	-2 pcm/°F

The maximum reactivity insertion rate used bounds the most reactive banks wired in common withdrawing at maximum rate. The minimum reactivity insertion rate used is typical of boron dilution.

15.4.2.4 Analysis of Results. At each of the power levels a spectrum of reactivity insertion rates ranging from 0.1 pcm/sec to 50 pcm/sec were analyzed for both positive reactivity feedback and negative reactivity feedback.

The limiting rod bank withdrawal event is from full power initial conditions with an insertion ramp of 1 pcm/sec and positive reactivity feedback.

Figures 15.4.2-1 and 15.4.2-2 present MDNBR (based on the Cycle 17 XCOBRA-IIIC model) vs. Reactivity Insertion Rate for the full power and mid-power transients, respectively. (No low-power cases were analyzed, because the mid-power cases were less limiting than the full-power cases.)

Figures 15.4.2-3 through 15.4.2-9 show the plant response for the limiting case: slow bank withdrawal (1.0 pcm/s) initiated at full power with positive reactivity feedback. Table 15.4.2-1 presents the sequence of events. Power increased steadily in response to the reactivity insertion, until the reactor scrammed. Coolant temperatures also increased steadily, due to the primary-to-secondary system power mismatch. The pressure increase due to coolant expansion and pressurizer insurge was limited by the primary PORVs, with the pressurizer pressure peaking at 2278 psia. The high flux and overtemperature ΔT trip setpoints were both reached at 56.8 seconds, and rod insertion began at 57.3 seconds. The calculated DNBR reached a minimum value of 1.20 at 57.5 seconds.

15.4.2.5 Conclusions. Reactivity insertion transient calculations demonstrate that the DNB safety limit of 1.154 will not be breached during any credible reactivity insertion transient at full power, mid power, or low power. The MDNBR of 1.20, reached during the most limiting transient, occurs at full power and retains margin to the MDNBR limit.

The fuel melt SAFDL is also met because the OPΔT trip function provides protection during slow transients which are not characterized by localized radial power redistribution.

TABLE 15.4.2-1

LIMITING BANK WITHDRAWAL AT POWER EVENT SUMMARY

TIME	EVENT	VALUE
0.0 s	Bank withdrawal began	-
48.0 s	Pressurizer pressure peaked (see Figure 15.4.2-6)	2278 psia
56.8 s	Core power reached high-flux trip setpoint (see Figure 15.4.2-3)	118% of rated
56.8 s	Vessel temp. rise reached OTΔT trip setpoint (see Figure 15.4.2-5)	67°F
57.3 s	Scram rod insertion began	-
57.5 s	Minimum DNBR occurred (see Figure 15.4.2-9)	1.20

15.4.3 Control Rod Misoperation (System Malfunction or Operator Error)

Rod Cluster Control Assembly (RCCA) misoperation events include:

1. Withdrawal of a single full length RCCA

2. Static misalignment of a single full length RCCA

3. Dropped full length RCCA

4. Dropped full length RCCA bank

Each RCCA has a position indicator which displays the position of the assembly. The displays of assembly positions are grouped for the operator's convenience. Fully inserted assemblies are further indicated by a rod bottom light. Group demand position is also indicated. The full-length RCCAs are always moved in preselected banks and the banks are always moved in the same preselected sequence.

The statically misaligned RCCA, dropped RCCA, and dropped RCCA bank events are classified as Condition II events. The withdrawal of a single RCCA event is classified as a Condition III event. Acceptance criteria are presented in Section 15.0.1.1.

The analyses are performed using ANF-RELAP to model system response and XCOBRA-IIIC to calculate minimum DNB ratios. Bounding values were obtained by coupling conservative local power peaking to the MDNBR calculations. The power peak associated with each event is characterized through an augmentation factor which relates the maximum power peak to the steady state power peak. The steady state power distributions and augmentation factors are calculated with the XTGPWR reactor simulator (Reference 15.4.3-1).

For control rod misoperation events, the maximization of power peaking results in a reduction in the DNBR. To assure that bounding values are determined for the radial power peaking, the following approach is used for each event. The increase in power peaking above that associated with equilibrium steady state conditions is determined for a spectrum of cycle exposures and applicable control rod configurations. Based on these results, a conservative augmentation factor is derived. This augmentation factor is then applied to the allowable $F_{\Delta H}$ to ensure a bounding value for the peak pin power input to the DNB analysis.

15.4.3.1 Withdrawal of a Single Full-Length RCCA.

15.4.3.1.1 Identification of causes and event description. The event is initiated by the inadvertent withdrawal of a single control rod at power. The ensuing reactivity insertion causes core power to increase. In the event that the secondary steam dump control system does not respond to the increased power production, secondary system temperature and pressure will increase, causing a corresponding increase in primary coolant temperature. This increase in primary coolant temperature occurs slowly enough that the pressurizer pressure control system, if available, is capable of suppressing

the primary pressure increase. The degradation of coolant conditions coupled with the power increase is essentially the same as expected for RCCA bank withdrawals at power, and may approach DNB conditions in the hot channel.

The single RCCA withdrawal is distinguished from the withdrawal of an RCCA bank by a severe radial power redistribution. High radial power peaking is quite localized in the region of the single withdrawn RCCA and may, in severe cases, surpass the design limits. Thus, assemblies in the immediate vicinity of the withdrawn RCCA may experience boiling transition. Such exposure would be limited to short time periods. Some fuel damage might occur.

Primary protection for this event is afforded by the high nuclear flux trip and the overtemperature ΔT trip.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single RCCA from the inserted RCCA bank during full power operation. Procedures are available to permit the operator to withdraw a single RCCA in the control bank since this feature is necessary in order to retrieve an assembly should one be accidentally dropped. The event can occur only as the result of multiple wiring failures or multiple operator action. The probability of such a combination of conditions is low. This event is, therefore, classified as a Class III event during which some fuel damage is permitted.

In the extremely unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, the rod position indicators would indicate the relative positions of the assemblies in the bank. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would similarly result in the same visual indications. Withdrawal of a single RCCA results both in a positive reactivity insertion tending to increase core power, and in an increase in local power density in the core area associated with the RCCA.

15.4.3.1.2 Analysis method. The transient response of the reactor system exclusive of radial power redistribution effects is as calculated with the ANF-RELAP code (Reference 15.0-3) for the most limiting case of uncontrolled RCCA withdrawal at power. The coolant flow rate, primary pressure, and core inlet coolant temperature boundary conditions at the time of MDNBR (determined by ANP-RELAP) are transferred to the XCOBRA-IIIC computer code (Reference 15.0-4) for calculation of MDNBR. The core average heat flux at the time of MDNBR is adjusted to include design power peaking and a radial peaking augmentation factor calculated to describe the radial power peaking redistribution due to the single withdrawn RCCA.

The fraction of the fuel to experience boiling transition for the event is conservatively taken to be the number of fuel assemblies with calculated minimum DNB ratios below the safety limit, divided by the total number of assemblies.

15.4.3.1.3 Definition of events analyzed and bounding input. The initial input is selected such that the analysis bounds power operation. The initial input for the case analyzed is the same as that previously identified to provide the limiting transient response for the uncontrolled RCCA bank withdrawal at power. That case employed positive neutron kinetics feedbacks

in an RCCA bank withdrawal from rated power. For the withdrawal of a single full-length RCCA, a radial power peaking augmentation factor of 1.17 is employed.

15.4.3.1.4 Analysis of results. The minimum DNB ratio calculated for the event is less than the safety limit. The extreme radial power peaking calculated for the single RCCA withdrawal is localized in the neighborhood of the withdrawn RCCA. Only one of the 157 fuel assemblies in the core is calculated to experience boiling transition.

The radiological consequences evaluation (Reference 15.3.2-1) for the Design Basis LOCA event assumed all fuel assemblies in the core failed. Acceptable results were obtained for the LOCA, i.e., less than 10 percent of the 10 CFR 100 limits. This is also an acceptable result for a Condition III event. Using the conservative assumption that boiling transition results in fuel failure, less than the full core exhibited DNB and the integrity of the primary system is maintained; therefore, the radiological results of the withdrawal of a single full length RCCA event are bounded by those of the LOCA event.

The single RCCA withdrawal event is classified as a Condition III event. Less than 10 percent of the core experiences boiling transition, with radiological release less than 10 percent of 10 CFR 100 limits. Reactor vessel pressurization is well below 110 percent of the design limit. It is not anticipated that core cooling would be significantly hindered by less than 10 percent fuel failures. No more limiting fault is engendered by the occurrence of the event. The result of the analysis is thus in conformance with the acceptance criteria for a Condition III event and is, therefore, acceptable.

15.4.3.1.5 Conclusions. For the case of the accidental withdrawal of a single RCCA, with the reactor initially operating at full power with Bank D at the insertion limit, an upper bound of the number of fuel rod experiencing DNB is 10 percent of the total fuel rods in the core. This event, therefore, satisfies 10 CFR 100 criteria.

15.4.3.2 <u>Static Misalignment of a Single RCCA</u>.

15.4.3.2.1 Identification of causes and event description. The static misalignment of an RCCA is defined as a malfunction of the Control Rod Drive (CRD) mechanism, or of the rod control power supply, which causes an RCCA to be out of alignment with its bank; i.e., either higher or lower than any of the other RCCAs in the same bank. The reactor is in the steady state at rated full power conditions, and no excursion of core temperature, pressure, flow, or power occurs. For extreme RCCA misalignments, the core radial power distribution may be characterized by peaking factors in excess of design limits. Highly localized increases in clad surface heat flux, coolant temperature, and flow diversion may occur. In severe cases, the SAFDL on DNB may be approached.

The full-length RCCAs are always moved in preselected sequence. A quadrant tilt monitor alarm (upper and lower ex-core neutron detectors) is provided to indicate significant power tilts. If this alarm is temporarily out of service, periodic checks of individual rod positions and ex-core detector currents, and even core symmetry checks using in-core thermocouples and movable detectors can be made.

The operator is provided with rod position indication for each RCCA. An alarm is actuated when any RCCA bottom defeat switch is actuated so that an RCCA can be inserted into the core. This defeat switch must be actuated to prevent a load cutback.

15.4.3.2.2 Analysis method. Primary system pressure, core inlet temperature, and coolant flow rate at the rated full power operating point are input to the XCOBRA-IIIC code to calculate MDNBR. The rated full power core average clad surface heat flux is input to the MDNBR calculation after having been adjusted to include the design radial and axial power peaking distribution factors and a radial peaking augmentation factor calculated to bound the radial power redistribution characteristics of a misaligned RCCA.

15.4.3.2.3 Definition of events analyzed and bounding input. The event is analyzed at the rated full power operating point to bound power operation. Analysis inputs reflect the following allowance from nominal full power operating conditions:

Power	102% of rated
Core Inlet Temperature	544.4°F
Pressurizer Pressure	Nominal -30 psi
Coolant Flow	Minimum allowed by Technical Specifications

The radial peaking factor augmentation is 1.10, calculated to bound future cycle operation.

Two cases are analyzed to bound the misalignment conditions where the single RCCA is stuck fully out of the core or stuck fully in the core. For the condition with the single RCCA misaligned above the RCCA's in the same bank, it is conservatively assumed that Bank D is fully inserted to the full extent allowed by the Rod Insertion Limits (RIL) controlled by the Technical Specifications as specified on a cycle-specific basis by the Core Operating Limits Report. However, it is assumed that the most reactive "D" bank RCCA is fully withdrawn from the core (Case 1). For the condition with a single RCCA misaligned below its corresponding bank, the analysis is performed with all Banks fully withdrawn and the most reactive RCCA fully inserted to the bottom of the core (Case 2).

15.4.3.2.4 Analysis of results. Case 1 represents the most limiting case in the current analysis. The calculated MDNBR for the Static Misalignment of a Full-Length RCCA is 1.24, which is greater than the 1.154 DNB limit. The peak pellet linear heat generation is 18.2 kw/ft, which is below the threshold limit of 20.2 kw/ft, so that fuel centerline melt does not occur. Since no fuel failure is calculated to occur, there is no radiological release consequent to this event. The result of the analysis is,

thus, in conformance with the acceptance criteria for Condition II events and is, therefore, acceptable.

15.4.3.2.5 Conclusions. An RCCA out of position can result only from a malfunction in the mechanism or its associated power supply and, in such a case, it is clearly indicated to the operator by independent monitoring systems. The cases discussed above have indicated that the DNB ratio remains greater than the safety limit in the event of a rod misalignment. The DNB SAFDL is, therefore, satisfied for this event.

15.4.3.3 <u>Dropped RCCA and RCCA Bank</u>.

15.4.3.3.1 Identification of causes and event description. The event is defined to be initiated by a dropped RCCA. The dropped RCCA promptly inserts negative reactivity which reduces reactor power and disturbs the power distribution, resulting in increased local power peaking. The rod bottom and negative flux rate signals can independently initiate turbine runback to 70% of full power. With turbine runback, the reduction in load initially results in a load mismatch if the dropped rod reactivity does not match that required for the runback power level. If reactivity insertion is greater than that required to match the runback power level, Tavg initially decreases. If reactivity is less, Tavg initially increases. The reactor protection system will limit consequences should conditions approach setpoint values.

If a RCCA drops into the core during power operation, it would be detected by either a rod bottom signal device or by the use of the excore chambers. The rod bottom signal device provides an individual position indication signal for each RCCA. The other independent indication of an RCCA drop is obtained through the excore power range channel signals. This rod drop detection circuit is actuated upon sensing a rapid decrease in local flux such as could occur from depression of flux in one region by a dropped RCCA.

A rod drop signal from any rod position indication channel, or from one or more of the four power range channels, initiates protective action by reducing turbine load by a preset adjustable amount. This action prevents core damage. The turbine runback is redundantly obtained by acting upon the turbine load limit and on the turbine govenor control system.

15.4.3.3.2 Analysis method. The analyses are performed by coupling a conservative power peak to transient response and DNBR calculations. The power peak associated with the event is characterized through an augmentation factor which relates the maximum power peak to the steady state power peak. The steady state power distributions and augmentation factors are calculated with the XTGPWR reactor simulator. Standard neutronic methodology is used to calculate neutronics parameters such as control rod worth and power peaking.

The system response to a single dropped RCCA is analyzed with ANF-RELAP code. The DNB analysis is performed using the XCOBRA methodology, using the operating conditions from the ANF-RELAP calculation. Local power redistribution effects due to the dropped rod are input to the XCOBRA methodology by a local power augmentation factor. The Technical Specification value of the allowed $F_{\Delta H}$ is multiplied by this augmentation factor.

15.4.3.3.3 Definition of events analyzed and bounding input. The limiting Condition II event analyzed is a dropped full length RCCA of low worth with turbine runback. No single failure assumption is required since manual rod control is assumed.

Key analysis conditions include:

Initial power	102% of rated
Moderator temperature coefficient	+5 pcm/°F
Doppler coefficient	-1 pcm/°F
Dropped rod worth	30 pcm (as a bounding minimum value)
Radial peaking augmentation factor	1.07 (cycle specific)

15.4.3.3.4 Analysis of results. The event was initiated by a step negative reactivity insertion representing a minimum-worth dropped rod. After the rod had reached the bottom of the core, at 2.2 seconds, a turbine runback signal was issued. The turbine load demand followed the programmed rampdown to 70% at 11.2 seconds. The average coolant temperature initially decreased in response to the power reduction caused by the dropped rod, but later increased due to the reduced secondary load demand. Due to positive moderator feedback, the temperature increase was exacerbated by an increase in reactor power. The temperature increase caused pressurizer insurge, which resulted in a pressure increase sufficient to open the PORVs at 17.0 seconds. Reactor scram on overtemperature ΔT occurred at 35.9 seconds.

The minimum DNBR was calculated by XCOBRA-IIIC to be 1.20, which is greater than the 1.154 DNB limit. The peak pellet linear heat generation rate was calculated to be 17.7 kW/ft, which is below the threshold LHGR for fuel centerline melt (20.2 kW/ft).

The event summary is provided in Table 15.4.3-1. Figures 15.4.3-1 through 15.4.3-7 depict the system response to a dropped RCCA of low worth.

15.4.3.3.5 Conclusions. Dropped Full-Length RCCA While in Manual Rod Control - The minimum calculated DNBR is greater than the safety limit. Therefore, the event acceptance criterion on DNBR is met.

The impact of a dropped full-length RCCA bank is mitigated by automatic turbine cutback. The results of this event are bounded by the results of the dropped full-length RCCA. The DNB SAFDL is, therefore, satisfied for this event.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN THE BORON CONCENTRATION IN THE REACTOR COOLANT

15.4.6.1 Identification of Causes and Event Description. Reactivity can be added to the core with the CVCS by feeding reactor makeup water into the RCS via the reactor makeup control system. The normal dilution procedures call for a limit on the rate and magnitude for any individual dilution, under strict administrative controls. Boron dilution is a manual operation. A boric acid blend system is provided to permit the operator to match the concentration of reactor coolant makeup water to that existing in the coolant at the time. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

There is only a single, common source of reactor makeup water to the RCS from the reactor makeup water system, and inadvertent dilution can be readily terminated by isolating this single source. The operation of the reactor makeup water pumps which take suction from this tank provides the only supply of makeup water to the RCS. In order for makeup water to be added to the RCS, the makeup pumps must be running in addition to the reactor charging pumps.

The rate of addition of unborated water makeup to the RCS is limited to the capacity of the charging pumps. This limiting addition rate is 230 gpm. For totally unborated water to be delivered at this rate to the RCS at pressure, three charging pumps must be operated. Normally only one charging pump and one reactor make-up pump are operating.

A minimum of two separate operations are required for dilution. First, the operator must position the makeup mode switch from the "automatic makeup" mode to the "dilute" or "alternate dilute" mode. Second, the control switch must be positioned to "start." Omitting either step would prevent dilution. A dilution could also be initiated by manual operator action at the control board by repositioning individual component control switches. More than two separate actions would be required to initiate a dilution manually. This makes the possibility of inadvertent dilution very small.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction.

To cover all modes of plant operation, boron dilution during refueling, cold shutdown, hot shutdown, startup, and power operation are considered in this analysis.

15.4.6.2 Analysis Methods. The dilution time required to overcome the shutdown margin is calculated by solving the differential equation,

$$M \bullet \frac{dC(t)}{dt} = -W \bullet C(t)$$

so that the dilution time is given by

$$T_D = \frac{M}{W} \bullet \ln \frac{C_{initial}}{C_{critical}}$$

where:

M = mass of water in the primary system
C = boron concentration in the primary system
W = mass flow of unborated water

The critical boron concentration and a conservative boron worth are determined utilizing the XTGPWR reactor simulator code.

15.4.6.3 Definition of Events and Bounding Input.

15.4.6.3.1 Dilution During Refueling. During refueling the following conditions exist:

a) One residual heat removal pump is running to ensure continuous mixing in the reactor vessel.

b) The valve in the seal water header to the reactor coolant pumps is closed.

c) The valves on the suction side of the charging pumps are adjusted for addition of concentrated boric acid solution.

d) The boron concentration of the refueling water is 1950 ppm.

e) Neutron sources are installed in the core and BF_3 detectors connected to instrumentation giving audible count rates are installed within the reactor vessel to provide direct monitoring of the core.

A minimum water volume in the RCS of 3200 ft^3 is considered. This corresponds to the volume necessary to fill the reactor vessel to the centerline of the nozzles to ensure mixing via the residual heat removal (RHR) loop. The maximum dilution flow rate of 230 gpm and uniform mixing are also considered.

15.4.6.3.2 Dilution During Cold Shutdown. Two cases are considered for dilution during cold shutdown. For the first case a minimum water volume (3200 ft^3) in the RCS is used which corresponds to the volume necessary to fill the reactor vessel to the centerline of the nozzles to ensure mixing via the RHR loop. With the reactor in this configuration, a minimum shutdown margin of 1% $\Delta\rho$ is maintained and administrative controls are applied which ensure no more than one charging pump can deliver water resulting in a maximum dilution flow rate of 77 gpm.

The second cold shutdown case uses the minimum coolant volume of 8043 ft^3 which is the volume of the RCS excluding the pressurizer. A minimum shutdown margin of 1%$\Delta\rho$ is required. The maximum dilution flow of 230 gpm is considered.

15.4.6.3.3 Dilution during hot standby. Conditions at hot standby require the reactor to have available at least 1.0%$\Delta\rho$ shutdown margin. Dilution flow is assumed to be 230 gpm. The volume of the reactor coolant is approximately 8043 ft^3 which is the volume of the RCS excluding the pressurizer.

15.4.6.3.4 Dilution during startup. Conditions at startup are identical to the hot standby core with the exception of the reactor coolant temperature. Mixing of reactor coolant is maintained by operation of the reactor coolant pumps. Again the maximum dilution flow (230 gpm) is considered. The volume of reactor coolant is approximately 8043 ft^3 which is the volume of the RCS excluding the pressurizer. High source level and all reactor trip alarms are effective.

15.4.6.3.5 Dilution during power operation. Dilution rate during power operation is dependent on charging pump capacity and coolant boron concentration. The maximum reactivity addition rate for a boron dilution flow of 230 gpm during power operation is $1.1 \times 10^{-5}\Delta\rho$/sec. The reactivity insertion rates considered in Sections 15.4.1 and 15.4.2 cover any rate achievable by boron dilution and demonstrate that the core is protected from DNB.

15.4.6.4 Analysis of Results. The results of the analysis for this event are summarized in Table 15.4.6-1 with the exception of boron dilution during power operations. The results show that there is adequate time for the operator to manually terminate the source of dilution flow. The reactor will be in a stable condition. The operator can then initiate reboration to recover the shutdown margin. Boron dilution during power operation is bounded by the analyses presented in Sections 15.4.1 and 15.4.2.

15.4.6.5 Conclusions. Because of the procedures involved in the dilution process, an erroneous dilution is considered incredible. Nevertheless, if an unintentional dilution of boron in the reactor coolant does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator to determine the cause of the addition and to take corrective action before shutdown margin is lost.

TABLE 15.4.6-1

RESULTS OF THE ANALYSES OF CVCS MALFUNCTION

Reactor Conditions	Critical Boron Concentration (ppm)	Initial Boron Concentration (ppm)	Time to loss of Shutdown Margin* (minutes) Calculated	Time to loss of Shutdown Margin* (minutes) Minimum Acceptable
Refueling	1263	1950	45.2	30
Cold Shutdown				
Case 1 (drained)	1264	1361	23.0	15
Case 2 (full RCS)	1264	1361	19.3	15
Hot Shutdown	1226	1326	19.9	15
Startup	859	986	27.2	15
Power Operation	------- Bounded by analysis in Section 15.4.1 and 15.4.2 ------			

* The time it takes to go from an initial condition that (just) fulfills our Technical Specification Shutdown Margin requirements to critical (i.e., K_{eff}=1.0) with all control rods but the highest worth control rod inserted.

15.4.7 Inadvertent Loading of a Fuel Assembly into the Improper Location

15.4.7.1 Identification of Causes and Event Description. Core loading errors arise from the loading of one or more fuel assemblies into improper core locations. This can result in changes in the power distribution and increases in local power density which may go undetected by incore instrumentation.

Reactor protection for the misloaded fuel assembly event depends on administrative plant procedures. To reduce the probability of core loading errors, each fuel assembly is marked with an identification number and loaded in accordance with a fuel loading or shuffle procedure to achieve the design core loading plan, Reference 15.4.7-1. The location of each assembly is verified prior to replacing the upper internals.

Incore instrumentation is used to determine the core power distribution and can also be used to monitor for possible misloaded assemblies. The instrumentation includes 48 incore thimble tubes to accommodate incore neutron flux probes. A minimum of 36 operable thimbles is required for power distribution flux maps. For excore instrument calibrations, 15 thimbles are required with at least 2 thimbles per core quadrant. Incore flux maps are taken at cycle startup and during initial power ascension at power levels of 30%, 70%, and 100% of rated thermal power, and at monthly surveillance intervals thereafer.

In the unlikely event that a loading error occurs, the power distribution will be changed by an amount proportional to the change in reactivity of the misloaded assembly. Large changes in the measured power distribution relative to the projected power distribution will be readily detectable by the incore instrumentation system at startup and during initial power ascension. However, small changes in the measured power distribution may go undetected by startup power ascension flux maps and continued operation at rated power can result in an increase in the radial peaking factor primarily for the case where the misloaded assemblies are the fresh gadolinia-bearing assemblies. If power operation persists with radial peaking factors in excess of Technical Specification limits due to an undetected misloading event, the DNBR SAFDL may be penetrated.

15.4.7.2 Analysis Method. A spectrum of misloading events has been analyzed with the XTGPWR code using a full core 3-dimensional twenty-four (24) axial node model. Full core power distributions were calculated for the correctly loaded core and for a spectrum of misloading configurations. A misloading that resulted in a greater than or equal to 15% increase in the misloaded assembly power was considered to be detectable. A misloading that resulted in a 3% or greater quadrant power tilt ratio was also considered detectable. The 30% power level map can be used as an early detection of a misloaded assembly since the power distribution changes only slightly during power escalation.

For undetectable misloading cases, the analysis focuses on core power peaking limits. If power peaking values for the misloaded core are calculated not to exceed Technical Specification limits (including uncertainties), no further evaluation is necessary as DNB will not be exceeded. If calculations indicate that Technical Specification peaking limits could be exceeded, additional analysis is necessary. The additional analysis includes a DNBR

determination. If penetration of the critical heat flux correlation safety limit has occurred, then a determination of the fraction of the fuel to experience boiling transition is made and the radiological consequences of such failures is assessed.

15.4.7.3 Definition of Events Analyzed and Bounding Input. A spectrum of misloading cases was analyzed. These cases represent the misloading of assemblies into core locations which are designated to be occupied by exposed or fresh fuel with different assembly reactivity characteristics.

For those cases which are found to be undetectable at beginning-of-cycle, a cycle depletion calculation was performed to determine the power history as a function of cycle exposure. From the results of the depletion calculation, the peak $F_{\Delta H}$ can be assessed relative to the Technical Specification limit. Since plant procedures require that measured power distributions be taken at monthly intervals, some of the undetectable events at BOL will be prevented from exceeding the Technical Specification limit by this periodic assessment. For those misloading events that remain undetectable, a DNB analysis is performed to determine the potential impact on the core.

15.4.7.4 Analysis of Results. The fuel misloading analysis determined the maximum value of $F_{\Delta H}$ and F_Q which can be expected to go undetected. The events analyzed can be categorized as the replacement of:

1. Exposed fuel with exposed fuel,
2. Exposed fuel with fresh fuel, and
3. Fresh fuel with fresh gadolinia fuel.

The worst undetectable misloading cases occurred in categories 1 and 2. The maximum undetected values of $F^T_{\Delta H}$ and F^T_Q which occur during Cycle 18 were calculated to be 1.95 and 2.57, respectively.

15.4.7.5 Conclusion. The consequences of this event, with $F^T_{\Delta H}$ = 1.95 and F^T_Q = 2.57, are bounded by the consequences of the Static Misalignment of Single Full-Length RCCA event (15.4.3.2) with $F^T_{\Delta H}$ = 2.08 and F^T_Q = 2.74, which meets the SAFDLs. Therefore, the Misloaded Assembly event (undetected case) is tolerable at full-power operation without fuel failures.

15.4.8 Spectrum of Rod Cluster Control Assembly (RCCA) Ejection Accidents

15.4.8.1 Identification of Causes and Accident Description. This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

In order for this accident to occur, a rupture of the control rod mechanism housing must be postulated creating a full system pressure differential acting on the drive shaft. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature and terminated by reactor trip actuated by high nuclear power signals.

15.4.8.1.1 Design precautions and protection. A failure of a control rod mechanism housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons:

1. Each control rod drive mechanism housing is completely assembled and shop-tested at 4100 psi.

2. The mechanism housings were individually hydrotested to 3105 psig when they were installed on the reactor vessel head to the head adapters, and checked during the hydrotest of the completed RCS.

3. Stress levels in the mechanism are not affected by system transients at power, or by thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress range specified by the ASME Code, Section III for Class A components, and

4. The latch mechanism housing and rod travel housing are each a single length of forged Type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

A significant margin of strength in the elastic range, together with the energy absorption capability in the plastic range, gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and rod travel housing are threaded joints reinforced by canopy-type rod welds.

The operation of a chemical shim plant is such that the severity of an ejection accident is inherently limited. Since control rod clusters are used to control load variations only and core depletion is followed with boron dilution, only a few rods in the core are at full power. There are low level insertion monitors, each with both visual and audio signals. Operating instructions require boration at the low level alarm. The control rod position monitoring and alarm systems are described in detail in Section 7.3.

15.4.8.1.2 Event classification and acceptance criteria. The probability of a rod being rapidly ejected from the core is so low that Rod Ejection is classified as a Condition IV event. The acceptance criteria require that whole-body and thyroid doses in the exclusion area and low population zone be less than 25% of the 10 CFR 100 guidelines.

15.4.8.2 Analysis Method. The analysis was performed using the ANF-RELAP and XCOBRA-IIIC Codes. The ANF-RELAP code (Reference 15.0-3) was used to model the salient system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). A DNBR calculation was performed to estimate the approximate time at which the DNBR was a minimum. The core fluid boundary conditions[a] and average rod surface heat flux at this time were then used as input to the XCOBRA-IIIC code (Reference 15.0-4), which was used to evaluate the MDNBR.

The Rod Ejection event was also evaluated with the procedures developed in the SPC Generic Rod Ejection Analysis (Reference 15.4.8-1) to determine the fuel pellet energy deposition resulting from an ejected rod.

15.4.8.3 Definition of Events Analyzed and Bounding Input. One case, for full-power conditions at BOC (with parameters biased to challenge the DNB acceptance criterion), was analyzed. Full-power conditions bound lower-power conditions because energy deposition is highest at full power, and energy deposition is the primary driver for DNB performance, peak coolant pressures, and peak fuel temperatures.

An over-pressure case was not analyzed, because pressures are more limiting for the Loss of External Load event (15.2.2). The initial increase in power due to an ejected rod causes an over-power condition of about 30%, resulting in a 30% power overload on the secondary. The Loss of External Load event, on the other hand, results in a 100% power overload on the secondary. Both of these events are very rapid and have approximately the same time to peak pressure (less than 10 seconds). Therefore, the Loss of External Load event bounds the Rod Ejection event with respect to over-pressure.

No single active failure will adversely affect the consequences of this event. However, loss of offsite power was conservatively assumed to occur at the start of the transient. This minimizes the reactor coolant flow while the energy due to power increase from the ejected rod is being transferred to the primary coolant, thus minimizing DNBR.

A BOC Doppler coefficient was used because the Doppler coefficient is least negative at BOC, which minimizes negative Doppler feedback. A minimum delayed neutron fraction which bounds the cycle was conservatively used to convert reactivity to dollars in ANF-RELAP because it maximizes the worth of the ejected rod. A maximum pellet-to-clad heat transfer coefficient which bounds the cycle was conservatively used because it maximizes the heat flux at the rod surface and minimizes negative Doppler feedback.

---

[a] The core outlet pressure at the time of MDNBR was reduced to account for the pressure loss due to the opening created by the ejected control rod.

The key analysis conditions are summarized below:

Initial power	102% of rated
Ejected RCCA worth	Bounding (maximum) value [100 pcm]
Moderator temp. coefficient	+5.0 pcm/°F
Doppler coefficient	-0.8 pcm/°F
Delayed neutron fraction, ß	Bounding (minimum) value [0.0045]
Pellet-to-clad HTC	Bounding (maximum) core-average value $[1751 \frac{BTU}{hr \cdot ft^2 \cdot °F}]$

15.4.8.4 Analysis of Results. The sequence of events for the analysis is given in Table 15.4.8-1. The transient tripped the reactor on the high-flux reactor trip. The key system response parameters are shown in Figures 15.4.8-1 through 15.4.8-4.

The pellet energy deposition was conservatively evaluated for BOC and EOC, at HFP and HZP, using the SPC Generic Rod Ejection methodology. The results of this analysis show that the peak deposited energy is 169 cal/g, which is less than the 280 cal/g limit as stated in Regulatory Guide 1.77.

15.4.8.5 Conclusion. The results of the analysis demonstrate that the event acceptance criteria are met. The predicted MDNBR is 1.16. This is greater than the 1.154 mixed-core DNB limit. Also, the predicted peak energy deposition is 169 cal/g. This is less than the 280 cal/g limit. Therefore, no fuel failures are predicted to occur, and there is no significant radiological release due to this event.

TABLE 15.4.8-1

ROD EJECTION EVENT SUMMARY

TIME	EVENT	VALUE
0.00 s	RCCA was ejected	-
0.00 s	Offsite power was lost	-
0.07 s	Core power reached high-flux trip setpoint (see Figure 15.4.8-1)	118% of rated
0.58 s	Scram rod insertion began	-
0.60 s	Core power peaked (see Figure 15.4.8-1)	135% of rated
1.10 s	Core-average rod surface heat flux peaked (see Figure 15.4.8-1)	111% of rated
1.60 s	Minimum DNBR occurred (Figure 15.4.8-4)	1.16

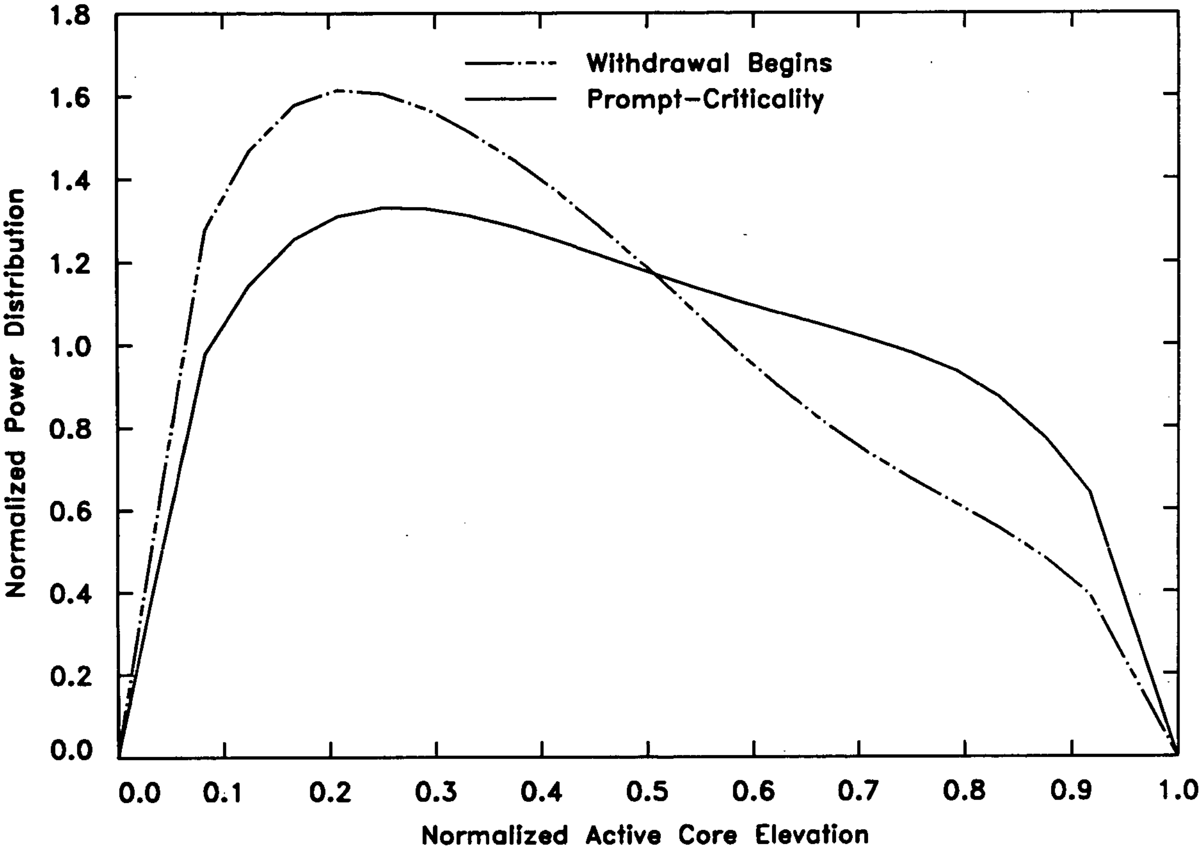
REFERENCES: SECTION 15.4

15.4.1-1 Deleted Revision No. 14

15.4.3-1 XN-75-27(A), "Exxon Nuclear Neutronic Design Methods for PWRs," Exxon Nuclear Company, April 1977.

15.4.7-1 XN-NF-83-72, Revision 2, Supplement 1, "H. B. Robinson Unit 2, Cycle 10 Safety Analysis Report, Revision 2 Disposition of Chapter 15 Events, Exxon Nuclear Company, July 1984.

15.4.8-1 XN-NF-78-44(A), "A Generic Analysis of the Control Rod Ejection Transient for PWR's," Exxon Nuclear Company, Richland, WA, October 1983.



REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Bank Withdrawal from Subcritical: Axial Power Distributions	FIGURE 15.4.1-1

15.5 INCREASES IN REACTOR COOLANT SYSTEM INVENTORY

Increase in reactor coolant system inventory can be caused by inadvertent operation of the ECCS or primary coolant system charging pumps.

15.5.1 INADVERTENT OPERATION OF EMERGENCY CORE COOLING SYSTEM

The shutoff head of the H. B. Robinson high pressure safety injection system pumps is approximately 1500 psia, which is much less than the trip setpoint pressure of 1850 psia, and therefore, cannot increase the primary inventory during power operation.

Pressurized thermal shock (PTS) is being addressed in the Unreviewed Safety Issue program A-49. Typical Combustion Engineering, Babcock & Wilcox and Westinghouse early design operating plants were modeled in this effort. The plants modeled were Calvert Cliffs, Oconee, and H. B. Robinson Unit 2. Approximately 200 cases have been analyzed in the thermal hydraulics portion of the H. B. Robinson program. Representative events examined were steam line break, loss of coolant accidents, and arbitrarily large step changes in coolant temperature.

Break spectrums were examined with the specific objective of achieving stagnation conditions in the primary system. In each event when primary pressure dropped below 1300 psia, the reactor coolant pumps were shut off. As required by the reactor protection logic, the safety systems were enabled injecting cold ECC water. All events were initiated at hot zero power or at power conditions in order to bound lower temperature operations. Thus, the effect of inadvertent operation of the ECCS in stagnant conditions in addition to a much broader spectrum of more limiting events has been addressed. 3

Probabilistic fracture mechanics analysis using these thermal hydraulic results is in progress. While not yet completed, extremely low probability of reactor vessel failure is indicated from preliminary results.

To further address the concerns of this issue, Carolina Power & Light is implementing a low radial leakage fuel management program and is installing part length shielding fuel assemblies. These actions assure that H. B. Robinson 2 will not reach the NRC screening criteria for RT_{NDT}.

The Westinghouse Owners' Group (WOG) has previously addressed this issue. This effort addressed all transients which may subject the reactor pressure vessel to overcooling thermal effects from loss of loop flow. The results of the report support the NRC screening criteria, i.e., plant operation is acceptable if the screening criteria for RT_{NDT} is not reached.

Therefore, the causes and consequences of this event and all other events which could lead to PTS have been addressed by the NRC and WOG programs and need not be further addressed in this license action.

15.5.2 CVCS MALFUNCTION THAT INCREASES REACTOR COOLANT INVENTORY

The consequences of unplanned additions to inventory and effect of reactivity additions due to dilution during refueling and startup are treated in Section 15.4.6. The consequences of dilutions at power are bounded by the analysis of Section 15.4.2, Uncontrolled RCCA Bank Withdrawal at Power.

3

The consequences of volumetric addition and effect on pressure boundary are mitigated by resetting the pressurizer PORV set pressure to 400 psig prior to going below 350 psig. There are two PORVs on the pressurizer, each independently actuated. Any one valve has adequate relief capacity and response time to prevent overpressurization due to malfunction of the CVCS.

15.6 Decreases in Reactor Coolant System Inventory

15.6.1 Inadvertent Opening of Pressurizer Safety or Power Operated Relief Valve

15.6.1.1 Identification of Causes and Event Description. This event is initiated by the failure of a pressurizer PORV or safety valve in the full-open position, which causes loss of Reactor Coolant System (RCS) inventory and rapid depressurization. The primary system pressure decreases rapidly until the pressurizer liquid is depleted and the RCS is stabilized at the saturation pressure of the hot leg. However, the Reactor Protection System will scram the reactor on low pressurizer pressure or OTΔT well before the pressurizer liquid is depleted, terminating a moderator-density-feedback core power transient and further challenge to the SAFDLs.

The initial challenge to DNB is produced by the rapid depressurization of the primary system. Protection against this challenge is provided by the low pressurizer pressure and the OTΔT trips. In the post scram period, a challenge to DNB can be produced if the core uncovers. The system response (blowdown and depressurization) for an open PORV is bounded by that for a cold leg break which corresponds to a 1.5 inch ID pipe ("small" SBLOCA). For this SBLOCA, a single HHSI pump is sufficient to prevent uncovery of the core. Since the core remains covered, there is no long term heatup and no challenge to DNB. Therefore, it is necessary to analyze this event only until a reactor trip occurs.

This event is primarily a depressurization event, but with a negative moderator density coefficient, power increases slightly, as well. Thermal margin is eroded by the significantly decreased pressures and the slightly increased power.

The objective of this analysis is to evaluate the ability of the low-pressurizer-pressure trip to protect thermal margin during a rapid depressurization. Consequently, the OTΔT trip was disabled for this analysis.

The event is classified as a Condition IV event (Table 15.0.1-1). The acceptance criterion is demonstrating that the radiological consequences meet 10 CFR 100 guidelines. The systems challenged in this event are redundant; no single active failure will adversely affect the consequences of the event.

15.6.1.2 Analysis Method. The analysis was performed using the ANF-RELAP and XCOBRA-IIIC codes. The ANF-RELAP code (Reference 15.0-3) was used to model the salient system components and calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures, and pressures). A DNBR calculation was performed to estimate the approximate time at which the DNBR was a minimum. The core fluid boundary conditions and average rod surface heat flux at this time were then used as input to the XCOBRA-IIIC code (Reference 15.0-4), which was used to evaluate the MDNBR.

15.6.1.3 Definition of Events Analyzed and Bounding Input. This event is principally of concern in the short term because of the potential challenge to the DNB SAFDL, due to depressurization before scram. The depressurization also has a small effect on core power. However, the core inlet coolant temperature and flow remain essentially constant during the transient.

A single case, at full-power conditions, was analyzed. Lower power levels present a less severe challenge to DNB.

The reactivity feedback due to the density change produced by the depressurization was derived from the maximum moderator temperature coefficient. Because a moderator temperature coefficient represents the reactivity feedback due to temperature-induced density changes (based on the thermal expansion curve for water), the reactivity change due to a given density change was set equal to the maximum moderator temperature coefficient times the temperature change which corresponded to the density change (using water property tables).

This event can be caused by the malfunction of either a pressurizer PORV or a pressurizer safety valve. Failure of a safety valve was analyzed, since the flow capacity of a safety valve (288,000 lb/hr) is larger than the flow capacity of a relief valve (255,600 lb/hr), and a malfunction of the larger-capacity valve will bound the two possible cases.

The key analysis conditions are summarized below:

Initial power	102% of rated
OTΔT trip	Disabled
Low pressurizer pressure trip	Available
Moderator density coefficient	Calculated from Technical Specifications maximum moderator temperature coefficient

15.6.1.4 Analysis of Results. The event was initiated by fully opening a pressurizer safety valve. This caused the pressure in the primary system to decrease as fluid was lost through the open valve (see Figure 15.6.1-3). A low-pressure trip signal was issued at 44.5 seconds when the pressurizer pressure was 1863 psia. The lead filter on the compensated pressurizer pressure signal accounts for the trip occurring at a pressure higher than the 1800 psia setpoint. Reactor scram was initiated a second later (at 45.5 seconds). This ended the slow power excursion (see Figure 15.6.1-1) caused by reactivity feedback of the reduced coolant density at lower pressures.

The core-average rod surface heat flux peaked at 107% of the rated-power value at 45.7 seconds (see Table 15.6.1-1 and Figure 15.6.1-1). The coolant temperatures remained fairly constant until reactor scram occurred (see Figure 15.6.1-2).

The minimum DNB ratio calculated for this event is 1.26 (see Table 15.6.1-1), which provides significant margin relative to the 1.154 DNB limit.

15.6.1.5 Conclusion. The analysis demonstrates that there is no fuel failure or significant radiological release for this event. Therefore the event acceptance criterion is met.

TABLE 15.6.1-1

OPEN PRESSURIZER SAFETY/PORV EVENT SUMMARY

TIME	EVENT	VALUE
0.0 s	Pressurizer safety valve failed fully open	-
44.5 s	Pressurizer pressure reached low-pressure trip setpoint (see Figure 15.6.1-3)	1863 psia actual 1800 psia compens.
45.5 s	Scram rod insertion began	-
45.5 s	Core power peaked	108% of rated
45.7 s	Core-average rod surface heat flux peaked (see Figure 15.6.1-1)	107% of rated
45.9 s	Minimum DNBR occurred[a]	1.26

[a] For this transient event, the average rod heat flux (see Figure 15.6.1-1) serves as a better DNBR trend indicator than the Tong DNB correlation (not shown).

pertain to the conditions of the reactor and associated safety system equipment at the time that the LOCA occurs and include such items as the core peaking factors, the containment pressure, and the performance of the ECCS system. Decay heat generated throughout the transient is also conservatively calculated as required by Appendix K of 10CFR50.

Small Break LOCA Evaluation Model

The analysis was performed with the approved Siemens Power Corporation (SPC) [formerly known as Advanced Nuclear Fuel (ANF) and Exxon Nuclear Corporation (ENC)] Small Break LOCA Evaluation Model (Reference 15.6.2-2). This methodology is based on three computer codes.

The Reactor Coolant System response is calculated with the ANF-RELAP computer code. The SPC modified version of RELAP5 is a best estimate code to which the 10CFR50 Appendix K required Moody two-phase critical flow model has been added.

The fuel heatup response is calculated with the TOODEE2 computer code. TOODEE2 incorporates conservative fuel heatup models which meet the requirements of 10 CFR 50 Appendix K.

The RODEX2 computer code is used to initialize the ANF-RELAP and TOODEE2 fuel rod models prior to the start of the analysis. The RODEX2 code conservatively predicts initial fuel rod temperatures and complies with Appendix K requirements.

Small Break Input Parameters and Initial Conditions

Table 15.6.2-1 lists important input parameters and initial conditions used in the small break analyses.

Safety injection flow into the Reactor Coolant System (RCS) as a function of the system pressure is used as part of the input. The SI delivery curve used for these analyses is depicted in Table 15.6.2-2 as a function of RCS pressure.

This table represents injection flow from one high head safety injection (HHSI) pump. The delivery data incorporates the standard FSAR ECCS assumption of minimum safeguards. The delivery data were developed based on as-built piping layout information and a composite minimum pump curve (based on system test performance) degraded by 5% of the design TDH. Other assumptions used for the development of the delivery data include no branch line header balancing, and the pump minimum flow path remains open throughout the entire injection phase. The effect of flow from the RHR pumps is not considered here since their shutoff head is lower than RCS pressure during the time portion of the transient considered here.

The Safety Injection System was also assumed to be delivering to the RCS 28.5 seconds after the generation of a safety injection signal. This delay time includes the time required for diesel start up and loading of the safety injection pumps onto the emergency buses.

The worst single active failure is one Emergency Diesel Generator that does not start. With loss of offsite power, failure of one emergency electrical bus results in the loss of one HHSI pump and one of two motor driven Auxiliary Feedwater pumps. With the failure of one of two HHSI pumps that automatically start, only a single HHSI pump is available to mitigate the Small Break LOCA. (The third HHSI pump is an installed spare that is not automatically supplied with electric power.)

Small Break Results

A range of small break analyses is presented which establishes that the limits of 10 CFR 50.46 will not be exceeded at 100% of licensed core power operation. The results of these analyses are summarized in Tables 15.6.2-3 and 15.6.2-4 (Reference 15.6.2-3).

As indicated in the results of clad heatup, the 2.5 inch diameter break size at End of Cycle conditions is limiting. For this limiting case, Figures 15.6.2-4 through 15.6.2-10 present the principal parameters of interest for the small break ECCS analyses:

1. RCS Pressure
2. Core Collapsed Liquid Level
3. Peak Clad Temperature
4. Combined High Head Safety Injection Flow
5. Break Flow Rate
6. Combined Accumulator Flow
7. RCS Fluid Mass

The maximum calculated Peak Cladding Temperature for the Small Breaks analyzed is 1820°F. These results are well below all acceptance criteria limits of 10 CFR 50.46 and demonstrate acceptability of operation with one HHSI pump at 100% of licensed core power.

For the Cycle 18, a minor increase in the U-238 capture to fission ratio above that assumed in the analysis of record has increased the power contribution calculated from decay heat. It has been calculated that this aspect of the Cycle 18 reload will result in an increase in the SBLOCA PCT of approximately 7°F. This effect is considered to be insignificant with respect to the 380°F of margin to the 2200°F PCT limit. Therefore, a complete re-analysis of this event is not necessary at this time.

TABLE 15.6.2-1

INPUT PARAMETERS USED IN THE SBLOCA ANALYSIS

Primary Heat Output, MWt (includes 2% for calorimetric uncertainty)	2,346
Total Peaking Factor, F_Q	2.50
Total Enthalpy Rise Factor, $F_{\Delta H}$	1.80
Elevation of Peak LHGR, (x/L)	0.81
Primary Coolant Flow Rate, lbm/hr	100.3×10^6
Primary Coolant System Volume, ft^3	9,122
Operating Pressure, psia	2,250
Inlet Coolant Temperature, °F	548.4
Reactor Vessel Volume, ft^3	3,621
Pressurizer Total Volume, ft^3	1,300
Accumulator Volume, ft^3 (each of three)	1,200
Accumulator Liquid Volume, ft^3 (each of three)	825
Accumulator Pressure, psig	600
Accumulator Fluid Temperature, °F	120
Total Number of Tubes per Steam Generator	3,214
Number of Tubes Plugged per Steam Generator	193 (6%)
Secondary Flow Rate/Steam Generator, lbm/hr	3.43×10^6
Steam Generator Secondary Pressure, psia	800
Steam Generator Feedwater Temperature, °F	441.5
SI Fluid Temperature, °F	70
SIS Activation Setpoint Pressure, psia	1,615
HHSI Pump Delay Time on SIS, sec	28.5
HHSI Delivery Curve	Table 15.6.2-2
Reactor Scram Low Pressure Setpoint, psia	1800*

*Reference 15.6.2-5

TABLE 15.6.2-3

SMALL BREAK LOCA TIME SEQUENCE OF EVENTS

Event	Event Time (seconds) Break Size (Diameter of Equivalent Pipe) 1.5"	2.0"	2.5"	3.0"
Event initiation	0.0	0.0	0.0	0.0
Reactor Trip (RCP trip, SG Feed & Steam valves begin to close)	70	39	25	18
SIS + 28.5 sec delay	141	96	75	64
SI Injection Starts	333	140	92	70
Auxiliary Feed On	150	115	101	94
Loop Seal Clears (BL)	~3,050	~1,430	-	-
Loop Seal Clears (IL-1)	-	-	~780	~530
Loop Seal Clears (IL-2)	~3,050	-	-	~530
Break Uncovers (void frac. ~1.0)	~3,050	1,450	810	545
Accumulator Injection Begins	-	3,230	1,750	1,275
PCT Occurs (From TOODEE2)	-	3,228	1,930	1,352
End of Calculation	15,000	3,500	2,500	2,000

TABLE 15.6.2-4

SMALL BREAK LOCA FUEL CLADDING RESULTS

	Break Size (Diameter of Equivalent Pipe)			
	1.5"	2.0"	2.5"	3.0"
Hot Rod Burst				
Time (seconds)	Note 1	3,028	1,711	
Elevation (feet)		11.0	10.5	
Channel Blockage Fraction		0.37	0.41	
Peak Clad Temperature				
Temperature (°F)		1,725	1,820	1,377
Time (seconds)		3,228	1,930	1,352
Elevation (feet)		10.5	11.25	10.0
Metal-Water Reaction				
Local Maximum (%)		3.47	3.93	0.14
Elevation of Local Max. (feet)		11.0	10.5	10.5
Hot Pin Total (%)		0.44	0.55	0.02

Note 1: TOODEE2 calculations were not performed for the 1.5 inch break case since the mixture level remained above the top of the core.

15.6.3 STEAM GENERATOR TUBE RUPTURE

15.6.3.1 Event Consequences

This event is assumed to be caused by the instantaneous rupture of a steam generator tube which relieves to the lower pressure secondary. The event is similar to the primary valve malfunction event, Section 15.6.1, except the primary fluid relieves to the faulted steam generator. The primary valve malfunction event was analyzed and results reported in Section 15.6.1. That analysis demonstrated that the SAFDLs were not penetrated. Therefore, no fuel failures are expected for that event.

The results of SAFDL evaluation for this event are bounded by those of Section 15.6.1. The primary release flow for event 15.6.1 was 288,000 lb/hr, 80 lb/sec. The maximum relief flow calculated for this event was 72.8 lb/sec. Therefore, the results regarding challenge to the SAFDLs are bounded by those of the primary valve malfunction. No fuel failure is expected for this event, and therefore, no release of fission products to the primary is expected as a consequence of this event.

15.6.3.2 Radiological Consequences

15.6.3.2.1 Background

The primary consequence of this event is the release of radioactivity from the
primary coolant. In the unlikely event of a concurrent loss of power, the 3
loss of circulating water through the condenser would eventually result in the
loss of condenser vacuum. Valves in the condenser bypass lines would
automatically close to protect the condenser, thereby causing steam relief
directly to the atmosphere from the steam generator relief valves. This
direct relief would continue until the faulty steam generator is isolated.
The isolation is assumed to require 30 minutes.

Since no fuel failures occured from the event, the Technical Specification limits on activity and the amount of coolant released would determine the activity that was released to the atmosphere. There has been no change in the Technical Specification limit on primary coolant activity.

In the original analysis Westinghouse calculated that in the 30 minutes needed to isolate the faulty steam generator, 70,000 lb of reactor coolant are discharged into the steam generator and 57,000 lb of steam are released into the atmosphere. Using the Technical Specification limit on primary coolant activity, the corresponding release of noble gas activity to the atmosphere was 9500 equivalent curies of Xe-133. The corresponding iodine activity discharge into the steam generator was 78 equivalent curies of I-131, of which 3.9 curies were discharged to the atmosphere. The resultant calculated site boundary doses were less than 0.3 rem whole body and less than 2 rem to the thyroid.

Since the coolant activity limits are unchanged, only the break flows must be verified. A conservative prediction of the break flows was calculated and this prediction was used to estimate the offsite doses based on a ratio of the previous and currently calculated total break flow. Inherent in this analysis

is the assumption that the transport behavior is unchanged from the previous analysis. This assumption is the same assumption used in the methodology for calculating doses from postulated accidents (Reference 15.6.3-1).

15.6.3.2.2 Break Flow Calculation

The RELAP5 computer code was used to model the H. B. Robinson Unit 2 steam generator secondary side so that the fluid conditions upstream of a stuck open PORV could be estimated. The stuck open PORV is the path for the primary coolant to escape from the faulted steam generator. Major calculation assumptions were that:

a) The primary pressure conservatively remained at 2280 psia instead of dropping and then recovering as would realistically be expected.

b) One-third of the core energy was removed by the faulted steam generator.

c) All pump and cooldown energy was conservatively removed by the faulted steam generator.

d) The decay heat used was 120 percent of the ANS standard with an infinite 100 percent power history.

3 e) The secondary side wall temperature was set low to maximize heat transfer out of the primary coolant in the faulted steam generator.

All of these assumptions maximize the discharge, and therefore will provide bounding results.

A matrix of four breaks was analyzed: normal hot leg, normal cold leg, and the hot and cold leg breaks at the cold and hot leg temperatures, respectively. This matrix was done to assure the bounding break was analyzed. The range of PORV discharge flows from this matrix was from 93,872 lbm to 95,495 lbm, with the maximum value occurring for a cold leg break at the hot leg temperature. The maximum primary to secondary transfer was 131 klbm occurring during the hot leg break at cold leg temperatures.

15.6.3.2.3 Dose Calculation

The calculated discharge in the 30 minutes assumed to isolate the steam generator was 95.5 klbm compared to the original Westinghouse value of 57,000 lbm. Similarly, the calculated maximum primary to secondary transfer was 131 klbm compared with 70 klbm in the original analysis. Using the same assumptions that all of the noble gas activity discharged to the steam generator is released to the atmosphere and all of the iodine in the steam is discharged to atmosphere, the release resultant doses can be ratioed based on the release masses. Thus, the calculated whole body dose is 0.6 rem and the calculated thyroid dose is 3.4 rem, using the calculated break flow. These doses are an overprediction and are a small fraction of the 10 CFR 100.11 requirements. Thus, the event acceptance requirements are satisfied.

15.6.3 STEAM GENERATOR TUBE RUPTURE

15.6.3.1 Identification of Causes and Accident Description

The event examined is a complete steam generator (SG) tube break adjacent to the tube sheet, since a minor leak may not necessitate immediate action, depending on the particular circumstances. If a tube breaks, reactor coolant would discharge into the secondary system. Since the reactor coolant is radioactive, methods of operation to limit uncontrolled condensate release have to be considered.

Once the reactor coolant system pressure is below the SG design pressure, the faulty SG will be isolated by stopping its main feedwater and closing the main steam isolation and bypass valves. This will remove the possibility of uncontrolled leakage.

The following sequence of events is initiated by a tube rupture:

a) Rapidly falling pressure in the pressurizer will initiate a safety injection signal, tripping the unit. The safety injection signal automatically terminates normal feedwater and initiates auxiliary feedwater. While not necessary for protection, there is sufficient capacity in the secondary system to contain, in a controlled manner, any leakage that might pass from the primary system to the secondary system, should no action be taken to isolate the leaks.

b) The SG liquid monitor and the air vacuum pump radiation monitor will alarm, indicating the passage of primary fluid into the secondary system. The air vacuum pump discharge is automatically diverted back to the plant vent within a few seconds.

c) The unit trip will automatically shut off steam flow through the turbine and will open the steam bypass valves and bypass steam to the condenser.

d) In the unlikely event of a concurrent loss of power, the loss of circulating water through the condenser would eventually result in loss of condenser vacuum and valves in the condenser bypass lines would automatically close to protect the condenser, thereby causing steam relief to be to atmosphere.

e) Cooldown procedures are followed which entail:

   1) Boration by the high head safety injection pumps

   2) Regulating pressurizer level with spray or relief valves

   3) Reduce system temperature and pressure using steam dump, and

   4) Condenser relief (if available) or atmospheric relief in order to reduce the reactor coolant temperature.

f) Isolation of the faulty SG is achieved by:

1) Stopping the auxiliary feedwater flow to the affected SG

2) Isolating main feedwater to the affected SG, and

3) Closing the steam line stop valve connected to the affected SG (determined by SG liquid sample activity monitor) and blocking the atmospheric relief.

g) Ordinarily this would end the leakage during the interval while cooldown is continuing by steam bypass from the intact SG. Should the faulty SG outlet valve not close, then the main steamline bypass valves would be closed and atmospheric relief from the intact SG would be used for plant cooldown.

h) After the Residual Heat Removal System is in operation, the condensate accumulated in the secondary system can be examined. If the radioactivity level is in excess of that allowed, the condensate can be processed through the waste disposal system.

The faulty unit will be isolated by a steam line isolation valve. This can be accomplished in approximately 30 min and will terminate the mass flow into the secondary system and steam relief from the faulty SG.

With power available to the circulating water pumps, the steam is bypassed to the condenser.

With a concurrent loss of power, a portion of the RCS activity is released to the atmosphere in steam relief during the 30 min to isolate the faulty SG.

15.6.3.2 Analysis of Effects and Consequences

All of the noble gas activity contained in the portion of reactor coolant discharged into the SG during the 30 min to isolate is assumed to be released to atmosphere.

The iodine transferred into the SG is assumed to partition between the liquid and vapor phases of the SG and the portion contained in the steam relief is assumed released to atmosphere. A distribution factor of 4×10^{-3} curies/cm^3 steam / curies/cm^3 water (Reference 15.6.3-1) has been selected as being representative of the pH and pressure conditions within the SG.

During the 30 min period needed to isolate the faulty SG, 70,000 lb of reactor coolant are discharged into the SG and 57,000 lb of steam are relieved to atmosphere. Based on a RCS activity concentration corresponding to 1 percent defective fuel, the noble gas activity release to atmosphere is 9,500 equivalent Curies Xe-133. The corresponding iodine activity discharge into the SG is 78 Curies equivalent I-131, of which 3.9 Curies are released to atmosphere.

15.6.3.3 Conclusions

The resultant site boundary dose is less than 0.3 rem whole body and less than 2 rem to the thyroid, using the two hour meteorological dispersion factor discussed in Section 15.6.5.

15.6.5 Loss-of-Coolant Accidents

15.6.5.1 Identification of Causes and Event Consequences. For the purpose of LOCA analyses, a major LOCA is defined as a rupture 1.0 ft^2 or larger of the Reactor Primary Coolant System piping, including the double-ended rupture of the largest pipe in the RCS or of any line connected to that system up to the first closed valve.

Should a major break occur, depressurization of the RCS results in a pressure decrease in the pressurizer. Reactor trip signal occurs when the pressurizer low pressure trip setpoint is reached. A SIS signal is actuated when the appropriate setpoint (high containment pressure) is reached. These counter measures will limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection complement void formation in causing rapid reduction of power to a residual level corresponding to fission product decay heat, and

2. Injection of borated water provides heat transfer from the core and prevents excessive cladding temperatures.

15.6.5.2 Method of Analysis. The Siemens Power Corporation EXEM/PWR ECCS evaluation model (Reference 15.6.5-3) was used to perform the required analysis. This model consists of the following computer codes.

1. RODEX2 for initial stored energy, fission gas release, and gap conductance.

2. RELAP4-EM for the system blowdown, hot channel blowdown, and accumulator and SIS flow split calculations.

3. CONTEMPT-LT/22 as modified in accordance with NRC Branch Technical Position CSB 6-1 for computation of containment back pressure.

4. REFLEX for computation of system reflood.

5. TOODEE2 for the calculation of final fuel rod heat up.

The quench time, quench velocity, and carryover rate fraction (CRF) correlations in REFLEX and the heat transfer correlation in TOODEE2 are based on SPC's 17x17 Fuel Cooling Test Facility (FCTF) data.

A spectrum of break sizes and axial power shapes was evaluated to identify the limiting case. Three different double-ended guillotine breaks of the cold leg with discharge coefficients of 0.6, 0.8, and 1.0, were considered. Three different axial power shapes were used to bound the power distributions anticipated to occur. The first profile was a center-peaked chopped cosine power shape, the second was a conservatively represented middle-of-cycle (MOC) power shape peaked at the relative axial elevation (X/L) of 0.73, and the third was a conservatively represented end-of-cycle (EOC) power shape peaked at X/L=0.81. The cosine and MOC axial shape cases utilized the maximum stored energy (at 1.04 GWD/kgU core average exposure) predicted over the entire range of exposure from beginning-of-cycle

(BOC) to EOC. The EOC axial shape case utilized the maximum stored energy (at 6.24 GWD/kgU core average exposure) predicted over the range of exposure from MOC to EOC. The limiting combination of break size and axial shape was found to be the case with a 0.8 discharge coefficient and MOC axial shape.

Two single failure cases were analyzed: loss of one Emergency Diesel Genertor and loss of one Low Head (RHR) pump. The limiting single failure was found to be the loss of a Low Head (RHR) pump.

In addition to the exposure studies, axial power shape studies, single failure studies and break size studies for the limiting UO_2 rod; gadolinia rod studies were performed to confirm the limiting case (Reference 15.6.5-2).

Additional input data is presented in Table 15.6.5-1 (Ref. 15.6.5-2).

15.6.5.3 Results. Table 15.6.5-2 presents the peak clad temperature and hot spot metal reaction results for the limiting case (0.8 C_d, double-ended cold-leg break/MOC axial shape/failed RHR pump/UO_2 hot rod). The peak clad temperature was calculated to be 2064°F. The maximum local zirconium-water chemical reaction was calculated to be 3.86%. Table 15.6.5-3 presents the time sequence of events for the limiting case. Figures 15.6.5-2 through 15.6.5-27 and 15.6.5-33 show the transient response of key parameters for the limiting case.

For the Cycle 18, a minor increase in the U-238 capture to fission ratio above that assumed in the analysis of record has increased the power contribution calculated from decay heat. It has been calculated that this aspect of the Cycle 18 reload will result in an increase in the LBLOCA PCT of approximately 4°F. This effect is considered to be insignificant with respect to the 136°F of margin to the 2200°F PCT limit. Therefore, a complete re-analysis of this event is not necessary at this time.

15.6.5.4 Conclusions. For break sizes up to and including the double-ended severance of a reactor primary coolant pipe, the Emergency Core Cooling System for H. B. Robinson Unit 2 will meet the acceptance criteria as specified in 10CFR50.46, with the 1.80 ($F_{\Delta H}$) limit and the axially dependent power peaking limit of 2.50 ($F_Q T$).

The criteria are as follows:

1. The calculated peak fuel element clad temperature does not exceed the 2200°F limit.

2. The amount of fuel element cladding that reacts chemically with water or steam does not exceed 1% of the total amount of zircaloy in the reactor.

3. The cladding temperature transient is terminated at a time when the core geometry is still amenable to cooling. The local cladding oxidation limit of 17% is not exceeded during or after quenching.

4. The core temperature is reduced and decay heat is removed for an extended period of time as required by the long-lived radioactivity remaining in the core.

15.6.5.5 Radiological Consequences. The results of analyses presented in this section demonstrate that the amount of radioactivity released to the environment in the event of a LOCA does not exceed the limits specified in 10CFR100.

The event causing the postulated releases is a double-ended rupture of a reactor coolant pipe, with subsequent blowdown, as described in Section 15.6.5.3. As demonstrated by the analysis described in Section 15.6.5.3, the ECCS, using emergency power, keeps cladding temperatures well below melting and limits zirconium - water reactions to an insignificant level, assuring that the core remains intact and in place. As a result of the increase in cladding temperature and the rapid depressurization of the core, however, some cladding failure may occur in the hottest regions of the core. For this reason, the entire inventory of volatile fission products contained in the pellet-cladding gap is assumed to be released during the time the core is being flooded by the ECCS. Of this gap inventory, 50 percent of the halogens and 100 percent of the noble gases are assumed to be released to the containment vessel atmosphere.

15.6.5.5.1 Fission product inventories. The core fission product inventory was calculated using the ORIGEN code (Reference 15.6.5-6). The maximum core average exposure was 35,000 MWD/MTU (consistent with a peak assembly exposure of 52,500 MWD/MTU) (Reference 15.6.5-7). Release fraction's to the gap from the fuel pellet for the various isotopes were then computed using the RODEX2 code (Reference 15.6.5-8) with the fission gas release models described in the proposed ANS Standard 5.4 (Reference 15.6.3-1). RODEX2 was run using the code logic switches set to calculate maximum release to the gap region of the fuel. The gap activity is the gap release fraction multiplied by the total activity. The resulting core and gap inventories are presented in Table 15.6.5-4.

15.6.5.5.2 Containment leakage. It is not expected that a significant amount of organic iodine would be liberated from the fuel as a result of a LOCA. This conclusion is based on the results of fuel meltdown experiments conducted by the Oak Ridge National Laboratory. The fraction of the total iodine which is released in organic forms is expected to be on the order of 0.2 percent, or less, since the rate of thermal radiolytic decomposition would exceed the rate of production.

Organic compounds of iodine can be formed by reaction of absorbed elemental iodine on contaminated surfaces of the containment vessel. Recent experiments have shown that the rate of formation is dependent on specific test conditions such as the concentrations of iodine and impurities, radiation levels, pressures, temperatures, and relative humidity. The rate of conversion of airborne iodine is proportional to the surface-to-volume ratio of the enclosure, whether the process is limited by diffusion to the surface or by the reaction rate of the absorbed iodine. The yields of organic iodine observed as a function of aging time in various test enclosures were extrapolated to determine the values for the H. B. Robinson containment vessel, using the variation of the surface-to-volume ratios. The iodine conversion rates predicted in this manner did not exceed 0.0035 percent of the atmospheric iodine per hour. For the purpose of calculating doses, it has been assumed that 2.5 percent of the iodine activity released from the cladding gaps in the accident is immediately converted to the organic forms, and that the containment spray has zero effectiveness in cleaning up iodine in this form. The actual effectiveness of the spray system in removing organic iodine is discussed in Section 6.5.2.3 of the Updated FSAR.

The effectiveness of the spray system for elemental iodine removal is also discussed in Section 6.5.2.3. For the H. B. Robinson plant, a three loop design, an iodine removal coefficient of 18.7 hr^{-1} was calculated for a containment pressure of 42 psig and a temperature of 264°F.

The maximum acceptable leak rate for the containment vessel is 0.1 percent per day, at the containment design pressure, and without the benefit of the Isolation Valve Seal Water System or the Penetration Pressurization System. All penetrations are constructed with a double barrier, and the intermediate space is provided continuous or intermittent pressure above the containment design pressure during reactor operation. The Isolation Valve Seal Water System, described in Section 6.8, provides a water seal in pipelines during accident conditions. .

The design leak rate of 0.1 percent per day ($1.16 \times 10^{-8} sec^{-1}$) was assumed to be maintained throughout the first 24 hours, and a leak rate of 0.045 percent per day ($0.52 \times 10^{-8} sec^{-1}$) was assumed for the remainder of the 30-day accident period.

15.6.5.5.3 Offsite Doses

The dose to the thyroid resulting from activity leaking from the reactor containment vessel following the postulated LOCA was computed for the five iodine isotopes from the following expression:

$$D(x,T) = \int_0^T S(t)\, L(t)\, \frac{\chi}{Q}(x,t)\, B(t)\, dt$$

The source term for the five isotopes is:

$$S(t) = \sum_{j=1}^{5} C_j\, DCF_j\, [(1-\beta) \exp(-\lambda_j - \lambda_{si})\, t + \beta \exp(-\lambda_j) t]$$

The terms in the relationships are defined as follows:

t = time, hr
T = time period over which dose is accumulated, hr
x = distance, meters
$D(x,T)$ = accumulated dose, rem
$L(t)$ = containment leak rate, sec^{-1}
$\chi/Q(x,t)$ = site dispersion factor, sec/m^3
$B(t)$ = breathing rate, m^3/hr
C_j = activity of isotope j in the containment, Curies
DCF_j = dose conversion factor for isotope j, rem/Curie
β= initial fraction of containment iodine inventory which is in the organic form
λ_j = radioactive decay constant for isotope j, hr^{-1}
λ_{si} = spray removal coefficient for inorganic iodine, hr^{-1}, including removal by condensation

7 The doses reported in Table 15.6.5-5 (Reference 15.6.5-7) for the site
boundary and low population zone were based on a spray removal coefficient of
10 hr^{-1}, somewhat lower than the actual value calculated for the H. B.
Robinson plant. The values of the containment leak rate and the fraction of
organic iodine were discussed in the previous section. The breathing rates
used were 3.47×10^{-4} cubic meters per second for the first two hours, and
2.32×10^{-4} cubic meters per second afterward, in accordance with T1D-14844
7 (Reference 15.6.5-9). The dose conversion factors are tabulated below.

TABLE 15.6.5-1

LARGE BREAK LOCA/ECCS ANALYSIS CONDITIONS

Calculational Basis

License Core Power, MWt	2300
Power Used for Analysis, MWt*	2346
Heat Flux Factor at Rated Thermal Power, F_Q^{RTP}	2.50
Nuclear Enthalpy Rise Factor, $F_{\Delta H}$	1.80
Steam Generator Tube Plugging, %	6.00
Maximum Peak Rod Average Exposure, GWD/kgU	62.0

* Including 1.02 factor for power uncertainty.

TABLE 15.6.5-2

LARGE BREAK LOCA/ECCS ANALYSIS RESULTS

Exposure at Time of Peak Stored Energy, GWD/kgU Core Average Exposure	1.04
Average LHGR, kw/ft	5.98
Peak Linear Heat Generation Rate (LHGR)*, kw/ft	14.06
Total Peaking Factor, Fq**	2.42
Axial Peaking Factor, F_{EZ}	1.34
Local Peaking Factor, F_L	1.06
Peak Clad Temperature	
- Temperature, °F	2064
- Time, seconds	61.1
- Elevation, feet	8.75
Hot Rod Burst	
- Time, seconds	39.7
- Elevation, feet	8.75
- Fractional Flow Area Reduction	0.288
Zr-H_2O Reaction at End Problem Time	
- Maximum Local Reaction, %	3.86
- Elevation of Maximum Local Reaction, feet	8.75
- Hot Pin Total Reaction, %	0.674
- Total Core Reaction, %	<1.0

* Power produced in peak pellet (does not include fraction attributed to direct moderator heating by gamma ray attenuation).

** Adjusted for the k(z) curve in Figure 15.6.5-1 (Reference 15.6.5-1) at the peak-power elevation of 8.75 feet.

TABLE 15.6.5-3

Large Break LOCA/ECCS Analysis Event Times

Event	Time (sec.)
Start	0.00
Initiate Break	0.05
Safety Injection Signal	0.60
Accumulator Injection (Broken Loop)	2.61
Accumulator Injection (Intact Loop)	10.97
End-of-Bypass (EOBY)	20.96
Safety Pump Injection, HPSI (Broken and Intact Loops)	29.11
Accumulator Empty (Broken Loop)	37.15
Safety Pump Injection, LPSI (Broken Loop)	37.15
Start of Reflood (BOCREC)	41.92
Accumulator Empty (Intact Loop)	44.31
Safety Pump Injection, LPSI (Intact Loop)	44.31
Peak Clad Temperature Reached	61.10

REFERENCES: SECTION 15.6

15.6.2-1 "Acceptance Criteria for Emergency Core Cooling System for Light Water Cooled Nuclear Power Reactors," 10CFR50.46 and Appendix K of 10CFR50, Federal Register, Volume 39, Number 3, January 4, 1974.

15.6.2-2 "Exxon Nuclear Company Evaluation Model - EXEM PWR Small Break Model", XN-NF-82-49 (P) (A), Revision 1, Supplement 1, December 1994.

15.6.2-3 "H. B. Robinson Unit 2 Small Break LOCA Analysis", EMF-94-203(P), October 1994.

15.6.2-4 Deleted by Revision No. 13.

15.6.2-5 Letter from H.G. Shaw (Siemens Power Corporation) to B.A. Morgan (CP&L) dated 11-7-94, "H.B. Robinson Small Break LOCA," serial number HGS:395:94.

15.6.3-1 "Assessment of Potential Radiological Consequences for High Exposure Fuel," XN-NF-719(P), August 1983.

15.6.5-1 H. B. Robinson, Unit 2 Technical Specifications, Docket No. 50-261, page 3.10-22, Figure 3.10-3, Amendment 109.

15.6.5-2 "H. B. Robinson Unit 2 Large Break LOCA Analysis for Cycle 17", EMF-95-040, March 1995.

15.6.5-3 Dennis M. Crutchfield (USNRC Asst. Director Division of PWR Licensing-B) to Gary M. Ward (ENC Manager, Reload Licensing), "Safety Evaluation of Exxon Nuclear Company's Large Break ECCS Evaluation Model EXEM/PWR and Acceptance for Referencing of Related Licensing Topical Reports," dated July 8, 1986.

15.6.5-4 "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10CFR50.46 and Appendix K of 10CFR50, Federal Register, Volume 39, Number 3, January 4, 1974.

15.6.5-5 "H. B. Robinson Unit 2 Large Break LOCA/ECCS Analysis with Increased Peaking Factors," EMF-91-237, Siemens Power Corporation, Revision 1, August 1993.

15.6.5-6 M. J. Bell, "ORIGEN - The ORNL Isotope Generation and Depletion Code," ORNL-4628, Oak Ridge National Laboratory, May 1973.

15.6.5-7 "H. B. Robinson Unit 2 Radiological Assessment of Postulated Accidents," EMF-91-208(P), December 1991, Siemens Nuclear Power Corporation.

15.6.5-8 "RODEX2: Fuel Rod Thermal-Mechanical Response Evaluation Model," XN-NF-81-58, Revision 2 with Supplements 1 and 2, March 1984, Supplements 3 and 4, June 1990.

REFERENCES: SECTION 15.6 (Continued)

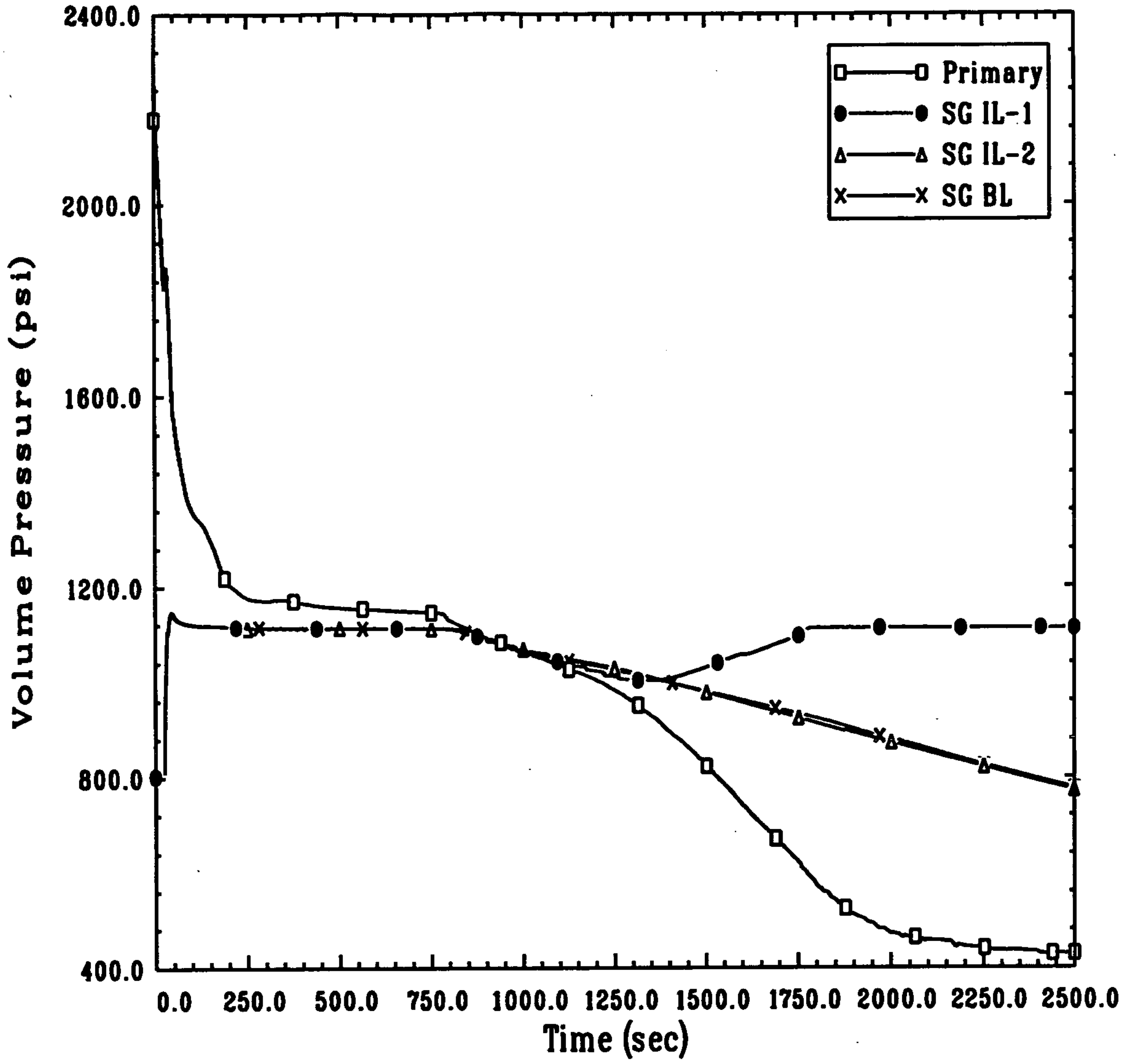
15.6.5-9 DiNunno, J. J., et. al., Calculation of Distance Factors for Power and Test Reactor Sites, AEC Report Number TID-14844, March 23, 1962.

15.6.5-10 Letter from E. E. Utley to NRC, dated December 31, 1980, "Control Room Habitability Requirements," Serial Number NO-80-1947.

15.6.5-11 Letter from L. I. Loflin to NRC, dated May 21, 1990, "Control Room Habitability Requirements," Serial Number NLS-90-027.

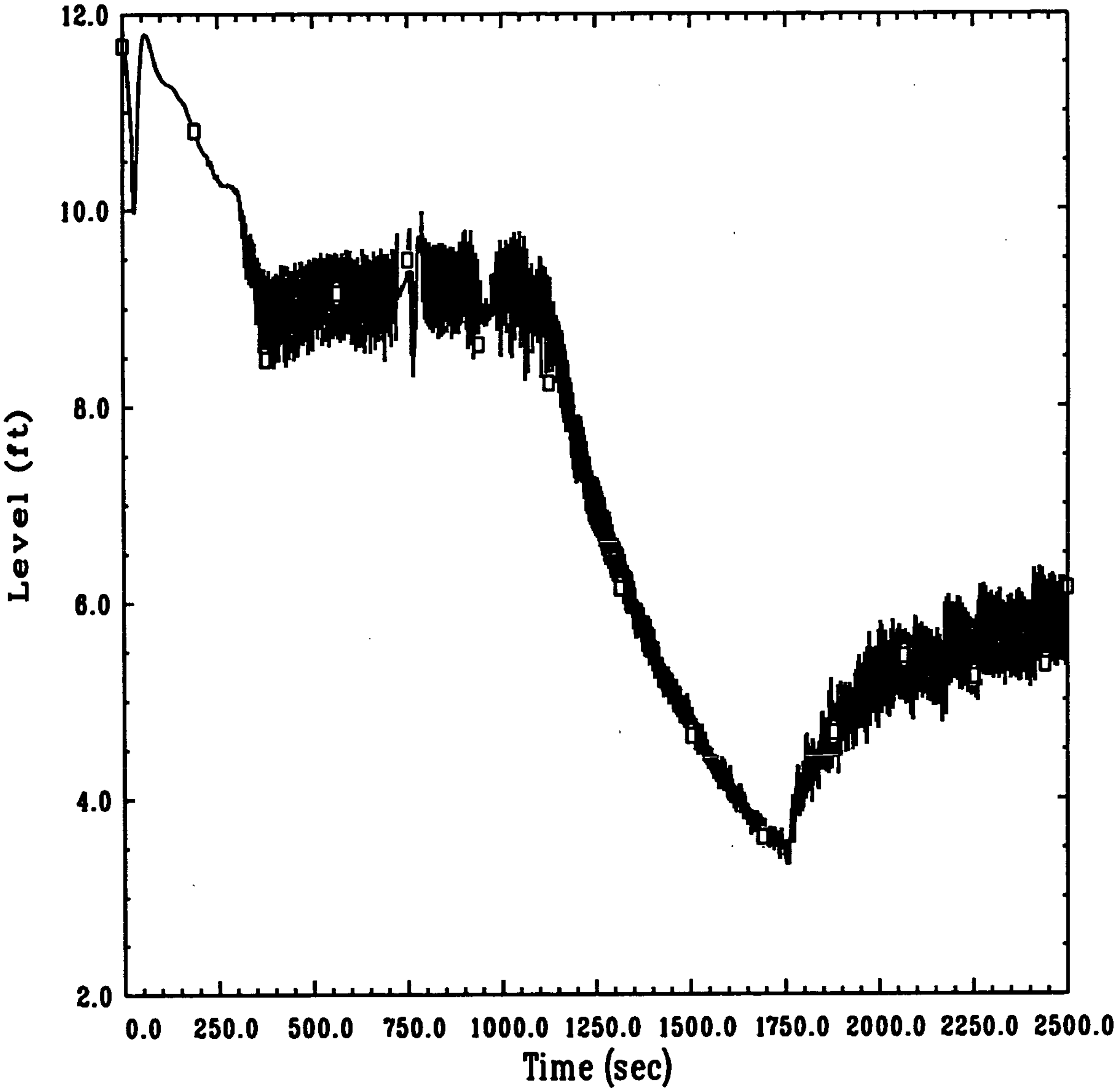
15.6.5-12 CP&L Calculation, "Control Room Operator 30-Day Thyroid Dose," RNP-M/MECH-1592, Revision 0, December 7, 1994.

Note: Dose conversion factors in the references are based on siting calculations. Dose conversion factors used in public evacuation are based on EPA-400-R92-001.



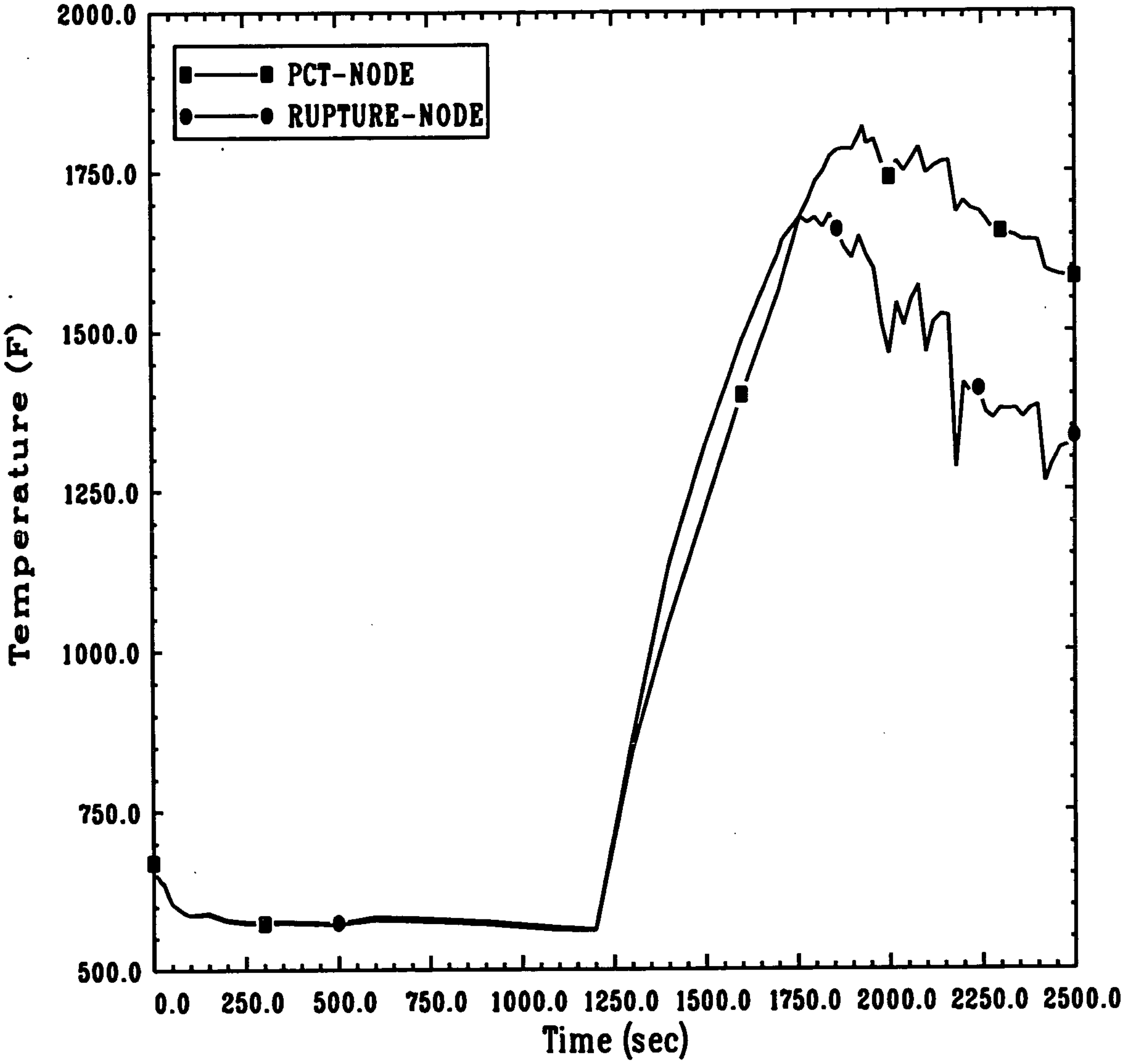
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	System Pressure for Small Break LOCA	FIGURE 15.6.2-4



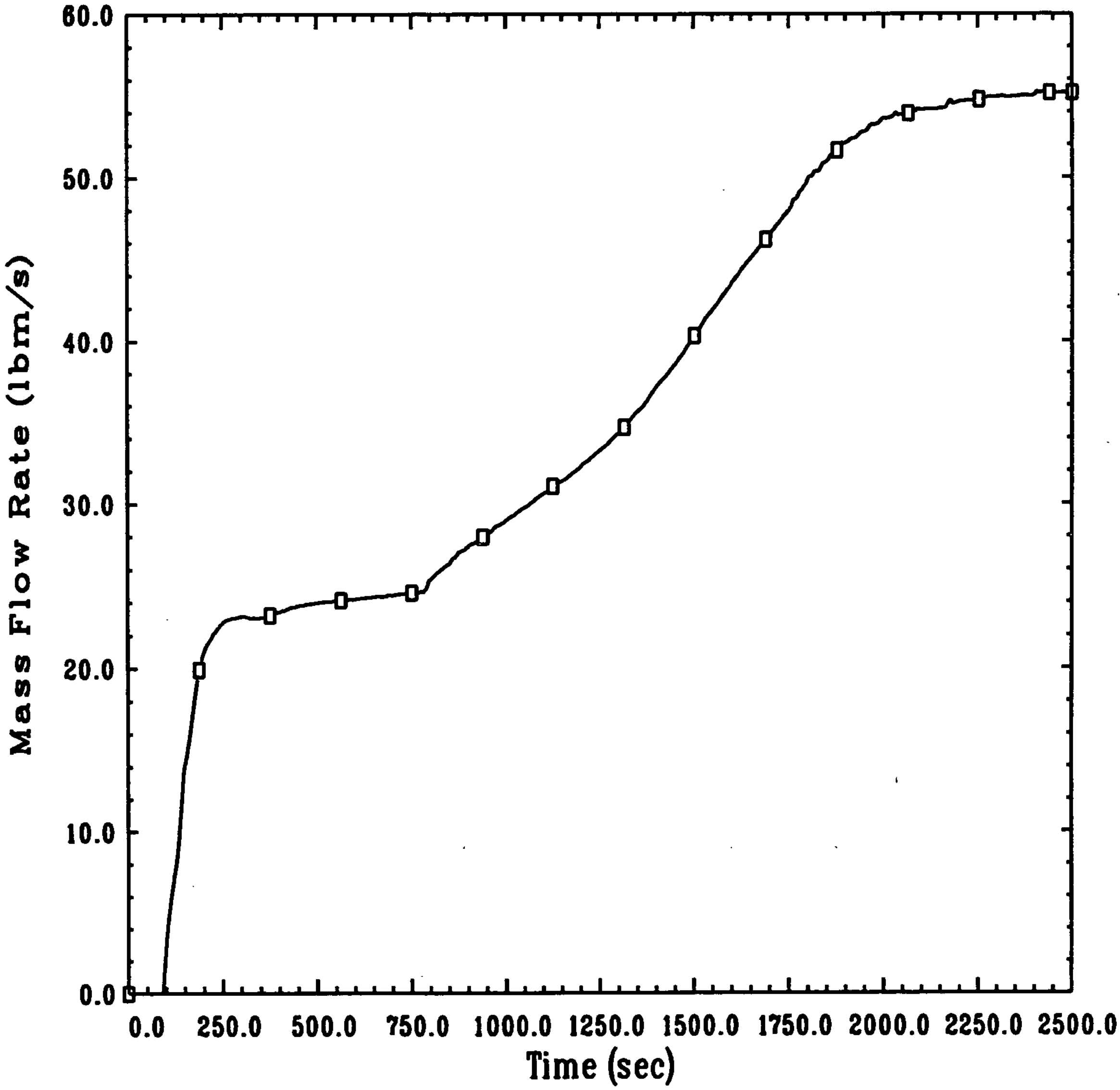
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Core Collapsed Liquid Level for Small Break LOCA	FIGURE 15.6.2-5



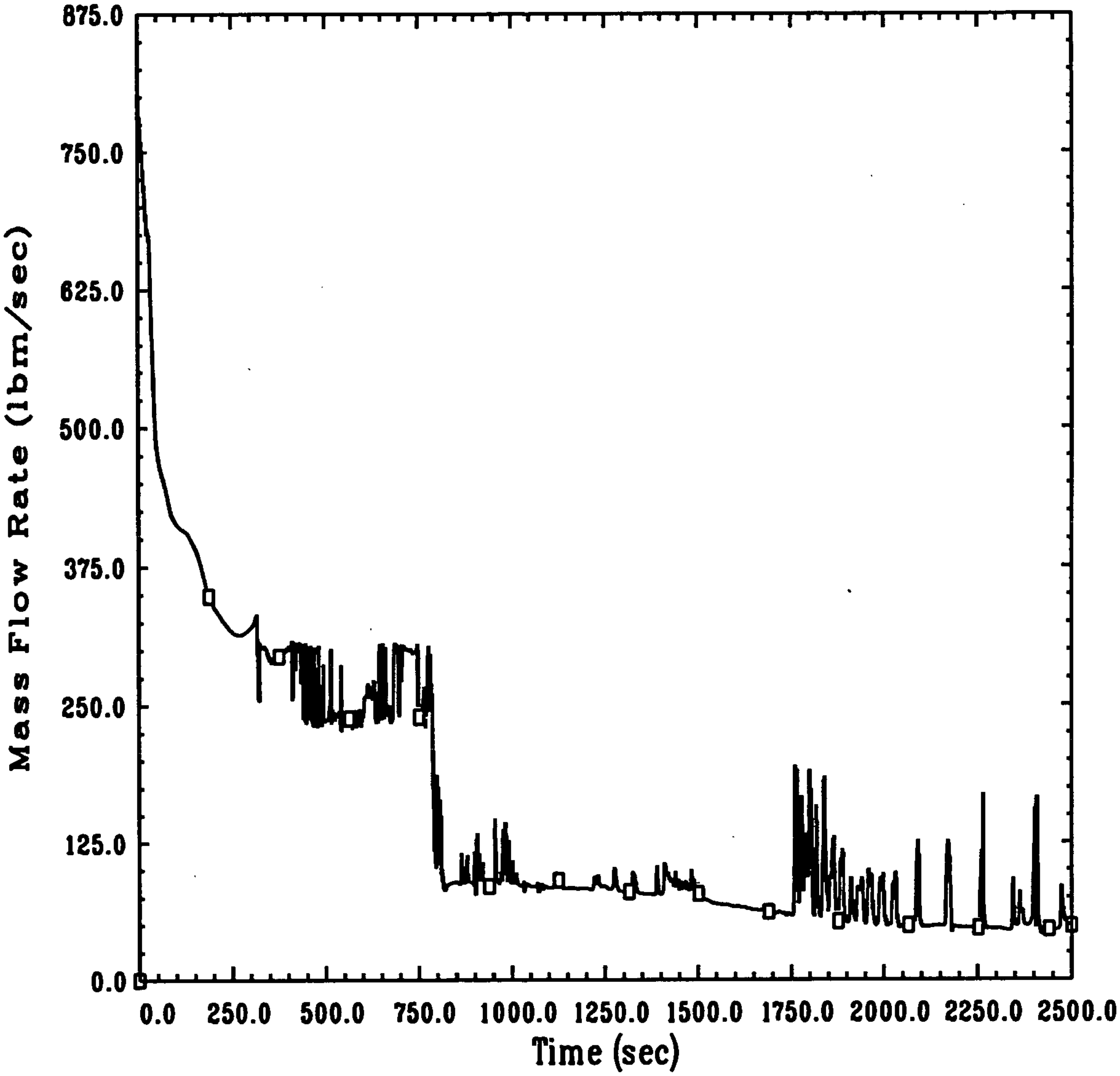
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Hot Rod Cladding Temperatures for Small Break LOCA	FIGURE 15.6.2-6



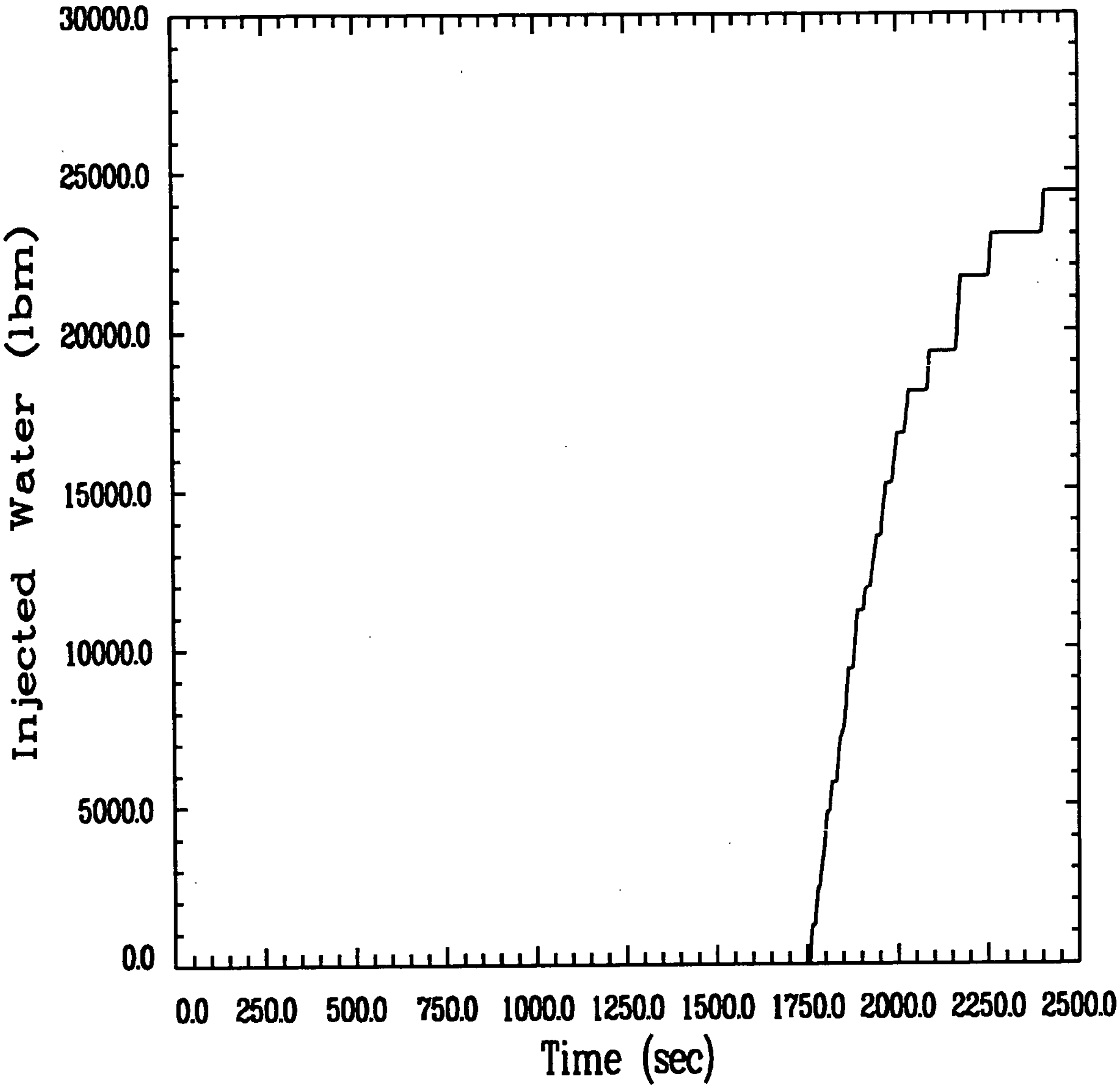
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Total SI Flow for Small Break LOCA	FIGURE 15.6.2-7



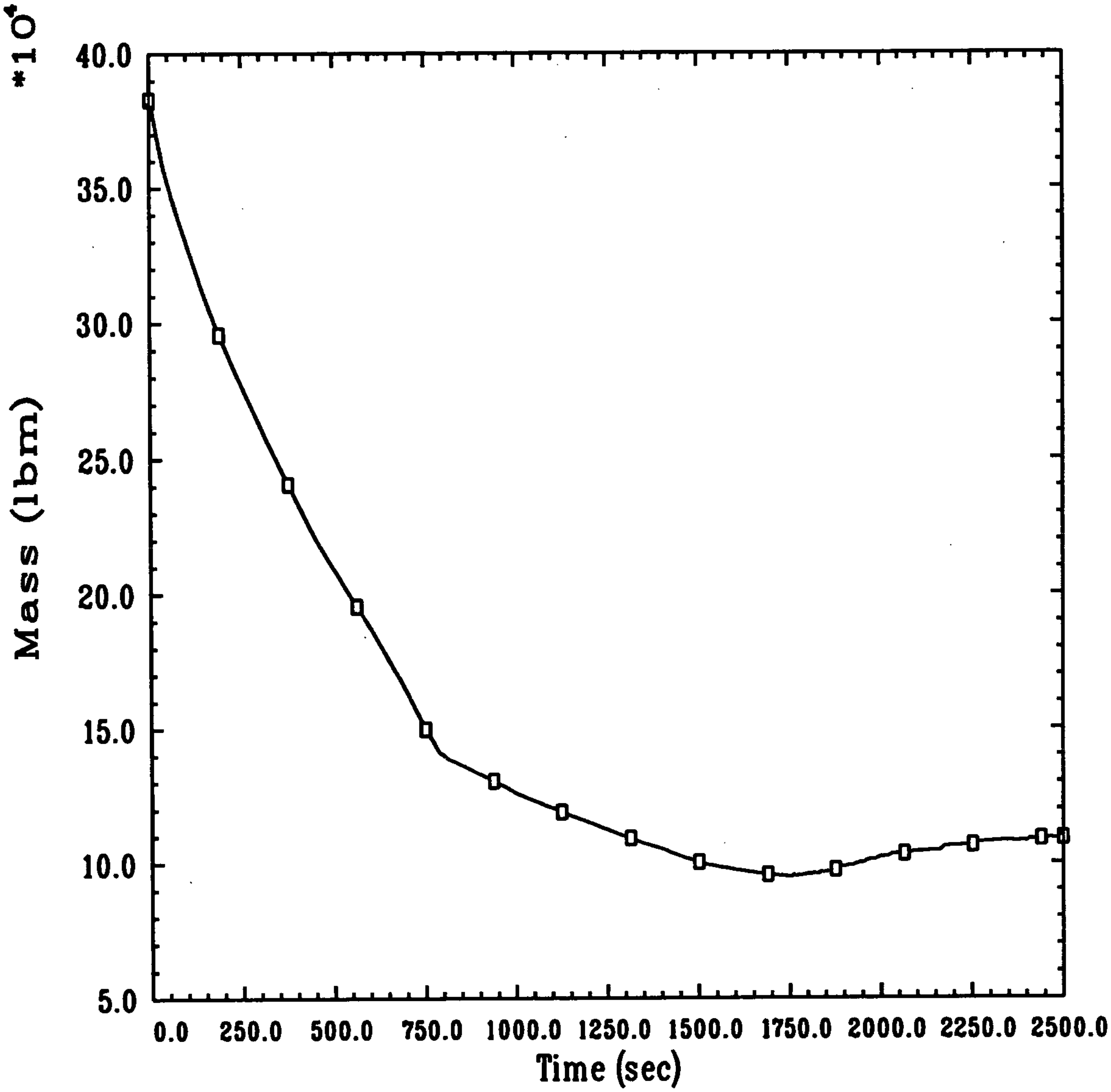
REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Break Flow Rate	FIGURE 15.6.2-8



REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Combined Accumulator Flow for Small Break LOCA	FIGURE 15.6.2-9



REVISION NO. 13

H. B. ROBINSON UNIT 2 Carolina Power & Light Company UPDATED FINAL SAFETY ANALYSIS REPORT	Primary System Fluid Mass for Small Break LOCA	FIGURE 15.6.2-10

If the fuel assembly were to strike a sharp object, it is possible that the sharp object might damage the fuel rods with which it comes in contact, but breaching of the cladding is not expected. It is on this basis that the assumption of the failure of all the fuel rods in an assembly is a very conservative upper limit.

15.7.4.2 Method of Analysis. Analyses have been made assuming the extremely remote situation where a fuel assembly is dropped and strikes a flat surface, where one assembly is dropped on another, and where one assembly strikes a sharp object. The analysis of a fuel assembly assumed to be dropped and to strike a flat surface considered the stresses the fuel cladding was subjected to and any possible buckling of the fuel rods between the grid clip supports. The results showed that the buckling load at the bottom section of the fuel rod, which would receive the highest loading, would be below the critical buckling load and the stresses would be relatively low and below the yield stress.

The end plates and guide thimbles would absorb a large portion of the kinetic energy as a result of bending in the lower plate of the falling assembly. The results of this analysis indicated that the buckling load on the fuel rods would be below the critical buckling loads, and the stresses in the cladding would be relatively low and below yield.

The refueling operation experience that was obtained with Westinghouse reactors prior to operation of HBR 2 and during HBR 2 operation has verified the fact that no fuel cladding integrity failures are expected to occur during any fuel handling operations.

For the assumed accident, there would be a sudden release of the gaseous fission products held in the fuel rod plenum and in the voids between the pellets and cladding of all 204 fuel rods. The low temperature of the fuel during handling operations precludes further significant release of gases from the pellets themselves after the cladding is breached. Halogen release is also greatly minimized due to their low volatility at these temperatures. The strong tendency for iodine in vapor and particulate form to be scrubbed out of gas bubbles during their ascent to the water surface further alleviates the inhalation hazard.

Decontamination factors of 10^{-3} (Reference 15.7.4-1) have been measured with much shallower water depths and much higher gas-to-water ratios. In a Westinghouse laboratory apparatus, elemental iodine (I_2) was passed in an air stream through a solution of 2000 ppm boron as boric acid. This solution is chemically similar to that in the spent fuel storage pit. The contact time in this apparatus corresponded to a bubble rise of 1.6 cm. Initially, the iodine decontamination factor (DF) in this apparatus was about 90 percent. The value decreased with time as the concentration of iodine in solution approached saturation, as expected. The DF at zero aqueous iodine concentration agreed with that obtained with an iodine fixing reagent (sodium thiosulfate) in solution, indicating that gas phase diffusion to the bubble wall was controlling when the laden bubbles contacted fresh solution. This condition can be assumed to represent the scrubbing of gas bubbles released from an accidental cladding failure as they rise through a vast reservoir of iodine

free solution in the spent fuel pit. The calculated contact time in the accident can be related to the experiment by the ratio of the submergence, which is at least 21 ft, in the case of the plant, compared with 1.6 cm in the experiment. Assuming the same mass transfer rate in the bubble the DF of 10^{-3} would be obtained in a rise of only 9.9 cm. While this extrapolation is undoubtedly optimistic, it indicates that a large margin is available in the height of bubble rise in the pool to compensate for differences in bubble size and the decay of eddy motion inside the bubble with time.

The activity could be released either in the containment or in the Auxiliary (Fuel Storage) Building. Ventilation systems in both areas are in operation under administrative control during refueling; hence, in calculating doses inside the structures, uniform dilution is assumed within the structure. Radioactivity monitors would immediately indicate and alarm the increased activity level. Activity in the containment would automatically close the purge ducts. In evaluating the dose to refueling personnel inside the containment, 15 min is assumed to be a reasonable time for evacuation. In the Fuel Storage Building, the integrated dose is evaluated based on the 8,000 cfm ventilation rate and the 50,000 ft^3 free volume. In the containment, the dose is based on the 35,000 cfm purge rate and 1.55×10^6 ft^3 of the containment free volume.

In calculating offsite exposure, it is assumed that the incident occurs in the spent fuel pit or the containment and that the activity is discharged to the atmosphere at the ground level through filters. This results in maximum ground level doses. This assumption is very conservative for two reasons: the ventilation systems exhaust to atmosphere at an elevated point, and the containment doors are closed. The whole body doses are based on the model described in Section 15.6.5.

Dispersion of this activity is computed using the Gaussian plume dispersion formula and taking credit for building wake dilution, as included in the two-hour dispersion factor developed in Section 15.6.5.4.

15.7.4.3 Radiological Consequences.

15.7.4.3.1 Postulated fuel handling accident in the fuel handling building. Using the assumptions listed in Table 15.7.4-1, the total offsite thyroid dose and whole body dose are 33.9 rem and 4.8 rem, respectively (Reference 15.7.4-2).

15.7.4.3.2 Postulated fuel handling accident inside containment. Using the assumptions listed in Table 15.7.4-2, the total offsite thyroid dose is 24.8 rem. The total whole body dose is 0.60 rem (Reference 15.7.4-2).

For Cycle 18 an evaluation has been preformed to demonstrate the acceptability of four specific fuel assemblies (ROB-13 originally loaded in Cycle 16) slightly exceeding the above referenced 52,500 MWD/MTU burnup value up to as much as 53,000 MWD/MTU. That evaluation determined that the assemblies would support the marginal burnup extension and the radiological consequences of extending the burnup of these four specific assemblies would still be bounded by the radiological analysis of record which assumed the 52,500 MWD/MTU.

TABLE 15.7.4-1

FUEL HANDLING ACCIDENT IN FUEL STORAGE BUILDING

ASSUMPTIONS

1. Accident occurs 100 hr after reactor shutdown.

2. Plant thermal power is 2300 Mwt.

3. All rods in one assembly rupture, releasing their gap activity.

4. Burnup in affected assembly is 52,500 MWD/MTU.

5. Fraction of assembly activity in gap

Iodines	0.10
Noble gases	0.10
Krypton-85	0.30

6. Iodine form split in clad gap

Elemental	99.75 percent
Organic	0.25 percent

7. Pool DF

Elemental Iodine	133
Organic Iodine	1
Noble gases	1

8. 157 assemblies in the core

9. All activity released from pool is immediately exhausted at ground level to the environment through filters.

10. Filter efficiencies for iodine removal

Elemental Iodine	90 percent
Organic Iodine	70 percent

11. Breathing rate is 3.47×10^{-4} m^3/sec

12. X/Q is 8.70×10^{-4} sec/m^3

REFERENCE: SECTION 15.7

15.7.4-1 Diffey, H. R. et. al., "Iodine Cleanup in a Steam Suppression System," International Symposium on Fission Product Release and Transport Under Accident Conditions, Oak Ridge, Tennessee, CONF-65047, Vol. 2, Pg. 776-804 (1965).

15.7.4-2 EMF-91-208(P), "H. B. Robinson Unit 2 Radiological Assessment of Postulated Accidents," Siemens Nuclear Power Corporation, Richland, WA, December 1991.

CHAPTER 17
QUALITY ASSURANCE

TABLE OF CONTENTS (Cont'd)

CHAPTER 17
QUALITY ASSURANCE

TABLE OF CONTENTS (Cont'd)

17.3.2 Performance/Verification

17.3.2.1 Methodology. Personnel performing work activities are responsible for achieving the acceptable level of quality.

Personnel performing verification activities are responsible for verifying the achievement of acceptable quality.

Work is accomplished and verified using instructions, procedures, or appropriate means that are of a detail commensurate with the activity's complexity and importance to safety.

Criteria that define acceptable quality are specified in procedures and/or other documents, and verification, when required is performed against these criteria.

17.3.2.2 Design Control. Procedures define requirements for the control of design activities associated with modifications of items that are safety-related.

Design changes are subject to appropriate controls which were applicable to the original design. CP&L may designate an organization to make design changes other than the organization which prepared the original design. In any case, CP&L will assure that the organization has access to pertinent background information, including an adequate understanding of the requirements and intent of the original design, and that the organization has demonstrated competence in applicable design areas.

Measures shall be taken to assure that the design selected to accomplish a necessary or desirable change does not create "new" problems in off-normal modes of operation or in adjacent inter-tied systems.

Design changes made to the plant are accomplished in a planned and controlled manner in accordance with written, approved procedures. These procedures include provisions, as necessary, to ensure that:

1. Design documents (such as specifications, drawings, procedures and instructions) reflect applicable regulatory, performance, quality, and quality verification requirements and design bases. These documents are checked for accuracy and completeness by qualified individuals and reviewed to assure that documents are prepared in accordance with procedures.

2. There is adequate review of the suitability of materials, parts, equipment, and processes which are essential to the safety-related functions of structures, systems, and components.

3. Materials, parts, and equipment which are commercial grade items or which have been previously approved for a different application are evaluated for suitability prior to selection.

4. Design documents and procedures are controlled to reflect design modifications and "as-built" conditions.

5. Internal and external design interfaces between organizations participating in modification activities are adequately defined and controlled, including the review, approval, release, and distribution of design documents and revisions.

The above controls are applied as necessary to such aspects of design as reactor physics; seismic, stress, thermal, hydraulic, radiation, and accident analyses; compatibility of materials; and accessibility for inservice inspection, maintenance, and repair.

Any errors or deficiencies found in the design process or the design itself are documented and corrected, as outlined in the applicable Department's corrective action program procedures.

Following completion of the design change/modification, controlled design change information is made available to affected personnel.

Training, on design changes/modifications that affect the operation of the plant, is provided to affected plant operating personnel.

17.3.2.3 Design Verification. Procedures require that the adequacy of design changes be verified by the performance of design reviews, alternate calculations, or qualification testing. The control measures specified in the plan for control of design verification activities are as follows:

1. Personnel responsible for design verification do not include the original designer or the designer's immediate supervisor unless the immediate supervisor is the only one capable of verifying the design.

2. Procedures identify the positions or organizations responsible for design verification and define their authority and responsibility. Procedures also provide guidelines as to the method of design verification to be used. Unless otherwise specified, design verification is performed by the method of independent design reviews and includes verification that Safety Analysis Report (SAR) commitments have been addressed.

3. Qualification tests to verify the adequacy of the design are performed using the most adverse specified design conditions.

4. Design changes are reviewed to assure that design parameters are defined and that inspection and test criteria are identified.

5. Design verification is completed prior to relying upon the component, system or structure to perform its function.

17.3.2.4 Procurement Control. Carolina Power & Light Company maintains a program for supplier evaluation, results of supplier evaluation, surveillance of suppliers, supplier furnished records, certificates of conformance, effectiveness of supplier quality control, and the purchase of spare or replacement parts.

Procedures define requirements for the control of procurement documents and ensure that purchased material and services are of acceptable quality.

Potential contractors and suppliers are evaluated by Vendor and Equipment Quality Unit personnel prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.

2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to CP&L for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.

3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Receipt inspections are performed by qualified inspectors in accordance with procedures to assure that:

1. Materials, equipment, or components are properly identified and correspond with associated documentation.

2. Inspection records or certificates of conformance attesting to the acceptance of materials, equipment, and components are completed and are available prior to installation or use.

3. Materials, equipment, and components are inspected and judged acceptable in accordance with predetermined inspection instructions prior to installation or use.

4. Items not meeting applicable requirements are identified and controlled until proper disposition is made.

Appropriate controls and provisions have been included in procurement procedures for selection, determination of suitability for the intended use, evaluation, receipt, and quality evaluation of commercial grade items to ensure that these items will perform satisfactorily in service.

<u>17.3.2.5 Procurement Verification</u>. CP&L procurement documents are prepared, reviewed, approved, and controlled in accordance with procedures to assure that requirements are correctly stated, inspectable, verifiable, and controllable, and there are adequate acceptance/rejection criteria. Procurement documents are reviewed by personnel knowledgeable in applicable technical and quality requirements, and documentary evidence of that review and approval is retained and available for verification.

17.3.2.6 Identification and Control of Items. Procedures require spare or replacement parts to be subject to QA program controls, codes and standards, and technical requirements which ensure they are suitable for their intended service.

Items accepted or released are identified as to their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work. (Bulk items will not require individual accept tags; however, status of unacceptable bulk items will be so indicated).

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items. These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.

2. Verification of item identification consistent with the CP&L inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

Consumables utilized in safety-related structures, systems and components are subject to appropriate controls as described in procedures.

17.3.2.7 Handling, Storage, and Shipping. Procedures define requirements for the control of the handling, storage, and shipping of safety-related items. These procedures require measures to be taken to ensure special handling, storage, cleaning, packaging, shipping, and preservation requirements are established to control these activities in accordance with design and specification requirements to preclude damage, loss or deterioration by environmental conditions such as temperature or humidity.

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

17.3.2.8 Test Control. Procedures define requirements for test programs when required and require that items be tested to demonstrate that they will perform satisfactorily in service.

Modifications, repairs, and replacements are accomplished in accordance with the original design and testing requirements or acceptable alternatives.

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test,

2. Use of proper test equipment,

3. Mandatory inspection hold points,

4. Acceptance criteria

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria is not met, affected areas are to be retested or evaluated, as appropriate.

<u>17.3.2.9 Measuring and Test Equipment Control</u>. Procedures define requirements for the control of measuring and test equipment used. These procedures include requirements to establish procedures for the calibration technique and frequency, maintenance, and control of measuring and test equipment.

Inspections and test devices are selected to assure accurate measurement (i.e., to overcome inherent inaccuracies associated with environment, human error, equipment, etc.).

Measuring and test equipment (M&TE) is identified and traceable to the calibration test data.

Measuring and test instruments are calibrated at specified intervals (or immediately before and after use) based upon one or more of the following:

1. Technical Specifications

2. Required accuracy

3. Intended use

4. Frequency of usage

5. Stability characteristics

6. Other conditions affecting measurement

7. Manufacturer's recommendations

Status of calibration for measuring and test equipment is provided through the use of tags, stickers, labels, routing cards, computer programs, or other suitable means. The status indicators indicate the date recalibration is due or the frequency of recalibration.

Portable measuring and test equipment are calibrated by standards at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art.

Special tools such as torque wrenches, calipers, and micrometers are calibrated to be at least as accurate as the application(s) for which it is used, using standards which are at least as accurate as the special tool being calibrated.

Installed measuring and test instruments are calibrated by instruments at least as accurate as the installed, unless limited by the state of the art.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

Measures are required to be taken and documented to determine the validity of previous inspections and test results, if the measuring and test equipment is found to be out of calibration.

17.3.2.10 Inspection, Test, and Operating Status. Procedures define requirements for the identification and control of the inspection, test, and operating status of safety-related structures, systems, and components.

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Measures are established for indicating the operating status of structures, systems, and components. These measures include the use of checklists, computer programs, logs, stickers, tags, labels, record cards, and test records to indicate the acceptable operating status of installed equipment. Installed equipment which, if operated, could cause damage to other equipment/systems or to personnel is tagged to indicate its non-operational status and to prevent inadvertent use.

Selected plant procedures and subsequent revisions receive separate technical review to ensure required inspections, tests, and other critical operations are included.

Altering the sequence of required tests, inspections, and safety-related operations can only be accomplished by methods outlined in procedures.

17.3.2.11 Special Process Control. Procedures define requirements for the control of special processes, such as welding, heat treating, and nondestructive examination.

Procedures require that special processes be performed by qualified personnel using proper equipment and in accordance with written qualified procedures. These personnel and procedures are to be qualified in accordance with applicable codes, standards, and specifications as described in procedures. Qualification records of special process procedures and personnel performing special processes are maintained and available for verification.

17.3.2.12 Inspection. Procedures define requirements for an inspection program to verify conformance to performance and quality requirements specified for those activities and services.

Inspections are performed by personnel who are not directly responsible for performing or supervising the activity being inspected. Inspection personnel are qualified in accordance with applicable codes and standards, and their qualifications and certifications are maintained current.

Inspections are performed in accordance with procedures or other documents which provide for the following:

1. Identification of individuals or groups responsible for performing the inspections

2. Identification of characteristics and activities to be inspected

3. Acceptance criteria

4. Inspection techniques

5. Recording the results of the inspection, review of the results, and identification of the inspector

6. Indirect control by monitoring of processing methods, equipment, and personnel when direct inspection is not possible

Procedures identify inspection holdpoints, beyond which work may not proceed until inspected.

When acceptance criteria are not met, the condition will be documented in accordance with the applicable department's corrective action program procedures and reinspected or evaluated, as appropriate.

Modification, repairs, and replacements are inspected in accordance with the original design and inspection requirements or acceptable alternatives.

17.3.2.13 Corrective Action. The primary goal of the CP&L corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by reinspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

17.3.2.14 Control of Documents. Procedures define requirements for the development, review, approval, issue, use, revision, and control of documents. These procedures define the scope of which documents are to be controlled.

Procedures require the identification of those individuals or organizations responsible for reviewing, approving, and issuing documents and revisions thereto.

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

Controlled documents are to be distributed to and used by the person performing the activity in accordance with plant procedures.

A document control system has been established to identify the current revision number of instructions, procedures, specifications, and drawings.

Superseded documents are controlled to prevent inadvertent use.

17.3.2.15 Records. The program requires that sufficient records be maintained to provide documentary evidence of the quality of items and the accomplishment of activities affecting quality.

Procedures define requirements for the identification, collection, and storage of quality assurance records.

Records are identifiable and retrievable through the use of indexes and filing systems, which are required by the program.

Procedures are required to be developed to indicate responsibilities and retention periods.

The structures in which certain records are maintained are designed to prevent destruction, deterioration, or theft. These structures ensure protection against destruction by fire, flooding, theft, and deterioration by the environmental conditions of temperature and humidity. The dual storage provision of ANSI N45.2.9-1979 is used for the storage of optical disks and other electronic media.

17.3.3 Assessment

17.3.3.1 Methodology. The overall objective at CP&L is to encourage ownership, involvement, and dedication by each individual supporting the Nuclear Generation Group. This involves continually and aggressively looking for ways to improve the overall performance and safety at each plant. This approach of identifying and correcting conditions early, requires active support by management and employees.

A process of assessment is an attitude by personnel that the CP&L Nuclear Generation Group is improving on a continual basis. This process, along with an effective corrective action program, ensures that conditions are identified early, corrected promptly and effectively before becoming significant quality or safety problems.

Personnel responsible for carrying out the assessment functions, including safety committee activities, nuclear safety reviews, verifications, self-assessment and independent assessments, are cognizant of day-to-day activities, events, and have necessary experience to act in a management advisory function.

The Nuclear Assessment Sections will hold periodic, but not less frequently than semi-annual (+25% for scheduling flexibility), peer review meetings at both the Section Manager and the Unit Manager level for the purpose of exchange of information among sites. The Unit Managers' and Section Managers' meetings will allow the use of a designated alternate to attend these meetings. The PES Manager will participate as a member of the Section Managers' peer group meeting. The Independent Review Engineers will also meet periodically, but not less frequently than semi-annually (+25% for scheduling flexibility), for the purpose of exchange of information among sites.

Assessment activities are accomplished using processes or procedures of a detail needed to accomplish the function based on complexity and importance to safety.

The managers of functions that support the Nuclear Generation Group are responsible for ensuring that self-assessment activities and processes are implemented within their functions on a continuing basis.

17.3.3.2 Self-Assessment. It is the management expectation that individuals and organizations self-assess their end product. Adverse conditions identified during self-assessment activities are reported and resolved in accordance with the corrective action program.

Self-Assessment activities are not necessarily a documented activity and personnel performing self-assessment do not require any special training and/or qualifications beyond that required to hold their present position.

17.3.3.2.1 Line organization. Each individual, work group, and manager should be aware of areas that may need improvement.

Members of the line organization are charged with the responsibility to continually evaluate their activities and use each opportunity to achieve higher standards of quality and improved performance.

Self-assessment activities focus on how well the integrated quality assurance program is working and is to identify conditions that hinder the organization from achieving its safety, quality, and performance goals and standards.

17.3.3.2.2 Nuclear Services and Environmental Support Department. The Performance Evaluation Section, in the Nuclear Services and Environmental Support Department, shall monitor specific functional areas, along with the line organization management, to determine that the desired levels of performance are being achieved. Individuals assigned these duties shall work with each nuclear plant to improve implementation of CP&L's Nuclear Generation Group programs and processes to support safe and reliable operation.

The primary functions of the PES are to: 1) independently assess the self-assessment and corrective action implementation process of the line organizations, and assess the NAS; 2) ensure that "lessons learned" are shared among the plants and support organizations; and 3) facilitate the use of industry peer evaluators to identify industry best practices.

A PES-led self-assessment shall be performed in each major functional area (maintenance, operations, engineering, E&RC and plant support) once every 24 months. The PES evaluation teams may include peers from other CP&L plants and from the nuclear utility industry, as appropriate, to lend expertise to the self-assessment.

The PES will by procedure, evaluate: 1) the effectiveness of the site's self-assessment program, 2) the site's ability to incorporate lessons learned from within CP&L, as well as industry events, and 3) the site's corrective action implementation program. To facilitate exchange of information among sites, PES and Nuclear Assessment Section, periodic peer group meetings will be held, not less than semi-annually (+25% for scheduling flexibility), among the PES Manager and the Nuclear Assessment Section Managers from each site.

The PES shall provide oversight of each plant's NAS by reviewing NAS assessment reports and by performing a NAS effectiveness assessment at least once every 24 months.

Written PES evaluations, including the results and recommended corrective actions, will be reported to plant and senior management.

17.3.3.3 Independent Assessment. The NAS is responsible for conducting independent assessments of functions and activities affecting the nuclear programs at CP&L.

17.3.3.3.1 Organization. Personnel performing independent assessment activities are generally assigned to the NAS from the line and other organizations on a rotational basis for two to five year assignments. Since these personnel are full-time assessors during this time period, they have no direct responsibilities in the areas being assessed. However, on an exception basis, personnel in the NAS may provide assistance to the line organization by participating in emergency preparedness activities, ad hoc committees or analyzing technical issues, if such assistance is deemed to be in the overall best interest of safety and is approved in advance by NAS management. In addition, peer assessors from the line organizations may be utilized to add

specific technical expertise to the assessment team. In these cases, the peer assessors will work under the direction of the assessment team leader and will not be assessing any functions associated with their normal job assignment.

Selection of assessment personnel is based on experience and/or training that establishes that their qualifications are commensurate with the complexity or special nature of the area being assessed. The process for qualification of personnel to perform and lead assessments is established in procedures.

The Site Vice President is responsible for ensuring that an environment exists for a strong self-assessment program. He is also responsible for ensuring that personnel are assigned from line and other organizations on a rotational basis to the NAS organization. The Site Vice President will approve all rotational assignments into and out of the nuclear assessment organizations. The corporate Performance Evaluation Section will perform an assessment of the Nuclear Assessment Section at least once per 24 months. This assessment will focus on the effectiveness of NAS, will include an evaluation to assure that the NAS is functioning as an independent organization, and will determine the effectiveness and independence of NAS employees in rotational assignments into and out of the NAS organization.

Personnel performing assessments shall have access to records, procedures, and personnel to gather data.

17.3.3.3.2 Assessment process. The independent assessment process includes gathering data, analyzing data, focusing on selected issues and identifying deficiencies to desired performance. The results of independent assessments are communicated to management in a manner that causes action to correct deficiencies and develop action to prevent recurrence. In addition, this process should evaluate corrective measures adopted to eliminate the deficiencies identified.

Data is gathered using performance based techniques during:

1. Observations of work activities (including line organization self-assessment activities)

2. Interviews

3. Reviews of documents to gather information (including the use of NRC, INPO, and other agency evaluations)

4. Nuclear Safety Review activities

5. Team independent assessments, and

6. Analysis of plant data and reports (including adverse condition reports, etc.)

Planning activities identify the organizations to be evaluated, the characteristics to be focused on during the independent assessment, and the applicable acceptance criteria. Independent Assessment activities are

selected with flexibility based on various factors. These factors include but are not limited to: importance to safety and reliability, NAS independent assessments of site work activities, time since last assessment, plant management perspective, outside agency audits, and problem areas identified from industry and CP&L experience.

Preparation activities may include a review of performance data, relevant documentation, previous assessment data, industry experience, team member experience, and management input. These activities enable the team to focus on issues which may impact safety and reliability when analyzing data.

Assessments are scheduled on the basis of the status and safety importance of the activities or processes being performed. The schedule is flexible and dynamic to allow assessment to be changed depending on plant conditions, events, or issues raised by Senior management.

17.3.3.3.3 NAS Assessment Program. Assessments of facility activities shall be performed by the Nuclear Assessment Section. Assessments will be performance based and will be scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months. These assessments shall encompass:

1. The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions

2. The performance, training and qualifications of the entire facility staff

3. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems or method of operation that affect nuclear safety

4. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10 CFR 50

5. Any other area of facility operation considered appropriate by the Vice President - Robinson Nuclear Plant

6. The Radiological Environmental Monitoring Program and the results thereof

7. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures

8. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive wastes

Assessments of activities prescribed by the Code of Federal Regulations will be performed at the frequencies prescribed by the applicable regulation. These assessments shall encompass:

1. Emergency Preparedness (per 10 CFR 50.54(t))

2. Security (per 10 CFR 50.54(p))

3. Radiation Protection (per 10 CFR 20.1101c)

17.3.3.3.4 Results. Adverse conditions are reported in accordance with the applicable department's corrective action program procedure or by formal correspondence between responsible levels of management.

Independent assessment results are communicated to line management to allow for timely action to address potential problems or recognize strengths and superior performance.

Independent assessment results are documented and reviewed with management personnel responsible for the areas assessed.

Results of independent assessments, special investigations, and analysis of data will be provided to the NAS Management for review. A periodic briefing of NAS activities, along with potential issues and recommendations, shall be presented to the Senior Nuclear Operating Officer, the Executive Vice President - Nuclear Generation Group.

Follow-up is accomplished to assure that corrective action is taken as a result of the assessment and that deficient areas are reassessed, when necessary, to verify implementation of adequate corrective actions.