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123.1	NA	14	NA	7	NA
123.2	NA	14	NA	7	NA
123.3	NA	14	NA	7(10)	NA
123.4	NA	14	NA	7(8)	NA
123.5	NA	14	NA	7	NA
123.6	NA	14	NA	7(8)	NA
123.7	NA	14	NA	7(8)	NA
123.8	NA	14	NA	7(8)	NA
123.9	NA	14	NA	7(8)	NA
123.10	NA	14	NA	7(8)	NA
123.11	3A	14	NA	6	NA
210(110.01)	3.10(B).2	1	NA	1	NA
210.2	3.6,5.4	17	NA	7	NA
210.3	3.9	27	NA	10	NA
220.1	NA	18	NA	7	NA
220.2	NA	18	NA	7	NA
220.3	NA	18	NA	7	NA
220.4	NA	18	NA	7	NA
220.5	NA	18	NA	7	NA
220.6	NA	18	NA	7	NA
220.7	NA	18	NA	7	NA
220.8	NA	18	NA	7	NA
270.1	3.11	28	NA	OL-20	NA
270.2	3.11	28	NA	12	NA
270.3	3.11	28	NA	12	NA
270.4	3.11	28	NA	12	NA
270.5	3.11	28	NA	12	NA
270.6	3.11	28	NA	12	NA
270.7	3.11	28	NA	12	NA
270.8	3.11	28	NA	12	NA
270.9	3.11	28	NA	12	NA
270.10	3.11	28	NA	12	NA
270.11	3.11	28	NA	12	NA
270.12	3.11	28	NA	12	NA
270.13	3.11	28	NA	12	NA
270.14	3.11	28	NA	12	NA
270.15	3.11	28	NA	12	NA
270.16	3.11	29	NA	12	NA

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270.17	3.11	29	NA	12	NA
270.18	3.11	29	NA	12	NA
271.1	NA	26	NA	8	NA
271.2	NA	26	NA	8	NA
271.3	NA	26	NA	8	NA
280(010.01)	F10.4-9	1	NA	1	NA
280.1	NA	6	NA	4	NA
280.2	NA	6	NA	4	NA
280.3	NA	6	NA	4	NA
280.4	NA	6	NA	4	NA
280.5	NA	6	NA	4	NA
280.6	NA	7	NA	4	NA
281.1	6.1.2	12	NA	5	NA
281.2	9.1.3	12	NA	5	NA
281.3	18.2-3	12	NA	5	NA
282.1	4.5.1	10	NA	5	NA
282.2	10.3.5	10	NA	5	NA
310.01	2.1	1	NA	NA	Yes
310.02	2.1	1	NA	NA	Yes
310.03	2.1.1.3.1	1	NA	NA	Yes
310.04	2.2.2.6	1	NA	NA	Yes
310.05	2.2.3	1	NA	NA	Yes
331.1	12.1.2.5b	3	NA	OL-21	NA
331.2	12.2.1.3	3	NA	3	NA
331.3	12.2.1.2.3	3	NA	3	NA
331.4	Table 12.2-7	3	NA	3	NA
331.5	12.3.4.2.2.2.2	3	NA	3	NA
360.1	11.4	4	NA	3	NA
360.2	11.4	4	NA	3	NA
420.1	NA	9	NA	OL-22c	NA
420.2	NA	9	NA	OL-22c	NA
420.3	NA	9	NA	OL-14	NA
420.4	Chapt 15	9	NA	OL-20	NA
430	8.3	1	NA	OL-14	NA
430	8.3	1	NA	OL-14	NA
430.1	8.3	8	NA	OL-14	NA
430.2	8.3	8	NA	OL-14	NA
430.3	8.3	8	NA	OL-14	NA

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430.4	8.3	8	NA	OL-14	NA
430.5	9.5.2	8	NA	OL-14	NA
430.6	9.5.3	8	NA	OL-14	NA
430.7	9.5.4	8	NA	OL-14	NA
430.8	9.5.4	8	NA	OL-14	NA
430.9	9.5.4	8	NA	OL-14	NA
430.10	9.5.4	8	NA	OL-14	NA
430.11	3.2,9.5.6, 9.5.4, 9.5.7, 9.5.5, 9.5.8	8	NA	OL-14	NA
430.12	9.5.4	8	NA	OL-14	NA
430.13	9.5.4, 9.5.6, 9.5.7, 9.5.8, 9.5.15	8	NA	OL-14	NA
430.14	9.5.4	8	NA	OL-14	NA
430.15	9.5.4	8	NA	OL-14	NA
430.16	9.5.4	8	NA	OL-14	NA
430.17	9.5.5	8	NA	OL-14	NA
430.18	9.5.5	8	NA	OL-14	NA
430.19	9.5.5	8	NA	OL-14	NA
430.20	9.5.5	8	NA	OL-14	NA
430.21	9.5.5	8	NA	OL-14	NA
430.22	9.5.5	8	NA	OL-14	NA
430.23	9.5.6	8	NA	OL-14	NA
430.24	9.5.6	8	NA	OL-14	NA
430.25	9.5.6	8	NA	OL-14	NA
430.26	9.5.6	8	NA	OL-14	NA
430.27	9.5.7	8	NA	OL-14	NA
430.28	9.5.7	8	NA	OL-14	NA
430.29	9.5.7	8	NA	OL-14	NA
430.30	9.5.7	8	NA	OL-14	NA
430.31	9.5.7	8	NA	OL-14	NA
430.32	9.5.7	8	NA	OL-14	NA
430.33	9.5.8	8	NA	OL-14	NA
430.34	9.5.8	8	NA	OL-14	NA
430.35	9.5.8	8	NA	OL-14	NA
430.36	9.5.8	8	NA	OL-14	NA
430.37	9.5.8	8	NA	OL-14	NA

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430.38	9.5.8	8	NA	OL-14	NA
430.39	10.1	8	NA	OL-14	NA
430.40	10.2	8	NA	OL-14	NA
430.41	10.2	8	NA	OL-14	NA
430.42	10.2	8	NA	OL-14	NA
430.43	10.2	8	NA	OL-14	NA
430.44	10.4.1	8	NA	OL-14	NA
430.45	10.4.1	8	NA	OL-14	NA
430.46	10.4.1	8	NA	OL-14	NA
430.47	10.4.1	8	NA	OL-14	NA
430.48	10.4.1	8	NA	OL-14	NA
430.49	10.4.1	8	NA	OL-14	NA
430.50	10.4.1	8	NA	OL-14	NA
430.51	10.4.1	8	NA	OL-14	NA
430.52	10.4.4	8	NA	OL-14	NA
430.53	10.4.4	8	NA	OL-14	NA
430.54	10.4.4	8	NA	OL-14	NA
430.55	10.4.4	8	NA	OL-14	NA
440.1	NA	23	NA	OL-14	NA
440.106	5.2.2	15	NA	OL-14	NA
440.207	5.4.7	15	NA	OL-14	NA
450.00	6.4	2	NA	5	NA
450.01	6.4	2	NA	5	NA
450.02	6.4	2	NA	5	NA
450.03	6.4	2	NA	5	NA
450.04	6.4	2	NA	5	NA
450.05	6.4	2	NA	5	NA
450.06	6.4	2	NA	5	NA
450.07	6.5.2	2	NA	5	NA
450.08	15.4.8(A)	2	NA	5	NA
450.09	15.6.3	2	NA	5	NA
450.10	6.5.2	13	450.07	7	NA
490.01	4.2	5	NA	3	NA
492.2	15.0	11	NA	5	NA
492.3	15.0	11	NA	5	NA
492.4	15.0	11	NA	5	NA
492.5	15.0	11	NA	5	NA
492.6	15.0	11	NA	5	NA

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492.7	15.0	11	NA	5	NA
492.8	15.0	20	NA	7	NA
492.9	NA	21	NA	8	NA
492.10	II.F.2	22	NA	8	NA
492.11	II.F.2	22	NA	8	NA
492.12	II.F.2	22	NA	8	NA
492.13	II.F.2	22	NA	8	NA
492.14	II.F.2	22	NA	OL-21	NA
492.15	II.F.2	22	NA	8	NA
492.16	II.F.2	22	NA	8	NA
492.17	II.F.2	22	NA	8	NA
492.18	II.F.2	22	NA	8	NA
492.19	II.F.2	22	NA	8	NA
492.20	II.F.2	22	NA	8	NA
492.21	II.F.2	22	NA	8	NA
492.22	II.F.2	22	NA	8	NA
492.23	II.F.2	22	NA	8	NA
492.24	II.F.2	22	NA	8	NA
492.25	II.F.2	22	NA	8	NA
492.26	II.F.2	22	NA	8	NA
492.27	II.F.2	22	NA	8	NA
492.28	II.F.2	22	NA	8	NA
492.29	II.F.2	22	NA	8	NA
492.30	II.F.2	22	NA	8	NA
492.31	II.F.2	22	NA	8	NA
492.32	II.F.2	22	NA	8	NA
492.33	II.F.2	22	NA	8	NA
492.34	II.F.2	22	NA	8	NA
640.1	14	19	NA	7	NA
640.2	14	19	NA	7	NA
640.3	14	19	NA	7	NA
640.4	14	19	NA	7	NA
640.5	14	19	NA	7	NA
640.6	14	19	NA	7	NA
640.7	14	19	NA	7	NA
640.8	14	19	NA	7	NA
640.9	14	19	NA	7	NA
640.10	14	19	NA	7	NA

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640.11	14	19	NA	7	NA
640.12	14	19	NA	7	NA
640.13	14	19	NA	7	NA
640.14	14	19	NA	7	NA
640.15	14	19	NA	7	NA
640.16	14	19	NA	7	NA
640.17	14	19	NA	7	NA
640.18	14	19	NA	10	NA
640.19	14	19	NA	7	NA
640.20	14	19	NA	7	NA
640.21	14	19	NA	7	NA
640.22	14	19	NA	7	NA
640.23	14	19	NA	7	NA
640.24	14	19	NA	7	NA
640.25	14	19	NA	7	NA
640.26	14	19	NA	7	NA
640.27	14	19	NA	7	NA
730.1	NA	16(25)	NA	17	NA

(1) NRC Letters:

1. USNRC letter from D. G. Eisenhest to J. K. Bryan (Union Electric Company) dated July 31, 1980. "Acceptance Review for the Callaway Plants, Insert Nos. 1 & 2."

2. USNRC letter from R. L. Tedesco to J. K. Bryan (Union Electric Company) and G. L. Koester (Kansas Gas & Electric Company) dated January 7, 1981, "SNUPPS FSAR - Request for Additional Information."

3. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated February 9, 1981. "SNUPPS FSAR - Request for Additional Information."

4. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated February 12, 1981. "SNUPPS FSAR - Request for Additional Information."

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5. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated February 25, 1981. "SNUPPS FSAR - Request for Additional Information."

6. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) dated April 10, 1981. "Request for Additional Information for the Review of the Callaway Plant, Unit 1."

7. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) dated May 15, 1981. "Request for Additional Information for the Review of the Callaway Plant, Unit 1."

8. Questions received at May 14, 1981 NRC meeting.

9. USNRC letter from R. J. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) "SNUPPS FSAR - Request for Additional Information."

10. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) dated April 10, 1981. Request for Additional Information for the Review of the Callaway Plant, Unit 1.

11. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated April 21, 1981. "SNUPPS FSAR - Request for Additional Information."

12. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated May 26, 1981. "SNUPPS FSAR - Request for Additional Information - Chemical Technology."

13. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated June 12, 1981. "SNUPPS FSAR - Request for Additional Information - Containment Spray System."

14. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated July 28, 1981, "SNUPPS FSAR - Request for Additional Information - Materials Engineering."

15. Questions received at July 21, 1981 NRC Meeting.

16. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and G. L. Koester (KG&E Co.) dated July 12, 1981, "SNUPPS FSAR - Request for Additional Information: Generic Issues."

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17. USNRC letter from B. J. Youngblood to J. K. Bryan (UE Co.) and G. L. Koester (KG&E Co.) dated August 25, 1981, "SNUPPS FSAR - Request for Additional Information: Mechanical Engineering."

18. USNRC letter from B. J. Youngblood to J. K. Bryan (UE Co.) and G. L. Koester (KG&E Co.) dated September 14, 1981. "SNUPPS FSAR - Request for Addition Information: Structural Engineering."

19. USNRC letter from R. L. Tedesco to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated August 7, 1981, "SNUPPS FSAR - Request for Additional Information - Initial Test Program."

20. USNRC letter from B. J. Youngblood to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated August 25, 1981. "SNUPPS FSAR - Request for Additional Information."

21. USNRC letter from B. J. Youngblood to J. K. Bryan (UE Co.) and to G. L. Koester (KG&E Co.) dated September 1, 1981. "SNUPPS FSAR - Request for Additional Information - Core Performance."

22. USNRC letter from B. J. Youngblood to D. F. Schnell (UE Co.) and to G. L. Koester (KG&E Co.) dated October 16, 1981. "Request for Additional Information - Core Performance."

23. USNRC letter from B. J. Youngblood to D. F. Schnell (UE Co.) dated January 15, 1982. "Request for Additional Information for the Review of the Callaway Plant, Unit 1, Regarding Reactor Systems."

24. Deleted

25. USNRC letter from B. J. Youngblood to G. L. Koester (KG&E Co.) dated November 13, 1981. "Review of Unresolved Safety Issues in Wolf Creek Unit 1."

26. USNRC letter from B. J. Youngblood to J. K. Bryan (UE Co.) dated September 11, 1981. "Request for Additional Information for the Review of the Callaway Plant, Unit 1 Regarding Seismic and Dynamic Qualification of Equipment."

27. USNRC letter from B. J. Youngblood to D. F. Schnell (UE Co.) dated May 27, 1982. "Request for Additional Information for Review of the Callaway Plant, Unit 1."

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Q110.01 Section 3.10(B).2. addresses only Bechtel's scope of supply. Discuss your compliance with IEEE 344, 1975 and Regulatory Guide 1.100 for equipment outside Bechtel's scope of supply.

RESPONSE

Section 3.10 is presented in two parts: 3.10(B) and 3.10(N). Section 3.10(N) contains discussions on the compliance of the NSSS (Westinghouse) equipment to IEEE-344, 1975 and Regulatory Guide 1.100. All equipment subject to Regulatory Guide 1.100 is discussed in Section 3.10(B) or Section 3.10(N).

Q123.1 Identify whether SA-540 Class 1 or 2 material was used for closure bolting in the reactor coolant pumps. If SA-540 Class 1 or 2 materials were used for closure bolting in reactor coolant pumps, demonstrate the generic adequacy of the fracture toughness and demonstrate compliance with Paragraph I.C of Appendix G, to 10 CFR Part 50.

RESPONSE

SA-540 Class 1 or 2 material was not used for closure bolting in the reactor coolant pumps for the Callaway Plant.

Q123.2 Indicate whether the individuals performing the fracture toughness tests were qualified by training and experience and whether their competency was demonstrated in accordance with a written procedure. If the above information cannot be provided, state why the information cannot be provided and identify why the method used for qualifying individuals is equivalent to those of Paragraph III.B.4 Appendix G, 10 CFR Part 50.

RESPONSE

The fracture toughness tests for Callaway Plant reactor coolant pressure boundary components were performed by qualified operators in accordance with written procedures.

Q123.3 To demonstrate compliance with the beltline material test requirements of Paragraph III.C.2 of Appendix G, 10 CFR Part 50:

a. Provide a schematic for the reactor vessel showing all welds, plates and/or forgings in the beltline. Welds should be identified by shop control number, weld procedure qualification number, the heat of filler metal, and type and batch of flux. Provide the chemical composition for these welds (particularly Cu, P, and S content).

b. Indicate the post-weld heat treatment used in the fabrication of the test welds.

c. Indicate the plates used to fabricate the test welds.

d. Indicate whether the test specimen for the longitudinal seams was removed from excess material and welds in the vessel shell course following completion of the longitudinal weld joint.

RESPONSE

Figure 123.3-1 identifies the location of the beltline materials and welds for the Callaway Unit 1 reactor vessel. Weld identification information for these welds is given in Table 123.3-1.

Information concerning the fabrication and post-weld heat treatment of the surveillance test specimen weld is identified in WCAP-9842 for Callaway Unit 1.

The test weldment is fabricated as a separate weld, not as an extension of a longitudinal weld seam.

Q123.4 To demonstrate compliance with the fracture toughness requirements of Paragraph IV.A.1 of Appendix G, 10 CFR Part 50:

a. Provide the RT_{NDT} for all RCPB welds which may be limiting for operation of the reactor vessel.

b. Indicate whether there are any RCPB heat-affected zones which require CVN impact testing per paragraph NB-4335.2 of the 1977 ASME Code. Provide CVN impact test data for these heat-affected zones which may be limiting for operation of the reactor vessel.

c. Indicate that there are no ferritic RCPB base metals other than in vessels which require fracture toughness testing to NB-2300 of the ASME Code. If there are ferritic RCPB base metals other than in vessels which require fracture toughness testing to NB-2300 of the ASME Code, provide CVN impact and drop weight data for all materials which will be limiting for operation of the reactor vessel.

RESPONSE

Charpy V-notch test data for the heat-affected zone of the limiting beltline region plate are presented in WCAP-9842 for Callaway Unit 1.

There are no other heat-affected zones which require impact testing per Paragraph NB-4335.2 of the 1977 ASME Code.

There are no ferritic base metals other than in vessels in the reactor coolant pressure boundary.

Q123.5 Revise the FSAR to indicate that the conclusions of Westinghouse Topical Report WCAP-9292 are applicable to Callaway Unit 1 SA-533 Grade A, Class 2 steel and SA 508 Class 2a steels.

RESPONSE

The conclusions of Westinghouse Topical Report WCAP-9292 are applicable to the Callaway Plant. Refer to Section 5.2.3.3.1.

Q123.6 Provide actual pressure-temperature limits for Callaway Unit 1 based upon the limiting fracture toughness of the reactor vessel material and the predicted shift in the adjusted reference temperature, RT_{NDT}, resulting from radiation damage. The pressure-temperature limits for the following conditions must be included in the technical specifications when they are submitted:

a. Preservice hydrostatic tests,

b. Inservice leak and hydrostatic tests,

c. Heatup and cooldown operations, and

d. Core operation.

RESPONSE

The pressure-temperature limits are included in the Pressure and Temperature Limits Report (PTLR).

Q123.7 Provide full CVN impact curves for each weld and plate in the beltline region. Provide the data in tabulated and graphical form.

RESPONSE

Complete Charpy test results for each weld and plate in the Callaway Unit 1 reactor vessel beltline region are provided in Tables 123.7-1 through 123.7-3.

Q123.8 To demonstrate the surveillance capsule program complies with Paragraph II.C.3 of Appendix H:

a. Provide the withdrawal schedule for each capsule.

b. Provide the lead factors for each capsule.

c. Indicate the estimated reactor vessel end of life fluence at the 1/4 wall thickness as measured from the ID.

RESPONSE

The requested material is provided in WCAP-9842 for Callaway Unit 1.

Q123.9 Identify the location of each material surveillance capsule and the materials in each capsule.

a. For each base metal and heat-affected zone surveillance specimen provide the specimen type, the orientation of the specimen relative to the principal rolling direction of the plate, the heat number, the component code number from which the sample was removed, the chemical composition especially the copper (Cu) and phosphorus (P) contents, the melting practice and the heat treatment received by the sample material.

b. For each weld metal surveillance specimen provide the weld identification from which the sample was removed, the weld wire type and heat identification, flux type and lot identification, weld process and heat treatment used for fabrication of the weld sample.

c. Provide a sketch which indicates the azimuthal location for each capsule relative to the reactor core.

RESPONSE

The requested material is provided in WCAP-9842 for Callaway Unit 1.

Q123.10 Indicate the normal operating temperature of the flywheels and provide CVN impact and drop weight test data from each flywheel that indicates the RT_{NDT} of the flywheels are 100°F less than their normal operating temperatures.

RESPONSE

As stated in WCAP-8163 (Reference 1 to Section 5.4), the normal operating temperature of the reactor coolant pump motor flywheels is 120°F. The Westinghouse specifications require a maximum RT_{NDT} of 10°F, as discussed in Section 5.4.1.5.2.2. The Charpy V-notch and dropweight tests confirm that the normal operating temperature is in excess of 100°F above the RT_{NDT} of the flywheel material.

Q123.11 Submit for review an inservice inspection program for the pump flywheels which complies with Paragraph C.4 of Safety Guide 14, October 27, 1971.

RESPONSE

In lieu of Position C.4.b, a qualified in-place UT examination over the volume from the inner bore of the flywheel to the inner circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals. (See Technical Specification 5.5.7)

TABLE 123.3-1 CALLAWAY UNIT 1 VESSEL BELTLINE REGION WELD METAL IDENTIFICATION INFORMATION

Weld Seam Identification	Weld Control No.	Weld Procedure Qual. No.	Weld Wire		Flux	
			Type	Heat No.	Type	Lot No.
Int. shell long weld seam 101-124A, B, and C	G2.03	SAA-SMA-12.12-102	B4	90077	Linde 0091	0842
Lower shell long weld seam 101-142A, B, and C	G2.03	SAA-SMA-12.12-102	B4	90077	Linde 0091	0842
Inter. to lower shell girth seam 101-171	E3.14	SAA-SMA-3.3-107	B4	90077	Linde 124	1061
Surveillance test weld	E3.14	SAA-SMA-3.3-107	B4	90077	Linde 124	1061

Weld Metal Chemical Composition (Wt. %)

Weld Control No.	C	M_n	P	S	S_i	C_r	N_i	M_o	C_u	V
G2.03	.16	1.21	.008	.010	.19	.07	.06	.53	.04	.007
E3.14	.08	1.30	.006	.007	.52	.03	.04	.52	.04	.004

TABLE 123.7-1 CALLAWAY UNIT 1 BELTLINE REGION INTERMEDIATE SHELL PLATE TOUGHNESS

	Plate R2707-1				Plate R2707-2				Plate R2707-3		
Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)	Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)	Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)
-40	15	0	10	-40	10	0	5	-40	14	0	7
-40	10	0	6	-40	19	0	11	-40	16	0	8
-40	9	0	6	-40	10	0	4	-40	12	0	5
20	29	15	20	10	28	10	20	20	35	15	26
20	31	15	23	10	37	15	25	20	35	15	28
20	37	20	26	10	21	5	13	20	33	15	24
60	44	20	32	60	53	25	38	40	55	30	40
60	43	20	33	60	45	20	36	40	46	25	34
60	44	20	35	60	46	20	35	40	50	30	46
80	50	40	40	70	52	25	40	50	64	40	42
80	58	60	47	70	62	40	46	50	51	30	38
80	47	50	42	70	59	30	45	50	50	25	37
90	47	50	39	80	62	40	48	60	79	35	53
90	59	60	42	80	60	40	48	60	54	25	38
90	56	60	43	80	66	40	47	60	62	30	44
100	70	80	52	100	74	60	54	100	79	40	59
100	67	70	51	100	88	80	62	100	80	50	58
100	61	70	49	100	65	60	51	100	76	40	57
160	76	100	58	160	100	100	71	160	96	100	67
160	78	100	62	160	98	100	65	160	103	100	69
160	81	100	61	160	103	100	72	160	98	100	68
	T_{NDT}	-40 F			T_{NDT}	-50 F			T_{NDT}	-40 F	
	RT_{NDT}	40 F			RT_{NDT}	10 F			RT_{NDT}	-10 F	

TABLE 123.7-2 CALLAWAY UNIT 1 BELTLINE REGION LOWER SHELL PLATE TOUGHNESS

Plate R2708-1				Plate R2708-2				Plate R2708-3			
Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)	Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)	Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)
20	10	0	5	-40	7	0	3	-40	6	0	2
20	9	0	4	-40	8	0	3	-40	7	0	3
20	11	0	5	-40	7	0	3	-40	6	0	3
60	18	0	13	30	29	10	19	0	14	0	11
60	16	0	13	30	22	5	16	0	13	0	9
60	18	0	15	30	21	5	14	0	15	0	11
80	22	5	18	60	43	20	29	50	32	15	26
80	27	10	23	60	43	20	28	50	33	10	28
80	27	10	22	60	42	20	28	50	47	20	32
100	45	20	35	70	51	25	35	70	46	20	31
100	41	15	32	70	57	30	39	70	52	25	35
100	40	15	33	70	51	25	36	70	45	20	31
110	58	25	41	100	68	30	47	80	52	25	37
110	57	25	41	100	57	25	40	80	54	25	38
110	50	25	35	100	81	40	51	80	57	30	39
160	79	60	52	160	90	90	60	100	71	25	54
160	89	70	56	160	98	95	62	100	64	30	46
160	78	60	52	160	101	90	65	100	67	30	48
212	78	100	57	212	105	100	63	160	94	80	60
212	76	100	58	212	110	100	74	160	92	80	66
212	74	100	58	212	100	100	64	160	100	90	68
								212	95	100	61
								212	100	100	62
								212	109	100	68

Plate R2708-1	Plate R2708-2	Plate R2708-3
T_{NDT} 0 F	T_{NDT} -30 F	T_{NDT} -10 F
RT_{NDT} 50 F	RT_{NDT} 10 F	RT_{NDT} 20 F

TABLE 123.7-3 CALLAWAY UNIT 1 BELTLINE REGION WELD METAL TOUGHNESS

Weld Control No. G2.03

Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)
-80	16	0	7
-80	18	0	8
-80	18	0	7
-40	38	20	26
-40	32	15	17
-40	34	15	19
0	79	40	52
0	61	70	39
0	95	70	60
10	96	70	62
10	101	70	60
10	84	60	58
60	118	80	78
60	130	90	80
60	117	80	75
100	137	100	82
100	132	100	82
100	141	100	83
180	142	100	82
180	145	100	85
180	143	100	83

T_{NDT} -60 F

RT_{NDT} -60 F

Weld Control No. E3.14

Temp. (F)	Energy (ft lb)	Shear (%)	Lat. Exp. (mils)
-80	16	0	9
-80	17	0	13
-80	21	0	15
-40	38	15	29
-40	59	30	42
-40	50	25	36
0	84	60	59
0	83	60	57
0	72	40	48
60	108	90	76
60	106	90	76
60	109	90	79
100	109	100	77
100	114	100	80
100	108	100	79
160	115	100	83
160	108	100	80
160	114	100	81

T_{NDT} -60 F

RT_{NDT} -60 F

Q210
(110.01)
(3.10(B).2)

Section 3.10(B).2. addresses only Bechtel's scope of supply. Discuss your compliance with IEEE 344, 1975 and Regulatory Guide 1.100 for equipment outside Bechtel's scope of supply.

RESPONSE

Section 3.10 is presented in two parts: 3.10(B) and 3.10(N). Section 3.10(N) contains discussions on the compliance of the NSSS (Westinghouse) equipment to IEEE-344, 1975 and Regulatory Guide 1.100. All equipment subject to Regulatory Guide 1.100 is discussed in Section 3.10(B) or Section 3.10(N).

Q210.2

The applicant states that all circumferential breaks in the RCS piping are assumed to result in a limited separation such that the maximum flow area is less than a full break area. The applicant must provide the design information assumed for each location where limited break areas are postulated including gap size, restraint stiffness, blowdown force, and maximum restraint deflection. The results of the time-history analysis (if used) should include the break area vs. time and mass flux rate vs. time which were used to calculate the subcompartment pressurization.

In addition, all restraint locations on the RCS piping must be shown.

RESPONSE

In the reactor coolant loop analysis described in Section 3.6, limited break areas are assumed at the reactor vessel inlet and outlet nozzles. At these locations, the break is limited because of the physical constraint built into the plant design. At this location, the reactor coolant piping restraints located in the shield wall annulus limit the break opening area. A description of these restraints specifically for the Callaway Plant is contained in Section 5.4.14.

In the reactor coolant system analysis, all other circumferential breaks are assumed to be double-ended. However, because of the physical configuration of the plant, these breaks are also limited in area. The specific restraint configurations which limit the break opening are described in Section 5.4.14.

Refer to revised Sections 3.6 and 5.4.14.

Q210.3 In Section 1.8 of the Callaway SER (NUREG-0830), the staff identified a confirmatory item regarding the testing of pressure isolation valves. In Section 3.9.6 of the SER, the staff stated that the applicants have addressed the leak testing of only those check valves with an Event V configuration which form an interface between RCS pressure and low pressure coolant injection systems. The applicant's response for the Event V configuration is documented in a letter from N. Petrick to H. Denton dated September 11, 1981. However, the SER also stated that other low pressure interfacing systems exist with valve configurations whose failure could lead to an intersystem LOCA. These other systems include the accumulator discharge check valves, the boron injection system pressure isolation valves, and the motor operated valves in the RHR system. The SER stated, as a confirmatory item, that the staff will require that the leaktight integrity of the pressure isolation valves in the above systems be verified by testing.

In order to complete the confirmatory item, it will be necessary for the applicants to identify all pressure isolation valves that will be included in their leak test program. The staff requires that these valves be included in the Callaway and Wolf Creek Technical Specifications. Limiting conditions for operation which will require corrective action and surveillance requirements which state the testing frequency should also be provided in the Technical Specifications. The applications should also submit four sets of Piping and Instrumentation Drawings (P&ID) for each system containing the pressure isolation valves to be tested. After reviewing the list of pressure isolation valves and provided we find it acceptably complete, we will consider the confirmatory item completed.

It should be emphasized that a proposed maximum allowable leakage limit of 10 gpm is not acceptable to the staff. The staff will require a maximum allowable leakage limit of 1.0 gpm in the Callaway and Wolf Creek Technical Specifications unless adequate justification is made for an exception.

<u>RESPONSE</u>

Proposed Technical Specifications were provided in SNUPPS letter SLNRC 82-032, dated July 14, 1982. These specifications identified all pressure isolation valves that were included in the Callaway leak test program. The PIV list is not contained in the Bases for Technical Specification 3.4.14. The applicable piping and instrumentation drawings are included in the FSAR as Figures 5.1-1, 5.4-7, and 6.3-1.

Q220.1 The staff has determined that Section 3.7(b).4.1 of the SNUPPS FSAR does not comply with the intent of R. G. 1.12, Rev. 1, as it claims. Nevertheless, it does comply, to a greater extent although not fully, with the positions of R. G. 1.12, Proposed Rev. 2, than that of R. G. 1.12, Rev. 1. The staff would accept that section of the FSAR if it is revised to comply with the positions of R. G. 1.12, Proposed Rev. 2, July, 1981.

RESPONSE

A design change has been made to add a response spectrum recorder at the containment foundation. This change is described in Section 3.7(B).4.1.

Q220.2 Provide a discussion on how major cable tray test results were used in arriving at the 20% modal damping. The discussion should assure consistency of observed data and calculations used.

RESPONSE

See Subsection 3.10(B).3.2.2.

Q220.3 Why was cable tray test input loading applied at a 45° angle instead of simultaneous horizontal and vertical load input? What are the implications of this testing method upon the validity of the recommended 20% damping (e.g., with respect to statistical independency requirements of different directional inputs)?

RESPONSE

See Subsection 3.10(B).3.2.1.

Q220.4 Will sprayed-on fireproofing affect cable friction and thus the damping ratios?

RESPONSE

Yes. However, sprayed-on fireproofing is not utilized on cables.

Q220.5 The cable tray test conditions do not reflect the actual physical site situation. Provide the rationale for extending the test results to the actual design which is different from the test configuration.

RESPONSE

See Subsection 3.10(B).3.2.1.

Q220.6 Specify different conditions under which different modal damping ratios ranging from 7-20% are used. (cable tray)

RESPONSE

See Subsection 3.10(B).3.2.2.

Q220.7 It appears that the scope of the cable tray test and the number of tests may not support direct extension to SNUPPS (the appropriate project) cable tray design. Justify that the scope of test conducted is adequate for direct design application.

RESPONSE

See Subsection 3.10(B).3.2.

Q220.8 Justify the use of 7% critical damping for conduit supports for all seismic input levels.

RESPONSE

See Subsection 3.10(B).3.2.3.

Q270.1 (SRP 3.11)

Correlate the systems listed in Table 3.2-1 of the FSAR with the systems listed in Appendix B of the environmental qualification (EQ) program submittal of March 10, 1983. Provide justification for any system listed in Table 3.2-1 which is excluded from Appendix B (e.g., all components of the system are located in a mild environment, etc.). Identify the Class 1E function for all systems in Appendix B.

RESPONSE

Appendix B of the submittal includes a listing of all systems that have Class 1E equipment. Section 2.3 of the submittal indicates that the systems in Appendix B are included “even if only a portion of the system provides a safety-related function.” Additionally, Section 2.3 states that “the listing identifies the function that the system performs (or supports).” The “X”s in Appendix B identify the safety-related function of the system. Multiple entries indicate that the system provides multiple safety functions.

Section 3.2 of the FSAR clearly identifies that Table 3.2-1 of the FSAR contains more than just safety-related systems. Comparing Table 3.2-1 (FSAR) to Appendix B (submittal) is inappropriate since the two listings were developed to different criteria and for different purposes. To reiterate, all safety-related components receiving Class 1E power are included in Appendix B of the submittal.

It should also be noted that the listing of Appendix B includes all systems receiving Class 1E electrical power. No systems have been deleted due to their location (e.g., in a mild environment) as indicated by your questions.

Three systems identified in Appendix B are listed only because some portion of the system provides electrical isolation. The system identifiers are PN, RJ, and RK. These systems do not have any other Class 1E function. Accordingly, no “X”s are provided for these systems.

NOTE: The above four paragraphs were provided as the original response to NRC Question 270.1 during the licensing phase at Callaway Plant. This response was incorporated into the SNUPPS FSAR Revision 12. SNUPPS FSAR Section 3.11(B), Table 3.11(B)-96, “Safety Related System Listing,” was originally developed as Appendix to the EQ Program submitted to the NRC in March of 1983 in accordance with 10 CFR 50.49. The table was intended to list all of the safety-related systems that utilize Class 1E power. As requested by NRC Question 270.1, Callaway Plant provided a comparison between SNUPPS FSAR Table 3.2-1, “Classifications of Structures, Components, and Systems.” SNUPPS FSAR Section 3.2 clearly idenitified that Table 3.2-1 contained more than just safety-related systems. For this reason the Callaway Plant response points out that a comparison between SNUPPS FSAR Table 3.11(B)-9 and SNUPPS FSAR Table 3.2-1 is not meaningful because the two tables were developed to different criteria and for different purposes.

When Callaway Plant converted from the SNUPPS FSAR to the Standard Plant FSAR (FSAR-SP), the above original response was replaced with one sentence that directed one to “See Section 3.11(B).1.” This sentence was incorporated into the FSAR-SP Revision OL-0, and the text of the original four-paragraph response was simplified and incorporated into FSAR-SP Section 3.11(B).1.

Currently, the listing of systems that perform or support these functions is contained in the Callaway Equipment List (CEL). All safety-related systems with components receiving Class 1E power are included in the CEL. The specific safety function of each system is described in FSAR system description sections and in the CEL database. The CEL database is governed by plant procedures and is subject to 10 CFR 50.59 review.

Q270.2 (SRP 3.11)	Identify, by categories listed in NUREG-0737, the components included in the qualification program in response to TMI Action Plan Requirements.

<u>RESPONSE</u>

This information is historical in nature and was only used to establish the basis for NUREG-0830 Supplement 3 findings that appropriate qualification program requirements were in place. Refer to the response to Q270.2 in the licensing basis (10/18/84) version of the FSAR.

Q270.3 (SRP 3.11)	The description of the criteria used for establishing environmental qualification does not reference Section II.B.2 of NUREG-0737 as the basis for establishing radiation dose from recirculating fluids. Discuss your compliance with the recommendations of this section of the Action Plan.

<u>RESPONSE</u>

Subsection 3.11(B).1.2.3 clearly identifies the methodology utilized in developing the contribution of recirculating fluids. The methodology is in compliance with the criteria established in Section II.B.2 of NUREG-0737.

Section 18.2.2 of the FSAR discusses in detail the Callaway position concerning Section II.B.2 of NUREG-0737.

Q270.4 (SRP 3.11)	Provide a statement that 1E equipment located in areas which experience a significant increase in radiation during a LOCA has been reviewed for possible damage to solid state devices.

<u>RESPONSE</u>

See Sections 3.11(B).2.1.f and 3.11(B).5.7.

Q270.5
(SRP 3.11)

Section 8.11 of the March 10, 1983 EQB program submittal indicates a minimized coverage of synergistic effects. Discuss what activity will be undertaken to identify known synergistic effects and how these will be factored into the EQ program.

RESPONSE

See Section 3.11(B).5.8.

Q270.6
(10 CFR 50.49)

To demonstrate compliance with 10 CFR 50.49, the following information must be submitted before an operating license is granted:

a. In accordance with the scope defined in 10 CFR 50.49, provide:

- A list of all nonsafety-related electrical equipment located in a harsh environment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions by the safety-related equipment. A description of the method used to identify this equipment must be included. The nonsafety-related equipment identified must be included in the environmental qualification program.

- A statement that all safety-related electric equipment in a harsh environment, as defined in the scope of 10 CFR 50.49, is included in this list of equipment identified in the March 10, 1983 submittal (including equipment required for MELB, spent fuel rod drop accident, etc.).

- A list of all Category 1 and 2 post-accident monitoring equipment currently installed, or to be installed before plant operation, in response to Regulatory Guide 1.97, Revision 2. The equipment identified must be included in the environmental qualification program.

b. Provide information demonstrating qualification of all equipment in a harsh environment within the scope of 10 CFR 50.49, or provide justification for interim operation pending completion of qualification as required by 10 CFR 50.49. This material should be submitted to allow sufficient time for staff review and approval before issuance of an operating license.

RESPONSE

a. See Section 3.11(B).1.

b. See the Report of Independent Review of Environmental Qualification Programs to NUREG-0588, Rev. 3, transmitted by SLNRC 86-02, dated January 17, 1986.

Q270.7 (SRP 3.11) Indicate your compliance with a one hour time margin for equipment with operability times less than 10 hours, or provide justification for reduced margins.

RESPONSE

See Section 3.11(B).5.2.

Q270.8 (SRP 3.11) Before the Safety-Related Mechanical (SRM) equipment audit items can be selected, you must indicate the qualification status of the SRM equipment. If qualification is not complete, briefly describe the tasks to be performed. Provide a list of SRM equipment which is considered qualified from which audit items can be selected. Your review of equipment should be essentially complete before items are selected.

RESPONSE

Callaway considers all safety-related mechanical equipment to be qualified for its intended use. An extensive program was implemented during the original phases of the design effort to define system and environmental conditions to which mechanical equipment would be exposed. This information was utilized in developing the purchase specifications. Purchased equipment was then evaluated against the specified criteria.

Section 3.11(B).6 describes the program to review the mechanical equipment environmental qualification. This effort is complete.

Q270.9 (SRP 3.11) Table I Master Qualification Summary, Section II of the March 10, 1983 submittal, indicates that the qualification status has not been determined for 16 out of 74 qualification packages (3 packages - review is in progress, 13 packages - review has not started). The Equipment Qualification Branch considers the review incomplete until at least 85% of all equipment items have been categorized.

RESPONSE

The Callaway equipment qualification program was completed as discussed in Section 3.11(B) and Reference 5 to Section 3.11(B).

Q270.10 (SRP 3.11) A number of Qualification Summary Sheets state that qualification documentation is auditable but is incomplete, yet the equipment is considered qualified. Please explain this apparent contradiction.

RESPONSE

There is no contradiction involved. When the submittal indicates that specific equipment documentation is auditable but incomplete and the equipment is considered qualified, then the majority of the information has been submitted and reviewed, and the remaining documentation is considered proprietary, but the content is known and is at the vendor's facility available for audit.

Q270.11 (SRP 3.11) The justification given to reconcile test failures, tests not performed and inconsistencies between test parameter levels and plant requirements seem strained in a number of instances (e.g., E028, E029, E093, E062, M 223A, etc.). Please review the basis for determining qualification and, if appropriate, strengthen the justifications or re-evaluate the qualification status.

RESPONSE

For the identified specifications (and all others), it should be noted that only the summary is submitted in Reference 5 to Section 3.11(B). Additional data leading to the conclusion reached are available in Union Electric's files. Due to the extensive conservatism built into the Callaway qualification review program, we feel that the justifications are not strained. No changes of qualification status are necessary.

Q270.12 (SRP 3.11) Provide an example of the equipment surface temperature calculations referenced in Section 6.2.2 of the EQ submittal which allows credit for specific equipment surface temperature response for MSLB environments.

RESPONSE

See Section 3.11(B).1.2.2 and Figure 3.11(B)-49.

Q270.13 (SRP 3.11) Provide an example of the equipment specific analysis referenced in Section 6.3.1 of the EQ submittal to demonstrate how radiation dose reductions were obtained.

RESPONSE

See Section 3.11(B).1.2.3.

Q270.14 (SRP 3.11) Provide information on the specific maintenance/surveillance programs to be applied to 1) Cables located inside containment, 2) Limitorque valve operators, 3) Amphenol electrical penetrations, 4) Motor control center relays and circuit breakers, and 5) Barton pressure transmitters.

RESPONSE

See Section 3.11(B).5.6.

Maintenance/surveillance requirements for the specific equipment listed in the NRC request is provided as follows:

a. Cables Located Inside Containment

EQ Review: No requirements identified.

Technical Specifications: No requirements identified.

Maintenance/Surveillance Activities: A periodic inspection program to monitor in-service aging of electrical cable insulation on selected cables inside containment has been established.

ISI Program: Not applicable.

b. Limitorque Valve Operators

EQ Review: No requirements identified.

Technical Specifications: Periodic actuation tests are required for automatic valves (including motor-operated valves).

Maintenance/Surveillance Activities: Operators should be operated periodically, not less than twice yearly, if possible. Operators are operated as required by the IST Program and Technical Specifications. Periodic tests of motor IR and wire insulation are initially scheduled for an 18 month or 2 year frequency. Test results will be reviewed and changes made to the frequency as necessary. Lubricant inspection (and if necessary replacement) will initially be performed at 18 month intervals with interval changes made as experience indicates with consideration of Maintenance Rule 10CFR50.65 and licensing commitments.

IST Program: Full stroke test required periodically on active motor-operated valves. Valves that can be stroked during normal plant operation are stroked once every 3 months; others are stroked when plant conditions permit.

c. Amphenol Electrical Penetrations

EQ Review: No requirements identified.

Technical Specifications: Periodic containment integrated leak rate test. Periodic testing of the penetration overcurrent protective devices per Section 16.8.1.

Maintenance/Surveillance Activities: No requirements identified.

ISI Program: Not applicable.

d. Motor Control Center Relays and Breakers

EQ Review: No requirements identified.

Technical Specifications: Periodic functional tests and inspections of MCC breakers which supply power through containment electrical penetrations (item c above). Also motor-operated valve functional tests, as discussed in b above, functionally test the associated MCC relays and breakers.

Maintenance/Surveillance Activities: Callaway maintenance personnel initially plan to perform periodic inspections of MCC's including inspections at refueling outages, to perform periodic maintenance including operation of all devices, replacement of worn contacts, breaker trip settings, and evidence of heat or mechanical damage. The frequency of these inspections can be changed as inspection results indicate with consideration of Maintenance Rule 10CFR50.65 and licensing commitments.

IST Program: Valve stroking of motor-operated valves, as discussed in b above, also tests the MCC relays and breakers associated with those valves.

e. Barton Pressure Transmitters

EQ Review: The cover O-ring must be replaced each time the cover is removed.

Technical Specifications: Periodic channel checks and channel calibrations apply to most transmitters because of their use in the reactor protection and engineered safety feature actuation systems.

Maintenance/Surveillance Acivities: Transmitters do not require a routine preventive maintenance program other than periodic calibration.

ISI Program: Not applicable.

Q270.15 The temperature profiles shown for postulated

(SRP 3.11) HELBs outside containment do not meet the screening criterion of saturation temperature at the calculated pressure. Please provide an example of the analysis used to determine the environmental conditions resulting from a line break outside containment.

RESPONSE

See Section 3.11(B).1.2.3.

Q270.16 (SRP 3.11) The applicant is requested to identify the systems listed in FSAR Table 3.2-1 which include Instrumentation and Control (I&C) equipment. This may be done by modifying Table 3.2-1 to include Instrumentation and Control as subsets or portions of the systems identified.

RESPONSE

See Section 3.11(B).1.1.

Q270.17 (SRP 3.11) Describe the criteria used to determine the I&C systems and components important to safety to be covered by the equipment qualification program.

RESPONSE

The SNUPPS design addresses safety-related and nonsafety-related classifications. It should also be noted that many design reviews and studies have been performed to ensure that the safety-related equipment could perform the required functions without the support of nonsafety-related equipment and assuming adverse failures of nonsafety-related equipment (e.g., seismic/non-seismic interaction, plant hazards analysis, control room fire analysis, etc.).

As Section 3.11(B).1.1 indicates, the SNUPPS design has utilized safety-related equipment to satisfy the requirements of accident mitigation (including support systems) and to provide for post-accident monitoring. All of the equipment that is safety-related is provided with Class 1E power and as described in Section 3.11(B).1.1, all Class 1E equipment was included in the equipment qualification program. Additionally, FSAR Section 7.1.1, Identification of Safety-Related Systems, identifies the criteria for the selection of I&C equipment as being safety-related.

Q270.18 (SRP 3.11) Describe the method used to identify each specific I&C component covered.

RESPONSE

See Section 3.11(B).1.1.

Q271.1 In accordance with the requirements of GDC 2 and 4 all safety-related equipment is required to be designed to withstand the effects of earthquakes and dynamic loads from normal operation, maintenance, testing and postulated accident conditions. GDC 2 further requires that such equipment be designed to withstand appropriate combinations of the effects of normal and accident conditions with the effects of earthquake loads.

The criteria to be used by the staff to determine the acceptability of your equipment qualification program for seismic and dynamic loads are IEEE Std. 344-1975 as supplemented by Regulatory Guides 1.100 and 1.92, and Standard Review Plan Sections 3.9.2, 3.9.3 and 3.10. State the extent to which the equipment in your plant meets these requirements and the above requirements to combine seismic and dynamic loads. For equipment that does not meet these requirements justification will be needed for the use of other criteria.

RESPONSE

All safety-related equipment is designed to withstand the effects of earthquake and dynamic loads. The extent to which the Callaway equipment meets the requirements of the questioned documents is provided in the FSAR Sections referenced below.

IEEE Std. 344-1975: 3.10(B), 3.10(N)

Regulatory Guide 1.100: 3.10(B), Appendix 3A

Regulatory Guide 1.92: Appendix 3A, 3.7(B), 3.7(N)

Standard Review Plan (SRP) 3.9.2: 3.9.2(B), 3.9.2(N)

SRP 3.9.3: 3.9.3(B), 3.9.3(N)

SRP 3.10: 3.10(B) 3.10(N)

In addition, the extent to which Callaway equipment meets the recommendations of Regulatory Guide 1.29, "Seismic Design Classification" is provided in FSAR Section 3.2 and Appendix 3A.

Q271.2
(271.3)

To confirm the extent to which the equipment important to safety meets the requirements of General Design Criterion 2 and 4, the Seismic Qualification Review Team (SQRT) will conduct a plant site review. For selected equipment, SQRT will review the combined required response spectra (RRS) or the combined dynamic response, examine the equipment configuration and mounting, and then determine whether the test or analysis which has been conducted demonstrates compliance with the RRS if the equipment was qualified by test, or the acceptable analytical criteria if qualified by analysis.

In order to select equipment types for a detailed review it is necessary to obtain a list of all equipment important to safety. Equipment should be divided first by system then by component type. Attachment #1 shows a tabular format which should be followed to present the status summary of seismic and dynamic qualification of all equipment important to safety. Attachment #2 shows suggested categories of component type to be listed in Attachment #1. Provide a complete set of floor response spectra identifying their applicability to the equipment listed in Attachment #1.

After the information on Attachment #1 is received, a selection will be made of the equipment to be reviewed by the site audit. Specific information on equipment selected for audit should be presented as shown on Attachment #3 which should be provided to the NRC staff two weeks prior to the plant site visit. The applicant should make available at the plant site for SQRT review all the pertinent documents and reports of the qualification for the selected equipment. After the visit, the applicant should be prepared to submit certain selected documents and reports for further staff review.

The purpose of the site audit is to confirm the acceptability of the seismic and dynamic qualification of all equipment important to safety based on the review of a few selected pieces. If a number of deficiencies are observed or significant generic concerns arise, the deficiencies should be removed for all equipment important to safety subject to confirmation by a follow-up audit of randomly selected items before the fuel loading date.

RESPONSE

A list of all safety-related equipment was provided to the NRC by SLNRC 82-06 dated February 4, 1982. The list was updated by SLNRC 83-026 dated May 9, 1983.

Q280
(010.01)
(F10.4-9)

Describe the device located on the suction side of the auxiliary feedwater pumps. This item is identified as SS001, SS002, and SS003 on Figure 10.4-9.

RESPONSE

The P&ID legend is provided on FSAR Figure 1.1-1. The subject device is a startup strainer. These strainers are used during the preoperational cleaning and testing program. Startup stainers in safety-related systems will be removed prior to fuel load.

Q280.1 Provide a table that lists all equipment including instrumentation and vital support system equipment required to achieve and maintain hot and/or cold shutdown. For each equipment listed:

a. Differentiate between equipment required to achieve and maintain hot shutdown and equipment required to achieve and maintain cold shutdown,

b. Define each equipment's location by fire area,

c. Define each equipment's redundant counterpart,

d. Identify each equipment's essential cabling (instrumentation, control, and power). For each cable identified: (1) Describe the cable routing (by fire area) from source to termination, and (2) Identify each fire area location where the cables are separated by less than a wall having a three-hour fire rating from cables for any redundant shutdown system, and

e. List any problem areas identified by item 1.d.(2) above that will be corrected in accordance with Section III.G.3 of Appendix R (i.e., alternate or dedicated shutdown capability).

RESPONSE

The final fire hazards analysis, FSAR Section 9.5.1, identifies all redundant safe shutdown components and circuits on a fire area by fire area basis, and demonstrates that either the required separation exists or that alternate means are available to perform the safe shutdown function.

FSAR Table 3.11(B)-3, identifies all the equipment required for safe shutdown, differentiates between hot and cold shutdown requirements, and identifies the location of each component.

Q280.2 Provide a table that lists Class 1E and Non-Class 1E cables that are associated with the essential safe shutdown systems identified in item 1 above. For each cable listed: (* Note).

a. Define the cables' association to the safe shutdown system (common power source, common raceway, separation less than IEEE Standard-384 guidelines, cables for equipment whose spurious operation will adversely affect shutdown systems, etc.),

b. Describe each associated cable routing (by fire area) from source to termination, and

c. Identify each location where the associated cables are separated by less than a wall having a three-hour fire rating from cables required for or associated with any redundant shutdown system.

*NOTE

Option 3a is considered to be one method of meeting the requirements of Section II.G.3 Appendix R. If option 3a is selected the information requested in items 2a and 2c above should be provided in general terms and the information requested by 2b need not be provided.

RESPONSE

As stated in FSAR Section 8.1.4.3, in complying with Regulatory Guide 1.75, associated circuits are separated and identified as if they are safety related.

Where non-Class 1E circuits are associated by reason of their sharing of Class 1E sources, they are provided with a Class 1E isolation device, or else it has been determined that their failure will not cause an unacceptable influence on the Class 1E system. Up to the isolation device, these circuits are treated as Class 1E and are separated accordingly. Nonsafety-related cables are not routed through safety-related raceways.

The final fire hazards analysis, described in FSAR section 9.5.1 demonstrates that adequate separation is provided for safe shutdown systems.

Q280.3 Provide one of the following for each of the circuits identified in item 2.c above:

a. The results of an analysis that demonstrates that failure caused by open, ground, or hot short of cables will not affect it's associated shutdown system, (* Note)

b. Identify each circuit requiring a solution in accordance with section III.G.3 of Appendix R, or

c. Identify each circuit meeting or that will be modified to meet the requirements of section III.G.2 of Appendix R (i.e., threehour wall, 20 feet of clear space with automatic fire suppression, or one-hour barrier with automatic fire suppression).

*NOTE

Option 3a is considered to be one method of meeting the requirements of Section II.G.3 Appendix R. If option 3a is selected the information requested in items 2a and 2c above should be provided in general terms and the information requested by 2b need not be provided.

RESPONSE

As stated in the response to Question 280.2, there are no associated circuits whose failure would affect safe shutdown systems.

Q280.4 To assure compliance with GDC 19, we require the following information be provided for the control room. If credit is to be taken for an alternate or dedicated shutdown method for other fire areas (as identified by item 1.e or 3.b above) in accordance with section III.G.3 of new Appendix R to 10 CFR Part 50, the following information will also be required for each of these plant areas.

a. A table that lists all equipment including instrumentation and vital support system equipment that are required by the primary method of achieving and maintaining hot and/or cold shutdown.

b. A table that lists all equipment including instrumentation and vital support system equipment that are required by the alternate, dedicated, or remote method of achieving and maintaining hot and/or cold shutdown.

c. Identify each alternate shutdown equipment listed in item 4.b above with essential cables (instrumentation, control, and power) that are located in the fire area containing the primary shutdown equipment. For each equipment listed provide one of the following:

(1) Detailed electrical schematic drawings that show the essential cables that are duplicated elsewhere and are electrically isolated from the subject fire areas, or

(2) The results of an analysis that demonstrates that failure (open, ground, or hot short) of each cable identified will not affect the capability to achieve and maintain hot or cold shutdown.

d. Provide a table that lists Class 1E and Non-Class 1E cables that are associated with the alternate, dedicated, or remote method of shutdown. For each item listed, identify each associated cable located in the fire area containing the primary shutdown equipment. For each cable so identified provide the results of an analysis that demonstrates that failure (open, ground, or hot short) of the associated cable will not adversely affect the alternate, dedicated, or remote method of shutdown.

RESPONSE

FSAR Table 3.11(B)-3 provides a list of all equipment required for both hot and cold safe shutdown. This list includes equipment required by the primary method of shutdown and equipment that provides an alternate means of performing a safe shutdown function. The list also identifies primary and local control and indication locations, and identifies the controls and indications available on the auxiliary shutdown panel.

FSAR Section 5.4A describes the safe shutdown systems and identifies the diverse or alternate systems and components that are provided to perform safe shutdown functions. FSAR Section 7.4.3 describes the capability of the auxiliary shutdown panel for safe shutdown from outside the control room.

The final fire hazards analysis, described in FSAR Section 9.5.1, considers primary, alternate, and associated circuits and demonstrates that any single fire will not prevent the safe shutdown of the plant.

Q280.5 The residual heat removal system is generally a low pressure system that interfaces with the high pressure primary coolant system. To preclude a LOCA through this interface, we require compliance with the recommendations of Branch Technical Position RSB 5-1. Thus, this interface most likely consists of two redundant and independent motor operated valves with diverse interlocks in accordance with Branch Technical Position ICSB 3. These two motor operated valves and their associated cable may be subject to a single fire hazard. It is our concern that this single fire could cause the two valves to open resulting in a fire-initiated LOCA through the subject high-low pressure system interface. To assure that this interface and other high-low pressure interfaces are adequately protected from the effects of a single fire, we require the following information:

a. Identify each high-low pressure interface that uses redundant electrically controlled devices (such as two series motor operated valves) to isolate or preclude rupture of any primary coolant boundary.

b. Identify each device's essential cabling (power and control) and describe the cable routing (by fire area) from source to termination.

c. Identify each location where the identified cables are separated by less than a wall having a three-hour fire rating from cables for the redundant device.

d. For the areas identified in item 5.c above (if any), provide the bases and justification as to the acceptability of the existing design or any proposed modifications.

RESPONSE

The reactor coolant system high-low pressure interfaces that rely on redundant electrically controlled devices for isolation include the RHR letdown isolation valves.

The fire hazards analysis, described in FSAR SEction 9.5.1, demonstrates that no single credible fire could cause the spurious opening of these valves in a manner that would breach the primary coolant boundary.

Q280.6 FIRE PROTECTION

Notification of Appendix R to 10 CFR Part 50 as a Licensing Requirement

Appendix R to 10 CFR Part 50 will also be used as guidance for our review of your fire protection program. Your compliance with the requirement set forth in Appendix R as modified by accepted exceptions will be made a license condition. Identify any exceptions your program takes to the requirements of Appendix R as well as BTP ASB 9.5-1, and describe your alternative for providing an equivalent level of fire protection.

RESPONSE

In accordance with the providsions of 10 CFR 50.48(c)(i), a fire protection program that complies wih NFPA 805 is maintained as an alternative to compliance with Appendix R. Refer to Operating License Condition C.(5).

Q281.1 Indicate the total amount of protective coatings and organic materials (including conduit covered and uncovered cable insulation) used inside the containment that do not meet the requirements of ANSI NIOI.2 (1972) and Regulatory Guide 1.54. Evaluate the generation rates vs. time of combustible gases that can be formed from these unqualified organic materials under DBA conditions. Also evaluate the amount (volume) of solid debris that can be formed from these unqualified organic materials under DBA conditions that can reach the containment sump. Provide the technical basis and assumptions used for this evaluation.

RESPONSE

FSAR Table 6.1-3 provides the qualification information for coating materials used inside the containment. As shown by the table, only a very small fraction of these coatings is not qualified to the requirements of Regulatory Guide 1.54.

FSAR Table 6.1-10 identifies the quantity of organic lubricants found inside containment. The quantity of electrical cable insulation inside the containment is less than 50,000 pounds.

If it is assumed that the above organic materials, excluding coatings (that were already included in the analyses in Section 6.2.5), can be considered as unsaturated hydrocarbons, Reference 1 indicates that they would have a G value for hydrogen of 1 molecule per 100 eV of energy absorbed and a G value for methane of .01 to .4 molecules per 100 eV of energy absorbed. The integrated DBA dose that this material could be subjected to would be <3.0 x 10^7 Rads over a 1-year period following an accident.

Applying these conservative assumptions, approximately 1.7 lb-moles of hydrogen and approximately 0.7 lb-moles of methane could be potentially released from these sources over the 1-year period.

This quantity of hydrogen is not considered to be a significant contribution compared to the sources identified in FSAR Figure 6.2.5-4, and is not included in the evaluation in Section 6.2.5. Likewise, the small amount of methane that might be produced is not considered a significant contributor to combustibility.

The quantities of organic lubricants given in FSAR Table 6.1-10 are those quantities subject to be released into the containment. Due to the environmental qualification requirements for the cable insulation used inside containment, it is expected to essentially maintain its mechanical stability and not contribute any debris that might reach the containment sump.

Reference 1 - Effects of Radiation on Materials and Components, J. F. Kircher and R. E. Bowman, 1964.

Q281.2 Regarding the fuel pool cooling and cleanup system, indicate the sampling frequency and criteria for filter and/or ion exchanger resin replacement. Items to be addressed should include (1) decontamination factor; (2) radiation level, and (3) differential pressure.

RESPONSE

The spent fuel pool cleanup system will be operated as required to maintain clarity of water in the spent fuel pool and radiation levels in the fuel building equal to or less than 2.5 mrem/hr, in the areas designated B in Figure 12.3-2. As described in Subsection 9.1.3.2.3.2, operation of this system is expected to be intermittent, depending on the radiation level and clarity of the spent fuel pool water. It is expected that the replacement criterion for the filters and demineralizer resin will be differential pressure. However, if the system is unable to maintain sufficient clarity of the pool water and radiation levels adjacent to the pool when operated continuously, the filter and/or resin will be replaced. No set radiation sampling frequency has been established for the pool water. In general, sampling will be more frequent during and immediately after a refueling or if pool water radiation levels are higher than at other times.

Design parameters for the spent fuel pool cleanup system are as follows:

		Filter	Demineralizer
1.	Decontamination factor		
	Iodine	1	100
	Cesium and rubidium	1	10
	Other nuclides	1	100
2.	Radiation level (See Subsection 12.2.1.3.2)	NA	NA
3.	Differential pressure	25 psi @ 150 gpm	15 psi @ 300 gpm

Q281.3 Describe the provisions to meet the requirements of post-accident sampling of the primary coolant and containment atmosphere. The description should address all the requirements outlined in Section II.B.3 of Enclosure 3 in NUREG-0737 (Clarification of TMI Action Plan Requirements) and should include the appropriate P&ID's. In addition, if gas chromatography is used for reactor coolant analysis, special provisions (e.g., pressure relief and purging) should be provided to prevent high-pressure carrier gas from entering the reactor coolant. With respect to clarification (4) in Section II.B.3 of NUREG-0737, if the chloride concentration in the reactor coolant samples exceeds the limit in the Technical Specification, verification that oxygen is less than 0.1 PPM will be mandatory. Provide also either (a) a summary description of procedures for sample collection, sample transfer or transport, sample analysis and analytical accuracy or (b) copies of procedures for sample collection, sample transfer or transport, sample analysis and analytical accuracy.

RESPONSE

The provisions to meet the guidance of NUREG-0737 for post-accident sampling of reactor coolant, containment sump, and containment atmosphere are discussed in Section 18.2.3.

Q282.1 (4.5.1) To evaluate the compatibility of the control rod drive structural materials with the reactor coolant water, provide the list of materials and specifications which are used for each component of the control rod drive mechanism. The information in the FSAR does not adequately identify the materials.

RESPONSE

The requested information is located in Table 5.2-2.

Q282.2 (10.3.5) Provide the following on your secondary water chemistry control and monitoring programs:

1. Sampling schedule for the critical parameters and of control points for these parameters for the cold startup mode of operation;

2. Procedures used to measure the values of the critical parameters;

3. Procedure for the recording and management of data;

4. Procedures defining corrective actions* for off-control point chemistry conditions; and

5. A procedure identifying (a) the authority responsibile for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

Verify that the steam generator secondary water chemistry control program incorporates technical recommendations of the NSSS. Any significant deviations from NSSS recommendations should be noted and justified technically.

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*Branch Technical Position MTEB 5-3 describes the acceptable means for monitoring secondary side water chemistry in PWR steam generators, including corrective actions for off-control point chemistry conditions. However, the staff is amenable to alternatives, particularly to Branch Technical Position B.3.b(9) of MTEB 5-3 (96-hour time limit to repair or plug confirmed condenser tube leaks).

RESPONSE

See the Site Addendum.

331.0 Radiological Assessment Branch

Q331.1 (12.1.2.5b) Section 12.1.2.5.b addresses a neutron shield design at the RPV in containment. Please specify the neutron and gamma dose equivalent rates that will exist at specific locations within the various levels of containment prior to shield installation and after the shield is installed. A figure or table showing respective dose rates would be a suitable format. Describe your plan for neutron personnel dosimetry whenever an entry is made while the reactor is at power, the frequencies at which entries are made, and the number of people making these entries.

RESPONSE

The neutron shield design for the reactor vessel cavity consists of a permanent cavity seal ring and mirror reflective insulation with integral neutron shielding of similar effectiveness to the original water bag shield analyzed below. The permanent cavity seal ring and insulation shielding are located in the reactor vessel flange area above the hot and cold leg nozzles. Based on this design, an average neutron dose rate at the top of the refueling pool has been calculated to be 1.8 rem/hour, using the Morse Monte Carlo code (Ref. 1). Dose rates in other areas of the containment were estimated using Cain's Hypothesis (Ref. 2) along with actual dose rate measurements (Ref. 3) taken at the Farley Nuclear Plant by Lawrence Livermore Laboratories (LLL). The dose rate values obtained using this technique are given below.

Location	Neutron Dose Rate (mrem/hr)
Equipment hatch	8-31
Personnel hatch	56

D. E. Hankins and R. V. Griffith (Ref. 3) of LLL found that the neutron-gamma dose rate ratio in the Farley containment was 7:1. Based on this ratio, the gamma dose rates are expected to be as follows.

Location	Gamma Dose Rate (mrem/hr)
Top of refueling pool	260
Equipment hatch	1-4
Personnel hatch	8

The replacement reactor vessel closure head included upgraded mirror reflective insulation with integral shielding which was analyzed and found to have similar effect (Ref. 4):

	Neutron Dose Rate (mrem/hr)	(Gamma Dose Rate mrem/hr) (Ref. 3)
Equipment Hatch	18.5	2.6
Personnel Hatch	23.8	3.4

The neutron dosimetry method will comply with Revision 1 of Regulatory Guide 8.14. Exposures will be determined by time-dose calculations, using rem meters. There are no specific requirements for personnel entry into the containment during normal operating conditions. The frequency of entries will be based on operational needs and indications of abnormal conditions within the containment.

Entries into the containment when the reactor is at power will be made by at least two persons, one of whom will provide radiation protection surveillance.

REFERENCES

1. Straker E. A., Stevens P. N., Irving D. C., and Cain V. R., "The MORSE Code -- A Multigroup Neutron and Gamma-Ray Monte Carlo Transport Code," ORNL-4585, September 1975.

2. Hopkins W. C., "Calculations of the Neutron Environment Inside PWR Containments," ORNL/RSIC-43, Page 127, February 1979.

3. Hankins D. E. and Griffith R. V., "A Survey of Neutrons Inside the Containment of a Pressurized Water Reactor," ORNL/RSIC-43, Page 114, February 1979.

4. M-2012-00604, “Callaway Neutron Streaming Analysis,” Revision 0; SCP140012, Revision 1, “Transmittal of Callaway Neutron Streaming Analysis, Revision 1,” dated September 9, 2014; LTR-REA-13-120, Rev. 1, “Transmittal of Neutron Streaming Analysis,” dated August 19, 2014.

Q331.2 (12.2.1.3)

Radiation levels in excess of 100 R/hr can occur in the vicinity of spent fuel transfer tubes; therefore, all accessible portions of the transfer tubes must be shielded during fuel transfer. Please address the manner in which shielding, access control and radiation monitoring will be incorporated into the radiation protection program to prevent either occupants or transient workers from receiving very high exposures during transfer of spent fuel from the reactor to the spent fuel pool through the fuel transfer tubes. Use of removable shielding for this prupose is acceptable. Provide appropriate figures (e.g., plan and elevation) that show the shielding arrays for all direct gamma radiation and streaming pathways from the spent fuel during the transfer. On the same figure show the location of any administrative controls by barriers, signs, audible and visual alarms, locked doors, etc. All accessible portions of the transfer tubes that cannot be adequately shielded shall be clearly marked with a sign stating that potentially lethal fields are possible during fuel transfer.

RESPONSE

See Subsection 12.2.1.3.1.

Q331.3 (12.2.1.2.3)

Describe the procedure for extracting a sample from the Nuclear Sampling System of RCS, RHR and CVCS with as low as is reasonably achievable exposures to personnel withdrawing the sample. In your response include use of shielding, area monitoring, portable survey meters, hand contact with sample containers, dose rate levels in sampling area, dose rate level of sample container, etc. Consider samples taken during normal operations, anticipated operational occurrences and accidents. The response to this question should satisfy the requirements of NUREG-0578 item 2.1.8.a, Post Accident Sampling, with regard to Radiation Protection.

RESPONSE

See Subsection 12.2.1.2.3.

Q331.4 (TABLE 12.2-7)

Table 12.2-7 indicates the radionuclide concentration in the spent fuel pool (SFP) water. Relevant reactor operating experience shows that the 60_{Co} activity, from crud transferred to the SFP from the interchange of the primary coolant water during refueling, is several orders of magnitude greater than that shown in the table even after purification by the SFP clean-up system. Please justify the values given in the table for 60_{Co}, 58_{Co}, 134_{Cs}, and 137_{Cs} and show that these values will be retained after several years of reactor operation. Provide an estimate of the dose rate above the SFP during a refueling operation and for the period thereafter. Include in the estimate the effect on the dose rate of any radioactive equipment that might be stored therein.

RESPONSE

The radionuclide concentrations given in Table 12.2-7 were calculated based on the primary coolant activities given in Table 11.4-7 without consideration of the crud which could be released to the refueling pool and the spent fuel pool during refueling operations. Typical spent fuel pool concentrations at operating plants with similar cleanup systems are listed in revised Table 12.2-7.

As stated in Section 9.1.2, the plant is designed so that dose rates above the spent fuel pool will not exceed 10 mrem/hr during refueling and 2.5 mrem/hr for the storage period.

The above dose rates consider the contribution from spent fuel and the spent fuel pool water. No other radioactive equipment that would significantly contribute to the dose rate is stored in the pool.

Q331.5 (12.3.4.2.2.2.2)

Please clarify how iodine radioactivity levels can be "inferred from the particulate and noble gas radioactivity levels" when monitoring the exhaust from the radwaste and auxiliary buildings as addressed in sections 12.3.4.2.2.2.2 and 12.3.4.2.2.2.4.

RESPONSE

The referenced FSAR sections have been revised to indicate that particulate iodine radioactivity levels in the HVAC duct flow paths (prior to filtration and discharge to the radwaste building and auxiliary building vents) will be determined by periodic laboratory isotopic analyses of the particulate cartridge filters associated with monitors 0-GH-RE-22 and 0-GL-RE-60. Also, if required, grab samples will be taken at various room locations to locate the source of the release. Analyses of these grab samples will be made for particulate, gaseous iodine, and noble gas activity.

The rate of iodine radioactivity discharged from the radwaste building vent and the unit vent is continuously monitored by 0-GH-RE-10A and 0-GT-RE-21A. These instruments monitor particulates and gaseous iodine. Parallel monitors 0-GH-RE-10B and 0-GT-RE-21B monitor noble gases.

An alarm from either the particulate monitor upstream of the HVAC filters or the noble gas monitor downstream of the filters will indicate that an increase in airborne activity is occurring. Laboratory analyses of the cartridge filters from the continuous monitors and the grab samples would then be used to determine the level of gaseous iodine.

Q360.1 EFFLUENT TREATMENT

360.1 (11.4) Table 11.4-3 (sheet 2) of the SNUPPS FSAR indicates that the estimated annual volume of dry and compacted waste is based upon Table 2-49 of WASH-1258. The estimated volume was 3,380 ft^3. Page 11.4-8 of the SNUPPS FSAR states that the filled drums are sealed and moved to the dry waste storage area in the radwaste building, where they are stored until they are shipped offsite. Figure 1.2-3 of the SNUPPS FSAR shows that the storage area has a storage capacity of 722 drums, if stacked three high, and 1055 drums, if stacked five high. Data made available since the publication of WASH-1258 have made that document inappropriate for waste projections. The dry waste volumes estimated by WASH-1258 are much lower than those being generated at operating reactors. NRC staff calculations, which are based on data from semi-annual effluent reports, show that the volume of dry wastes generated are independent of reactor size and amount to approximately 10,000 ft^3 (compacted) annually, which is a factor of three greater than the estimates presented in the SNUPPS FSAR. Also, the growing uncertainty of the availability of burial space has made the availability of adequate storage space at the reactor facility an important issue.

Based upon the material presented above, provide information verifying that the storage space at Callaway will be sufficient to handle the storage of drummed waste in accordance with the requirements of Branch Technical Position, ETSB 11-3 (Rev. 1), item III (Waste Storage).

<u>RESPONSE</u>

See Section 11.4. See Section 11.4 of the Site Addendum.

Q360.2
(11.4)

Page 11.4-12 of the SNUPPS FSAR discusses shielded storage areas for "high-level" solidified radwaste and "low-level" solid radwaste. The term "high-level" is inappropriate and should be revised. "High-level" generally refers to reprocessing wastes resulting from the first cycle of solvent extraction. More recently, use of the term has been extended to cover spent reactor fuel. See 10 CFR Part 50, Appendix F, item 2.

RESPONSE

The terms "high-level" and "low-level" were eliminated and replaced by primary and secondary, respectively in Section 11.4 to differentiate drummed solid wastes that require radiation shielding from those that do not.

Q420.1 <u>Loss of Non-Class 1E Instrumentation and Control Power System Bus During Power Operation (IE Bulletin 79-27)</u>

If reactor controls and vital instruments derive power from common electrical distribution systems, the failure of such electrical distribution systems may result in an event requiring operator action concurrent with failure of important instrumentation upon which these operator actions should be based. This concern was addressed in IE Bulletin 79-27. On November 30, 1979, IE Bulletin 79-27 was sent to operating license (OL) holders, the near term OL applicants (North Anna 2, Diablo Canyon, McGuire, Salem 2, Sequoyah, and Zimmer), and other holders of construction permits (CP), including Callaway 1 and Wolf Creek. Of these recipients, the CP holders were not given explicit direction for making a submittal as part of the licensing review. However, they were informed that the issue would be addressed later.

You are requested to address these issues by taking IE Bulletin 79-27 Actions 1 thru 3 under "Actions to be Taken by Licensees". Within the response time called for in the attached transmittal letter, complete the review and evaluation required by Actions 1 thru 3 and provide a written response describing your reviews and actions. This report should be in the form of an amendment to your FSAR and submitted to the NRC Office of Nuclear Reactor Regulations as a licensing submittal.

<u>RESPONSE</u>

For supplemental information regarding this response see FSAR Section 8.3.1.1.5.

Power for the vital reactor instrumentation and protection systems is provided by the Class 1E instrument ac power system. This system is composed of four independent 120-volt ac power supplies to provide power to the four channels of the vital reactor protection and instrumentation systems. With one channel inoperable, the remaining three channels are capable of monitoring the vital reactor parameters continuously and safely shutting down the reactor.

Each essential power panel is fed from a dedicated Class 1E inverter, which, in turn, is fed from one of four independent Class 1E batteries. Each Inverter has a 125 VDC supply and a separate 120 VAC supply from an internal constant voltage transformer which combined makes a UPS cabinet. In the event of a failure of the Inverter DC rectifier section, the UPS internal constant voltage transformer will supply the 120 VAC panel until the swing (backup) Inverter can be placed in service to replace it. Each battery has an associated charger that is fed from a diesel-generator-backed bus.

Power for the four non-Class 1E reactor process control channels is provided by the non-Class 1E AC power system through two non-Class 1E uninterruptible power supplies (UPSs). Each power supply train supplies a dedicated UPS that, in turn, supplies two process control cabinets. A backup DC supply is provided to the UPS in the event that the primary source is not available.

The backup DC power source is the non-Class 1E DC system. This system is composed of two station batteries and two battery chargers. Both of the chargers are powered from a diesel-generator-backed bus.

In the event of loss of power as a result of an inverter failure, two trains of backup power to the process cabinets are provided by manual switches from the non-Class 1E AC system. These trains of AC power are provided with a cross tie for additional reliability.

Power for miscellaneous non-Class 1E instrument loads is provided by the non-Class 1E instrument AC power system. This system is powered from the Class 1E power system through a qualified isolating regulating transformer. One transformer is provided for each train of instrument AC. No cross ties are provided.

The Class 1E instrument AC power system is provided with the following alarms in the control room:

a. UPS common/trouble alarm

b. Inverter Static Switch Transfer/Bypass Supplying Load

c. Loss of switchboard voltage

The non-Class 1E DC system is provided with the following alarms in the control room:

a. System ground

b. Battery imbalance

c. Charger DC overvoltage

d. Charger AC undervoltage

e. Charger DC undervoltage

f. Charger AC and DC breakers open

g. Charger failure

h. Loss of distribution board voltage

i. Loss of switchboard voltage

The non-Class 1E instrument ac system is provided with a loss of bus voltage alarm in the control room.

Procedures will be developed that address Action Item No. 2 of IE Bulletin 79-27 (i.e., emergency procedures, administrative procedures, and/or alarm procedures). As a result of the review of IE Bulletin 79-27 and IE Circular 79-02, no design modifications are required. However, the ongoing development of procedures and administrative controls will consider these IE issuances.

Q420.2 Engineered Safety Features (ESF) Reset Controls (IE Bulletin 80-06)

If safety equipment does not remain in its emergency mode upon reset of an engineered safeguards actuation signal, system modification, design change or other corrective action should be planned to assure that protective action of the affected equipment is not compromised once the associated actuation signal is reset. This issue was addressed in IE Bulletin 80-06 (enclosed). For facilities with operating licenses as of March 13, 1980, IE bulletin 80-06 required that reviews be conducted by the licensees to determine which, if any, safety functions might be unavailable after reset, and what changes could be implemented to correct the problem.

For facilities with a construction permit including OL applicants Bulletin 80-06 was issued for information only.

The NRC staff has determined that all CP holders, as a part of the OL review process, are to be requested to address this issue. Accordingly, you are requested to take the actions called for in Bulletin 80-06 Actions 1 thru 4 under "Actions to be Taken by Licensees". Within the response time called for in the attached transmittal letter, complete the review verifications and description.

<u>RESPONSE</u>

A review has been conducted of the drawings for all systems serving safety-related functions at the schematic level to determine whether or not, upon reset of an ESF actuation signal, all associated safety-related equipment remains in its emergency mode. The review revealed that certain equipment would, in particular circumstances, change state upon ESF reset. The affected equipment included the control room and electrical equipment room air-conditioning units, the containment air coolers, the hydrogen mixing fans, and the component cooling water heat exchanger temperature control valves. The control circuits for this equipment were revised to provide seal-in features so that an ESF reset would not change the safeguards state of the equipment.

There are two preoperational tests (see Subsections 14.2.12.1.71 and 14.2.12.1.72) which require that equipment alignment be verified after reset of ESF actuation signals. These tests will verify that the installed controls are consistent with the schematics reviewed and that all equipment remains in its emergency mode upon ESF reset.

Q420.3 Qualification of Control Systems (IE Information Notice 79-22)

Operating reactor licensees were informed by IE Information Notice 79-22, issued September 19, 1979, that certain non-safety grade or control equipment, if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. Enclosed is a copy of IE Information Notice 79-22, and reprinted copies of an August 30, 1979 Westinghouse letter, and a September 10, 1979 Public Service Electric and Gas Company letter which address this matter. Operating Reactor licensees conducted reviews to determine whether such problems could exist at operating facilities.

We are concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review to determine what, if any, design changes or operator actions would be necessary to assure that high energy line breaks will not cause control system failures to complicate the event beyond your FSAR analysis. Provide the results of your review, including all identified problems and the manner in which you have resolved them to NRR.

The specific "scenarios" discussed in the above referenced Westinghouse letter are to be considered as examples of the kinds of interactions which might occur. Your review should include those scenarios, where applicable, but should not necessarily be limited to them. Applicants with other LWR designs should consider analogous interactions as relevant to their designs.

<u>RESPONSE</u>

See Section 3.11(B).7.

Q420.4 The analyses reported in Chapter 15 of the FSAR are intended to demonstrate the adequacy of safety systems in mitigating anticipated operational occurrences and accidents.

Based on the conservative assumptions made in defining these design-basis events and the detailed review of the analysis by the staff, it is likely that they adequately bound the consequences of single control system failures.

To provide assurance that the design basis event analyses adequately bound other more fundamental credible failures you are requested to provide the following information:

1. Identify those control systems whose failure or malfunction could seriously impact plant safety.

2. Indicate which, if any, of the control systems identified in (1) receive power from common power sources. The power sources considered should include all power sources whose failure or malfunction could lead to failure or malfunction of more than one control system and should extend to the effects of cascading power losses due to the failure of higher level distribution panels and load centers.

3. Indicate which, if any, of the control systems identified in (1) receive input signals from common sensors. The sensors considered should include, but should not necessarily be limited to, common hydraulic headers or impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

4. Provide justification that any simultaneous malfunctions of the control systems indentified in (2) and (3) resulting from failures or malfunctions of the applicable common power source or sensor are bounded by the analyses in Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

RESPONSE

INTRODUCTION

The evaluation required to answer Question 420.4 consists of postulating failures which affect the major NSSS control systems and demonstrating that for each failure the resulting event is within the bounds of existing accident analyses. The events which are considered are:

a. Loss of any single instrument

b. Break of any single instrument line

c. Loss of power to all systems powered by a single power supply system (i.e., single inverter)

The analysis is conducted for all five major NSSS control systems:

a. Reactor control system

b. Steam dump system

c. Pressurizer pressure control system

d. Pressurizer level control system

e. Feedwater control system

The initial conditions are assumed to be anywhere within the full operating power range of the plant (i.e., 0-100 percent), where applicable.

The results of the analysis indicate that, for any of the postulated events considered in a. through c. above, the Condition II accident analyses given in Chapter 15.0 are bounding.

LOSS OF ANY SINGLE INSTRUMENT

Table 420.4-1, Loss Of Any Single Instrument, is a sensor-by-sensor evaluation of the effect on the control systems itemized above caused by a sensor failing either high or low. The particular sensor considered is given, along with the number of channels which exist, the failed channel, the control systems impacted by the sensor, the effects on the control systems for failures in both directions, and the bounding FSAR accident. Where no control action occurs or where control action is in a safe direction, no bounding accident is given.

The table clearly shows that for any single instrument failure, either high or low, the Condition II events itemized in FSAR Chapter 15.0 are bounding.

LOSS OF POWER TO A PROTECTION SEPARATION GROUP

Table 420.4-2, Loss Of Power To A Protection Separation Group, analyzes the effects on the control systems caused by the loss of power to a protection separation group. The overall power supply is composed of eight inverters. Four inverters power protection separation groups 1 through 4. Two Class 1E swing (backup) inverters (with a DC transfer switch), are installed to function as a backup for either of two of the four inverters. (One swing inverter (and its transfer switch) can be aligned to replace a separation group 1 or 3 inverter with no loss of functional capability; the other swing inverter and transfer switch can likewise be aligned to replace a separation group 2 or 4 inverter.) Two other inverters supply power to control separation group 5 and control separation group 6. Control separation group 5 consists of control groups 1 and 3, and control separation group 6 consists of control groups 2 and 4. The control systems affected, the sensors affected, the failure direction, the effect on the control systems, and the bounding FSAR accident are identified in the table. Where no control action occurs or where control action is in a safe direction, no bounding accident is given.

Besides the loss of power to a complete control separation group or protection separation group, there is the chance of having an electrical fault on one of the control system circuit cards. The control systems are designed so that each card is used in only one control system. A circuit card failure cannot directly impact more than one control system. A failure on a control card would cause the controller to generate either an "off" or a "full on" output, depending on the type of failure. This result would be similar to having a fault in a sensor feeding the control system. Therefore, the failure of or loss of power in any control system circuit card would be bounded by the Loss of Any Single Instrument analysis described in Table 420.4-1.

The analysis is conservative in the sense that, in cases where switches enable the operator to choose from which protection separation group a given signal is desired, it is assumed that the switch is in the position of the failed protection separation group.

The table shows that for a loss of power to any protection separation group, the Condition II events analyzed in the FSAR Chapter 15.0 are bounding.

LOSS OF POWER TO CONTROL SEPARATION GROUPS

Table 420.4-3, Loss Of Power To a Control Separation Group, examines the effects on the control systems caused by the loss of power to a control separation group. Loss of power to control separation group 5 (control groups 1 and 3) is considered, followed by loss of power to control separation group 6 (control groups 2 and 4). The control systems affected, the equipment or signals affected, the failure direction, the effects of the failure, and the bounding accident are given.

The table shows that, for either a loss of power to control separation group 5 or control separation group 6, the resulting failure is bounded by a loss of normal feedwater flow, which is a Condition II event analyzed in the FSAR.

BREAK OF COMMON INSTRUMENT LINES

Table 420.4-4, Break Of Common Instrument Lines, considers the scenario whereby an instrument line which supplies more than one signal ruptures, causing faulty sensor readings.

Three sets of sensors used for control are located in common lines:

a. Loop steam flow (control separation groups 5 and 6, any steam generator) and narrow range steam generator level (protection separation groups 1 or 2, any steam generator)

b. Pressurizer level (protection separation groups 1, 2, or 3) and pressurizer pressure (protection separation groups 1, 2, 3, or 4)

c. T_{cold} and T_{hot} (any loop)

Not shown on the table, since they are not part of the plant control system but are used just for protection, are the loop flow transmitters. There are three flow transmitters in each loop with each transmitter having a common high pressure tap but separate and unique low pressure taps. Therefore, a break at the high pressure flow transmitter tap would result in disabling all three flow transmitters in one loop, resulting in a low flow reading for all three transmitters. This would result in a reactor trip if the plant is above the P-8 setpoint, or an annunciation if it is below P-8.

The only malfunction mode explicitly analyzed was a break in the common instrument line at the tap. Another possibility is to have a complete blockage in the sensor tap, causing the sensor to read a constant (before blockage) value. However, this failure mode is not analyzed, since it is really not a credible event. There is no anticipated agent available that would cause a tap blockage. The reactor coolant system piping and fittings and the instrument impulse line tubing are all stainless steel, so no products of corrosion are expected. Also, the water chemistry is of high quality which, along with high temperature operation, precludes the presence of solids in the water and ensures the maintenance of the solubility of chemicals in the water. In addition, prior to startup, and during any shutdown as well, it is routine maintenance and servicing practice for instrument lines to be blown down to a canister. Since the buildup of sludge is a slow process, any buildup would be detected during response time testing done during shutdown. Therefore, the hypothesis of the presence of a complete blockage of the sensor tap is not sufficiently credible to warrant its consideration as a design basis.

In the extremely unlikely event that a complete instrument line blockage were to occur, the condition is detectable because the reading would become static (no variations over time). In an unblocked channel, a reading would always vary somewhat due to noise (i.e., flow induced noise in flow channels) or slight controller action (i.e., cycling operation of spray and heaters in pressurizer). By a comparison of the static channel to the redundant unblocked channels, the operator would be informed that a blockage in one channel has occurred.

Table 4 indicates that, even in the event of an instrument line break which supplies more than one control signal, the resulting failures are bounded by the FSAR Chapter 15.0 analyses.

CONCLUSIONS

The preceding tables have illustrated that failures of individual sensors, losses of power to protection separation groups or to control separation groups, or breaks in common instrument lines all result in events which are bounded by FSAR Chapter 15.0 analyses. Therefore, the FSAR adequately bounds the consequences of these fundamental failures.

Q430 (F8.3-1) Figure 8.3-1 shows a "hold" symbol next to MCC PG 12J. Explain.

RESPONSE

The circle next to MCC PG 12J on Figure 8.3-1 was inadvertently not removed for the original submittal of the FSAR. The circle indicates that a change had taken place from the previous revision of the P&ID.

Q430 (F8.3-2)	Figure 8.3-2 has several loads listed as "later." Indicate the status of these loads.

RESPONSE

Since the original revision of the FSAR, Figure 8.3-2 has been revised to provide information for all "laters."

Q430.1 (8.3) RSP	Operating experience at certain nuclear power plants which have two cycle turbocharged diesel engines manufactured by the Electromotive Division (EMD) of General Motors driving emergency generators have experienced a significant number of turbocharger mechanical gear drive failures. The failures have occurred as the result of running the emergency diesel generators at no load or light load conditions for extended periods. No load or light load operation could occur during periodic equipment testing or during accident conditions with availability of offsite power. When this equipment is operated under no load conditions insufficient exhaust gas volume is generated to operate the turbecharger. As a result the turbocharger is driven mechanically from a gear drive in order to supply enough combustion air to the engine to maintain rated speed. The turbocharger and mechanical drive gear normally supplied with these engines are not designed for standby service encountered in nuclear power plant application where the equipment may be called upon to operate at no load or light load condition and full rated speed for a prolonged period. The EMD equipment was originally designed for locomotive service where no load speeds for the engine and generator are much lower than full load speeds. The locomotive turbocharged diesel hardly ever runs at full speed except at full load. The EMD has strongly recommended to users of this diesel engine design against operation at no load or light load conditions at full rated speed for extended periods because of the short life expectancy of the turbocharger mechanical gear drive unit normally furnished. No load or light load operation also causes general deterioration in any diesel engine.

To cope with the severe service the equipment is normally subjected to and in the interest of reducing failures and increasing the availability of their equipment EMD has developed a heavy duty turbocharger drive gear unit that can replace existing equipment. This is available as a replacement kit, or engines can be ordered with the heavy duty turbocharger drive gear assembly.

To assure optimum availability of emergency diesel generators on demand. Applicant's who have in place, or order or intend to order emergency generators driven by two cycle diesel engines manufactured by EMD should be provided with the heavy duty turbocharger mechanical drive gear assembly as recommended by EMD for the class of service encountered in nuclear power plants. Confirm your compliance with this requirement.

RESPONSE

Callaway Plant diesel generators are not manufactured by EMD; they are Fairbanks Morse diesel engines.

As discussed in response to FSAR Question 430.3, and Subsection 9.5.8.2.3, specific guidance has been provided by the diesel manufacturer on procedures for operating the engines at light or no load.

Q430.2 (8.3) Provide a detail discussion (or plan) of the level of training proposed for your operators, maintenance crew, quality assurance, and supervisory personnel responsible for the operation and maintenance of the emergency diesel generators. Identify the number and type of personnel that will be dedicated to the operations and maintenance of the emergency diesel generators and the number and type that will be assigned from your general plant operations and maintenance groups to assist when needed.

In your discussion identify the amount and kind of training that will be received by each of the above categories and the type of ongoing training program planned to assure optimum availability of the emergency generators.

Also discuss the level of education and minimum experience requirements for the various categories of operations and maintenance personnel associated with the emergency diesel generators.

RESPONSE

See the Site Addendum Section "NRC Questions and Responses."

Q430.3
(8.3)
RSP

Periodic testing and test loading of an emergency diesel generator in a nuclear power plant is a necessary function to demonstrate the operability, capability and availability of the unit on demand. Periodic testing coupled with good preventive maintenance practices will assure optimum equipment readiness and availability on demand. This is the desired goal.

To achieve this optimum equipment readiness status the following requirements should be met:

1. The equipment should be tested with a minimum loading of 25 percent of rated load. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequences of no load or light load operation are potential equipment failure due to the gum and varnish deposits and firm in the engine exhaust system.

2. Periodic surveillance testing should be performed in accordance with the applicable NRC guidelines (R. G. 1.108), and with the recommendations of the engine manufacturer. Conflicts between any such recommendations and the NRC guidelines, particularly with respect to test frequency, loading and duration, sould be identified and justified.

3. Preventive maintenance should go beyond the normal routine adjustments, servicing and repair of components when a malfunction occurs. Preventive maintenance should encompass investigative testing of components which have a history of repeated malfunctioning and require constant attention and repair. In such cases consideration should be given to replacement of those components with other products which have a record of demonstrated reliability, rather than repetitive repair and maintenance of the existing components. Testing of the unit after adjustments or repairs have been made only confirm that the equipment is operable and does not necessarily mean that the root cause of the problem has been eliminated or alleviated.

4. Upon completion of repairs or maintenance and prior to an actual start, run, and load test a final equipment check should be made to assure that all electrical circuits are functional, i.e., fuses are in place, switches and circuit breakers are in their proper position, no loose wires, and test loads have been removed, and all valves are in the proper position to permit a manual start of the equipment. After the unit has been satisfactorily started and load tested, return the unit to ready automatic standby service and under the control of the control room operator.

Provide a discussion of how the above requirements have been implemented in the emergency diesel generator system design and how they will be considered when the plant is in commercial operation, i.e., by what means will be above requirements be enforced.

RESPONSE

1. See Subsection 9.5.8.2.3 System Operation (Emergency Diesel Engine Combustion Air Intake and Exhaust System).
2. Callaway is in compliance with the requirements of Regulatory Guide 1.108. Refer to Section 8.1.4.3 for details.
3. See Site Addendum Section "NRC Questions and Responses."
4. See Site Addendum Section "NRC Questions and Responses."

Q430.4
(8.3)
RSP

The availability on demand of an emergency diesel generator in dependent upon, among other things, the proper functioning of its controls and monitoring instrumentation. This equipment is generally panel mounted and in some instances the panels are mounted directly on the diesel generator skid. Major diesel engine damage has occurred at some operating plants from vibration induced wear on skid mounted control and monitoring instrumentation. This sensitive instrumentation is not made to withstand and function accurately for prolonged periods under continuous vibrational stresses normally encountered with internal combustion engines. Operation of sensitive instrumentation under this environment rapidly deteriorates calibration, accuracy and control signal output.

Therefore, except for sensors and other equipment that must be directly mounted on the engine or associated piping, the controls and monitoring instrumentation should be installed on a free standing floor mounted panel separate from the engine skids, and located on a vibration free floor area. If the floor is not vibration free, the panel shall be equipped with vibration mounts.

Confirm your compliance with the above requirement or provide justification for noncompliance.

RESPONSE

See Subsection 8.3.1.1.3.

Q430.5 The information regarding the onsite communications system (Section 9.5.2) does not adequately cover the system capabilities during transients and accidents. Provide the following information:

(a) Identify all working stations on the plant sita where it may be necessary for plant personal to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents (including firms) in order to mitigate the consequences of the event and to attain a safe cold plant shutdown.

(b) Indicate the maximum sound levels that could exist at each of the above identified working stations for all transients and accident conditions.

(c) Indicate the types of communication systems available at each of the above identified working stations.

(d) Indicate the maximum background noise level that could exist at each working station and yet reliably expect effective communication with the control room using:

1. the page party communications systems, and

2. any other additional communication system provided that working station.

(e) Describe the performance requirements and tests that the above onsite working stations communication systems will be required to pass in order to be assured that effective communication with the control room or emergency shutdown panel is possible under all conditions.

(f) Identify and describe the power source(s) provided for each of the communications systems.

(g) Discuss the protective measures taken to assure a functionally operable onsite communication system. The discussion should include the considerations given to component failures, loss of power, and the severing of a communication line or trunk as a result of an accident or firm.

RESPONSE

(a) Refer to Section 9.5.2.

(b) Refer to Section 9.5.2.

(c) Refer to revised Table 9.5.2-1.

(d) Refer to Section 9.5.2.

(e) Refer to Section 9.5.2.

(f) Refer to Section 9.5.2.

(g) Refer to Subsection 9.5.2.3.

Q430.6 Identify the vital areas and hazardous areas where emergency lighting is needed for safe shutdown of the reactor and the evacuation of personnel in the event of an accident. Tabulate the lighting system provided in your design to accommodate those areas so identified. Include the degree of compliance to Standard Review Plan 9.5.1 regarding emergency lighting requirements in the event of a fire.

RESPONSE

Refer to Section 9.5.3.

Q430.7 (9.5.4) Describe the instruments, controls, sensors and alarms provided for monitoring the diesel engine fuel oil storage and transfer system and describe their function. Discuss the testing necessary to maintain and assure a highly reliable instrumentation, controls, sensors and alarm system and where the alarms are annunciated. Identify the temperature, pressure and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe what operator actions are required during alarm conditions to prevent harmful effects to the diesel engine. Discuss the system interlocks provided. (SRP 9.5.4, Part III, item 1).

RESPONSE

See Subsection 9.5.4.5.

Q430.8 (9.5.4)

The diesel generator structures are designed to seismic and tornado criteria and are isolated from one another by a reinforced concrete wall barrier. Describe the barrier (including openings) in more detail and its capability to withstand the effects of internally generated missiles resulting from a crankcase explosion, failure of one or all of the starting air receivers, or failure of any high or moderate energy line and initial flooding from the cooling system so that the assumed effects will not result in loss of an additional generator. (SRP 9.5.4, Part III, Item 2).

RESPONSE

The barrier separating the two diesel generators is a 2-foot thick reinforced concrete wall. The wall reinforcement is such that the wall is capable of withstanding the impact of all the externally generated missiles identified in Table 3.5-1 of the Standard Plant FSAR.

There are four openings in the wall, but they are located within 3 feet of the north end of the building. This location and the small size of the openings (1 foot square or smaller) will effectively prevent any internally generated missiles from passing through the openings and damaging equipment in the adjacent area. In addition, these openings actually serve as penetrations for piping and are sealed.

The Callaway diesel engine is a low speed (514 rpm) engine which has a vented crank case. The engine manufacturer has never experienced nor knows of any crank case explosions or engine failures which resulted in missiles.

As noted above, the internal wall separating the two diesel engines is designed to withstand a tornado missile impact. In the highly unlikely event that the engine did generate an external missile, the energy of that missile would be significantly less than that of the tornado missile.

The air tanks are seismically mounted on their skids, which are in turn seismically anchored to the floor. Rupture of a tank would not generate missiles whose energy exceeds that of a tornado missile.

There are no high energy lines in the diesel generator building. The only moderate energy lines are those directly associated with each diesel engine. Therefore, a postulated failure of a moderate energy line would be considered the diesel single failure. There are no open penetrations between rooms, and therefore, flooding of one room will not degrade the opposite diesel engine.

Q430.9 (9.5.4)	Figure 9.5.4-1 and the FSAR text state that the fuel oil storage tank fill and vent lines are non-seismic. We require these lines to be designed seismic Category I and Quality Group C. Confirm your compliance with this position. Also describe the design provisions made to protect the fuel oil storage tank fill and vent lines from damage by tornado missiles. (SRP 9.5.4, Part II).

RESPONSE

See Subsection 9.5.4.2.2.

Q430.10 (9.5.4)	Discuss the means for detecting or preventing growth of algae in the diesel fuel storage tank. If it were detected, describe the methods to be provided for cleaning the affected storage tank. (SRP 9.5.4, Part III, Item 4).

RESPONSE

If any growth of algae should occur, detection would be accomplished by either periodic sampling of the fuel oil or visual inspection of the tank interior. Should any algae be found, a decision would be made at that time as to what methods of treatment would be employed to prevent future occurrences. Cleanup would be a manual operation. Should any algae occur and get into the fuel oil system, the system strainers and filters would remove it before it entered the diesel engine.

Q430.11 (3.2) (9.5.4) (9.5.5) (9.5.7) (.5.8)	The FSAR text and Table 3.2-1 states that the components and piping systems for the diesel generator auxiliaries (fuel oil system, cooling water, lubrication, air starting, and intake and combustion system) that are mounted on the auxiliary skids are designed seismic Category I and are ASME Section III Class 3 quality. The engine mounted components and piping are designed and manufactured to DEMA standards, and are seismic Category I. This is not in accordance with Regulatory Guide 1.26 which requires the entire diesel generator auxiliary systems be designed to ASME Section III Class 3 or Quality Group C. Provide the industry standards that were used in the design, manufacture, and inspection of the engine mounted piping and components. Also show on the appropriate P&ID's where the Quality Group Classification changes from Quality Group C.

RESPONSE

Only those components and piping supplied with the standard diesel engine and which either make up an integral part of the engine or whose design and reliability have been proven through years of previous diesel engine service are not Quality Group C. All other piping, tubing, and components are ASME Section III, Class 3. A tabulation of components, indicating those which are not Quality Group C, is attached.

The FSAR figures for the diesel engine auxiliary systems differentiate between seismic and nonseismic portions of the systems and identify those portions of the systems provided by the diesel engine manufacturer.

The standards used in the design, manufacture, and inspection of the Non-Quality Group C components are the manufacturer's standards, developed from his manufacturing and testing experience. By nature of its design and construction, the engine-mounted piping is considered to provide equivalency to ANSI B31.1 standards.

TABULATION OF DIESEL GENERATOR COMPONENTS

FUEL OIL SYSTEM

	Quality Group C		Non-Quality Group C
1.	Duplex filter	1.	Engine-driven fuel oil pump
2.	Basket strainer	2.	Flexible hose connections
		3.	Instrumentation

All piping, tubing, valves, and fittings associated with the fuel oil system are ASME Section III, Class 3 components, except for the injector nozzles and pumps and their immediate manifold piping.

INTERCOOLER AND INJECTOR COOLING SYSTEM

	Quality Group C		Non-Quality Group C
1.	Intercooler heat exchanger	1.	Engine-driven pump
2.	Three-way thermostatic valve	2.	Flexible hose connections
		3.	Instrumentation

All piping, tubing, valves, and fittings associated with the system are ASME Section III, Class 3 components, except those directly associated with the injector cooling.

LUBE OIL SYSTEM

	Quality Group C		Non-Quality Group C
1.	Lube oil heat exchanger	1.	Engine-driven lube oil pump
2.	Three-way thermostatic valve	2.	Engine-driven rocker lube oil pump
3.	Lube oil filter	3.	Motor-driven rocker lube oil pump
4.	Lube oil strainer	4.	Rocker lube oil filter

LUBE OIL SYSTEM (Cont.)

Quality Group C	Non-Quality Group C
5. Keep-warm heater	5. Flexible hose connections
6. Aux. lube oil tank	6. Instrumentation
7. Lube oil level control	7. Rocker lube oil reservoir
8. Keep-warm pump tank	

The lube oil level control tank was fabricated by the vendor under a Quality Assurance Program per ASME. The tank is made of ASME material and is seismically qualified. The tank has a rectangular configuration not covered by ASME, but the tank is essentially atmospheric and not pressure retaining.

The keepwarm pumps are not ASME "N" stamped components. However, they are seismically qualified and procured with appropriate controls to assure equivalency to ASME Section III, Class 3, Seismic Category I, Quality Group C requirements.

All piping and valves associated with the rocker lube oil system are not Quality Group C. This system is an internal part of the engine and does not connect to any ASME Code piping.

All other piping, valves, and fittings associated with the lube oil system, except those portions which are an integral part of the engine assembly, are ASME Section III, Class 3 components.

CRANKCASE VACUUM, AIR INTAKE, AND EXHAUST SYSTEM

The only portion of this system which is ASME Section III, Class 3 is the instrumentation tubing and valves associated with the crankcase vacuum monitoring and engine shutdown. All other components, including intake exhaust silencers, intake filters, etc., are standard manufacturer's components proven through previous service or are an integral part of the engine.

STARTING AND CONTROL AIR SYSTEM

Quality Group C	Non-Quality Group C
1. Start and shutdown solenoid valves	1. Instrumentation
2. Air strainers	2. All components up to the air tanks
3. Air tanks	3. Barring interlock

All valves, piping, and tubing from the air tanks to the barring interlock device are ASME Section III, Class 3 components. From the barring device onward is the standard, integral engine air start system, and this portion is not Quality Group C.

JACKET WATER SYSTEM

	Quality Group C		Non-Quality Group C
1.	Three-way thermostatic valve	1.	Engine drive pump
2.	Heat exchanger	2.	Flexible hoses
3.	Keep-warm pump	3.	Instrumentation
4.	Keep-warm heater		
5.	Expansion tank		

All the valves, piping, and tubing associated with the system, except that which is internal or an integral part of the engine, are ASME Section III, Class 3 components.

Skid piping meets or exceeds ANSI B31.1 criteria. Engine-proper piping has been designed to manufacturer's standards and has proven acceptable through years of successful operation.

Q430.12 (9.5.4)

Discuss what precautions have been taken in the design of the fuel oil system in locating the fuel oil day tank and connecting fuel oil piping in the diesel generator room with regard to possible exposure to ignition sources such as open flames and hot surfaces. (SRP 9.5.4, Part III, Item 6).

RESPONSE

See Subsection 9.5.4.2.1.

Q430.13 (9.5.4) (9.5.5) (9.5.6) (9.5.7) (9.5.8)

Identify all high and moderate energy lines and systems that will be installed in the diesel generator room. Discuss the measures that will be taken in the design of the diesel generator facility to protect the safety related system, piping and components from the affects of high and moderate energy line failure to assure availability of the diesel generators when needed. (SRP 9.5.4, Part III, item 8; SRP 9.5.5, Part III, item 4; SRP 9.5.6, Part III, item 8; SRP 9.5.7, Part III, item 3; SRP 9.5.8, Part III, item 6c).

RESPONSE

See Subsection 8.3.1.4.1.4.

Q430.14 (9.5.4)

In section 9.5.4 of the FSAR you state that accumulated sediment and moisture may be withdrawn, prior to adding a new fuel oil, through the sample nozzle to minimize the possibility of degrading the overall quality of the new fuel in the unlikely event that would require replenishment of fuel oil without interrupting operation of the diesel generator. This is unacceptable since the sample nozzle would only permit removal of accumulated moisture but not the sediment. Discuss that provisions that will be made in the design of the fuel oil storage fill system to minimize the creation of turbulance of the sediment in the bottom of the storage tank. Stirring of this sediment during addition of new fuel has the potential of causing the overall quality of the fuel to become unacceptable and could potentially lead to the degradation of failure of the diesel generator. Two methods of minimizing this problem are suggested. 1) Design a fuel oil storage tank fill system that will minimize turbulence in the tank. 2) Cross connect the fuel oil storage tank of each diesel in a manner that will permit supply of fuel oil to either engine from either tank. In this manner one tank could be filled while the other tank supplies fuel to the operating D/G. After filling the tank fuel would not be drawn from the tank for a period of time to permit settling of sediment.

RESPONSE

Refer to Subsection 9.5.4.2.1.

Q430.15 (9.5.4)

You state in section 9.5.4.3 that diesel oil is normally delivered to the site by tanker truck and if road transportation is unavailable, it can be delivered onsite by railroad tanker. Discuss per sources where diesel quality fuel oil will be available and the distances required to be travelled from the source to the plant. Also discuss how fuel oil will be delivered onsite under extremely unfavorable environmental conditions including maximum probable flood conditions.

RESPONSE

See the Site Addendum Section "Responses to NRC Questions."

Q430.16 (9.5.4)

You state in Section 9.5.4.2 that the diesel generator fuel oil storage tank is provided with an individual fill and vent line. Indicate where these lines are located (indoor or outdoor) and the height these lines are terminated above finished ground grade. If these lines are located outdoors discuss the provisions made in your design to prevent entrance of water into the storage tank during adverse environmental condition including maximum probable flood conditions.

RESPONSE

See Subsection 9.5.4.2.2.

Q430.17 (9.5.5) Discuss the design margin (excess heat removal capability) included in the design of major components and subsystems of the D/G cooling water system (SRP 9.5.5, Part III, Item I).

RESPONSE

Heat exchanger design by the engine manufacturer is based on maximum heat rejection requirements and a specified .002 fouling factor and 95°F entering water temperature. Because these design conditions are inherently conservative, the diesel engine cooling system contains a suitable margin for operation under all design conditions.

Q430.18 (9.5.5) Provide the results of the failure mode and effects analysis to show that failure of a piping connection between subsystems (engine water jacket, lube oil cooler, governor lube oil cooler, and engine air inter-cooler) does not cause total degradation of the diesel generator cooling water system. (SRP 9.5.5, Part III, Item 1a).

RESPONSE

See Section 9.5.5.

Q430.19 (9.5.5) Indicate the measures to preclude long-term corrosion and organic fouling in the diesel engine cooling water system that would degrade system cooling performance, and the compatability of any corrosion inhibitors or antifreeze compounds used with the materials of the system. Indicate if the water chemistry is in conformance with the engine manufacturers recommendations. (SRP 9.5.5, Part III, Item 1c.)

RESPONSE

See Subsection 9.5.5.2.3.

Treatment of the essential service water system that serves the cooling water heat exchanger is described in Section 9.2 of the Site Addendum.

Q430.20 (9.5.5) You stated in Section 9.5.5.2.3 the diesel engine cooling water is treated as appropriate to minimize corrosion. Provide additional details of your proposed diesel engine cooling water system chemical treatment, and discuss how your proposed treatment complies with the engine manufacturers recommendations. (SRP 9.5.5, Part III, Item 1c).

RESPONSE

See Subsection 9.5.5.2.3.

Q430.21
(9.5.5)

Describe the instrumentation, controls, sensors and alarms provided for monitoring of the diesel engine cooling water system and describe their function. Discuss the testing necessary to maintain and assure a highly reliable instrumentation, controls, sensors, and alarm system, and where the alarms are annunciated. Identify the temperature, pressure, level, and flow (where applicable) sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe what operator actions are required during alarm conditions to prevent harmful effects to the diesel engine. Discuss the systems interlocks provided. (SRP 9.5.6, Part III, item 1c).

RESPONSE

See Subsection 9.5.5.5.

Q430.22
(9.5.5)
RSP

In Section 9.5.8.2 of the FSAR, you state that "To reduce the possibility of accumulation of combustion and lube oil products in the exhaust system at the lower loads, the engine will be operated at 50 percent or higher loads for short periods at stipulated time intervals as recommended by the engine manufacturer." Provide the time duration of the "short periods" and the manufacture's recommended "time intervals." We require that this "light load or no load operation" procedure be made part of plant operating procedures. Confirm your compliance with this position.

RESPONSE

Refer to our response to 430.3 and Subsection 9.5.8.2.3.

Light load or no load operation will be addressed in plant operating procedures.

Q430.23
(9.5.6)

Provide a discussion of the measures that have been taken in the design of the standby diesel generator air starting system to preclude the feeling of the air start valve or filter with moisture and contaminants such as oil carryover and rust. (SRP 9.5.6, Part III, item 1).

RESPONSE

See Subsection 9.5.6.2.3.

Q430.24 (9.5.6) Describe the instrumentation, controls, sensors and alarms provided for monitoring the diesel engine air starting system, and describe their function. Describe the testing necessary to maintain a highly reliable instrumentation, control, sensors and alarm system and where the alarms are annunciated. Identify the temperature, pressure and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe any operator actions required during alarm conditions to prevent harmful affects to the diesel engine. Discuss system interlocks provided. Revise your FSAR accordingly. (SRP 9.5.6, Part III, item 1).

RESPONSE

See Subsection 9.5.6.5.

Q430.25 (9.5.6) Expand your description of the diesel engine starting system. The FSAR text should provide a detail system description of what is shown on Figure 9.5.6-1. The FSAR text should also describe: 1) components and their function, 2) instrumentation, controls, sensors and alarms, and 3) a diesel engine starting sequence. In describing the diesel engine starting sequence include the number of air start valves used and whether one or both air start systems are used.

RESPONSE

The diesel engine air start system components and their functions are described in Subsection 9.5.6.2.2.

Instrumentation, controls, sensors, and alarms are described in Subsection 9.5.6.5.

System operation is discussed in Subsection 9.5.6.2.3.

Q430.26 Provide the source of power for the diesel engine air starting system compressors and motor characteristics, i.e., motor hp, operating voltage, phase(s), and frequency. Revise your FSAR accordingly.

RESPONSE

Refer to Table 9.5.6-1 for the response to this question.

Q430.27 (9.5.7) For the diesel engine lubrication system in Section 9.5.7 provide the following information: 1) define the temperature differentials, flow rate, and heat removal rate of the interface cooling system external to the engine and verify that these are in accordance with recommendations of the engine manufacturer; 2) discuss the measures that will be taken to maintain the required quality of the oil, including the inspection and replacement when oil quality is degraded; 3) describe the capability for detection and control of system leakage. (SRP 9.5.7, Part II, Item 8a, 8b, 8c, Part III, Item I).

RESPONSE

1. Requested information for lube oil cooler is given in FSAR Table 9.5.7-1. Design information given in Table 9.5.7-1 is manufacturer's data.

2. See Subsection 9.5.7.2.3.

3. See Subsection 9.5.7.2.3.

Q430.28 (9.5.7) What measures have been taken to prevent entry of deliterious materials into the engine lubrication oil system due to operator error during recharging of lubicating oil or normal operation. (SRP 9.5.7, Part III, Item 1c).

RESPONSE

See Subsection 9.5.7.2.3.

Q430.29 (9.5.7) Describe the instrumentation, controls, sensors and alarms provided for monitoring the diesel engine lubication oil system and describe their function. Describe the testing necessary to maintain a highly reliable instrumentation, control, sensors and alarm system and where the alarms are annunciated. Identify the temperature, pressure and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe any operator action required during alarm conditions to prevent harmful effects to the diesel engine. Discuss systems interlocks provided. Revise your FSAR accordingly. (SRP 9.5.7, Part III, item 1c).

RESPONSE

See Subsection 9.5.7.5.

Q430.30 (9.5.7) Expand your description of the diesel engine lube oil system. The FSAR text should include a detail system description of what is shown on Figure 9.5.7-1. The FSAR text should also describe: 1) components and their function, and 2) a diesel generator starting sequence for a normal start and an emergency start. Revise your FSAR accordingly.

RESPONSE

Refer to Subsections 9.5.7.2.2 and 9.5.7.2.3 for component description and operation.

Q430.31 (9.5.7) Provide the soure of power for the diesel engine prelube oil pump, lube oil transfer pump, clean lube oil transfer pump and used lube oil tank transfer pump, and motor characteristics, i.e., motor hp, operating voltage, phase(s) and frequency. Also provide the pump capacity and discharge head. Revise your FSAR accordingly.

RESPONSE

The diesel engine is equipped with a main lube oil pump, an auxiliary lube oil (keep warm) pump, a rocker lube oil pump, and a rocker prelube pump. Refer to FSAR Table 9.5.7-1 for the requested information.

Q430.32 In Section 9.5.7.2 of the FSAR you state that pre-lubrication of the rocker arm assembly during standby conditions is done periodically in accordance with the engine manufacturer's recommendations. Provide the following:

(a) (RSP) We require that the electric prelube pump automatically prelube the rocker arm assembly and that alarms be provided which alert the operator of pump failure to start on automatic prelubrication.

(b) Provide the manufacturer's periodic prelubrication recommendations.

(c) Discuss how the lubricating oil in the rocker arm assembly lubrication system is cooler during engine operation and kept warm to enhance engine starting during standby operation.

RESPONSE

See Subsection 9.5.7.2.3.

Q430.33 (9.5.8) Describe the instrumentation, controls, sensors and alarms provided in the region of the diesel engine combustion air intake and exhaust system which alert the operator when parameters exceed ranges recommended by the engine manufacturer and describe any operator action required during alarm conditions to prevent harmful effects to the diesel engine. Discuss systems interlocks provided. Revise your FSAR accordingly. (SRP 9.5.8, Part III, item 1 & 4).

RESPONSE

See Subsection 9.5.8.5.

Q430.34 (9.5.8) Provide the results of an analysis that demonstrates that the function of your diesel engine air intake and exhaust system design will not be degraded to an extent which prevents developing full engine rated power or cause engine shutdown as a consequence of any meteorological or accident condition. Include in your discussion the potential and effect of other gases that may intentionally or accidentally be released on site, on the performance of the diesel generator. (SRP 9.5.8, Part III, item 3).

RESPONSE

See Subsections 9.4.7.2.3 and 9.5.8.2.3.

Refer to the Site Addendum, Section 2.2, for a discussion of the location of any gases stored on site. There are no gases stored sufficiently close to the diesel building, such that a release would impair operation of the diesel engine through ingestion of the gases into the engine.

Q430.35 (9.5.8) Discuss the provisions made in your design of the diesel engine combustion air intake, D/G supply ventilation system, and exhaust system to prevent possible clogging, during standby and in operation, from abnormal climatic conditions (heavy rain, freezing rain, dust storms, ice and snow) that could prevent operation of the diesel generator on demand. (SRP 9.5.8, Part III, item 5).

RESPONSE

See response to 430.34 and Subsections 9.4.7.2.3 and 9.5.8.2.3.

Q430.36 (9.5.8)

Figure 1.2-1 of the Callaway (and Wolf Creek) FSAR shows the ESF transformers located near the control/diesel generator building complex. An ESF transformer fire with the right meteorological conditions could degrade engine operation by the products of combustion being drawn into the D/G ventilation system which supplies D/G combustion air. Discuss the provisions of your design (site characteristics, ventilation system and building design, etc.) which preclude this event from occurring.

RESPONSE

See Subsection 9.5.8.3.

Q430.37 (9.5.8)

Experience at some operating plants has shown that diesel engines have failed to start due to accumulation of dust and other deleterious material on electrical equipment associated with starting of the diesel generators (e.g., auxiliary relay contacts, control switches - etc.). Describe the provisions that have been made in your diesel generator building design, electrical starting system, and combustion air and ventilation air intake design(s) to preclude this condition to assure availability of the diesel generator on demand.

Also describe under normal plant operation what procedures(s) will be used to minimize accumulation of dust in the diesel generator room; specifically address concrete dust control. In your response also consider the condition when Unit 1 is in operation and Unit 2 is under construction (abnormal generation of dust).

RESPONSE

See Subsection 9.4.7.2.1.

Q430.38 (9.5.8) (RSP)

Section 9.5.8.2.2 and 3.2.2 of the FSAR state that the portions of the EDEAIES outside the D/G building are non-seismic and Quality Group D. This is unacceptable. We require that these portions of the system also be designed seismic Category I and Quality Group C. In addition we required also that the exhaust stacks located outside the D/G building be tornado missile protected. Separation by distance does not constitute adequate protection. Confirm your compliance with these positions.

RESPONSE

Although the Callaway Plant safety-related structures and components are designed for the design basis tornado and the design basis tornado missiles, the diesel exhaust stacks can reasonably be exempt from the requirement for specific missile barriers without jeopardizing the health and safety of the public. During the PSAR review stage, the NRC staff questioned the tornado missile protection provided for the stacks (Question 020.13), and reached the same conclusion for the present design.

After the construction permit review was complete, the NRC issued Regulatory Guide 1.117 "Tornado Design Classification," which is applicable to Construction Permit applications docketed after May 30, 1978. Even though this guide is not applicable to the Callaway Plant, it has been addressed in the FSAR, and its provisions are adequately met to state that the design is in compliance with the regulatory recommendations.

The diesels and the intake and exhaust system are provided with adequate protection to ensure that the diesels will remain functional following the occurrence of a design basis tornado. Only the exhaust stacks are not specifically provided with tornado missile barriers, since it is extremely unlikely that a missile(s) will adversely affect the proper functioning of the diesel engines. The basis for this conclusion includes consideration of 1) the exhaust stacks inherent resistance to damage from credible missiles and the acceptability of penetration and/or significant denting, 2) the improbability of design basis tornados and the low probability that the design basis missiles could exist at the high elevations required, and 3) the significant protection afforded the stacks by existing plant structures. The arguments below demonstrate that it is extremely unlikely that a tornado missile will damage an exhaust stack and inhibit diesel operation. It is even more unlikely that both stacks could be damaged.

I. EXHAUST STACK DESIGN

The diesel stacks are seismically supported, 35 feet apart, and inherently resistant to damage from tornado missiles due to their large diameter (42-inch 0.D.) and 3/8-inch-thick steel wall construction. High kinetic energy missiles could, however, deform the stack or even penetrate it if the impact area is small relative to the kinetic energy. Penetration or significant deformation will not adversely affect the function of the stacks since they are oversized.

The total allowable pressure drop for the exhaust system for rated power output is 10 inches of water. The pressure drop from the engine through the exhaust silencer and to the diesel building roof line is approximately 5 inches of water. The exposed portion of pipe above the diesel generator roof is only 50 feet long and has an allowable length of more than 926 feet (corresponding to an allowable pressure drop of 5 inches of water). If this pipe were only 32 inches in diameter, its allowable length would be 280 feet. Thus significant local damage due to denting or penetration by a tornado missile is acceptable because full power diesel operation would not be impaired.

II. DISCUSSION OF MISSILE SELECTION CRITERIA

The missiles currently postulated by the NRC in Standard Review Plan 3.5.1.4 are likely to be near a nuclear power plant, but are not necessarily those most likely to attain high energy nor the most likely to be entrained in a tornado vortex and high windfield. The missiles chosen all have a unique feature which could cause local damage to a concrete structure or penetrate a small opening. For the diesel stacks, the automobile and utility pole are not applicable since they are not credibly postulated above 30 feet. The other missiles are postulated because of their high energy to impact area ratios for end-on impact. This type of impact is not of concern since penetration of the stack is acceptable. For the diesel stacks, other high density and high energy objects could be postulated. However, any effort to specifically define another missile spectrum is inappropriate.

The improbability of any missile of high density and high energy being elevated to the heights of the diesel stacks is obvious from NUREG-0121 "An Assessment of the Basis for Selection Criteria for Protection Against Tornado-Entrained Debris." Excerpts from NUREG-0121 are provided below, and remarks are added to show their applicability to the diesel stack design. These discussions are provided to highlight the low probability of any high density, high energy missile which approaches the characteristics of the current set of design basis missiles.

- Any set of design basis tornado missiles should consider:

  1. Objects likely to be in the plant vicinity

  2. Objects in the vicinity and likely to become airborne and hurled by a tornado windfield

  3. Airborne objects likely to damage plant structures if impacted at high speed.

"Of the present list of seven missiles, only missile "G", the automobile, clearly meets all three tests. For the other high density missiles the potential for lofting and acceleration is questionable." (NUREG-0121, Page 2)

(Remark: The automobile and utility poles are not credibly postulated above 30 feet. The minimum height of the exposed stack is 47.5 feet.)

- "The information in WASH 1300 suggests that the design basis tornado is itself no more probable than 10^{-7} per year and that the median tornado windspeed of all U. S. tornados studied was about 45 m/sec. Fewer than 10 percent of these studied tornados were deduced to have windspeeds above 70 m/sec., fewer than 1 percent above 90 m/sec., and fewer than 0.1 percent above 130 m/sec.

"In regard to damage potential, typical missiles in a 10^{-7} per year tornado become very rare in a 10^{-6} per year tornado, and are physically impossible in tornados having higher incidence rates." (NUREG-0121, Pages 3 and 4)

(Remark: Only the near design basis tornado missiles have sufficient energy to cause adverse damage to the diesel stacks.)

- "A rigid body may be lifted into a windfield by any or all conceivable mechanisms: (1) aerodynamic lift ..., (2) drag lift ..., (3) suction .... These last two mechanisms, however, are of great importance only to objects directly in the path of the tornado vortex. The first mechanism, aerodynamic lift, can be postulated to affect missiles over a much greater area." (NUREG-0121, Pages 6 and 7)

  (Remarks: Unless a missile is lifted while in the vortex of the tornado, it will not achieve any significant height unless its aerodynamic properties are unique. Missiles of concern to the diesel stack would have to be lifted between 47 and 97 feet while remaining in the vortex and high wind speed region of the tornado in order to be accelerated to significant velocities.)

- "Missiles that do not "fly" will experience predominately horizontal forces and will be accelerated by them. At some point in their trajectory, a maximum velocity will be reached, after which the missile must decelerate." (NUREG-0121, Page 8)

  (Remarks: The missiles of concern are dense and usually of poor airfoil design and are therefore unlikely to "fly" to the heights required to damage the diesel stacks.)

- "In order to achieve any significant fraction of the maximum tangential wind speed, a massive missile must pass through the maximum wind, and the most significant - single parameter of a missile trajectory in determining that missiles' maximum velocity is the distance traveled within the maximum windfield.... such missiles are lifted and accelerated only by the highest velocity winds but can not be easily deflected from a nearly straight path in order to follow the tornado vortex." (NUREG-0121, Pages 12 and 13)

  (Remarks: Massive missiles fly straight and therefore do not remain in the maximum windfield for long durations. Once out of the maximum windfield, they fall rapidly due to gravity. Therefore the missiles which could damage the diesel stacks would have to be raised to heights greater than 47.5 feet or be in or near the maximum windspeed section of the tornado at the moment of impact.)

- "The study has shown that it is relatively easy for a missile to acquire about 10 percent of the maximum tornado windspeed by a brief passage in the windfield, but to acquire significantly higher velocities, a comparatively long distance must be traveled within the windfield. However, massive missiles cannot stay within a windfield long enough to attain high velocities because of centrifugal forces." (NUREG-0121, Page 23)

(Remarks: Only high energy missiles are of concern to the diesel stack functionality.)

- "Real tornados are not uniform windfield, but distorted helical flows... Should a tornado pass over the barrier while a missile is entrained therefore, there is a significant probability that the missile will not, in fact, impact the barrier." (NUREG-0121, Page 17)

(Remarks: The surface of the diesel stack which is normal to the flight of a postulated missile is small. Glancing blows of a missile or impacts of an end of a tumbling missile will not adversely affect the diesel stacks.)

III. DISCUSSION OF STRUCTURAL PROTECTION

The following discussion addresses horizontal missile trajectories and missiles recently ejected from the maximum windfield. Missiles falling from greater heights are not specifically addressed, since it is considered extremely improbable that a design basis missile will exceed the heights of the surrounding buildings. FSAR Figures 1.2-26, 1.2-27, and 1.2-28 provide detailed plan and elevation views of the stacks and surrounding structures. Figure 430.38-1 depicts the plan location of the diesel stacks and the inherent protection provided for them by the surrounding power block structures from tornado missiles which could potentially affect the full power operation of the diesel. For analysis purposes approach of missiles on the diesel stacks has been considered for seven zones. (Zones A through G are indicated on Figure 430.38-1.) The exact boundaries of each zone are not strictly defined since the stacks are 35 feet apart and tumbling missiles would affect the zone boundaries.

Zone A Protection is provided by the control building to a height of 87 feet. Only the top 10 feet of the stacks are exposed to missiles which must rise above nine stories and traverse the control building roof prior to impacting the stacks.

Zone B The turbine building roof is approximately 140 feet high and would effectively preclude design basis missiles from reaching the diesel stacks. The control building again affords protection for most of the stacks.

Zone C The containment structure provides complete protection from missiles from this direction.

Zone D The fuel building is 106 feet high and provides complete protection from credible missiles possessing sufficient energy to inflict adverse damage.

Zone E — The diesel generator intake penthouse provides protection up to 66 feet above grade. The radwaste building will also provide protection up to 55 feet above grade and effectively disrupt the funnel and windfield to help eject previously entrained missiles prior to their reaching the diesel building.

Zone F — The diesel generator intake penthouse provides protection up to 66 feet above grade to effectively shield the exhaust stacks from high energy missiles.

Zone G — This relatively narrow zone is the least protected direction for which missiles could emanate and impact the stacks. However, missiles of concern would have to be raised over five stories while being accelerated to high velocities. These missiles would have to be ejected from the maximum windfield at a significant distance from the control/diesel building to reach the stacks. Once a funnel reaches these buildings, the windfield will be disturbed, and entrained missiles will be less likely to have been accelerated to high velocities. For a tornado approaching from the east, missiles in the leading edge of the windfield when the funnel reaches the diesel building will be traveling in a north/south direction and not impact the stacks.

Q430.39 (10.1) — Provide a general discussion of the criteria and bases of the various steam and condensate instrumentation systems in Section 10.1 of the FSAR. The FSAR should differentiate between normal operation instrumentation and required safety instrumentations.

RESPONSE

The criteria and bases of the various steam and condensate instrumentation are to monitor system variables to provide maximum plant availability, automatic control of equipment, and identification of abnormal conditions. Sections 7.3, 7.4, and 7.5 describe the required safety instrumentation associated with Section 10.1. All remaining steam and condensate instrumentation systems included in Section 10.1 are nonsafety-related and are used for normal operation.

Q430.40 (10.2) — The FSAR discusses the main steam stop and control, and reheat stop and intercept valves. Show that a single failure of any of the above valves cannot disable the turbine overspeed trip functions. (SRP 10.2, Part III, Item 3).

RESPONSE

Subsection 10.2.2.3.2 describes the component redundancy which precludes single failure of any main stop, control, intermediate stop, and intercept valve from resulting in rotor speed exceeding design overspeed. All the above valves have independent operating controls and mechanisms.

Q430.41 (10.2) In the turbine generator section discuss: 1) the valve closure times and the arrangement for the main steam stop and control and the reheat stop and intercept valves in relation to the effect of a failure of a single valve on the overspeed control functions; 2) the valve closure items and extraction steam valve arrangements in relation to stable turbine operation after a turbine generator system trip; 3) effects of missiles from a possible turbine generator failure on safety related systems or components. (SRP 10.2, Part III, Items 3, 4.)

RESPONSE

See revised Subsection 10.2.2.2. Main stop and control valves, intermediate stop, and intercept valves' closure times are provided. Extraction nonreturn valves are free swinging and close on decreasing flow as described in Subsection 10.2.2.2. Valve arrangements and single failure effects plus stable turbine operation after a trip are described in Subsections 10.2.2.2 and 10.2.2.3.2, Table 10.2-1, and Figure 10.4-6. Turbine missiles are discussed in Subsection 3.5.1.3.

Q430.42 (10.2) Discuss the effects of a high and moderate energy piping failure or failure of the connection from the low pressure turbine to condenser on nearby safety related equipment or systems. Discuss what protection will be provided the turbine overspeed control system equipment, electrical wiring and hydraulic lines from the effects of a high or moderate energy pipe failure so that the turbine overspeed protection system will not be damaged to preclude its safety function. (SRP 10.2, Part III, Item 3).

RESPONSE

The turbine overspeed protection system is not safety related. The ultimate protection from turbine missiles is discussed in Section 3.5.1. No high/moderate energy pipe break or hazards analysis is performed for nonsafety-related turbine building piping or components. However, Subsection 10.2.2.3.2 describes the following component redundancies which may protect the turbine overspeed control system's function from the effects of high or moderate energy piping failures.

a. Main stop valves/control valves

b. Intermediate stop valves/intercept valves

c. Primary speed control/backup speed control

d. Fast acting solenoid valves/emergency trip fluid system (ETS)

e. Speed control/overspeed trip/backup overspeed trip

Figures 1.2-32 and 1.2-33 show the physical separation between redundant stop/ control valves and intermediate stop/intercept valves. Fail safe design of the ETS hydraulic system and the trip power circuitry provide additional turbine overspeed protection. Failure of the low pressure turbine/condenser connection will draw air into the condenser and increase turbine backpressure until trip occurs as stated in Subsection 10.2.2.3.4.

Q430.43 (10.2) Describe with the aid of drawings, the bulk hydrogen storage facility including its location and distribution system. Include the protective measures considered in the design to prevent fires and explosions during operations such as filling and purging the generator, as well as during normal operations.

RESPONSE

See the Site Addendum Section "Responses to NRC Questions."

Q430.44 (10.4.1) Provide a tabulation in your FSAR showing the physical characteristics and performance requirements of the main condensers. In your tabulation include such items as; 1) the number of condenser tubes, material and total heat transfer surface, 2) overall dimensions of the condenser, 3) number of pauses, 4) hot well capacity, 5) special design features, 6) minimum heat transfer, 7) normal and maximum steam flows, 8) normal and maximum cooling water temperature, 9) normal and maximum exhaust steam temperature with no turbine by-pass flow and with maximum turbine by-pass flow, 10) limiting oxygen content in the condensate in cc per liter, and 11) other pertinent data. (SRP 10.4.1, Part III, item 1).

RESPONSE

Table 10.4-1 has been revised to include the requested information.

Q430.45 (10.4.1) Discuss the measures taken; 1) to prevent loss of vacuum, and 2) to prevent corrosion/errosion of condenser tubes and components. (SRP 10.4.1, Part III, Item 1).

RESPONSE

Measures taken to prevent loss of vacuum and the Section describing them include:

a. Hydrostatic test of condenser shell (10.4.1.4).

b. Water seal for the LP turbine/condenser connection expansion joint with level indication (10.4.1.2).

c. Provision of condenser vacuum pumps (two operational and one standby) (10.4.2.2).

d. Control room indication of circulating water pump status (Site Addendum Section 10.4.5).

Measures taken to prevent corrosion/erosion of condenser tubes and components:

a. Provision of 304 stainless steel tubes in the impingement areas of all tube bundles (Table 10.4-1).

b. Feedwater/circulating water chemistry control (Standard Plant Section 10.3.5 and Site Addendum Section 10.4.5).

Q430.46 (10.4.1) Indicate and describe the means of detecting and controlling radioactive leakage into and out of the condenser and the means for processing excessive amounts. (SRP 10.4.1, Part III, Item 2).

RESPONSE

The means of detecting, controlling, and processing radioactive leakage into and out of the condenser resulting from a steam generator tube leak are discussed in Chapter 11.0. The means for detecting and controlling radioactive leakage into and out of the condenser are described in Subsections 11.5.2.2.2.2, 11.5.2.2.2.3, 11.5.2.2.3.4, and 11.5.2.3.2.1. Processing of excessive radioactive leakage is discussed in Sections 11.2.2 and 11.3.2.

Q430.47 (10.4.1) Discuss the measures taken for detecting and controlling and correcting condenser cooling water leakage into the condensate stream. (SRP 10.4.1, Part III, Item 2).

RESPONSE

The measures taken for detecting, controlling, and correcting condenser cooling water leakage into the condensate stream are discussed in Section 10.4.1.

Q430.48 (10.4.1) Provide the permissible cooling water inleakage and time of operation with inleakage to assure that condensate/feedwater quality can be maintained within safe limits. (SRP 10.4.1, Part III, item 2).

RESPONSE

The information is provided in Section 10.4.6, Condensate Cleanup System.

Q430.49 (10.4.1) In section 10.4.1.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice inspection of the main condenser. Provide this information in the FSAR. (SRP 10.4.1, Part II).

RESPONSE

The extent of inservice inspection of the main condenser includes the following:

1. Monitor condensate conductivity, temperature, and dissolved oxygen level.

2. Check water level in the condenser/turbine connection expansion joint water seal for seal leak detection.

The frequency of these inspections will depend on past condenser operating experience and the type of problems identified in the previously described inspections.

Q430.50 (10.4.1) Indicate what design provisions have been made to preclude failures of condenser tubes or components from turbine by-pass blowdown or other high temperature drains into the condenser shell. (SRP 10.4.1, Part III, item 3).

RESPONSE

See revised Subsection 10.4.1.2.3.

Q430.51 (10.4.1) Discuss the effect of loss of main condenser vacuum on the operation of the main steam isolation valves (SRP 10.4.1, Part III, item 3).

RESPONSE

Loss of main condenser vacuum does not trip the main steam isolation valves. Loss of main condenser vacuum trips the turbine and blocks turbine bypass. Turbine trip at power levels above 50 percent results in a reactor trip as described in Section 7.2. The effects of potential failure modes on the NSSS and turbine system are addressed in Sections 15.1.4, 15.2.3, and 15.2.5.

Q430.52 (10.4.4) Provide additional description (with the aid of drawings) of the turbine by-pass system (condenser dump valves and atmosphere dump valves) and associated instruments and controls. In your discussion include: 1) the size, principle of operation, construction and set points of the valves, 2) the malfunctions and/or modes of failure considered in the design of the system.

RESPONSE

Condenser Dump Valves

Subsection 10.4.4.2.1 and Figure 10.3-1, Sheet 3 provide a description of the turbine bypass system and the condenser dump valves. The condenser dump valves are air actuated, carbon steel, 8 inch, 1,500 pound globe valves. The valves are pilot-operated, spring-opposed, and fail closed upon loss of air or loss of power to the control system, as stated in Subsection 10.4.4.2.2. Section 7.7.1.8 and Figures 7.2-1, Sheet 10 and 10.3-1, Sheet 3 describe the associated instruments and controls. The malfunctions and failure modes considered in system design and their effect on the NSSS and turbine system are addressed in Sections 15.1.4 and 15.2.3.

Steam Generator Power Operated Relief Valves

Section 10.3.2.2, Table 10.3-2 and Figure 10.3-1, Sheet 1 provide a description of the steam generator power-operated relief valves. The steam generator power-operated relief valves are air actuated, carbon steel, 8-inch, 1,500-pound globe valves. The valves are opened by pneumatic pressure and closed by spring action as stated in Section 10.3.2.2. Section 7.4.1.2 and Figures 7.2-1, Sheet 10 and 10.3-1, Sheet 1 describe the associated instruments and controls. The malfunctions and failure modes considered in the system design are addressed in Section 7.4.1.2 and Section 15.1.4.

Q430.53 (10.4.4) Section 10.4.4 of the FSAR describes the turbine bypass system and states that the TBS dumps steam to the condenser through condenser spargers. Figure 10.3.1, sheet 3 in the FSAR shows the turbine bypass as described in Section 10.4.4. It also shows six 3 inch lines branching off the TBS lines upstream of the TBS valves. These lines are labelled "To Condenser Sparger" and seem to have normally open valves. Explain the purpose of these lines and the status of these valves.

RESPONSE

The purpose of these lines in steam supply to the condenser hotwell spargers used for deaeration of the condensate, as described in Sections 10.3.5 and 10.4.1.2.3. The valves in phantom on Figure 10.3.1, Sheet 3 are shown on P&ID M-02AD01 (Figure 10.4.2, Sheet 1) as normally closed.

Q430.54 (10.4.4) In Section 10.4.4.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice testing and inspection of the turbine by-pass system. Provide this information in the FSAR. (SRP 10.4.4, Part II).

RESPONSE

See Subsection 10.4.4.4.

Q430.55 Provide the results of an analysis indicating that failure of the turbine by-pass system high energy line will not have an adverse effect or preclude operation of the turbine speed control system or any safety related components or system located close to the turbine by-pass system. (SRP 10.4.4, Part III, item 4).

RESPONSE

See response to Question 430.42. There is no safety-related equipment in the vicinity of the turbine bypass system, as stated in Section 10.4.4.3.

Q440.1
(440.3WC)
(440.1C)

The analyses of a locked reactor coolant pump rotor and a sheared reactor coolant pump shaft in the FSAR assumes the availability of offsite power throughout the event. In accordance with Standard Review Plan 15.3.3 and GDC 17, we require that this event be analyzed assuming turbine trip and coincident loss of offsite power to the undamaged pumps.

Appropriate delay times may be assumed for loss of offsite power if suitably justified.

Steam generator tube leakage should be assumed at the rates specified in the Technical Specifications.

The event should also be analyzed assuming the worst single failure of a safety-system active component. Maximum technical specification primary system activity and steam generator tube leakage should be assumed. The analyses should demonstrate that offsite doses are less than 10 CFR 100 guidelines values.

RESPONSE

The locked reactor coolant pump rotor/sheared reactor coolant pump shaft analyses in FSAR Sections 15.3.3 and 15.3.4 contain the assumptions of a turbine trip and loss of offsite power to the undamaged pumps. Refer to FSAR Sections 15.3.3 and 15.3.4 for details of the events.

Q440.106 (5.2.2) In reviews of certain other Westinghouse-designed plants, a failure of a D.C. power bus was identified which could both initiate an overpressure event at low temperature (by isolating letdown) and fail closed one of the PORVs. A postulated single failure (closed) of the other PORV would fail mitigating systems for this event. Address this scenario for the SNUPPS design.

RESPONSE

The response to the above scenario will depend on whether the RHR system is isolated from the reactor coolant system; however, in any event, the design provides adequate protection against overpressure of the reactor coolant system.

In the case where the RCS is at low temperature and the RHR letdown isolation valves for either or both RHR loops are open, the RCS is protected from overpressurization by the RHR inlet relief valves. These valves are each sized to relieve the combined flow of all the charging pumps at a setpoint of 450 psig.

During normal startup and shutdown, a pressurizer bubble is maintained whenever the RHR system is isolated. The normal steam bubble volume in this condition would be approximately 1350 ft^3. Should normal letdown be isolated, the maximum makeup rate imbalance would be approximately 150 gpm, which is the capacity of the normal charging pump that is normally in operation. This value would actually be much less as the transient progressed, since the charging flow control system would throttle the flow to try to maintain pressurizer level. However, even if no credit is taken for the charging control system, and assuming that the pressurizer level is initially at the high level alarm setpoint (i.e., approximately 500 ft^3 steam bubble), the plant operator would have more than 10 minutes to terminate the event.

Q440.207 The NRC wanted to know if the solid water condition between RHR suction valves could, because of heating, expand and cause system damage or valve inoperability.

RESPONSE

RHR suction valve seat leakage is expected to prevent system damage or valve inoperability resulting from contained fluid thermal expansion.

TABLE 420.4-1 LOSS OF ANY SINGLE INSTRUMENT

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Feedwater Header Pressure	3 per plant		Feedwater control	Lo	No effect on Feedwater (FW) Control.	No event if FW pump speed control is in manual. If FW pump speed control is in manual and the FCV is in manual, the bounding event is Excessive FW Flow (FSAR 15.1.2) or Loss of Normal Flow (FSAR Section 15.2.7).
				Hi	No effect on Feedwater (FW) Control.	No event if FW pump speed control is in manual. If FW pump speed control is in manual and the FCV is in manual, the bounding event is Excessive FW Flow (FSAR 15.1.2) or Loss of Normal Flow (FSAR Section 15.2.7).
Steam Header Pressure	3 per plant 1 per plant		Feedwater Control Steam Dump (TAVG Model)	Lo	No effect on Feedwater (FW) Control.	No event if FW pump speed control is in manual. If FW pump speed control is in manual and the FCV is in manual, the bounding event is Excessive FW Flow (FSAR 15.1.2) or Loss of Normal Flow (FSAR Section 15.2.7).
				Hi	No effect on Feedwater (FW) Control.	No event if FW pump speed control is in manual. If FW pump speed control is in manual and the FCV is in manual, the bounding event is Excessive FW Flow (FSAR 15.1.2) or Loss of Normal Flow (FSAR Section 15.2.7).
Steam Header Pressure	3 per plant 1 per plant		Feedwater Control Steam Dump (Pressure Mode)	Lo	No effect on Feedwater (FW) Control.	No event if FW pump speed control is in manual. If FW pump speed control is in manual and the FCV is in manual, the bounding event is Excessive FW Flow (FSAR 15.1.2) or Loss of Normal Flow (FSAR Section 15.2.7).

TABLE 420.4-1 (Sheet 2)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Steam Header Pressure (continued from sheet 1)				Hi	No effect on FW Control. Steam dump valves open. Steam dump blocked on Low-Low T-avg (P-12). FW pump speed decreases if in AUTO mode due to decreased steam pressure. FW control valves open due to decreased flow if in AUTO mode.	Steam dump in pressure mode at hot standby conditions or at very low power. Hence, dump valves would open for only a very short time until Lo-Lo TAVG is reached. If pump speed is in manual, or if both pump speeds and FCV are in auto, then this event is bounded by excessive increase in secondary steam flow (FSAR 15.1.3).
Loop Steam Flow	2 per loop (averaged)	1of the channels used for averaging	Feedwater Control	Lo	If the control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.
				Hi	If the control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.
Loop FW Flow	2 per loop (averaged)	1of the channels used for averaging	Feedwater Control	Lo	If the control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.
				Hi	If the control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.
Narrow Range Level	4 per Steam Generator (two available for control by averaging)	I or II	Feedwater Control	Lo	If control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.
				Hi	If control system detects failure of one channel, the control system will use the functional channel resulting in no effect.	No event if the control system detects failure of one channel.

TABLE 420.4-1 (Sheet 3)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Pressurizer Level (Control)	3 per plant	I or III	Prz. Level Control	Lo	Charging flow increases. Heaters turn off (except for local control}. Letdown isolated.(VCT empties, charging pumps take suction from RWST.)	Bounding event is Increased Reactor Coolant Inventory (FSAR 15.5.2).
				Hi	Charging flow decreases. Backup heaters on. (Later, letdown isolation from interlock channel and heaters blocked from interlock channel.)	While heaters are on, no net depressurization of RCS. After heaters blocked, the decreased charging flow acts to depressurize the RCS. Depressurization event is therefore bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1).
Pressurizer Level (Interlock)	3 per plant	I or III	Prz. Level Control	Lo	Letdown isolation. Prz. heaters blocked (except for local control). (Charging flow controller reduces flow to maintain level).	Reach new steady-state with high pressurizer level. No event.
				Hi	No control action, get Hi level annunciation.	Not applicable.
Pressurizer Pressure	4 per plant	II or IV	Prz. Pressure Control	Lo	No control action. PORV 456A blocked from opening. PORV 455A opens if required, closes when pressure falls below deadband.	Not applicable.
				Hi	PORV 456A opens. (PORV closes when pressure drops below deadband.)	Bounding event is Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1).
Pressurizer Pressure	4 per plant	II or III	Prz. Pressure Control	Lo	Backup heaters on. Spray remains off. PORV 455A blocked from opening (PORV 456A opens if required, closes when pressure falls below deadband.)	Heater on causes increase in prz. pressure to PORV 456A actuation. No event.

TABLE 420.4-1 (Sheet 4)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
				Hi	PORV 455A opens. Spray on. (PORV 455A closes when pressure drops below deadband).	Bounding event is Inadvertent Opening of a Prz. Safety or Relief Valve FSAR 15.6.1).
TAVG	1 per loop	Any Auct. Hi Auct. Lo	Steam dump (TAVG mode) Reactor Control Prz. Level Control Turbine Loading/ Dispatching	Lo	stop turbine loading/ defeat remote dispatching. (C-16-Annunciation occurs).	Not applicable.
				Hi	Rods in (safe direction). Charging flow increases until full power prz. level is reached (if at reduced power). (If reactor trips, steam dump enabled and dump valves open until steam dump stops when Lo-Lo TAVG (P-12) is reached.)	No event unless reactor trips, then steam dump valves open and this is bounded by Excessive Increase in Secondary Steam Flow (FSAR 15.1.3)
Tavg	1 per loop	Any Auct. Hi Auct. Lo	Steam dump (Pressure mode) Reactor Control Prz. Level Control Turbine Loading/ Dispatching	Lo	stop turbine loading/ defeat remove dispatching (C-16). Annunciation occurs.	Not applicable.
				Hi	Rods in (safe direction). Charging flow increases until full power prz level is reached (if at reduced power).	Reach steady-state with pressurizer at full-power level. No event.
Steamline Pressure	3 per loop for protection, 1 per loop for control (different from those used for protection)	Control Channel	S. Gen PORV	Lo	No Control Action.	Not applicable.

TABLE 420.4-1 (Sheet 5)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
				Hi	S. GEN. relief valve opens.	Result is bounded by Inadvertent Opening of a s. Gen. Relief or Safety Valve (FSAR 15.1.4).
Intermediate Range Flux	2 per plant	I or II	Reactor Control	Lo	No control action.	Not applicable.
				Hi	Get reactor trip (during startup) due to C-1 actuation, otherwise no control action.	Not applicable.
Turbine Impulse Chamber Pressure	2 per turbine	I (Control)	Steam Dump (TAVG Mode) Reactor Control FW Control	Lo	Rods in (safe direction). Auto rod withdrawal blocked (C-5). (If reactor trip occurs, steam dump unblocked and dump valves open until no load TAVG is reached.) No effect on FW control since constant level program.	Not applicable.
				Hi	Rods out until blocked by Hi flux, overpower, or overtemperature rod stop, or until programmed TREF limit is reached. (If reactor trip occurs, steam dump unblocked and dump valves open until no load TAVG is reached.) No effect on FW control since have constant S.G. level program.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2).

TABLE 420.4-1 (Sheet 6)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Turbine Impulse Chamber Pressure	2 per turbine	II (Interlock)	Steam Dump (TAVG Mode) Reactor Control FW Control	Lo	Steam dump unblocked. Rods in (safe direction). Auto rod withdrawal blocked (C-5). (If reactor trip occurs, dump valves open until no load TAVG is reached}. No effect on FW control, since have constant S.G. level program.	Not applicable.
				Hi	Rods out until blocked by Hi flux, overpower, or overtemperature rod stop, or until programmed TREF limit is reached. (If reactor trip occurs, steam dump valves open until no load TAVG is reached.) No effect on FW control, since have constant S.G. level program.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4. 2).
Turbine Impulse Chamber Pressure	2 per turbine	I (Control)	Steam Dump (Pr, Mode) Reactor Control FW Control	Lo	Auto rod withdrawal blocked (C-5). Rods in (safe direction). No effect on FW control, since have constant S.G. level program. (If reactor trip occurs, dump valves open to keep steam header pressure at or below setpoint.)	Not applicable. Result is bounded by Un- controlled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2).
				Hi	Rods out until blocked by Hi flux, overpower or overtemperature rod stop or until programmed TREF is reached. (If reactor trip occurs, dump valves open to keep steam header pressure at or below setpoint.) No effect on FW control since have constant S.G. level program.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2).

TABLE 420.4-1 (Sheet 7)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Turbine Impulse Chamber Pressure	2 per turbine	II (Interlock)	Steam Dump (Pr. Mode) Reactor Control FW Control	Lo	Auto rod withdrawal blocked (C-5).Rods in (safe direction). No effect on FW control since have constant S.G. level program. (If reactor trip occurs, dump valves open to keep steam header pressure at or below setpoint.)	Not applicable.
				Hi	Rods out until blocked by Hi flux, overpower or overtemperature rod stop or until programmed TREF is reached. (If reactor trip occurs, dump valves open to keep steam header pressure at or below setpoint.) No effect on FW control since have constant S.G. level program.	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2).
Power Range Flux	4 per plant	Any	Reactor Control FW Control	Lo	No control action (auctioneered Hi).	Not applicable. Increased bypass valve opening would be bounded by Excessive FW flow (FSAR 15.1.2).
				Hi	Auto and manual rod withdrawal blocked (C-2). Rods in (safe direction). FW bypass valve opens if in auto.(If reactor trip occurs, dump valves open, until no load TAVE is reached. Rising S.G. level causes valve to close till steam and feed flows match.	Increased bypass valve opening would be bounded by Excessive FW flow (FSAR 15.1.2).

TABLE 420.4-1 (Sheet 8)

SENSOR	NUMBER OF CHANNELS	FAILURE CHANNEL	SYSTEM	ASSUMED FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Condenser Available	2 per condenser	Any	Steam Dump	Lo	No control action. Steam dump unblocked, i.e., condenser available for steam dump.	Not applicable.
				Hi	No control action. Steam dump stays blocked, i.e., condenser unavailable for steam dump.	Not applicable.
TAVG (High Auctioneer)	1		Steam Dump Reactor Control Prz. Level Control	Lo	Charging flow decreases until no-load level reached. Rods out until blocked by Hi flux, overpower or overtemperature rod stop. Steam dump blocked (TAVG mode only).	Result is bounded by Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (FSAR 15.4.2).
				Hi	Identical to TAVG channel failing high, see analysis above.	See above.
Steam Flow Pressure Compensator	2 per loop	1 selected for control	Steam Flow	Lo	Identical to loop steam flow channel failing low. See analysis above.	See above.
				Hi	Identical to loop steam flow channel failing high. See analysis above.	See above.

TABLE 420.4-2 LOSS OF POWER TO A PROTECTION SEPARATION GROUP

CONTROL SYSTEMS AFFECTED	EQUIPMENT OR SENSORS AFFECTED	FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
Steam Dump	Turbine Pressure (control)	Lo	No control action. Steam dump unblocked (pressure mode). S. Gen. PORV (Loop 1) remains closed.	Loss of Normal FW Flow (FSAR 15.2.7) event is bounding since increased charging flow/isolated letdown has little effect relative to the decreased feed flow.
	Steamline Pressure	Lo		
Reactor Control	Power Range Flux	Lo	Rods in (safe direction). Power decreases. Stop turbine loading/defeat remote dispatching.	
	Turbine Pressure	Lo		
	Turbine Pressure (Interlock)	Lo		
	TAVG (Loop 1)	Lo		
FW Control	Narrow Range Level	Lo	Feedwater isolation valves close. See Table 10.4-7 for feedwater control and bypass valves.	
	Turbine Pressure	Lo		
	Feedwater Control Valves	-		
	Feedwater Isolation Valves	Fc		
	Steam Flow Pressure Compensation	Lo		
Prz. Level	Prz. Level (control)	Lo	Charging flow increases. Heaters blocked. Letdown isolated. (All actions occur if on channel 1).	
Prz. Pressure	Prz. Pressure (PORV 455A)	Lo	No control action. PORV 455A stays closed.	
	PORV 455A	Fc		
Steam Dump	Turbine Pressure (Interlock)	Lo	No control action. Steam dump unblocked (Both modes). S. Gen. PORV (Loop 2) remains closed.	Bounding event is either Excessive FW Flow (FSAR 15.1.2) or Loss of Normal FW Flow (FSAR 15.2.7), depending on channels used. These scenarios are bounding since let-down isolation has little effect relative to the FW flow events.
	Steamline Pressure	Lo		
Reactor Control	Power Range Flux	Lo	Rods in (safe direction). Power decreases. Stop turbine loading/defeat remote dispatching.	
	Turbine Pressure	Lo		
	Turbine Pressure (Interlock)	Lo		
	TAVG (Loop 2)	Lo		

TABLE 420.4-2 (Sheet 2)

CONTROL SYSTEMS AFFECTED	EQUIPMENT OR SENSORS AFFECTED	FAILURE DIRECTION	EFFECTS	BOUNDING EVENT
FW Control	Narrow Range Level	Lo	If affected level signal used for control, FCV opens in affected loop, and FW flow increases (overrides steam flow signal). Otherwise, channel not connected, get decreased FW flow in loops with failed steam flow pressure compensation only. No effect on remaining loops.	
	Turbine Pressure			
	Steam Flow Pressure Compensation	Lo		
Prz. Level	Prz. Level (Interlock)	Lo	Letdown isolated. Heaters blocked. (If on channel 2).	
Prz. Pressure	Prz. Pressure (PORV 456A)	Lo	No control action. PORV 456A stays closed.	
	PORV 456A	Fc		
Steam Dump	Steamline Pressure	Lo	No control action. Stop turbine loading/ defeat remote dispatching. S. Gen. PORV (Loop 3) stays closed.	Combining effects of pressurizer level and pressure control systems, could have either increasing charging flow with heater off causing a depressurization, or else heaters cause pressure to increase until PORV 456A is actuated. Either way, event is bounded by Inadvertent Opening of a Pressurizer Safety or Relief Valve (FSAR 15.1.2).
	Power Range Flux	Lo		
Reactor Control	TAVG (Loop 3)	Lo		
Prz. Level	Prz. Level (Control)	Lo	Charging flow increases. Heaters blocked. Letdown isolated. (If on channel 3). or Letdown isolated. Heaters blocked. (If on channel 3). If affected pressure signal used for control, PORV 455A stays closed, backup heaters on (if allow by level signal, see above) and spray off.	
	or			
	Prz. Level (Interlock)	Lo		
Prz. Pressure	Prz. Pressure (PORV 455A)	Lo		
Steam Dump	Steamline Pressure	Lo	No control action. S. Gen. PORV (Loop 4) remains closed.	
Reactor Control	Power Range Flux	Lo	Stop turbine loading/defeat remote dispatching.	
	TAVG (Loop 4)	Lo		
Prz. Pressure	Prz. Pressure (PORV 456A)	Lo	No control action. PORV 456A stays closed.	Bounding event is Loss of Normal FW Flow (FSAR 15.2.7).
FW Control	FW Control Valves	-	Feedwater isolation valves close. See Table 10.4-7 for feedwater control and bypass valves.	
	FW Isolation Valves	Fc		

TABLE 420.4-3 LOSS OF POWER TO A CONTROL SEPARATION GROUP

CONTROL SYSTEMS AFFECTED	EQUIPMENT OR SENSORS AFFECTED	FAILURE DIRECTION	ITEMIZED EFFECTS	BOUNDING EVENT
Steam Dump	Condenser Available	Hi	No control action. Steam dump stays blocked.	
	S.G. Header Pressure	Lo		
	Dump Valves	Fail closed		
FW Control	Steam Flow (S.G. 1 and 3)	Lo		
	FW Flow (S.G. 1 and 3)	Lo	Loss of FW flow.	Loss of normal FW flow. FSAR 15.2.7.
	FW Control Valves (S.G. 1 and 3)	Fail Closed		
	S. G. Header Pressure	Lo		
	FW Header Pressure	Lo		
	Feed Pumps	Coast Down		
Pressurizer Pressure	Prz. Pressure (PORV 455A)	Lo	PORV 455A Stays closed.	
Steam Dump	Auctioneered	Lo	No control action.	
	TAVG			
Reactor Control	Auctioneered TAVG Control rods	Lo	Rods stationary. Stop turbine loading/defeat remote dispatching (C-16). Annunciation occurs.	Loss of normal FW flow. FSAR 15.2.7.
FW Contrtol	Steam Flow (S.G. 2 and 4)	Lo	Loss of FW flow.	
	FW Flow (S.G. 2 and 4)	Lo		
	FW Control Valves (S.G. 2 and 4)	Fail closed		
Pressurizer Level	Autioneered TAVG	Lo	RCS inventory remains relatively constant.	
	Prz. Heaters	F off		
	Charging Control Valve	F open		
	Charging Pump	Coast down		
	Letdown Isolation Valves	Fail closed		
Pressurizer Pressure	Prz. Pressure (PORV 455A)	Lo	PORV 455A Stays closed.	

TABLE 420.4-4 BREAK OF COMMON INSTRUMENT LINES

SENSORS	FAILED CHANNELS	SYSTEM	FAILURE DIRECTION	EFFECT	BOUNDING EVENT
Loop Steam Flow and Narrow Range Level	I or II	o Feedwater Control	Lo Hi	FW valve closes in affected S.G. Pump speed decreases.	Bounding event is Loss of Normal FW Flow (FSAR 15.1.2).
Pressurizer Level (Interlock or Control) and	I	o Prz. Level Control	Hi	Charging flow decreases. (Control) Backup heaters on. (Control) (On low level, letdown isolated and heaters blocked from interlock channel.	This is a depressurization event which is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1)
Pressurizer Pressure (Either PORV)	I	o Prz. Pressure Control	Lo	PORV 455A stays closed.	
Pressurizer Level (Interlock or Control) and	II	o Prz. Level Control	Hi	No control action.	Not applicable.
Pressurizer Pressure (Either PORV)	II	o Prz. Pressure Control	Lo	PORV 456A stays closed.	
Pressurizer Level (Interlock or Control) and	III	o Prz. Level Control	Hi	Charging flow decreases and backup heaters on if on control channel. On low level, letdown isolated and heaters blocked from interlock channel. No control action if on interlock channel.	Depending on switch position, this event is at most a depressurization event which is bounded by Inadvertent Opening of a Prz. Safety or Relief Valve (FSAR 15.6.1).
Pressurizer Pressure (Either PORV)	III and IV	o Prz. Pressure Control	Lo	Either PORV (or neither) stays closed.	
T_{cold} and/or T_{hot}	I, II, III, or IV	o Steam Dump o Reactor Control o Prz. Level Control	Lo or Hi	See failure of TAVG in "Loss of any Single Instrument" Table 1	

TABLE 440.1-1 DELETED

Q450.00 (6.4) In your description of the control room habitability system, include the provisions for emergency food, water and medical supplies.

RESPONSE

See Section 6.4.

Q450.01 (6.4) In the evaluation of toxic gas protection, document the degree of leaktightness of the control room isolation dampers.

RESPONSE

The total leak-tightness of the control room and its potential leakage paths are discussed in Subsection 9.4.1.2.3, under EMERGENCY OPERATION.

The specific criteria for the control room isolation dampers are discussed in Subsection 9.4.1.2.2.

Q450.02 (6.4) Provide a description and drawing showing the locations of control room outside air inlets relative to potential radiation releases.

RESPONSE

The control room has two sources of outside air as discussed in Subsection 9.4.1.2.3.

Q450.03 (6.4) In your analysis of toxic gas protection for control room personnel, provide the number and type of respiratory devices, the type of operator training for respiratory use, the estimated time for donning or deploying the equipment, the length of time the equipment can be used, and the equipment testing and maintenance provisions.

RESPONSE

See Section 6.4.

Q450.04 (6.4) List the areas, equipment and materials in the zone serviced by the control room emergency ventilation system.

RESPONSE

See Subsection 6.4.2.2.

Q450.05 (6.4) Discuss how the control room design precludes the buildup of noxious gases from control room equipment such as gases from batteries.

RESPONSE

See Subsection 6.4.2.4.

Q450.06 (6.4)

In Section 6.4.5, the testing and inspection of the control room habitability systems is described. In particular, the last paragraph states: "The control room is classified as Type B per Regulatory Guide 1.78. Since the air exchange rate exceeds 0.06 air exchanges per hour for the control room, periodic testing of the control room pressurization system is not required per the exclusion provisions of the regulatory guide."

Apparently, there is some confusion as to the applicability of Regulatory Guide 1.95 (and 1.78) to the control room ventilation design for radiological protection. For a control room outside air makeup rate during emergency pressurization less than 0.25 volume change per hour (as in Callaway), SRP Section 6.4 recommends the following:

1. acceptance test to verify adequate pressure,
2. supporting calculations to verify adequate air flow, and
3. periodic verification testing.

If this guidance is not followed, justify the departures.

<u>RESPONSE</u>

a. FSAR Section 14.2.12.1.45 provides a discussion of the initial test program for the control building HVAC system. This test program will provide assurance that the control room pressurization fans will maintain the control room pressure at the required positive pressure.

b. Detailed design calculations for control room leakage rates and required pressurization system design conditions have been performed. See Subsection 9.4.1.2.3.

c. The control room pressurization system flow rate for the control room is an optimized value, based on detailed design calculations, which provides acceptable protection for the control room operators during both radiological and toxic gas accidents. The pressurization makeup rate provides for approximately 0.24 volume changes per hour. Periodic verification testing of the pressurization system is, therefore, not justified in this case.

d. See Section 6.4.5.

Q450.07 (6.5.2)

In Section 6.5.2.2.3 of the SNUPPS FSAR, it stated that the containment spray system recirculation flow is manually initiated. It is the staff's position that the containment spray switchover be automatic. Justify your departure from this position.

RESPONSE

The method of switchover of the ECCS and the containment spray system from injection to recirculation evolved from a totally manual design to one of limited and reasonable operator action during the PSAR stage. The current design provides for the automatic switchover to the recirculation mode for the RHR pumps followed by manual realignment of the containment spray pumps, the high head ECCS centrifugal charging pumps, and the intermediate head safety injection pumps. The necessary indications and the sequence of events for the switchover of the containment spray system are described in FSAR Section 6.2.2.1.2.3. The sequence of events for the switchover of the ECCS is described in FSAR Section 6.3.2.8.

FSAR Table 6.2.2-4 provides the minimum duration of containment spray flow in the injection mode for the various assumed flow conditions. These durations provide an adequate time frame for the necessary operator actions required for ECCS and containment spray system management.

The current design was found to be acceptable by the NRC at the PSAR stage and is the basis, in that regard, for the issuance of the SNUPPS CPs. This design continues to be in substantial compliance with all published regulations, and we are aware of no regulations or technical basis for requiring automatic switchover to the recirculation mode.

The thermal-hydraulic analyses provided in FSAR Section 6.2.1 and the radiological consequences of the accidents analyzed in FSAR Chapter 15.0 demonstrate the adequacy of the existing containment spray system.

Q450.08 (15.4.8(A)) With respect to rod ejection accident, provide the transient time for the depressurization of the primary system to the termination of primary to secondary leakage.

RESPONSE

Primary and secondary pressures are equalized at 1100 seconds following the accident, thus terminating primary to secondary leakage in the steam generators. Refer to Figures 450.08-1 and 450.08-2.

Q450.09 (15.6.3) The following information is currently missing from the Callaway FSAR and is needed to complete our review. For the steam generator tube rupture accident provide the following figures:

1. SGTR break flow rate vs Time
2. SGTR integrated tube leak mass vs Time
3. Primary system pressure vs Time
4. Secondary system pressure vs Time

5. PORV flow rate vs Time
6. MS Safety valve flow rate per steamline vs Time
7. Atmospheric dump valve flow rate vs Time
8. Steam generator steaming rate vs Time
9. Reactor coolant temperature vs Time
10. Feedwater flow rate into the steam generators vs Time
11. Water level in the affected steam generator relative to the top of the tube bundle vs Time.

Also, provide the mass of secondary coolant in a steam generator.

RESPONSE

Refer to revised Section 15.6.3.

Q450.10 (6.5.2) (RSP) The SNUPPS FSAR indicates that the mode of initiation of switchover of the containment spray system suction from the Refueling Water Storage Tank to the containment sump is manual. The staff finds that this practice departs from that currently deemed acceptable. SRP Section 6.5.2 (II. Acceptance Criteria, item 2.a) states "The Containment spray system should be designed...and should be capable of continuous operation thereafter until the design objectives of the system have been achieved. In all cases the operating period should not be less than two hours." Manual initiation of the switchover does not guarantee continuous operation for two hours and does not provide assurance that the design objectives of the spray system are achieved for delayed fission product releases from the core. It is the staff's position that we require a design modification which will change from manual to automatic the switchover of the containment spray system from the RWST to the containment sump. State your intent regarding compliance with our position.

RESPONSE

Question 450.07 stated an NRC Staff position that the containment spray system (CSS) switchover to recirculation be automatic. The response to that question stated that the CSS design was essentially the same as that reviewed and approved by the NRC at the construction permit stage of review. The response also referenced other sections of the FSAR that showed the adequacy of the CSS design.

This question repeated the staff position concerning CSS switchover. It is not clear that the NRC Staff has evaluated the design, but rather has placed a questionable interpretation on the Standard Review Plan (SRP) and then simply demanded a design change. The SRP states that the spray system should be capable of continuous operation for at least 2 hours. The NRC's position is that manual switchover to the containment sump suction does not guarantee continuous operation.

The Union Electric position is that the CSS is capable of continuous operation for much longer than 2 hours. The pumps do not have to be secured in order to complete the simple, manual switchover. FSAR Section 6.2.2.1.2.3 and Tables 6.2.2-3 and 6.2.2-4 show that sufficient time is available for the manual actions. Assuming the incredible maximum LOCA, minimum starting refueling water storage tank (RWST) level, maximum ECCS and CSS suction rates from the RWST, and zero containment pressure, the minimum injection phase of the CSS is about 24 minutes. For a smaller LOCA, a normal RWST level, and reasonable assumptions for rate of withdrawal from the RWST, the injection phase would be much longer. Allowing credit for operator action from the control room, even at only 24 minutes after an event, is reasonable and consistent with other NRC Staff positions. The required operator action is a simple matter of opening the valves from the containment sumps to the CSS suction. Alarms and safety-related display indication are provided to ensure that the operator has the necessary information.

The CSS has a containment heat removal function and a fission product removal function. After the injection phase, the system's heat removal function is complete. A large percentage of the fission product removal is also completed prior to the initiation of recirculation. The radiological consequences of the design basis LOCA (see Section 15.6) show that a significant margin exists between the calculated offsite dose and the maximum allowable by regulations. The design basis for the CSS assumes successful switchover to recirculation. However, based on the above reasoning, even if the switchover were not completed the consequences would not be severe.

The NRC has traditionally required more and more automatic features in plant designs in order to mitigate theoretical accident scenarios. Experience has shown that incidents do not follow the classical scenarios and, therefore, not all automatic functions are desirable. In the case in question, a design change to provide automatic opening of containment sump isolation valves is not sound. The automatic feature increases the potential for the opening of these valves at an undesirable time and outweighs the consequences of an operator's failure to open the valves at the appropriate time. The containment sump suction lines to the spray pumps should only be opened by a deliberate operator action which is based on all of the information available for the particular set of circumstances.

In summary, the design meets published NRC criteria, the suggested design changes are not sound, and the design will not be changed.

Q490.1 Since the issuance of Construction Permits for SNUPPS plants, several significant changes have taken place that will affect our review of Section 4.2, "Fuel System Design." The most fundamental changes deal with the format and content of Section 4.2 as they relate to the Standard Review Plan; the other changes deal with technical issues that have arisen recently. All of these changes are discussed below.

Standard Review Plan

The basic fuels sections of the Standard Format (Rev. 3), the Standard Review Plan (Rev. 1, 1978), and the SNUPPS FSAR are all the same: 4.2.1 Design Bases, 4.2.2 Description and Design Drawings, and 4.2.3 Design Evaluation. Unfortunately, 4.2.1 of the Standard Format (and, hence, of the SNUPPS FSAR) does not clearly call for a quantitative (usually numerical) statement of all design bases as does the Standard Review Plan. Similarly, the other sections of the Standard Format and the SNUPPS FSAR mix up design bases, design descriptions, and design evaluations, but that information is sorted out clearly in the Standard Review Plan.

Because of improvements in clarity and completeness in this 1978 version of the Standard Review Plan, we will conduct our review and prepare the SER according to the SRP. Our questions, then, will not be open-end, but they will simply ask for the residual information called for in the SRP but not present in the SNUPPS FSAR. There are, thus, two options at this stage of the review.

Option 1 - You could revise Section 4.2 of the SNUPPS FSAR to follow the details of the SRP (remember, the basic organization structure would be unchanged). This would automatically bring out all of the information that is needed.

Option 2 - A cross reference could be provided to link each item in the SRP with a paragraph in the SNUPPS FSAR. This method would leave Section 4.2 of the SNUPPS FSAR in its present format, but might lead to additional questions since all of the information is not present.

We recommend Option 1. Revision 1 of the SRP, to which we refer, was formally issued more than two years ago. Therefore, we do not view this change as either precipitous or disruptive. Furthermore, it is likely that you will have to identify and justify all deviations from the SRP under the provisions of a proposed rule (Federal Register 45, p. 67099, October 9, 1980) since your SER will be issued after January 1, 1982.

We urge you to provide the information that would be needed to demonstrate compliance with the SRP at your earliest convenience. To help you anticipate an imminent revision to SRP-4.2, the following comments are provided.

Revision 1 - This revision was issued in October 1978 and contains all of the basic requirements that you need to address. It will not be changed significantly by the planned revision.

Revision 2 - This revision is planned for April 1981 and is the revision alluded to in the notice of proposed rulemaking on SRP compliance. In SRP-4.2 this revision will (a) add acceptance criteria for mechanical response to seismic and LOCA loads, and (b) make editorial changes largely confined to adding and correcting citations to regulations and regulatory guides that are already addressed in Rev. 1. The acceptance criteria for mechanical response were recently implemented as part of the resolution of Unresolved Safety Issue, Task A-2 and are given in Appendix E of NUREG-0609. Therefore, you can base the SNUPPS FSAR revisions on SRP-4.2 Rev. 1 (current version) plus Appendix E of NUREG-0609, and last-minute changes in referencing can be made in April prior to your submittal of the additional fuel-related information.

Recent Technical Issues

The following is a list of current technical issues that have frequently been noted as outstanding issues in recent SERs and that should be given special attention in the SNUPPS FSAR.

1. Supplemental ECCS analysis with NUREG-0630.
2. Combined seismic and LOCA loads analysis.
3. Enhanced fission gas release analysis at high burnups.
4. Fuel rod bowing and analysis.
5. Fuel assembly control rod guide tube wear analysis.
6. Fuel assembly design shoulder gap analysis.
7. End-of-life fuel rod internal pressure analysis.

RESPONSE

The FSAR was written to meet the information requirements of Revision 3 of the Standard Format (Regulatory Guide 1.70). The purpose of the Standard Format is to define the information requirements, whereas the Standard Review Plan provides guidance to staff reviewers. Union Electric believes that the information presented below, along with the current FSAR Section 4.2, provides sufficient information for the NRC to complete the safety review.

A. Further Quantification of Design Bases

Union Electric has reviewed Section 4.2 of the NRC Standard Review Plan in order to identify those areas of the FSAR where more quantitative design basis information has been suggested. Although the design bases section of the FSAR is not as quantitative as is discussed in the Standard Review Plan, all of the fuel system damage and fuel rod failure mechanisms listed in subsection II.A of the SRP are included and discussed in the design analysis section (Section 4.2.3) of the FSAR. The information presented is intended to demonstrate that the functional capabilities of the fuel equal or exceed those assumed in the safety analysis. In some cases, empirically determined manufacturing or process specifications have been established that reduce failures due to a given postulated mechanism to a level where they cannot be distinguished from failures due to unknown causes, i.e. one defective fuel rod for each 10,000 rods in operation (Ref. 1). These specifications cannot and should not be classified as design bases since no quantitative cause and effect relationship has been established between the mechanism and the specification.

The Standard Review Plan, in subsection I.A and subsection II.A.2(b) on pellet/ cladding interaction, recognizes that design bases for some potential failure mechanisms can only be expressed as general criteria. This is particularly true in cases where insufficient evidence exists to quantitively describe known fuel rod failures in terms of a specific physical model. A considerable amount of operating data has been obtained on light water reactor fuel over the last 10 years (Ref. 2). This experience has led to the identification of many of the potential failure mechanisms that are discussed in the SRP. However, conclusive evidence has not been presented that links some of these postulated mechanisms with fuel failure. In fact, fuel rod bowing, strain cycle fatique, and external corrosion are all mechanisms where fuel failure has not occurred in PWRs (Ref. 2).

Both fuel rod bowing and fatique are discussed in detail in FSAR Section 4.2.3 and the topical reports referenced in that section. For other mechanisms, such as zirconium hydriding, modification of a single design or fabrication specification has all but eliminated that mechanism as a significant contributor to fuel rod failures. Such a single specification change based on empirical evidence cannot be treated as a design basis since it may be but one of many techniques for alleviating the cause of failure, which is not well understood. Elimination of fretting wear as a significant failure mechanism has been accomplished, using a similar philosophy. In those few instances where failures have been associated with fretting phenomena, the failures have been traced to excessive localized hydraulic forces (Ref. 2 and 3), and the failure mechanism was eliminated by design modifications that reduced the hydraulic imbalance, but by placing arbitrary limits on fretting wear. No significant wear of the clad or grid supports is expected during the life of the fuel assembly based on out-of-pile flow tests, performance of similarly designed fuel in operating reactors, and design analyses. Evidence for this conclusion is provided in References 3 and 4, which are also listed references in Section 4.2 of the FSAR.

The design bases for fuel coolability given in subsection II.A.3 of the Standard Review Plan, that are not presented in FSAR Section 4.2.1, are described in FSAR Sections 15.4 and 15.6.

Union Electric believes that a quantification of the design bases beyond that required by Regulatory Guide 1.70 is premature in view of the current state of the art of fuel failure technology. Such quantification could place unwarranted confidence on empirically derived relationships between design parameters and failure mechanisms. In addition, Union Electric believes that the large body of successful operating experience described in the FSAR references, combined with the design evaluation presented in Section 4.2.3, provides adequate evidence that the Callaway Plant fuel has the required functional capabilities. It can be anticipated that further accumulation of operating data and out-of-pile examination of irradiated fuel specimens will contribute to an enhanced understanding of many of the fuel failure mechanism.

References

1. Proceedings of the ANS Topical Meeting on Light Water Reactor Fuel Performance, Portland, Oregon, April 29, 1979.

2. Garzarilli, F. et al., The Main Causes of Fuel Element Failure in Water Cooled Reactors, Atomic Energy Review, Vol. 17, No. 1 (1979).

3. Slagle, W. H., "Operational Experience with Westinghouse Cores," WCAP-8183 (Reference 1 of Section 4.2.5).

4. Demario, E. E., "Hydraulic Flow Test of the 17 x 17 Fuel Assembly," WCAP-8278 (WCAP 8279-Non proprietary) February 1974 (Reference 14 of Section 4.2.5).

B. Fuel System Description and Design Drawings

Much of the design data listed in subsection II.B of the SRP that is not included in FSAR Section 4.2 is included in other sections of the FSAR. The following tabulation presents the location of this information in the FSAR:

Table 4.1-1	Coolant System Pressure

Table 4.3-1A/1B	Cladding Outside Diameter Cladding Thickness Pellet Outside Diameter Pellet Density Pellet Length Burnable Poison Content Active Fuel Length Fissible Enrichment
Section 4.2.2.1	Type and Metallurgical State of the Cladding
Figure 4.2-2	Overall Rod Length
Section 4.2.3.1b	Fill Gas Type and Pressure

The figure numbers for design drawings are as follows:

4.2-1	Fuel assembly cross section
4.2-2	Fuel assembly outline
4.2-3	Fuel rod schematic
4.2-6	Top grid to nozzle point
4.2-7	Guide thimble to bottom nozzle joint
4.2-9	Control rod assembly cross section
	Control rod assembly outline
4.2-10	Control rod schematic
4.2-11	Burnable poison rod assembly outline
4.2-12	Burnable poison rod assembly cross section
	Burnable poison rod schematic
4.2-13	Primary source assembly
4.2-14	Secondary source assembly
4.2-14A	Encapsulated Secondary Source Assembly
4.2-15	Thimble plug assembly

C. Recent Technical Issues

With regard to the seven current technical issues presented in question 490.1, it is Union Electric's understanding that many of the generic issues have been resolved in connection with NRC staff reviews of similar plants with fuel assembly designs and fuel fabrication specifications that are the same as those for the Callaway Plant. The Safety Evaluation Report for the Virgil C. Summer Station (NUREG-0717) is an example of such a plant. The following paragraphs address these issues.

1. Supplemental ECCS analysis with NUREG-0630

   NUREG-0717 describes the current status of NRC requirements relative to ECCS evaluation models. Union Electric plans to comply with current NRC requirements and provide a supplemental calculation of the plant ECCS analysis performed with the materials models of NUREG-0630 on a mutually agreeable schedule. We expect this calculation to demonstrate that no total peaking factor reduction will be required for the Callaway Plant.

2. Combined seismic and LOCA loads analysis

   The combination of seismic effects and loads due to a double ended loss-of-coolant accident are discussed in the FSAR Section 4.2.3. The fuel assembly response resulting from the most limiting reactor coolant pipe break was analyzed using time history numerical techniques. The vessel motion for this type of accident causes primarily lateral loads on the reactor core. Consequently, a finite element model similar to the seismic model described in References 1 and 2 was used to assess the fuel assembly deflections and impact forces.

   The time history motions of the upper and lower core plates and the barrel at the upper core plate elevation which are simultaneously applied to the simulated reactor core model as input motion were obtained from the time history analysis of the reactor vessel and internals. The fuel assembly response, namely the displacements and impact forces, was obtained with the reactor core model by using the motions resulting from a reactor pressure vessel inlet nozzle break which produced the limiting structural loads for the fuel assembly.

   Grid Analyses

   The maximum grid impact forces for both the LOCA and seismic accidents occur at the peripheral fuel assembly locations adjacent to the baffle wall. The maximum grid impact forces obtained from the nozzle inlet break and seismic analyses were approximately 39 and 60 percent of the allowable grid strength, respectively. It should be noted that the maximum grid impact forces obtained from the two accidents did not occur at the same grid elevations.

With respect to the guidelines of Appendix A of SRP Section 4.2, Westinghouse has demonstrated that a simultaneous SSE and LOCA event is highly unlikely. The fatigue cycles, crack initiation, and crack growth due to normal operating and seismic events will not realistically lead to a pipe rupture (Reference 3). The factor applied to the LOCA grid impact load due to flashing is considered unrealistic, since the thermal/ hydraulic conditions for flashing are not present at the time of peak grid impact load.

However, a calculation of the grid maximum combined impact forces was performed consistent with the guidelines of SRP Section 4.2, Appendix A. The resulting value was approximately 73 percent of the allowable grid strength.

Non-Grid Analyses

The stresses induced in the various fuel assembly non-grid components are assessed based on the most limiting seismic and LOCA conditions. The fuel assembly axial forces resulting from a LOCA are the primary source of the stresses in the thimble guide tube and fuel assembly nozzles. The fuel rod accident induced stresses, which are generally very small, are caused by bending due to the fuel assembly deflections during the seismic accident. A summary of the combined seismic and LOCA induced stresses, which is expressed in terms of a percentage of allowable stress limits for the fuel assembly major components, is given in Table 490.1-1. The component stresses, which include normal operating stresses, are substantially below the established allowable limits. Consequently, the structural designs of the fuel assembly components are acceptable under the postulated accident design conditions for the Callaway Plant.

3. <u>Enhanced fission gas release analysis at high burnups</u>

   The subject of fission gas release is discussed in Westinghouse topical report WCAP-10851-P-A (Reference 20 in Section 4.2.5 of the FSAR).

4. <u>Fuel rod bowing analysis</u>

   The subject of fuel rod bowing is discussed in Section 4.2.3 of the FSAR, as well as Westinghouse topical report WCAP-8691/8692 (Reference 13 of Section 4.2.5 of the FSAR).

5. <u>Fuel assembly control rod guide tube wear analysis</u>

   Westinghouse topical report WCAP-8278/8279 (Reference 14 of Section 4.2.5 of the FSAR) presents flow test results for fretting wear at contact points between the control rods and control rod guide thimbles.

Additional experimental data have been submitted to the NRC by Westinghouse (see W letters NS-TMA-1936, 1992, and 2102), and a post-irradiation examination program has been established to address this specific subject (see NUREG-0717). We anticipate that the information derived from this program will confirm the Westinghouse predictions, and that this issue will be resolved for the Callaway Plant as it was for Virgil C. Summer Station.

6. Fuel assembly design shoulder gap analysis

Appropriate rod-to-nozzle gaps will be provided in the fuel to accommodate thermal expansion and irradiation-induced growth of the fuel rods relative to the overall fuel assembly structure. Westinghouse's ability to model fuel rod growth has been confirmed by comparison with measurements from 15 x 15 and 17 x 17 in-reactor data, and also is in good agreement with established experimental results as discussed in Reference 4.

7. End-of-life fuel internal pressure analysis

For the safety analysis presented in Section 4.2, the internal fuel rod pressure criteria are as follows:

(a) The internal pressure is limited such that the fuel-to-cladding gap does not increase during steady state operation.

(b) Extensive departure from nucleate boiling propagation does not occur in postulated transients and accidents.

These criteria are described in approved Westinghouse topical report WCAP-8963/8964 (Reference 7 to Section 4.2 of the FSAR). These criteria and analyses are the same as those submitted in connection with the NRC evaluation of the Virgil C. Summer Station (NUREG-0717).

References

1. Gesinski, L. and Chiang, D., "Safety Analysis of the 17 x 17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident," WCAP-8236 (Proprietary) and WCAP-8288 (Non-Proprietary), December 1973.

2. Beaumont, M. D., et al., "Verification Testing and Analyses of the 17 x 17 Optimized Fuel Assembly," WCAP-9401-P-A (Proprietary) and WCAP-9402-A (Non-Proprietary), August 1981.

3. Witt, F. J., Bamford, W. H., and Esselman, T. C., "Integrity of the Primary Piping Systems of Westinghouse Nuclear Power Plants During Postulated Seismic Events," WCAP-9283, March 1978.

4. Balfour, J. B., Destefan, J., Melehan, M. G., and Cerni, S. "Evaluation and Performance of Westinghouse 17 x 17 Fuel," presented at the ANSI Topical Meeting on LWR Fuel Performance held April 30 through May 2, 1979.

Q492.2 The effects of fuel rod bowing must be included in the thermal-hydraulic design. The predicted extent of rod bow (gap closure) versus exposure and the effect of rod bowing on DNBR must be addressed. Use of the staff report "Revised Interim Safety Evaluation Report on the Effects of Fuel Rod Bowing on Thermal Margin Calculations for Light Water Reactors," February 16, 1977, represents an acceptably conservative treatment of rod bowing.

RESPONSE

The DNB analyses described in the FSAR of the 17x17 core were performed such that generic DNBR margins described in the "Revised Interim Safety Evaluation Report on Effects of Fuel Rod Bowing on Thermal Margin Calculations for Light Water Reactors (Revision 1)," February 16, 1977, are available for offsetting rod bow penalties. There is no rod bow penalty in the area of IFM spans. Outside of the IFM spans see the discussion in Section 4.4.2.2.5.

Q492.3 Operating experience on two pressurized water reactors (not of the Westinghouse design) indicate that significant reduction in core flow rate can occur over a relatively short period of time as a result of crud deposition on the fuel rods. In establishing the Technical Specifications for Callaway and Wolf Creek we will require provisions to assure that the minimum design flow rates are not exceeded. Therefore, provide a description of the flow measurements capability for Callaway and Wolf Creek as well as a description of the procedures to measure flow and the actions to be taken in the event of an indication of lower than design flow.

RESPONSE

Operating experience to date has indicated that a flow resistance-allowance for possible crud deposition is not required. There has been no detectable long-term flow reduction reported at any Westinghouse plant. Inspection of the inside surfaces of steam generator tubes removed from operating plants has confirmed that there is no significant surface deposition that would affect system flow. Although all of the coolant piping surfaces have not been inspected, the small piping friction contribution to the total system resistance and the lack of significant deposition on piping near steam generator nozzles support the conclusion that an allowance for piping deposition is not necessary. The effect of crud enters into the calculation of core pressure drop through the fuel rod frictional component by use of a surface roughness factor. Present analyses utilize a surface roughness value which is a factor of three greater than the best estimate obtained from crud sampling from several operating Westinghouse reactors.

The operator has at his disposal several methods of detecting significant RCS flow reduction, these are:

a. Flow meter on each RCS loop.

b. If operating in an automatic control rod mode (T_C held constant) a reduction in reactor power would be present for significant reductions in RCS flow.

c. If operating in a manual control rod mode (power held constant) an increase in ΔT across the core would be present for significant reductions in flow.

d. Local changes in flow could be indicated by incore flux maps (assuming significant changes in local power), and

e. Core exit thermocouple readings.

The operator will verify flow, perform calorimetric power checks, and perform incore flux maps as required by the Technical Specifications. Engineering and Operations personnel are both involved in verifying RCS flow, performing calorimetric power checks, and performing incore flux maps as required by the Technical Specifications.

Q492.4 The NRC approval of the THINC-IV code, for use in the thermal-hydraulic design, indicates that the pressure gradient at the core exit must be modeled. Provide a revised THINC-IV calculation at the steady state reactor design conditions including the modeling of the core exit radial pressure gradient. Provide the following specific information from that calculation:

1. minimum DNB ratio (value and location)

2. hot channel flow vs. axial position

3. hot channel enthalpy vs. axial position

4. hot channel void fraction vs. axial position

5. the assumed core exit pressure gradient.

RESPONSE

On October 25, 1977, Westinghouse met with the NRC to discuss the effects of nonuniform upper plenum pressure distribution as part of the NRC staff's review of RESAR-414. The Westinghouse material presented at that meeting was transmitted to the NRC via letter NS-CE-1591, dated November 2, 1977, from C. Eicheldinger (Westinghouse) to J. F. Stolz (NRC). This letter addresses the THINC-IV information requested by Question 492.4, and is applicable to all Westinghouse 4-loop plants, including the Callaway Plant.

In addition, this issue was pursued further by the NRC during the McGuire FSAR review. The McGuire fuel is identical to the Callaway Plant fuel, and the same thermal-hydraulic models and correlations were used. As a result of this review, the staff concluded that this issue was adequately resolved. This conclusion is equally applicable to the Callaway Plant.

Q492.5 Insufficient information has been provided to justify the design power level of 2389 Mwt (70% of full power) during three-loop operation. Temperature differences in the active cold legs of a few degrees could exist during three-loop operation. Therefore a radial power tilt and an increase in enthalpy rise factor could result. As a result, we request that a complete detailed description of the following items be provided:

1. The method of determining the temperature distribution among the cold legs and the associated radial power tilt;

2. The method of accounting for differences (if any) in the three-loop thermal-hydaulic design;

3. The instrumentation available and monitoring procedures during three-loop operation;

4. The DNBR Technical Specification and how it will be implemented for three-loop operation;

5. The reactor protective system setpoints related to DNBR protection and how they are generated;

6. The effects of anticipated operational occurrences on the cold leg temperature distributions and how this effect is included in the design.

RESPONSE

This question is not applicable to the Callaway Plant, since Union Electric does not currently plan to operate in the N-1 mode.

Q492.6 Please state your intent regarding the use of the Westinghouse optimized fuel assembly in your plant. If the use of this design is being considered, provide a discussion of the status and schedule for any revised submittals.

RESPONSE

Union Electric does not currently plan to incorporate Westinghouse optimized fuel for the first fuel cycle.

Q492.7 Please state your intent regarding the use of the Westinghouse "Improved Thermal Design Procedure" described in WCAP-8567, dated July, 1975. If you intend to use these methods, responses to the following questions will be required:

a. Provide a block diagram depicting sensor, process equipment, computer, and readout devices for each parameter channel used in the uncertainty analysis. Within each element of the block diagram, identify the accuracy, drift, range, span, operating limits and setpoints. Identify the overall accuracy of each channel transmitter to final output and specify the minimum acceptable accuracy for use with the new procedure. Also identify the overall accuracy of the output value and maximum accuracy requirements for each input channel of this final output device.

b. Discuss the method(s) for incorporating environmental effects (e.g., noise, EMI) on instrument channels into the uncertainty analysis.

c. Provide data to verify that the plant instruments will perform with a high degree of confidence, within their design accuracies. This information may be obtained from operating history of identical instruments installed in other plants. This request pertains to the instruments affecting the uncertainties in the design procedure (as identified in question l above), the overtemperature ΔT trip, the high flow trip, the low pressure trip and the pump voltage trip.

d. Provide the ranges of applicability of sensitivity factors.

e. Demonstrate that the linearity assumption of equation 3-8 in WCAP-8567 is valid when the WRB-1 correlation is used.

RESPONSE

The NRC approved version of the Westinghouse Improved Thermal Design Procedure is used.

Q492.8 Standard format and content of Safety Analysis Reports, Regulatory Guide 1.70, states that in Chapter 4 of the SAR

> "...the applicant should provide an evaluation and supporting information to establish the capability of the reactor to perform its safety functions throughout its design lifetime under all normal operation modes..."

Are the analyses presented in Section 4.4 representative of the initial core only or have future cycles been analyzed? Provide a discussion of how power distributions for future cycles are considered in the FSAR analyses. Is there any assurance that the Callaway Units (Wolf Creek) can operate at the licensed power level without excessive DNB trips throughout future cycles? Will revisions to the design methodology be required in order to maintain sufficient thermal margin?

RESPONSE

The goal of the reload safety evaluation is to confirm the validity of the existing safety analysis. The existing safety analysis is defined as the reference safety analysis and is intended to be valid for all plant cycles. Thus safety analysis input parameter values are selected to bound the values expected in all subsequent cycles. This bounding analysis concept is the key to the Westinghouse reload safety analysis methodology. When all reload safety-related parameters for a given accident are bounded, the reference safety analysis is valid. On the other hand, when a reload parameter is not bounded, further evaluation is necessary. The purpose of this further evaluation is to confirm that the margin of safety defined in the basis for any technical specification is not reduced. This reload safety evaluation methodology is applied whenever the input parameter values for a reference safety analysis are available. In summary, Westinghouse reload safety evaluation methodology consists of:

1. A systematic evaluation to determine whether the reload parameters are bounded by the values used in the reference safety analysis.

2. A determination of the effects on the reference safety analysis when a reload parameter is not bounded to ensure that specified design bases are met.

When the above process identifies either a need for a license amendment or a change in the plant Technical Specifications, Union Electric will make the appropriate notification to the NRC.

Q492.9 The staff has reviewed the applicants' response to the requirements of Item II.F.2 of NUREG-0737 and found that the applicants have not provided the documentation required by Item II.F.2. Therefore, the staff will require that the applicants provide the documentation required by Item II.F.2 of NUREG-0737.

RESPONSE

See revised Section 18.2.13.

Q492.10 Justify that the single upper head penetration meets the single failure requirement of NUREG-0737 and show that it does not negate the redundancy of the two instrument trains.

RESPONSE

Redundancy is not compromised by having a shared tap since it is not conceivable that the tap will fail either from plugging or breaking. Freedom from plugging is enhanced by 1) use of stainless steel connections which preclude corrosion products, and 2) absence of mechanisms, such as flow for concentrating boric acid. It is also inconceivable that the tap will break because it is in a protected area. It should also be pointed out that in other cases where sharing of a tap occurs in the RCS, we know of no prior experience reporting deleterious malfunctions of the shared tap. Also, even if the shared tap does fail, it should be recognized that RVLIS is not a protection system initiating automatic action, but a monitoring system with adequate backup monitoring such as by core exit thermocouples for operator correlation.

Q492.11 Describe the location of the level system displays in the control room with respect to other plant instrument displays related to ICC monitoring, in particular, the saturation meter display and the core exit thermocouple display.

RESPONSE

The four reactor vessel water level indicators (Tag Nos. LI-1311, LI-1312, LI-1321, and LI-1322) are located on the main control board reactor auxiliaries console, RL-021. The two subcooling temperature indicators are located immediately above the four level indicators on the vertical portion of the control board, RL-022. The core exit thermocouple display is mounted on the subcooling monitor cabinet, RP-081.

Q492.12 Describe the provisions and procedures for on-line verification, calibration and maintenance.

RESPONSE

In general, the system electronics are verified, maintained, and calibrated on-line by placing one of the redundant trains into a test and calibrate mode while leaving the other train in operation to monitor inadequate core cooling.

A general verification is performed before shipment, but plant specific data are not used. The capability exists for the operator to verify the operation of the system. This would involve disconnecting the sensors at the RVLIS electronics, providing an artificial input, and observing the response of the system on the front panel and remote display.

On-line calibration of the system is made possible by the "card edge" adjustments. The P.C. cards are calibrated at the factory; however, if the function is changed or a component on the card is replaced, the calibration procedure is given within the equipment reference manual.

The RVLIS system requires the normal maintenance given to other control and protection systems within the plant. On-line maintenance is accomplished by placing only one of the two redundant trains into test at a time; this will allow continued monitoring of inadequate core cooling.

ATTACHMENT TO Q492.12 RESPONSE
SYSTEMS OPERATING PROCEDURES

1. PURPOSE

The objectives of these instructions are to establish the requirements for the use of the reactor vessel level instrumentation system (RVLIS) for various plant conditions and to specify the maintainability requirements of the system equipment.

2. PREREQUISITES

- The capillary lines have been vacuum filled, per the instructions of Section 4.
- Ensure that the hydraulic isolators are zeroed (within ±0.1 cubic inch).
- Calibrate the d/p cells per instructions of ITT Barton Manual for Model 752, Level B, transmitters.
- The process equipment must be scaled using the appropriate scaling document.
- Determine the height of the upper tap piping above the inside top of the vessel.

3. INITIALIZATION

With the plant less than 200°F and less than 430 psig, obtain the following data for trains A and B:

1. With an automatic data logger, record the following:
   - T_{hot}
   - RCS pressure
   - d/p transmitter output
   - Signal to the remote display
2. Manually record:
   - Level indication readings
   - Hydraulic isolator dial readings

- Reference leg RTD output

3. Record the above data for the following reactor coolant pump operations:

NOTE

The various configurations should be obtained through the normal startup if possible.

- No pumps running

NOTE

An indication of 100 percent reading represents a level to the inside top of the vessel. The height of the upper tap piping above the inside top of the vessel will result in a reading greater than 100 percent. This added height is plant specific and must be determined prior to adjusting the process equipment (narrow range) for full scale indication.

- One loop pump running
- Two loop pumps running
- Three loop pumps running
- All pumps running - Adjust process equipment so that wide range indication reads 100 percent.

4. With all pumps running, increase RCS pressure - temperature to T_{avg} no-load and record data. Refer to step (1) every 50°F increment. Data of step (2) should be recorded at 350°F and at T_{avg} no-load. Adjust process electronics for density compensation at T_{avg} no-load. Verify that wide range indication reads 100 percent.

5. Trip all pumps and record data per steps (1) and (2). Verify that narrow range indication is in agreement with the reading of step (3) "No pumps running."

6. Restart pumps in sequence and record wide range readings for both trains for each pump combination.

7. Enter into the equipment programming the expected percent level for the various pump combinations per the instruction manual.

4. NORMAL PLANT OPERATION

With the plant at power, the level readings should be as follows:

Wide range	~110 percent (wide range reading will increase from 100 percent to approximately 110 percent with all pumps running, as reactor power is increased from zero to 100 percent)
Narrow range	Off Scale - High

Any reduction in wide range expected readings (with all pumps running) can only be caused by the presence of voids in the circulating water. Voids will not exist without reduced pressure which could trip the reactor, so all accident conditions will proceed from a condition of zero power (100 percent reading on the wide range). Check that the pressure has decreased or that subcooling meter confirms saturation conditions exist; then readings below 100 percent are an indication of voids in the coolant.

If the actual readings differ from the expected readings by 3 percent for a single train, refer to troubleshooting (Section 7).

If the indication for both trains differs from the expected readings, refer to the emergency operating instructions for immediate and subsequent action.

5. REFUELING

After depressurization and prior to lifting the reactor vessel head, perform the following steps to prepare the RVLIS:

1. Close reactor vessel level head connection isolation valve.

2. Disconnect piping between the isolation valve and the sensors.

NOTE

Contaminated water residue may be in the pipe.

3. Provide temporary plugs for the pipe ends of the removable section and stationary sections.

Restore the RVLIS after reactor vessel head installation as follows:

1. Remove pipe end plugs and reconnect piping section.

2. With the isolation valve open, backfill the piping from sensors by attaching a water source to the sensor vent.

3. Disconnect waterfill apparatus.

4. At startup (450 psig, <200°F), visually inspect piping/coupling of the reinstalled piping for leakage.

5. At full system pressure, repeat inspection.

6. PERIODIC TESTING

6.1 Plant at Power

Perform monthly Channel Checks of the system.

6.2 Refueling Outages

1. For the d/p transmitters, injection point for the transmitter calibration will be the High Volume Sensors. The transmitter output will be measured in the RVLIS cabinets. Overall accuracy of the sealed filled system and the transmitter will be 0.5% of span.

2. Perform the calibration check of the process electronics in accordance with the equipment technical manual.

3. At the process equipment cabinets, compare the reference leg RTD channel outputs with ambient temperature measurements. Check the RTD resistances and adjust the RTD channel outputs if the temperatures differ by more than ±5°F.

6.3 Plant Startup

Verify the operability of the RVLIS system during the startup/heatup of the plant following a refueling by tracking the displays of the two trains. Readings should be within ±2 percent of the expected values.

7. TROUBLESHOOTING, PLANT AT POWER

When single indication varies from the expected value, check the following:

1. Compare hydraulic isolator dial reading with reading taken from diverse train and those taken at T_{avg} no-load conditions. Dial readings deviating by more than ±0.1 cubic inch may be indicative of potential capillary line leakage; however, it may not be the reason for the deviation in the display reading until the isolator reached the valve-off point.

2. Perform a calibration check of the process equipment, per the appropriate instruction manual.

3. Perform a zero check of the appropriate d/p transmitter.

If more than one indicator/display deviates from the diverse train or from T_{avg} no-load readings, check the following:

- Common isolator dial readings versus previous readings
- d/p transmitter valve lineup
- Process equipment power supplies

If repairs are required to the capillary lines, the system must be vacuum-filled and calibrated per the instructions contained in the RVLIS System Manual and the appropriate equipment instruction manuals.

Q492.13 Describe the diagnostic techniques and criteria to be used to identify malfunctioning components.

RESPONSE

The cabinet-mounted equipment is designed to facilitate periodic tests to identify malfunctioning components and to ensure that the equipment functional operability is maintained comparable to the original design standards. Component power supply failure is annunciated in the main control room.

Q492.14 Estimate the in-service life under conditions of normal plant operations and describe the methods used to make the estimate, and the data and sources used.

RESPONSE

The in-service life of the RVLIS-based electronics is dependent upon proper maintenance, including the replacement of individual component parts when necessary. The provisions for this maintenance are included in the technical manual. Based on the assumption of normal conditions and proper maintenance of the components, the only limitation to the in-service life will be the availability of replacement parts. It is estimated that in 20 years, some of the components will be technically obsolete and no longer produced. Consequently, the cards may have to be modified in the future to accommodate the current technology. Thus, any individual component failures are regarded as maintenance considerations, and their replacement is necessary to prolong in-service life.

In-service life which is different than design life and qualified life is dependent upon implementing a scheduled preventative maintenance program including periodic overhaul of the equipment. In this manner, the equipment is restored to a level that will ensure continual operability. In developing the maintenance program, repair costs may necessitate replacement of the equipment.

If the maintenance program is followed, there is no apparent reason that operation of the equipment cannot be extended.

Some of the equipment is similar to equipment installed in present Westinghouse plants that have been operating for 10 to 15 years.

The following valves have been supplied by Westinghouse or AREVA for the RVLIS for the SNUPPS units:

AREVA or Westinghouse Valve ID	Qty	Manufacturer	AREVA or Westinghouse Design Specification	Code Applicability
3/8 HN Series*	2	Swagelok	08-9163787; Rev. 3	ASME B&PV Class 2
1/4 X 28I	5	Autoclave Engineers	G-955230; Rev. 2	N & S
1/4 N 28I**	4	Autoclave Engineers	G-955230; Rev. 2	N & S

* AREVA supplied valve as part of Replacement Reactor Vessel Closure Head Project.

** Shutoff valve which is part of the transmitter access assembly.

The 3/8 HN Series valve is a stainless steel, manually operated needle valve whose basic function is to isolate the flow of fluid. The design life of the valve is 45 years.

The instrumentation valves (Westinghouse Valve IDs 1/4 X 28I and 1/4 N 28I) are stainless steel, manually operated valves, designed to meet the requirements of the above-referenced specification, which calls for zero leakage (environmentally and across the seats), minimal fluid displacement during stroke, and a 1000-cycle life. For normal plant operating conditions, the metallic parts are designed for a 40-year service life. The consumable items, where applicable, are identified in the appropriate drawings and instruction manuals, with recommended maintenance schedules.

Q492.15 Explain how the value of the system accuracy (given as +/- 6% was derived. How were the uncertainties from the individual components of the system combined? What were the random and systematic errors assumed for each component? What were the sources of these estimates?

RESPONSE

The system accuracy of ±6 percent water level was a target value established during the conceptual design and was related to the dimensions of the reactor vessel (12 percent from nozzles to top of core) and core (30 percent), and the usefulness of the measurement during an accident. Subsequent analyses have established a system accuracy based on the uncertainties introduced by each component in the instrument system. The individual uncertainties, resulting from random effects, were combined statistically to obtain the overall instrument system accuracy. Some of the individual uncertainties vary with conditions such as system pressure. The following table identifies the individual uncertainties for the narrow range measurement while at a system pressure of 1200 psia.

	Component and Uncertainty Definition	Uncertainty Level, percent
a.	Differential pressure transmitter calibration and drift allowance (±1.5 percent of span) multiplied by the ratio of ambient to operating water density.	±2.1
b.	Differential pressure transmitter allowance for change in calibration due to ambient temperature change (±0.5 percent of span for ±50°F) multiplied by the density ratio.	±0.7
c.	Differential pressure transmitter allowance for change in calibration due to change in system pressure (±0.2 percent of span per 1000 psi change) multiplied by the density ratio.	±0.34
d.	Differential pressure transmitter allowance for change in calibration due to exposure to long-term overrange (±0.5 percent of span) multiplied by the density ratio.	±0.7
e.	Reference leg temperature instrument (RTD) uncertainty of ±5°F and/or allowance of ±5°F for the difference between the measurement and the true average temperature of the reference leg, applied to each vertical section of the reference leg where a measurement is made. Stated uncertainty is based on a maximum containment temperature of 420°F, and a typical reference leg installation.	±0.64
f.	Reactor coolant density based on auctioneering for highest water density obtained from hot leg temperature (±6°F) or system pressure (±60 psi). Magnitude of uncertainty varies with system pressure and water level, with largest uncertainty occurring when the reactor vessel is full.	±2.3

g.	Sensor and hydraulic isolator bellows displacements due to system pressure changes or reference leg temperature changes will introduce minor errors in the level measurement due to the small volumes and small bellows spring constants. The changes, such as pressure or temperature, tend to cancel; i.e., the bellows associated with each measurement move in the same direction. Maximum expected error due to differences in capillary line volume and local temperatures is equivalent to a level change of about 5 inches, multiplied by the density ratio.	±1.46
h.	Density function generator output mismatch with ASME Steam Tables limited to this maximum.	±0.50
i.	Overall uncertainty of electronics system calibration is limited to less than this amount.	±1.0
j.	Control board indicator resolution.	±0.5

The statistical combination (square root of the sum of the squares) of the individual uncertainties described above results in an overall system instrumentation uncertainty of ±3.9 percent of the level span for the narrow range indication of approximately 40 feet, or ±1.5 feet, at a system pressure of 1200 psia. Examples of the uncertainty at other system pressures are:

Uncertainty = ±3.6 percent at 400 psia

Uncertainty = ±4.2 percent at 2000 psia

Q492.16 Assume a range of sizes for "small break" LOCA's. What are the relative times available for each size break for the operator to initiate action to recover the plant from the accident and prevent damage to the core? What is the dividing line between a "small break" and a "large break"?

RESPONSE

Inadequate core coolant (ICC) was defined in WCAP-9754, "Inadequate Core Cooling Studies of Scenario With Feedwater Available Using the NOTRUMP Computer Code," as a high temperature condition in the core such that the operator is required to take action to cool the core before significant damage occurs. During the design basis small loss-of-coolant accident, the operator is not required to take any action to recover the plant other than to verify the operable status of the safeguards equipment, trip the reactor coolant pump (RCPs) when the primary side pressure has decreased to a specific point, and initiate cold and hot leg recirculation procedures as required. In the design basis small LOCA, a period of cladding heat-up may occur prior to automatic core recovery by the safeguards equipment. The heat-up period is dependent upon the break size and ECCS performance.

An ICC condition may arise if there is a failure of the safeguards equipment beyond the design basis. In that case, adequate instrumentation exists in the Callaway Plant to diagnose the onset of ICC and to determine the effectiveness of the mitigation actions taken. The instrumentation which may be used to determine the adequacy of core cooling consists of a subcooling meter, core exit thermocouples (T/Cs), and the reactor vessel level instrumentation system (RVLIS).

For a LOCA of an equivalent size equal to approximately 6 inches or less, an ICC condition can only occur if two or more failures occur in the ECCS. As indicated in WCAP-9754, an ICC condition can be calculated by hypothesizing the failure of all high head safety injection (HPSI) for LOCAs of approximately 1 inch in size. For a 4-inch equivalent-size LOCA, one can hypothesize an ICC condition by assuming the failure of all HPSI as well as the failure of the passive accumulator system (a truly incredible sequence of events).

For LOCAs of sizes of 6 inches or less, the approach to ICC is unambiguous to the reactor operators. The first indication of a possible ICC situation is the indication that some of the ECCS pumps have failed to start or are not delivering flow. The second indication of a possible ICC situation is the occurrence of a saturation condition in the primary coolant system as indicated on the subcooling monitor. Shortly after the second indication, the RVLIS would start to indicate the presence of steam voids in the vessel. At some point in time the RVLIS will indicate a collapsed liquid level below the top of the core. The core exit thermocouples will begin to indicate superheated steam conditions. If appropriate, the RVLIS and core exit T/C behavior will provide unambiguous indications to the operator to follow the ICC mitigation procedure.

WCAP-9754 indicates that the selected core exit T/Cs will read 1200°F at approximately 11,000 seconds after the initiation of a 1-inch LOCA with the loss of all HPSI. The Generic Westinghouse EOP Guideline instructs the operator to pursue ICC mitigation procedures when these conditions are reached. The 4-inch LOCA will indicate 1200°F at about 1350 seconds. By following the Westinghouse recommended Emergency Operating Procedures (EOPs), the operators will have earlier indication of a possible ICC situation. Recovery procedures to depressurize the primary below the low pressure safety injection shutoff head may be followed. These procedures include correction of the HPSI failure, opening steam dump, or opening pressurizer PORVs. The RCPs may be restarted to provide additional steam cooling flow.

Large break LOCAs consist of LOCAs in which the fluid behavior is inertially dominated. Small break LOCAs, on the other hand, have the fluid behavior dominated by gravitational effects. For LOCAs which are significantly larger than an equivalent 6-inch break, the ECCS has the maximum potential for flow delivery, since the primary coolant system is at low pressure.

No early manual action is useful in recovering from ICC. Analyses for LOCAs in this range indicate ambiguous behavior of the core exit T/Cs and RVLIS early in the accident due to dynamic blowdown effects. This behavior is temporary and the core exit T/Cs and the RVLIS will indicate the progress being made by the ECCS in recovering the core. When the core exit T/Cs and RVLIS may be temporarily providing ambiguous indications, no manual action is needed or useful. Later in the accident when manual action may be useful, the core exit T/Cs and RVLIS will provide an unambiguous indication of ICC if it exists. This unambiguous indication may be present as early as 30 seconds after the initiation of the LOCA for a double ended guillotine rupture or a main coolant pipe.

It follows from the above discussion that, for ICC considerations, a reasonable definition of large breaks are breaks that are significantly larger than an equivalent 6 inch break. All other breaks are small breaks.

Q492.17 Describe how the system response time was estimated. Explain how the response times of the various components (differential pressure transducers, connecting lines and isolators) affect the response time.

RESPONSE

An analysis of the RVLIS hydraulics, an independent analysis of the hydraulics by ORNL, and the results of testing at the Semiscale Test Facility in Idaho generally support a response time (50 percent response to a step change in level) of 3 seconds or less for the hydraulics. There are, however, two types of transients which will affect the RVLIS response: a change in level and a change in system pressure. The major factors that influence the RVLIS hydraulics response to these two types of transients are the fluid volume within the RVLIS system and the length of capillary tubing connected to the d/p transmitter. For a level transient, the volume required to displace the transmitter bellows and the total length of capillary tubing are the significant parameters. Although the capillary tubing length (typically 600 feet) and diameter (0.089 inch) represent a significant resistance to flow, the volume required for a full span deflection of the transmitter bellows is small (0.1 cubic inch). The sensor and hydraulic isolator bellows displacement spring constants will introduce a small error in the measured level but will not impact the response time of the system.

For a system pressure transient, the total fluid volume of the RVLIS system and the difference in length between the two capillary lines connected to the d/p transmitter are the significant parameters. In theory, the transmitter would not respond to a change in pressure if the two capillary lines were equal in length. In practice, plant layout requirements result in lengths differing by as much as 100 feet. During a system pressure change, the water volume in the RVLIS system will expand or contract a small amount, but measurable pressure drops will develop in the capillary lines as the small volumes move to equalize pressure. The d/p transmitter will indicate a differential pressure or offset caused by one line being longer than the other. For a reasonably rapid transient of 100 psi per second imposed on an RVLIS system having a difference in line lengths of 100 feet, the offset or apparent level change would approach about 2 feet of water, and the offset would remain until the pressure transient is terminated. After the initial blowdown from a small break, the pressure transients would be much slower, and the level offset would be negligible. Much larger offsets approaching full scale deflection could occur (and have been observed during a large break test at Semiscale) during the initial large break transient, but an RVLIS output during this short period of less than 2 minutes would not otherwise be useful or required for actions associated with ICC.

In addition to the hydraulics response characteristics, the RVLIS electronics incorporate an adjustable lag to filter hydraulic noise when reactor coolant pumps are operating. The lag time constant, adjustable up to 10 seconds, will be set during startup to a value of about 1 to 3 seconds. The response time associated with the rest of the electronics has essentially no impact on the total response time, which is expected to be well within 10 seconds.

Q492.18 There are indications that the TMI-2 core may be up to 95% blocked. Estimate the effect of partial blockage in the core on the differential pressure measurements for a range of values from 0 to 95% blockage.

RESPONSE

Blockage in the core will increase the frictional pressure drop and increase the total differential pressure across the vessel. This will be reflected as a higher RVLIS indication. The increase in the RVLIS will be most significant under forced flow conditions when the reactor coolant pumps are operating.

In order for blockage to be present, the core would have to have been uncovered for a prolonged period of time. A low RVLIS indication along with a high core exit thermocouple indication would have been indicated during this time. If the RCPs had been operating throughout the transient, there would have been sufficient cooling to prevent significant core damage. Therefore, for significant blockage to exist during pump operation, the operator would have restarted the pumps after an ICC condition had existed for a period of time. Based on the history of the transient, the operator would know that the RVLIS would read higher than expected. Although the RVLIS would read high, it would still follow the trend in vessel inventory. The operator would be able to monitor the recovery with the RVLIS.

Under natural circulation conditions, the impact of core blockage is not expected to be large. Although the RVLIS indication will read slightly higher than normal, the RVLIS will still trend with the vessel inventory and provide useful information for monitoring the recovery from ICC. ICC will have been indicated at an earlier time, before a significant amount of core blockage has occurred. The operator will know that the RVLIS could read slightly high, based on the history of the transient.

Q492.19 Describe the effects of reverse flows within the reactor vessel on the indicated level.

RESPONSE

Reverse flows in the vessel will tend to decrease the d/p across the vessel which would cause the RVLIS to indicate a lower collapsed level than actually exists. The low indication would not cause the operator to take unnecessary actions, since an ICC recovery action would be based on a coincidence of a low level indication and a high core exit thermocouple indication (>700°F). In a reverse flow situation, the core exit thermocouples would be responding to the saturated temperature of the water flowing from the upper plenum to the core, so a high thermocouple indication of >700 F would not occur. It is important to note that large reverse flows are not expected to occur for breaks smaller than 6 inches in diameter during the time that the core is uncovered. Large reverse flow rates may occur early in the blowdown transient for large diameter breaks, but, as is discussed in the response to Question 492.16, it is not necessary to use the RVLIS as a basis for operator action for breaks in this range.

Q492.20 What is the experience, if any, of maintaining D/p cells at 300% overrange for long periods of time?

RESPONSE

Experience in overranging of differential pressure instruments has been obtained in previous applications of differential pressure capsules similar to those used in RVLIS. In dual range flow (differential pressure) applications, the "low flow" transmitter (and/or gauges) are overranged to 300 percent or greater by normal flow rates, yet provide reliable metering when required for start-up.

Also, test data exist on the basic transmitter design showing about 0.5 percent effect on calibration with 24 hours exposure to 3000 psig overrange. All units are similarly exposed to this overrange for 5 minutes in both directions as a part of factory testing.

There have been instances involving accidental overrange of these instruments (including RVLIS) as the result of leakage or operator errors where full line pressure overranges have occurred for up to several weeks with minimal effect on instrument accuracy.

Based upon this experience and test data, we expect to prove statistically that reliable measurements can be made by the selected overranged instrument designs used for RVLIS. On-line calibration capability is provided if needed to support gathering of statistical data.

Q492.21 Five conditions were identified which could cause the DP level system to give ambiguous indications. Discuss the nature of the ambiguities for 1. accumulator injection into a highly voided downcomer, 2. when the upper head behaves like a pressurizer, 3. upper plenum injection, and 4. periods of void redistribution.

RESPONSE

1. When the downcomer is highly voided and the accumulators inject, the cold accumulator water condenses some of the steam in the downcomer which causes a local depressurization. The local depressurization will lower the pressure at the bottom of the vessel which will lower the differential pressure across the vessel, causing an apparent decrease in level indication. The lower pressure in the downcomer also causes the mixture in the core to flow to the lower plenum, causing an actual decrease in level. The period of time when the RVLIS indication is lower than the actual collapsed liquid level will be brief.

   An example of a situation in which this phenomenon may occur is when the reactor coolant pumps have been running for a long period of time in a small break transient. After the RCS loops have drained and the pumps are circulating mostly steam, the level in the downcomer will be depressed. A large volume of steam will be present in the downcomer, above the low mixture level, which allows a large amount of condensation to occur. For most small break transients, the reactor coolant pumps will be tripped early in the transient, and the downcomer mixture level will remain high, even in cases where ICC occurs. When the downcomer level is high, the effect of accumulator injection on the RVLIS indication will be minor.

2. When the upper head begins to drain, the pressure in the upper head decreases at a slower rate than the pressure in the rest of the RCS. This is due to the upper head region behaving much like the pressurizer. The higher resistance across the upper support plate relative to the rest of the RCS prevents the upper head from draining quickly. This situation only exists until the mixture level in the upper head falls below the top of the guide tubes. At this time, steam is allowed to flow from the upper plenum to the upper head, and the pressure equilibrates. While the upper head is behaving like a pressurizer, the vessel differential pressure is reduced, and the RVLIS indicates a lower than actual collapsed liquid level.

   This phenomenon is discussed in the summary report on the RVLIS* relative to the 3-inch cold leg break. Since that time, the upper head modeling has been investigated in more detail. It was found that the modeling used at that time assumed a flow resistance that was too high for the guide tubes. Subsequent analyses have shown that the pressurizer effect has less impact on the vessel differential pressure than was originally shown. There is very little impact on the results after the level drains below the top of the guide tubes. The pressurizer effect is still believed to exist, and it becomes more significant as break size increases. The interval of time when the upper head behaves like a pressurizer is brief, and the RVLIS will resume trending with the vessel level after the top of the guide tubes uncovers. The reduced RVLIS indication will not cause the operator to take any unnecessary action, even if a level below the top of the core is indicated, since the core exit thermocouples are used as a corroborative indication of the approach to ICC.

3. The normal condition for continuous upper plenum injection (UPI) occurs only with the operation of the low head safety injection pumps, which does not occur until a pressure of under 200 psi is realized. The RVLIS may not accurately trend with vessel level during the initial start of UPI. During this short period of time, the cold water being injected will mix with the steam in the upper plenum causing condensation. This condensation will occur faster than the system response. The system will equilibrate after a short period of time. Upon equilibrating, the system will continue to accurately trend with the vessel level.

   In the range of break sizes where RVLIS is most useful in detecting the approach to ICC, the system pressure will equilibrate at a level above the pressure where UPI will normally occur. It is important to note that the flow from the low head

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* Westinghouse Electric Corporation, "Westinghouse Reactor Vessel Level Instrumentation System for Monitoring Inadequate Core Cooling," December 1980.

pumps is sufficient to recover the core, and no operator action based on the RVLIS indication will be necessary.

For the vast majority of small breaks, the condition of upper plenum injection does not cause a significant impact. For the remainder, the impact is very small and within tolerable limits.

4. During the time when the distribution of voids in the vessel is changing rapidly, there can be a large change in the two-phase mixture level with very little change in collapsed mixture level. The use of the RVLIS, in conjunction with the core exit thermocouples, is still valid for this situation, however. The only event that has been identified which could cause a large void redistribution is when the reactor coolant pumps are tripped when the vessel mixture is highly voided. After the pump performance has degraded enough that the flow pressure drop contribution to the vessel differential pressure is small, the change in RVLIS indication will be very small when the pumps are tripped. As discussed in the summary report, the approach to ICC would be indicated when the wide range indication read 33 percent. If the pumps were tripped at this time, the core would still be covered. The operator would know that the core may uncover if the pumps were tripped with a wide range indication lower than 33 percent. Prior to pump trip, the core will remain adequately cooled due to forced circulation of the mixture. When the pumps trip, the two-phase level may equilibrate at a level below the top of the core. The narrow range indication will provide an indication of core coolability at this time.

Q492.22 No recommendations are made as to the uncertainties of the pressure or temperature transducers to be used, but the choice appears to be left to the owner or AE. What is the upper limit of uncertainties that should be allowed? Describe the effect of these uncertainties on the measurement of level. What would be the effect on the level measurement should these uncertainties be exceeded?

RESPONSE

The reactor coolant pressure and temperature signals originate from the existing wide-range pressure and hot leg RTDs already installed in the plant, and the uncertainties for these instruments are understood. As indicated in the response to Question 492.I5, the pressure uncertainty is ±60 psi, and the temperature uncertainty is ±6°F, resulting in a maximum level uncertainty contribution of ±2.3 percent when the vessel is full. This uncertainty is smaller when the level is at the elevation of the reactor core. This contribution to the total uncertainty would increase roughly in proportion to an increase in the pressure or temperature measurement uncertainty.

Q492.23 Only single RTD sensors on each vertical run are indicated to determine the temperatures of the impulse lines. Where are they to be located? What are the expected temperature gradients along each line under normal operating conditions and under a design basis accident? What is the worst case error that could result from only determining the temperature at a single point on each line?

RESPONSE

RTD sensors are installed on every independently run vertical section of impulse line, to provide a measurement for density compensation of the reference leg. If the vertical section of impulse line runs through two compartments separated by a solid floor, an RTD sensor is installed in each compartment.

The RTD is installed at the midpoint of each vertical section based on the assumption that the temperature in the compartment is uniform or that the temperature distribution is linear in the vicinity of the impulse line. As stated in the response to Question 492.15, an allowance for a 5°F difference between the true average impulse line temperature and the RTD measurement is included in the measurement uncertainty analysis. This allowance permits a significant deviation from a linear gradient; e.g., 20 percent of the impulse line could differ by as much as 25°F from a linear gradient without exceeding the allowance. During normal operation, forced circulation from cooling fans is expected to maintain reasonably uniform compartment temperatures. During the LOCA, turbulence within a compartment due to release of steam would also produce a reasonably uniform temperature. Note that the impulse lines are protected from direct jet impingement by metal instrument tubing channels.

Q492.24 What is the source of the tables or relationships used to calculate density corrections for the level system?

RESPONSE

The relationships used in the analog-based RVLIS system to calculate density corrections are from the ASME Steam Tables, dated 1967. These relationships are implemented within the system by means of P.C. cards that generate an output signal which is a predetermined function of the input signal. The predetermined functions produce specific scopes which are added together to obtain the required input-output relationships.

Q492.25 The microprocessor system is stated to display the status of the sensor input. Describe how is this indicated and what this actually means with respect to the status of the sensor itself and the reliability of the indication.

RESPONSE

The remote display unit of RVLIS indicates the status of the input sensors. If any sensors are out of range, regardless of the reason, a symbol allows the affected level reading on the summary display page. The particular sensor that is out of range is identified at the bottom of the summary display page. Due to the redundant sensors and trains it is possible for the operator to disable some of the sensors without affecting the system reliability. The display indicates which level readings are affected. The disabled sensors are also displayed at the bottom of the summary page. A separate sensor status page can be displayed, showing all sensors that are disabled or out of range and their affected level readings.

Q492.26 Describe the provisions for preventing the draining of either the upper head or hot leg impulse lines during an accident. What would be the resultant errors in the level indications should such draining occur?

RESPONSE

The design does not include hot leg impulse lines. The layout of the impulse line from the upper head is arranged to prevent or minimize the impact of drainage during an accident. In general, however, the water in the impulse line will be cooler than the water in the reactor, and there will be sufficient subcooling overpressure in the line so that very little, if any, of the water would flash to steam during a depressurization or containment heat-up. Heat conduction along the small-diameter piping and tubing would be insufficient to result in flashing in a significant length of piping.

The connection to the upper head from a spare control rod drive mechanism port or vessel vent line drops or slopes down from the highest point of the vessel connection to the sensor bellows mounted on the refueling canal wall, so water would be retained in this piping. Draining of the vertical section immediately above the reactor vessel has no effect on the level measurement, since this section is included in the operating range of the instrument. Draining of the horizontal portion of vessel vent piping above the vessel also has no effect on the measurement, since no elevation head is involved.

The majority of the impulse line length is in capillary tubing sealed at both ends with a bellows (sensor bellows at the reactor end, hydraulic isolator at the containment penetration end), so water would be retained in this system at all times. The water will be pressurized by reactor pressure, and since the reactor temperature will be higher than containment temperature during an accident, the water in the sealed capillary lines cannot flash.

Q492.27 Discuss the effect on the level measurement of the release of dissolved, noncondensible gases in the impulse lines in the event of a depressurization.

RESPONSE

The majority of the impulse lines are sealed capillary tubes vacuum filled with demineralized, deaerated water. The lines contain no noncondensible gases and are not in a radiation environment sufficient for the disassociation of water.

The short runs of impulse line connected directly to the primary system will behave as described in the response to Question 492.26. Since there is no mechanism for concentration of gases at the top of the reactor vessel during normal operation, the connection to the top of the vessel would contain, at most, the normal quantity of dissolved gases in the coolant, and the subcooling pressure during an accident would maintain this quantity of gas in solution.

Q492.28 In some tests at Semi-scale, voiding was observed in the core while the upper head was still filled with water. Discuss the possibility of cooling the core-exit thermocouples by water draining down out of the upper head during or after core voiding with a solid upper head.

RESPONSE

One of the indicators of an approach to an inadequate core cooling (ICC) situation is the response of the core exit thermocouples (T/Cs) to the presence of superheated steam. The core exit thermocouples will not provide an indication of the amount of core voiding. Response of the core exit T/Cs provides a direct indication of the existence of ICC, the effectiveness of ICC recovery actions, and restoration of adequate core cooling. The core is adequately cooled whenever the vessel mixture level is above the top of the core, and the core may have a significant void fraction and still be adequately cooled.

Realistically, an indication of an ICC condition would not occur until the primary coolant system has drained sufficiently for the reactor vessel mixture level to fall below the top of the core. Westinghouse has performed analyses which indicate that the upper head will drain below the top of the guide tubes before ICC conditions exist. The guide tubes are the only flow path from the upper head to the upper plenum. In WCAP-9754, "Inadequate Core Cooling Studies of Scenarios With Feedwater Available, Using the NOTRUMP Computer Code," it was found that inadequate core cooling situations would not result for LOCAs of an equivalent size or equal to approximately 6 inches or less without two or more failures in the ECCS. In both specific scenarios examined in WCAP-9759, a 1-inch and 4-inch small LOCA, the upper head and upper plenum had completely drained before the onset of an ICC condition.

In the Callaway Plant, the core exit T/Cs protrude slightly from the bottom of the support columns (see Figure 492.28-1). In this location, they measure the temperature of the fluid leaving the core region through the flow passages in the upper core plate. Flow from the upper head must enter the upper plenum via the guide tube before being able to enter the upper core plate flow passages. In addition, the LOCA blowdown depressurization behavior must be such that there is a flow reversal for the core exit T/Cs to detect the upper head fluid temperature. The upper head fluid is expected to mix with the upper plenum fluid as it drains from the upper head.

The potential for core exit T/C cooling from colder upper head fluid, while the core has an appreciable void fraction, is not viewed as a potential problem for the detection of an inadequate core cooling situation. Although some Semi-scale tests indicated core voiding while the upper head was liquid solid, these tests do not imply that the core exit T/Cs would give an ambiguous indication of ICC calculations for a Westinghouse PWR, and consideration of the core exit T/C design would not result in ambiguous ICC indications.

Q492.29 Describe the behavior of the level measurement system when the upper head is full, but the lower vessel is not.

RESPONSE

During the course of a LOCA transient, the upper plenum will experience voiding before the upper head. The voids in the upper plenum will be indicated by a lower RVLIS reading. The RVLIS will not indicate where the voiding is occurring, but at this point in the transient, it is not necessary to know the location of the region of voiding. In the early part of the transient, when the mixture level is above the top of the guide tube in the upper head, it is sufficient for the operator to know that the vessel inventory is decreasing, irrespective of the region where voiding is occurring. As discussed in the response to Question 492.30, the fluid in the upper head does not affect the RVLIS indication after the upper head has drained to below the top of the guide tubes. As discussed in the response to Question 492.28, the upper head will drain before the onset of ICC, and there will not be an ambiguous indication during the period of time RVLIS will be used.

Q492.30 One discussion of the microprocessor system states that water in the upper head is not reflected in the plot. Does this mean that there is no water in the upper head or that the system is indifferent to water in the upper head under these conditions?

RESPONSE

The discussion in the system description is contained in the section describing the analysis of the system performance. The statement in question is referring to the WFLASH code calculation of mixture level, rather than how the RVLIS will respond to water in the upper head. The computer code includes calculation of water mass and pressure in the upper head, but this water mass is not included in the calculation of mixture level; hence, the mixture level is indicated only below the elevation of the upper support plate.

The RVLIS measurement from top to bottom of the vessel will measure the level in the following regions: top of vessel to top of guide tube; inside guide tube from top to upper support plate; upper plenum; reactor core; and lower plenum. During a LOCA, the RVLIS would measure the water level in the upper head only until the level drops to the top of the guide tubes; RVLIS would then measure level reduction in the guide tubes and upper plenum. The water remaining in the upper head below the top of the guide tubes would not be measured by RVLIS. This water would eventually drain through small holes into the guide tubes and downcomer, and this drainage would be accomplished within a few minutes, depending on the accident. In any case, the water temporarily retained in the upper head would have no effect on the RVLIS indication.

Q492.31 Describe the details of the pump flow/Dp calculation. Discuss the possible errors.

RESPONSE

Calculations are performed to obtain an estimate of the differential pressure that the wide range instrument will measure with all pumps operating, from ambient temperature to operating temperature. The calculations employ the same methods used to estimate reactor coolant flow for plant design and safety analysis. These calculations are used primarily to define the instrument span and to provide an estimate for the function that compensates the differential pressure signal over the full temperature range, i.e., that results in the wide range display indicating 100 percent over the full temperature range with all pumps operating, pumping subcooled coolant. During the initial plant startup following installation of the instrumentation, wide range differential pressure data would be obtained and used to confirm or revise the compensation function so that a 100-percent output is obtained at all temperatures. Since the calculated compensation function is verified by plant operating data, any uncertainties in the flow and differential pressure estimates are eliminated.

Q492.32 Have tests been run with voids in the vessel? Describe the results of these tests.

RESPONSE

At present a Westinghouse RVLIS is installed at the Semiscale Test Facility in Idaho. Small break loss-of-coolant experiments are being conducted at this facility by EG&G for the NRC. The results of these tests are used to compare the RVLIS measurements with Semiscale differential pressure measurements, gamma densitometer data, and core cladding surface thermocouple indications. To date, after correcting for difference between PWR reactor vessel internals and Semiscale modeling, good correlation between Semiscale level indications and RVLIS measurements has been observed. In cooperation with the NRC, EG&G, and ORNL, Westinghouse is preparing a report summarizing the RVLIS performance during selected Semiscale tests.

Q492.33 Estimate the expected accuracy of the system after an ICC event.

RESPONSE

The accuracy of the system as described in the response to Question 492.15 would be the same for any LOCA-type incident, including an ICC event, which would cause a temperature increase within the reactor containment. Uncertainties due to reference leg temperature measurements and sensor and hydraulic isolator displacements are included in the accuracy analysis.

Q492.34 Describe how the conversion of RTD resistance to temperature is made in the analog level system.

RESPONSE

The "7300" RVLIS incorporates P.C. cards that provide an output proportional to the change in resistance of the RTD. The card contains a resistance bridge driven by a power supply to produce a signal proportional to the changes in resistance of the RTD, and a signal characterizer which accommodates linear calibration of non-linear RTDs.

TABLE 490.1-1 FUEL ASSEMBLY COMPONENT STRESSES
(PERCENT OF ALLOWABLE)

Component	Uniform Stresses (Membrane/Direct)	Combined Stresses (Membrane+Bending)
Thimble	47.9	54.1
Fuel rod*	16.1	14.6
Top nozzle plate	<1.0	2.1
Bottom nozzle plate	<1.0	33.9
Bottom nozzle leg	10.9	14.4

*Includes primary operating stresses.

Q640.1 Through Q640.29

RESPONSE

The sections describing the Callaway initial test program have been deleted, as discussed in Section 14.2. Consistent with the deletion of the initial test program description, the responses to questions concerning the test program have also been deleted. The deleted responses are contained in the FSAR on record as of the receipt of the Callaway Operating License No. NPF-30, on October 18, 1984.

Q640.0 Procedures and Test Review Branch

Q640.1 (14.2.7) Certain exceptions to regulatory guides as listed in Appendix 3A are not acceptable or require further justification.

Provide the following information:

(1) Regulatory Guide 1.68

Describe existing tests that verify acceptable plant response for a loss of turbine-generator coincident with a loss of offsite power, or delete this exception and include the appropriate test description.

(2) Regulatory Guide 1.80

State which tests demonstrate that safety-related valves fail-safe on loss-of-instrument air.

(3) Regulatory Guide 1.118

The discussion states that nuclear instrumentation sensors are exempt from time response testing since their worst case response time is not a significant portion of the total overall system response (i.e., less than 5%). Given that this exemption is no longer permitted by IEEE-338 (1977 version), delete this exception or provide expanded technical justification for not conducting time response testing.

Q640.2 (14.2.10.2) Your initial criticality description should be expanded to include:

(1) A source range count of at least 1/2 count per second should be visible on the startup channels prior to commencing the startup.

(2) The signal to noise ratio should be known to be greater than 2.

(3) Criticality predictions for boron concentration and control rod positions should be provided, and criteria and actions to be taken should be established if actual plant conditions deviate from predicted values.

(4) The approach to criticality should be slow enough to limit start up rate at criticality to less than 1 decade per minute.

Q640.3 (14.2.11)

Section 14.2.11 of SNUPPS states that insofar as practicable, test requirements will be completed prior to exceeding 25-percent power for all plant structures, systems and components that are relied upon to prevent, limit or mitigate the consequences of postulated accidents. According to Table 14.2-5 the following startup tests are performed after exceeding 25-percent power:

(1) S070012 - Rod Drop and Plant Trip

(2) S07AB01 - Automatic Steam Generator Level Control

(3) S07SF05 - Automatic Reactor Control System

(4) S07SF07 - Startup Adjustments of Reactor Control System.

Perform these tests at 25% power or less, or provide technical justification for not fulfilling the testing requirements of Section 14.2.11.

Q640.4 (14.2.11)

Section 14.2.11 of SNUPPS states that startup test procedures will be available for NRC review at least 60 days prior to fuel loading. Table 14.2-5 indicates that twenty of thirty-eight startup tests will be in the procedure preparation, review and approval stage at that time. Modify Table 14.2-5 to indicate by a note or legend alteration that complete procedures will be available for review in the time frame stated in Section 14.2.11.

Q640.5 (14.2.12)

Provide a commitment to include in your test program the design features to prevent or mitigate anticipated transients without scram (ATWS) that may now, or in the future, be incorporated into your plant design (Subsection 15.8).

Q640.6 (14.2.12)

List those tests that will only be performed on the first SNUPPS unit. In addition cite the criteria that will be used during subsequent unit testing programs to ensure that follow-on units perform in an identical manner regarding those tests to be deleted.

Q640.7 (14.2.12.3)

Identify any of the post-fuel loading tests described in Section 14.2.12.3 which are not essential towards the demonstration of conformance with design requirements for structures, systems, components, and design features that meet any of the following criteria:

(1) Will be relied upon for safe shutdown and cooldown of the reactor under normal plant conditions and for maintaining the reactor in a safe condition for an extended shutdown period.

(2) Will be relied upon for safe shutdown and cooldown of the reactor under transient (infrequent or moderately frequent events) conditions and postulated accident conditions, and for maintaining the reactor in a safe condition for an extended shutdown period following such conditions.

(3) Will be relied upon for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility technical specifications.

(4) Are classified as engineered safety features or will be relied upon to support or assure the operation of engineered safety features within design limits.

(5) Are assumed to function or for which credit is taken in the accident analysis for the facility (as described in the Final Safety Analysis Report).

(6) Will be utilized to process, store, control, or limit the release of radioactive materials.

Q640.8 (14.2.12.3)

The objectives specified for several tests are inappropriate. In general, appropriate test objectives are:

- to measure
- to calibrate
- to obtain data
- to document
- to verify performance.
- Provide appropriate objectives for the following tests:

14.2.12.3.1	14.2.12.3.22
3.2	3.33

3.3	3.35
3.8	

Q640.9 (14.2.12.3) It is unacceptable to reference test instructions for test prerequisites. Provide acceptable prerequisites for the following tests:

14.2.12.3.1	14.2.12.3.24
3.4	3.25.2.a
3.5	3.26
3.6	3.27
3.7	3.29
3.8.2.a	3.30
3.13	3.31
3.14	3.32
3.21	3.33
3.22	3.34.2.b
3.23	3.35

Q640.10 (14.2.12) Certain terminology used in the individual test descriptions does not clearly indicate the source of the acceptance criteria to be used in determining test adequacy. An acceptable format for providing acceptance criteria for test results includes any of the following:

- Referencing technical specifications
- Referencing specific sections of the FSAR
- Referencing vendor technical manuals
- Providing specific quantitative bounds (only if the information cannot be provided in any of the above ways).

Modify the individual test description subsection presented below or, if applicable, add a paragraph to Subsection 14.2.12 that provides an acceptable description of each of the unclear terms.

(1) Within design specifications

14.2.12.1.3	14.2.12.1.50
1.4	1.51 (2 times)
1.5	1.52
1.7	1.53
1.9	1.59
1.10	1.60 (2 times)
1.11	1.61 (2 times)
1.12	1.62

1.15 (2 times)
1.18 (2 times)
1.21 (2 times)
1.23 (2 times)
1.24
1.25 (2 times)
1.26 (2 times)
1.27
1.28 (3 times)
1.29 (3 times)
1.30
1.32 (2 times)
1.33 (4 times)
1.34 (3 times)
1.36
1.37 (3 times)
1.39
1.41 (3 times)
1.42 (2 times)
1.43
1.44 (2 times)
1.45 (2 times)
1.46
1.47
1.48
1.49

1.64 (6 times)
1.65
1.66 (2 times)
1.68 (2 times)
1.71
1.72
2.1
2.2 (2 times)
2.3 (2 times)
2.4
2.5
2.6 (2 times)
2.7
2.8
2.10
2.11 (2 times)
2.14 (2 times)
2.15
2.16
2.19
2.22 (2 times)
2.25
3.15
3.18 (2 times)
3.20 (2 times)

(2) In accordance with design, in accordance with system design

14.2.12.1.1 (2 times)
1.6 (2 times)
1.8
1.44
1.45
1.46
1.48
1.51
1.54
1.55
1.56 (2 times)
1.57

14.2.12.1.59
1.63 (2 times)
1.64 (4 times)
1.65 (2 times)
1.66
1.68
1.69
1.70
1.71 (2 times)
1.72
1.73
2.15

1.58	(2 times)	2.16	

(3) In accordance with design specification, in accordance with system design specifications

14.2.12.1.39		14.2.12.2.13	
2.1		2.20	
2.9		2.21	(2 times)
2.11		2.24	
2.12		2.26	

(4) Design

14.2.12.1.10		14.2.12.1.70	
1.11		1.80	
1.17		2.17	
1.35		2.18	
1.42		3.15	
1.65	(3 times)	3.17	
1.67	(5 times)	3.37	

(5) Within design limits, without exceeding design limits, within the limits predicted by design analyses, within design requirements

14.2.12.1.16	(2 times)	14.2.12.1.62	
1.29		1.64	
1.32		1.73	
1.35		1.78	
1.37		1.79	
1.41		3.16	

(6) Within allowable limits, within required limits

14.2.12.1.22	
1.38	
1.62	

(7) Required

14.2.12.1.10		14.2.12.1.65	(2 times)
1.22		1.85	
1.64	(10 times)		

(8) Rated

14.2.12.1.62		14.2.12.1.65	
1.64	(2 times)	1.82	(3 times)

(9) Responds, responds properly, properly respond

14.2.12.1.12	14.2.12.1.48
1.34	1.49
1.36	1.51

(10) In accordance with test instructions, is provided in test instructions, meets the requirements of the test instructions, consistent with the acceptance criteria given in the test procedure, agrees with the acceptance criteria given in the test procedure, as required by the test instructions

14.2.12.1.74	14.2.12.3.13
1.75	3.14
1.76	3.23
3.2	3.30
3.6	3.31
3.7	3.32
3.8	3.33
3.11	

(11) Shall not exceed code-allowable stresses, must not exceed their code-allowable limits at the test or design conditions

14.2.12.1.80

1.81

3.37 (2 times)

(12) Set point tolerances

14.2.12.1.2

(13) Acceptable

14.2.12.1.14	14.2.12.2.17
1.64 (2 times)	2.18

(14) Adequate

14.2.12.1.37

1.83

(15) Approximate

14.2.12.1.14

1.80

3.37

(16) Predicted

14.2.12.1.14

(17) Verified

14.2.12.1.14

1.22

(18) Fails safe

14.2.12.1.73

(19) Operate satisfactorily per design

14.2.12.1.83

(20) Impair design functions

14.2.12.1.83

(21) Slightly above

14.2.12.1.20

Q640.11 (14.2.12)

Our review of your initial test program description disclosed that the operability of several of the systems and components listed in Regulatory Guide 1.68 (Rev. 2), Appendix A, may not be demonstrated. Expand your FSAR to include appropriate test descriptions (or identify existing descriptions) that address the following items from Appendix A, or provide technical justification for any exceptions to the guide in Subsection 14.2.7:

(1) <u>Preoperational Testing</u>

1.a.(2)(i) RCS safety valves

1.b.(1) Control rod drive system test

1.e.(5) Steam extraction system

1.e.(6) Turbine stop, control, and intercept valves

1.e.(10) Feedwater heater and drain systems

1.h Test of protective devices such as leaktight covers, structures, or housings provided to protect Engineered Safety Features from flooding

1.h.(8)	Tanks and other sources of water used for ECCS
1.i.(5)	Containment airlock leak rate test
1.i.(12)	Containment air purification and cleanup system
1.i.(15)	Containment penetration pressurization system tests
1.j.(6)	Loose parts monitoring system
1.j.(7)	Leak detection system for ECCS and containment spray system outside of containment
1.j.(8)	Reactor control system
1.j.(9)	Pressure control systems designed to prevent leakage across boundaries
1.j.(11)	Traversing incore probe system
1.j.(13)	Incore nuclear instrumentation
1.j.(14)	Instrumentation and controls that affect transfers of water supplies to auxiliary feedwater pumps, ECCS pumps, and containment spray pumps
1.j.(16)	Hotwell level control system
1.j.(17)	Feedwater heater temperature, level, and bypass control systems
1.j.(18)	Auxiliary startup instrument tests
1.j.(20)	Instrumentation used to detect internal and external flooding
1.j.(22)	Instrumentation that can be used to track the course of postulated accidents such as containment sump level monitors and humidity monitors
1.j.(24)	Annunciators for reactor control and engineered safety features
1.j.(25)	Process computers

1.l.(4)	Isolation features for steam generator blowdown
1.l.(7)	Isolation features for liquid radwaste effluent systems
1.m.(4)	Dynamic and static load testing of cranes, hoists, and associated lifting and rigging equipment, including the fuel cask handling crane. Static testing at 125% of rated load and full operational testing at 100% of rated load
1.n.(2)	Closed loop cooling water systems
1.n.(6)	Chemistry control systems for the reactor coolant and secondary coolant systems
1.n.(9)	Vent and drain systems for contaminated or potentially contaminated systems
1.n.(10)	Purification and cleanup systems for the reactor coolant system
1.n.(12)	Boron recovery system
1.n.(14)(c)	Battery room ventilation
1.n.(16)	Cooling and heating systems for the refueling water storage tank
1.o	Reactor components handling systems

(2) <u>Initial Fuel Load and Precritical Testing</u>

2.a	Shutdown margin verification for the fully loaded core
2.b	Control rod withdrawal and insertion speeds, sequencers and protective interlocks
2.d	Final reactor coolant system leak rate test

(4) <u>Low Power Testing</u>

4.b	Confirm by analysis that rod insertion limits will be adequate to ensure a shutdown margin consistent with accident analysis assumptions, with the greatest worth control rod stuck out of the core.

4.c	Pseudo-rod-ejection test
4.e	Flux distribution determination
4.f	Neutron and gamma radiation surveys
4.g	Determination of proper response of process and effluent radiation monitors
4.h	Chemical and radiochemistry tests
4.i	Demonstration of the operability of control rod withdrawal inhibit or block functions over the reactor power level range during which such features must be operable
4.j	Demonstration of the capability of the primary containment ventilation system.
4.n	Demonstration of the operability of the control room computer system
4.r	Demonstration of the operability of reactor coolant system purification and cleanup systems

4.t Performance of natural circulation tests of the reactor coolant system to determine that adequate heat removal capability exists. NUREG-0694 "TMI Related Requirements for New Operating Licenses," Item I.G.1, requires applicants to perform "a special low power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training." To comply with this requirement new PWR applicants have committed to a series of natural circulation tests. To date such tests have been performed at the Sequoyah 1, North Anna 2, and Salem 2 facilities. Based on the success of the programs at these plants, the staff has concluded that augmented natural circulation training should be performed for all future PWR operating licenses. Include descriptions of natural circulation tests that, in addition to validating the operating procedures, fulfill the following objectives:

Testing

The tests should demonstrate the following plant characteristics: length of time required to stabilize natural circulation, core flow distribution, ability to establish and maintain natural circulation with or without onsite and offsite power, the ability to uniformly borate and cool down to hot shutdown conditions using natural circulation, and subcooling monitor performance.

Training

Each licensed reactor operator (RO or SRO who performs RO or SRO duties, respectively) should participate in the initiation, maintenance and recovery from natural circulation mode. Operators should be able to recognize when natural circulation has stabilized, and should be able to control saturation margin, RCS pressure, and heat removal rate without exceeding specified operating limits.

If these tests have been performed at a comparable prototype plant, they need be repeated only to the extent necessary to accomplish the above training objectives.

(5) Power-Ascension Tests

5.b	Determine that steady-state core performance is in accordance with design
5.d	Demonstrate the capabilities of plant features and procedures for controlling core xenon transients
5.e	Pseudo-rod-ejection test
5.f	Single rod insertion and withdrawal
5.g	Demonstrate operation of the control rod sequencers, and rod withdrawal block functions
5.h	Check rod scram times from data recorded during the startup test phase
5.i	Demonstrate the capability of incore and excore neutron flux instrumentation to detect a control rod misalignment equal to or less than the technical specification limits
5.l	Demonstrate design capability of all systems and components provided to remove residual or decay heat from the reactor coolant system
5.m	Demonstrate that reverse flows through idle loops and differential pressures across the core are in agreement with design values

5.n	Obtain baseline data for reactor coolant system loose parts monitoring system
5.r	Verification of input to, and output from control room process computer
5.s	Verify the performance of the auxiliary feedwater control system, the hotwell level control system, steam pressure control system, and the reactor coolant makeup and letdown control systems
5.t	Verify the response times, relieving capacities, and reset pressures for the pressurizer relief valves; main steam line relief valves; atmospheric steam dump valves; and the turbine bypass valves
5.u	Verify operability and response times of main steam line isolation and branch steam line isolation valves
5.v	Verification of main steam system and feedwater system performance
5.w	Demonstrate that concrete temperatures surrounding hot penetrations do not exceed design limits.
5.y	Verify the proper operation of the incore nuclear instrumentation and instruments and systems used to perform a heat balance
5.z	Demonstrate that process and effluent radiation monitoring systems are responding correctly
5.aa	Demonstrate the operation of the chemical and radiochemical control systems
5.bb	Conduct neutron and gamma radiation surveys to establish the adequacy of shielding
5.cc	Demonstrate the operation of the gaseous and liquid radioactive waste processing, storage, and release systems
5.ff	Demonstrate that ventilation systems maintain design temperatures

5.ii Demonstrate that the dynamic response of the plant is in accordance with design for limiting reactor coolant pump trips

5.kk Demonstrate that the dynamic response of the plant is in accordance with design for the loss of or bypassing of the feedwater heaters

5.mm Demonstrate that the dynamic response of the plant is in accordance with design for the case of automatic closure of all main steam line isolation valves at 100 percent reactor power

5.nn Demonstrate that the dynamic response of the plant is in accordance with design for the case of full load rejection (tripping of the main generator breakers)

Q640.12 (14.2.12) We could not conclude from our review of your individual test descriptions that comprehensive testing is scheduled for several systems and components. Therefore, clarify or expand the appropriate test descriptions to address the following items:

(1) 14.2.12.1.1 - Clarify, or reference the FSAR section which clarifies, the purpose of a decreasing condenser pressure signal.

(2) 14.2.12.1.5 - Provide acceptance criteria for steam generator feedwater pump operation.

(3) 14.2.12.1.7 - Subsection 10.4.9.2.3 indicates four separate actuation signals can cause an automatic start of the motor-driven auxiliary feed pump. Ensure these four are included in your test description acceptance criteria.

(4) 14.2.12.1.8 - Our review of licensee event reports has disclosed several instances of turbine-driven auxiliary feedwater pump failure to start on demand. It appears that many of these failures could have been avoided if more thorough testing had been conducted during the plant's initial test programs. In order to discover any problems affecting pump startup and to demonstrate the reliability of your emergency cooling system, state your plans to demonstrate at least five consecutive, successful, cold quick pump starts during your initial test program.

(5) 14.2.12.1.9 - Commit to verifying operation of any pump permissive interlocks which serve to prevent cold water addition accidents or serve to protect RCS components from excessive differential pressures at low temperatures.

(6) 14.2.12.1.17 and 14.2.12.1.18 - State that flow and coastdown testing will be performed for all permissible combinations of pump operation.

(7) 14.2.12.1.29 - Verify that the maximum obtainable boron dilution rate is less than or equal to that assumed in your accident analysis (Subsection 15.4.6).

(8) 14.2.12.1.34 - Ensure that the interlocks and isolation valves for overpressure protection of the RHR system are tested (Subsection 5.4.7.2.5).

(9) 14.2.12.1.39 - State which safety signals are used to test boron recirculation pump and valve response.

(10) 14.2.12.1.40 - Verify that paths for the air-flow test of containment spray nozzles overlap the water-flow test paths of the pumps to demonstrate that there is no blockage in the flow path.

(11) 14.2.12.1.41 - State which safety signals are used to test containment spray pump and valve response.

(12) 14.2.12.1.48 - Verify that the cooling fans can operate in accordance with design requirements at the containment design peak accident pressure.

(13) 14.2.12.1.64 - a) Verify that the transfer pump flow capacity (Subsection 14.2.12.1.53) is sufficient to satisfy the fuel oil consumption rates. b) Ensure that the 2 hr. and 22 hr. load tests are accomplished within a 24 hr. period.

(14) 14.2.12.1.73 - a) Account for process-to-sensor hardware (e.g., instrument lines, hydraulic snubbers) delay times;
b) Provide assurance that the response time of each primary sensor is acceptable; and
c) Provide assurance that the total reactor protection system response time is consistent with your accident analysis assumptions.

Note: Item 2 can be accomplished by measuring the response time of each sensor during the preoperational test, ensuring that the response time of each sensor will be measured by the manufacturer within two years prior to fuel loading, or describing the manufacturer's certification process in sufficient detail for us to conclude that the sensor response times are in accordance with design.

(15) 14.2.12.2.6 - Verify that the operability of your liquid radwaste system will be demonstrated by actually processing representative chemical waste streams.

(16) 14.2.12.3.7 - Ensure that the moderator temperature coefficient will be derived, and that it meets the applicable criteria.

(17) 14.2.12.3.9 - Include testing at approximately 50% power. Commit to performing step and ramp changes of full design value, or explain how changes of a lower value can be used to determine the proper response to design load swings.

(18) 14.2.12.3.27 - Commit to retesting rods, whose scram times fall outside the two-sigma limit, at least three additional times.

Q640.13 (14.2.12)

We have noted on other plant startups that the capacities of pressurizer or main steam power-operated relief valves are sometimes in excess of the values assumed in the accident analyses for inadvertent opening or failure of these valves. Provide a description of the initial plant test or manufacturer's test that demonstrates that the capacity of these valves is consistent with your accident analysis assumptions.

Q640.14 (14.2.12.1)

Commit to the demonstration of the operability of the temperature sensors downstream of the primary power operated relief valves and safety valves (Figure 5.1-1, Sheet 2).

Q640.15 (14.2.12)

Failure of pressurizer overpressure protection valves to reseat, coupled with false position indication has occurred recently. One possible failure cause which has been identified was galling of the valve body due to dry stroking the valves when setting release limits. Explain what procedures will be used to protect valves during limit setting.

Q640.16 (14.2.12.1)

Verify that functional testing performed on valves with two actuation trains, such as the Main Steam (Subsection 10.3.2.2) and Main Feedwater (Subsection 10.4.7.2.2) Isolation Valves, includes verification of the operability of each actuation train.

Q640.17 (14.2.12.1)

Correct the following deficiencies that were noted in your Containment Isolation Valve test description:

(1) Subsection 14.2.12.1.10 states that Pressurizer Relief Tank Nitrogen Isolation Valves shut upon receiving a CIS, but these valves do not appear in Table 6.2.4-1.

(2) The following valves should close upon receiving a CIS (Table 6.2.4-1) but are not specifically addressed in your test procedure descriptions:

HV-7,8 - Containment Spray Recirculation
FV-29 - Instrument Air to Reactor Building
FV-95,96 - Reactor Sump Pump to Floor Drain Tank
HV-8843 - Boron Injection Tank to CIS Test Line

(3) Containment isolation valves should be tested in an integrated manner in as much as practicable. Note that a commitment satisfying this intent could be made in Subsection 14.2.12.1.71.4.C.

Q640.18 (14.2.12.1)

Provide test descriptions 1) that will verify that the plant's ventilation systems are adequate to maintain all ESF equipment within its design temperature range during normal operations; and 2) that will verify that the emergency ventilation systems are capable of maintaining all ESF equipment within their design temperature range with the equipment operating in a manner that will produce the maximum heat load in the compartment. If it is not practical to produce maximum heat loads in a compartment, describe the methods that will be used to verify design heat removal capability of the emergency ventilation systems.

Note that it is not apparent that post-accident design heat loads will be produced in ESF equipment rooms during the power ascension test phase; therefore, simply assuring that area temperatures remain within design limits during this period will probably not demonstrate the design heat removal capability of these systems. It will be necessary to include measurement of air and cooling water temperature and flows and the extrapolations used to verify that the ventilation systems can remove the postulated post-accident heat loads.

Q640.19 (14.2.12.1)

Modify the appropriate test description of the Engineered Safety Features System to ensure that the following items are addressed:

(1) The starting of the ESF pumps should be verified for both emergency and normal power sources.

(2) The SI and RHR pumps should be run under full flow conditions to verify an adequate margin to electrical trip.

(3) ESF pumps should be verified able to start under maximum startup loading conditions.

(4) Present or reference the full flow analysis done to satisfy the intent of Regulatory Guide 1.79, C.1a(2), as committed to in Appendix 3A.

(5) Ensure that the recirculation portion of the ECCS Sump Test (Subsection 14.2.12.1.83) verifies a value of NPSH greater than that required under accident temperature conditions.

Q640.20 (14.2.12.1)

Recently, questions have arisen concerning the operability and dependability of certain ESF pumps. Upon investigation, the staff found that some completed preoperational test procedures did not describe the test conditions in sufficient detail. Provide assurance that the preoperational test procedures for ECCS and containment spray pumps will require recording the status of the pumped fluid (e.g., pressure, temperature, chemistry, amount of debris) and the duration of testing for each pump. In addition, provide preoperational test descriptions to verify that each engineered safety feature pump operates in accordance with the manufacturer's head-flow curve. Include in the description the bases for the acceptance criteria. (The bases provided should consider both flow requirements for ESF functions and pump NPSH requirements).

Q640.21 (14.2.12.1)

Our review of licensee event reports has disclosed that many events have occurred because of dirt, condensed moisture, or other foreign objects inside instruments and electrical components (e.g., relays, switches, breakers). Describe administrative controls that will be implemented to prevent component failures such as these at your facility including precautions that will be taken during initial testing program.

Q640.22 (14.2.12)

For your DC Power System tests (Subsections 14.2.12.1.67, 14.2.12.2.17 and 18), verify that individual cell limits are not exceeded during the design discharge test and demonstrate that the DC loads will function as necessary to assure plant safety at a battery terminal voltage equal to the acceptance criterion that has been established for minimum battery terminal voltage for the discharge load test. Assure that each battery charger is capable of floating the battery on the bus or recharging the completely discharged battery within 24 hours while supplying the largest combined demands of the various steady-state loads under all plant operating conditions.

Q640.23 (14.2.12)

Your test descriptions are not sufficiently detailed to ascertain if the voltage levels at the safety-related buses are optimized for the full load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power source by appropriate adjustment of the voltage tap settings of the intervening transformers. We require that the adequacy of the design in this regard be verified by actual measurement and by correlation of measured values with analysis results. Provide a description of the method for making this verification.

Q640.24 (14.2.12.1)

Make a commitment in your test procedure descriptions to perform the pre- and post- hot functional examination for integrity as described in Subsection 3.9(N).2.4.

Q640.25 (14.2)

There are a number of discrepancies between Table 14.2-1 and Table 14.2-4. Make the appropriate corrections to address the following problems:

(1) S-03BB11 Reactor Coolant System Hydrostatic Test is included in Table 14.2-1 (Sheet 1) but missing from Table 14.2-4.

(2) S-X3NG01 480-V Class 1E System Preoperational Test is included in Table 14.2-1 (Sheet 4) but missing from Table 14.2-4.

Q640.26 (14.2)

Table 14.2-5 (Sheet 3) lists S-090007 Plant Performance Test as one of the startup tests. This test is not included in Table 14.2-3. Provide a footnote indicating that the test is a continuation of a nonsafety-related preoperational test.

Q640.27 (14.2)

Table 14.2-5 does not in many cases clearly indicate the power levels specified by the test method portion of the individual startup test descriptions. Modify Table 14.2-5 to indicate the power level or plateau at which each of the individual startup tests will be conducted.

Q640.28 (14.2.12)

The response to Item 640.18 on the Plant Performance Test (FSAR Subsection 14.2.12.2.27) should restate that the heat removal capability of the containment air coolers will be verified by extrapolation of data taken from the actual test conditions to the postulated post-accident heat load condition.

Q640.29 (14.2.12)

Recent FSAR revisions have made modification to various test abstracts. Provide technical justification for each of the following test abstract modifications, or modify the test abstracts accordingly.

(1) The Spent Fuel Pool Crane Preoperational Test (FSAR Subsection 14.2.12.1.54) should reinstate acceptance criteria regarding proper operation of the control circuits and associated interlocks.

(2) The LOCA Sequencer Preoperational Test (FSAR Subsection 14.2.12.1.64) should reinstate acceptance criteria for load group 2 and diesel generator operation (Acceptance Criteria items j through p have been deleted).

(3) The Reactor Protection System Logic Test (FSAR Subsection 14.2.12.1.73) should reinstate the acceptance criteria for all loop response times measured in the test method.

(4) The Plant Performance Test (FSAR Subsection 14.2.12.2.27) should provide objectives and test method regarding evacuation alarm audibility. Alternatively, the Public Address System Preoperational Test (FSAR subsection 14.2.12.2.21) should provide acceptance criteria regarding evacuation alarm audibility in high noise areas.

Q730.1 The Atomic Safety and Licensing Appeal Board in ALAB-444 determined that the Safety Evaluation Report for each plant should contain an assessment of each significant unresolved generic safety question. It is the staff's view that the generic issues identified as "Unresolved Safety Issues" (NUREG-0606) are the substantive safety issues referred to by the Appeal Board. Accordingly, we are requesting that you provide us with a summary description of your relevant investigative programs and the interim measures you have devised for dealing with these issues pending the completion of the investigation, and what alternative courses of action might be available should the program not produce the envisaged result.

There are currently a total of 26 Unresolved Safety Issues discussed in NUREG-0606. We do not require information from you at this time for a number of the issues since a number of the issues do not apply to your type of reactor, or because a generic resolution has been issued. Issues which have been resolved have been or are being incorporated in the NRC licensing guidance and are addressed as a part of the normal review process. However, we do request the information noted above for each of the issues listed below:

1. Waterhammer (A-1)
2. Steam Generator Tube Integrity (A-3)
3. ATWS (A-9)
4. Reactor Vessel Materials Toughness (A-11)
5. Steam Generator and Reactor Coolant Pump Support (A-12)
6. Systems Interaction (A-17)
7. Seismic Design Criteria (A-40)
8. Containment Emergency Sump Performance (A-43)
9. Station Blackout (A-44)
10. Shutdown Decay Heat Removal Requirements (A-45)
11. Seismic Qualification of Equipment in Operating Plants (A-46)
12. Safety Implications of Control Systems (A-47)

13. Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment (A-48)

RESPONSE

In the Safety Evaluation Report for Virgil C. Summer and Comanche Peak (NUREG-0717 and -0797), the NRC Staff concluded that those plants could be operated pending resolution of the unresolved safety issues. The reasoning that leads to these conclusions is applicable to the Callaway Plant. In general, Union Electric agrees with the previous NRC Staff assessments of these issues and also has concluded that the Callaway Plant can be operated without risk to the health and safety of the public. Programs and measurements taken for dealing with these generic issues are discussed below.

A-1 Waterhammer

The steam generator design incorporates a sealed thermal sleeve and J tubes on the feedring to prevent draining of water from the feedring in the event the feedwater is lost and the steam generator water level drops below the level of the feedring. The design also incorporates a short horizontal length of feedwater piping to the feedring. A waterhammer test of the feedwater system using normal plant procedures will be conducted. The feedwater connection on each of the steam generators is the highest point of each feedwater line downstream of the main feedwater isolation valve. The feedwater lines contain no high pockets which, if present, could trap steam and lead to waterhammer. The feedwater inlet arrangement for the AREVA Model 73/19T steam generator is of such a design as to minimize the potential for flow-induced tube vibration. A preoperational test for piping vibration and dynamic effects will be conducted. For further details refer to Sections 5.4.2.2, 10.4.7.2.1, 3.9(B).2.1, and 3.9(N).2.1.

A-3 Steam Generator Tube Integrity

The design includes the AREVA Model 73/19T steam generator which was developed to minimize steam generator tube problems. In addition, the Callaway Plant uses all volatile treatment (AVT) chemistry control. For further details refer to the following Sections: 5.4.2.2, 5.4.2.3.1, 5.4.2.3.3, 5.4.2.4.2, 5.4.2.5.4, 9.3.2, 10.4.6, 10.4.8, and the response to Regulatory Guide 1.121 in Appendix 3A.

A-9 Anticipated Transients Without Scram

Refer to Section 15.8.

A-11 Reactor Vessel Materials Toughness

Refer to Section 5.3 and responses to NRC Questions (123.3, .4, .6, .7, .8, and .9).

A-12 Steam Generator and Reactor Coolant Pump Support

The steam generator and reactor coolant pump supports were designed to meet the fracture toughness requirements of ASME Section III, subsection NF. Westinghouse has concluded that compliance with subsection NF is sufficient to resolve the concerns expressed in NUREG-0577. Refer to Sections 3.8.3.1.2, 3.8.3.1.3, and 5.4.14.

A-17 Systems Interaction

The Callaway Plant design is founded on principles of physical separation, independence of redundant safety systems, and protection against hazards such as high energy line breaks, missiles, flooding, seismic events, fires, and sabotage. The design has been subjected to multiple, interdisciplinary reviews. Examples of such reviews include:

a. FSAR Appendix 3B describes the hazards analysis review program which was conducted on a room-by-room basis for each room in the power block. All components within the rooms were reviewed for the effects of earthquake-induced failures, effects of high and moderate energy piping breaks (flooding, sprays, and jet impingement), and the effects of missiles.

b. A separate review was also conducted on a room-by-room basis to evaluate the fire protection design and the effects of fires in each fire area as discussed in the Fire Safety Analysis described in FSAR Section 9.5.1.

c. The responses to NRC questions 420.3 and 420.4 describe the reviews conducted to analyze control systems failures and how such failures impact interfacing safety grade systems.

d. Heavy loads analyses as requested in NRC generic letter 81-07.

e. Review of environmental impacts on systems to ensure that they are designed to provide acceptable performance during normal and design basis accident conditions as described in FSAR Sections 3.11(B) and 3.11(N).

A-40 Seismic Design Criteria

As discussed in Sections 3.7(B) and 3.7(N), the Callaway Plant has been designed to current seismic design criteria.

A-43 Containment Emergency Sump Performance

The containment sumps are described in Section 6.2.2.1.2.2 and Figure 6.2.2-3 (10 sheets). Thermal insulation used inside the containment will not be a significant source of debris. A detailed comparison of the containment sumps with the design recommendations of Regulatory Guide 1.82 is provided in Table 6.2.2-1. Sump testing is discussed in Appendix 3A response to Regulatory Guide 1.79.

A-44 Station Blackout (SBO)

The offsite and onsite power systems are described in Sections 8.2 and 8.3. Several responses to NRC questions in the 430-series are related to NUREG/CR 0660. The diversity of the turbine-driven auxiliary feedwater pump train from ac power is discussed in Section 10.4.9.2.2. Plans for emergency procedures and training were provided in SNUPPS letter, SLNRC 81-35 dated May 27, 1981.

Further evaluation of SBO per 10 CFR 50.63 is documented in FSAR Appendix 8.3A.

A-45 Shutdown Decay Heat Removal Requirements

The Callaway Plant design includes provisions so that cold shutdown conditions can be obtained using safety-grade equipment with only onsite or only offsite ac power. Refer to Appendix 5.4.A. As noted in that appendix, the design includes redundant, qualified, Class 1E pressurizer power-operated relief and block valves.

A-46 Seismic Qualification of Equipment in Operating Plants

Current seismic criteria were used in the Callaway Plant design. Refer to Sections 3.10(B) and 3.10(N).

A-47 Safety Implications of Control Systems

The control and safety systems have been designed with the goal of ensuring that control system failures will not prevent automatic or manual initiation and operation of any safety system equipment. This has been accomplished by providing independence or isolation between safety and non-safety systems. An analysis is documented in the response to NRC question 420.4.

A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

Section 6.2.5 describes hydrogen control provisions in the Callaway Plant design. Principal containment design parameters are given in Table 6.2.1-2.

A-49 Pressurized Thermal Shock

Section 5.3 and the responses to NRC Questions (123.3, .4, .6, .7, .8, and .9) provide information concerning reactor vessel material properties, material susceptibility to neutron irradiation induced embrittlement, and the increase of nil ductility transition temperature with operating life.