Question 005.1

In addition to the two code cases identified in Section 5.2.1.2 of the FSAR, identify all other ASME Code Cases (including those that are listed as acceptable in Regulatory Guides 1.84 and 1.85) that were used in the construction of each Quality Group A components within the reactor coolant pressure boundary. These code cases should be identified by code case number, revision, and title for each component to which the code case has been applied.

Response

The unapproved or conditionally approved (per Regulatory Guides 1.84 and 1.85) code cases used in the construction of the STPEGS Class l components, specifically Code Cases 1739 and 1528, have been addressed in Section 5.2.1.2.

In the case of code cases approved by the NRC via Regulatory Guides 1.84 and 1.85, the Applicant sees no need to specifically address the usage of these code cases in the STPEGS UFSAR since Regulatory Guides 1.84 and 1.85 are viewed by the Applicant as the NRC's communication of review/endorsement of code cases.

Question 005.3

Your response to Request No. 005.1 is unacceptable. Footnote 6 of the Codes and Standards Rule, Section 50.55a of 10 CFR Part 50, states that the use of specific Code Cases may be authorized by the Commission upon request. Therefore, each Quality Group A component within the Reactor Coolant Pressure Boundary to which a Code Case has been applied should be identified by Code Case number, revision, and title. This includes those ASME Code Cases which are identified as acceptable to the Commission in Regulatory Guides 1.84 and 1.85. Revise the FSAR to provide the information requested.

Response

As stated in the response to Question 005.1, unapproved or conditionally approved (per Regulatory Guides [RGs] 1.84 and 1.85) code cases used in the construction of the STPEGS Class l reactor coolant pressure boundary (RCPB) components, specifically Code Cases 1739 and 1528, have been addressed in Section 5.2.1.2. In the case of code cases approved by the NRC via RGs 1.84 and 1.85, we see no need to specifically address the usage of these code cases in the STPEGS UFSAR; however, all code cases (approved, conditionally approved, unapproved) used in the construction of STPEGS Class 1 RCPB components are identified in the manufacturers' data reports, which are included in the STPEGS QA data package.

Question 005.4

Your response to Request No. 005.2 states that in some cases portions of the Reactor Coolant Pressure Boundary that meet the exclusion requirements of Footnote 2 of the Codes and Standards Rule, Section 50.55a of 10 CFR Part 50, and with the interface criteria as defined in the ANS Nuclear Power Plant Standard Committee Policy 2.3 (Draft 6), are classified less than Safety Class 2. This is an incorrect interpretation of the regulation and is unacceptable.

Under no circumstances, regardless of interface criteria, may a component within the Reactor Coolant Pressure Boundary, as defined in 10 CFR 50.2(V) of the Code of Federal Regulations and meeting the exclusion requirements of Footnote 2, be classified less than Quality Group B, Safety Class 2, (i.e., must be constructed to ASME Section III, Class 2 in conformance with Regulatory Position C.1 of Regulatory Guide 1.26), and, in addition, the component must be designed to seismic Category I requirements in conformance with Regulatory Position C.1.a of Regulatory Guide 1.29 and the pertinent quality assurance requirements of Appendix B to 10 CFR Part 50.

The ANS Nuclear Power Plant Standard Committee Policy 2.3 (Draft 6) document is unacceptable for use in the licensing process, as the document is in conflict with Federal Regulations. Revise the FSAR as appropriate to comply with the above requirements.

Response

The statement, "This is an incorrect interpretation of the regulation and is unacceptable," is not understood. The reasons are as follows:

1. The regulation is clear and unambiguous in making exceptions of all piping, pumps, and valves from the Group A (Safety Class 1) requirements provided either of two criteria is met. Westinghouse meets these criteria in piping arrangements wherein non-nuclear safety equipment is provided within the Reactor Coolant Pressure Boundary (RCPB).

2. The regulatory basis for making equipment of the RCPB excluded from Group A requirements meet Group B (Safety Class 2) requirements derives from Position C.1 of Regulatory Guide (RG) 1.26. However, the Westinghouse approach to RG 1.26 has always been based on the standard front page allowance (of each RG) that "methods and solutions different from those set forth in the guides will be acceptable if they provide a basis for the findings requisite to the issuance or continuance of a permit or license by the Commission."

   The last corporate letter in which Westinghouse set forth comments on RG 1.26 was NS-CE-1740, sent to the Secretary of the Commission on April 28, 1978. A serious deficiency in the RG is the lack of rules governing the boundaries between classes of interconnected equipment (usually known as "interface criteria"). This is covered by Comment No. 8 of the cited letter. Given the existence of fully rational interface criteria, there would be no doubt about the acceptability of having some equipment of the RCPB exempted from the requirements associated with Group B.

Response (Continued)

3. The regulatory basis for making equipment of the RCPB excluded from Group A requirements meet seismic Category I requirements derives from Position C.1.a of RG 1.29. Again, Westinghouse takes exception to the use of RG 1.29. The deficiency of RG 1.29 applying to this case is the same one cited for RG 1.26.

4. Ever since the inception of the American Nuclear Society (ANS) system of classification, Westinghouse has been using that system of classification. In the early days, internal Westinghouse interface criteria were applied; later, with the issue of American National Standards Institute (ANSI) N18.2a-1975, the interface criteria of that standard were used; all in recognition of the necessity of using good interface criteria to fully and rationally classify equipment. Table Q005.4-1 identifies where in the RCPB, as defined in lOCFR50.2(v), non-nuclear safety (NNS) and nonseismic Category I piping is provided for this project; this is representative of previous projects. In all cases, the interface criteria of ANSI N18.2a-1975 are used to ensure that classification is consistent with the exception criteria set forth in Footnote 2 of lOCFR50.55a for the RCPB and the requirements of lOCFR50, Appendix A, Criterion 55 are met for RCPB Containment penetrations.

   Piping arrangements have been shown for every plant for which Westinghouse has been the nuclear supplier since the ANS system of classification was adopted many years ago. The drawings showing this were contained in respective SAR's and the plants were licensed on that basis.

5. It is Westinghouse policy to classify equipment on a rational basis with full consideration of safety. We feel this has been done in the instant case, others like it, and believe the safety of the plant has not been jeopardized in any way.

In summary, the Westinghouse arrangements of piping are not in violation of the regulation, nor has there been any neglect of the full consideration of safety.

TABLE Q005.4-1

NNS PIPING IN RCPB

Item	Location	Figure
1	ECCS check valve test lines for	6.3-1
	a) accumulator b) high head injection system c) low head injection system	6.3-4
2	accumulator nitrogen supply line	6.3-4
3	reactor coolant drain tank subsystem and supporting piping system	11.2-1

Question 121.5

The inspection program requirements, as detailed in Request No. 121.1, have recently been revised to reflect information gained from recent inspection program reviews. Therefore, Request No. 121.1 is now superseded by the following request. We still require that your inspection program for Class 1, 2, and 3 components be in accordance with the revised rules in 10 CFR Part 50, Section 50.55a, Paragraph (g).

To evaluate your inspection program, the following minimum information is necessary for our review:

(1) A preservice inspection plan to consist of the applicable ASME Code Edition and the exceptions to the code requirements.

(2) An inservice inspection plan submitted within six months of anticipated commercial operation.

The preservice inspection plan will be reviewed to determine compliance with preservice and inservice requirements. The basis for the determination will be compliance with:

(1) The Edition of Section XI of the ASME Code stated in your FSAR or later Editions of Section XI referenced in the FEDERAL REGISTER that you may elect to apply.

(2) All augmented examinations established by the Commission when added assurance of structural reliability was deemed necessary. Examples of augmented examination requirements can be found in staff positions on (a) high energy fluid systems in SRP Section 3.2, (b) turbine disk integrity in SRP Section 10.2.3, and (c) feedwater inlet nozzle inner radii.

Your response should define the applicable Section XI Edition(s) and subsections. If any examination requirements of the Edition of Section XI in your FSAR can not be met, a relief request including complete technical justification to support your conclusion must be provided.

The inservice inspection plan should be submitted for review within six months of anticipated commercial operation to demonstrate compliance with 10 CFR Part 50, Section 50.55a, Paragraph (g). Submittal at that time will permit you to incorporate Section XI requirements in effect six months prior to commercial operation and any augmented examination requirements established by the Commission. Your response should define all examination requirements that you determine are not practical within the limitations of design, geometry, and materials of construction of the components.

Response

HL&P's inservice inspection (ISI) program for Class 1, 2, and 3 components is in compliance with the rules of 10CFR Part 50, Section 50.55a, Paragraph (g). ASME Code Class 1, 2, and 3 components shall be examined in accordance with the applicable technical specifications and the requirements of the applicable edition/addenda of Section XI of the ASME Boiler & Pressure Vessel Code. The

<u>Response</u> (Continued)

1980 Edition of Section XI with addenda through the Winter 1981 Addenda was applied to the preservice inspection (PSI) of both units. The 1983 Edition of Section XI with addenda through the Summer of 1983 Addenda was applied to the first ten year inspection interval of both units.

The PSI and ISI plans contained a detailed listing of every weld and item required by the code to be examined, including all augmented examination requirements. The inspection plans identified all general exclusions, component exclusions and exceptions, code exceptions, and code-required examination exceptions. Relief requests including complete technical justification were submitted to support our conclusions and request. Upon completion of their development, the PSI plans were submitted to the NRC prior to the start of PSI examinations. PSI summary reports containing the results of PSI examinations were submitted to the NRC prior to the issuance of the operating license of each unit. Upon completion of the PSI, the plans were revised and served as the basis for development of master ten-year ISI plans. The ISI plan for the first ten year inspection interval of each unit was submitted to the NRC within six months after the issuance of the operating license of each unit. The results of each ISI will be submitted to the NRC within ninety days after completion of the inspections conducted during a refueling outage, as required by ASME Section XI, Section IWA-6000.

Question 121.7

Provide a sketch of the STPEGS l and 2 reactor vessels (including dimensions) showing all longitudinal and circumferential welds, and all forgings and/or plates. Welds should be identified by a shop control number (such as a procedure qualification number), the heat of filler metal, type and batch of flux, and the welding process. Each forging and/or plate should be identified by a heat number and material specification.

Response

The STPEGS Unit 1 and Unit 2 reactor vessel materials identification, location, and material properties are tabulated in Tables 5.3-3 and 5.3-4, respectively. Identification and location of the Unit 1 and Unit 2 reactor vessel beltline region materials are shown in Figures Q121.7-1 and Q121.7-2, respectively. Additional information for the beltline region materials is presented in the responses to items (3) and (4) of Question 121.8.

Refer to Figure Q121.7-1

Refer to Figure Q121.7-2

Question 121.8

Supply the following information for each of the ferritic materials of the pressure-retaining components in the reactor coolant pressure boundary of the STPEGS 1 and 2 plants.

(1) The unirradiated mechanical properties as required by the testing programs in Section III of the ASME Code and Appendix G of 10 CFR Part 50 (test results to be presented should include Charpy V-notch, dropweight, lateral expansion, tensile, upper shelf energy, T_{NDT} and RT_{NDT}). If any of these properties have not been determined by a test method required by Appendix G of 10 CFR Part 50, state the actual test procedure used and/or the method used to estimate the test result together with a complete technical justification for the procedure used and the associated test data.

(2) Identify the material(s) in the reactor coolant pressure boundary that will limit the pressure-temperature operating curves at the beginning-of-life.

For each reactor vessel beltline weld, plate or forging provide the following additional information:

(3) The chemical composition (particularly the Cu, P, and S content) and the maximum end-of-life fluence.

(4) The relationship used to predict the shift in RT_{NDT} and percent decrease in upper shelf energy as a function of neutron fluence.

(5) Identify the material(s) in the reactor coolant pressure boundary that will limit the pressure-temperature operating curves at the end-of-life.

Response

1. The ferritic pressure-retaining base materials and weldments of the STPEGS reactor vessels, steam generators, and pressurizers meet the fracture toughness requirements of Section III of the ASME Code (appropriate edition and/or addendum given in Table 5.2-1) and Appendix G of lOCFR50.

   The Unit l and Unit 2 reactor vessel material properties are tabulated in Tables 5.3-3 and 5.3-4, respectively.

   The fracture toughness requirements satisfied by the steam generator and pressurizer base materials and weldments are discussed in Section 5.2.3.3.1. As stated in Section 5.2.3.3.1, the test results for steam generator and pressurizer materials are given in the QA data package which is provided to Houston Lighting and Power Company.

2. The materials that limit the pressure-temperature operating curves at the beginning-of-life are identified in Tables Q121.8-lc and Q121.8-2c for Unit l and Unit 2, respectively.

<u>Response</u> (Continued)

3. The chemical composition of the Unit l reactor vessel beltline region plate and weld materials is given in Tables Q121.8-la and Q121.8-lb. The chemical composition of the Unit 2 beltline materials is given in Tables Q121.8-2a and Q121.8-2b.

   The maximum end-of-life fluence at the inner wall and at 1/4 T is given in Tables Q121.8-lc and Q121.8-2c for Unit l and Unit 2, respectively.

4. Shift in RT_{NDT} and decrease in upper shelf energy predicted using the Regulatory Guide 1.99 and the Westinghouse methodologies are given in Tables Q121.8-lc and Q121.8-2c for Unit l and Unit 2, respectively.

5. The materials that limit the pressure-temperature operating curves at the end-of-life are identified in Tables Q121.8-lc and Q121.8-2c for Unit 1 and Unit 2, respectively.

TABLE Q121.8-la

SOUTH TEXAS UNIT NO. 1 REACTOR VESSEL BELTLINE PLATE CHEMICAL COMPOSITION

	Intermediate Shell			Lower Shell		
Heat No.	B8120-2	B8120-1	C4326-2	B9566-2	B9575-2	B9575-1
Plate No.	R1606-1	R1606-2	R1606-3	R1622-1	R1622-2	R1622-3
C	22	.19	.25	.22	.21	.21
Mn	1.24	1.18	1.43	1.31	1.40	1.39
P	009	.008	.007	006	.006	.007
S	.015	.013	.018	.014	.010	.013
Si	.19	.19	.21	.20	.26	.25
Ni	.63	.61	.62	.61	.64	.66
Cr	.03	.03	.07	.05	.05	05
Mo	.56	.53	.61	.58	.60	.60
Cu	.04	.04	.05	.05	.07	.05
V	.004	.004	.004	.002	.003	.003
Cb	<.01	<.01	<.01	<.01	<.01	.01
Pb	N.D.	N.D.	N.D.	<.001	<.001	<.001
W	.01	<.01	<.01	<.01	<.01	<.01
As	.003	.003	.004	.005	.003	.005
Sn	.002	.002	.003	.003	.005	.006
Co	.011	.012	.011	.009	.006	.007
N2	.009	.008	.009	.010	.011	.008
Al	.016	.017	.017	.019	.027	.029
B	<.001	<.001	<.001	<.001	<.001	<.001
Ti	<.01	<.01	<.01	<.01	<.01	<.01
Zr	<.001	<.001	<.001	<.001	<.001	<.001

TABLE Q121.8-1b

SOUTH TEXAS UNIT NO. 1 REACTOR VESSEL BELTLINE REGION WELD CHEMICAL COMPOSITION

Weld	Weld	Control	Weld Wire		Flux		Chemical Composition (%)									
Location	Process	No.	Type	Heat No.	Type	Lot No.	C	Mn	P	S	Si	Ni	Cr	Mo	Cu	V
Inter. and Lower Shell Long Seams	Sub-arc	G1.70	B4	89476	Linde 0091	0145	.14	1.19	.004	.012	.13	.07*	.01	.47	.02*	.003
Inter. To Lower Shell Girth Seam	Sub-arc	E3.13	B4	89476	Linde 124	1061	.10	1.33	.007	.010	.48	.07*	.02	.52	.02*	.003

* Based on CE NPSD-1039 Rev. 1, "Best Estimate Copper And Nickel In CE Fabricated Reactor Vessel Welds."

TABLE Q121.8-1c

SOUTH TEXAS UNIT NO. 1 REACTOR VESSEL BELTLINE REGION MATERIAL INFORMATION

BELTLINE PLATE MATERIAL

				MAXIMUM END-OF-LIFE									
				Fluence ($10^{19}N/cm^2$)		ΔRT_{NDT}(°F)				ΔUse (Ft-Lb)			
						Inner Wall		1/4 T		Inner Wall		1/4 T	
Plate No.	T_{NDT} °F	RT_{NDT} °F	Average Use Ft-Lb	Inner Wall	1/4 T	RG 1.99	W	RG 1.99	W	RG 1.99	W	RG 1.99	W
R1606-1*	-40	10	109.5	2.1	1.2	65	93	5.0	81	24.5	8	21.5	8
R1606-2	-20	0	94.0	2.1	1.2	58	93	5.0	81	21.0	8	18.5	8
R1606-3*	-20	10	105.5	2.1	1.2	58	93	5.0	81	23.5	10	21.0	10
R1622-1	-30	-30	111.0	2.1	1.2	58	93	5.0	81	25.0	10	22.0	10
R1622-2	-30	-30	122.0	2.1	1.2	58	93	5.0	81	27.5	14	240	14
R1622-3	-30	-30	127.0	2.1	1.2	58	93	5.0	81	28.5	10	25.0	10

* Material that will limit the pressure-temperature operating curves at the beginning and end of life.

BELTLINE WELD MATERIAL

					MAXIMUM END-OF-LIFE									
					Fluence ($10^{19}N/cm^2$)		ΔRT_{NDT}(°F)				ΔUse (Ft-Lb)			
							Inner Wall		1/4 T		Inner Wall		1/4 T	
Weld Seam No	Weld Control No.	T_{NDT} °F	RT_{NDT} °F	Average Use Ft-Lb	Inner Wall	1/4 T	RG 1.99	W	RG 1.99	W	RG 1.99	W	RG 1.99	W
101-124A & 101-142A	G1.70	-50	-50	158	68	.39	. 50	70	50	60	27.5	6	24.0	3
101-124B&C &101-142 B&C	G1.70	-50	-50	158.	1.20	68	50	80	50	70	31.5	6	27.0	6
101-171	E3.13	-70	-70	100	2.10	1.20	58	93	50	81	22.5	6	20.0	6

TABLE Q121.8-2a

SOUTH TEXAS UNIT NO. 2 REACTOR VESSEL BELTLINE CHEMICAL COMPOSITION

	Intermediate Shell			Lower Shell		
Heat No.	NR62067-1	NR62230-1	NR62248-1	NR64647-1	NR64627-1	NR64445-1
Plate No.	R2507-1	R2507-2	R2507-3	R3022-1	R3022-2	R3022-3
C	.22	.23	.21	22	.22	.23
Mn	1.55	1.53	1.50	1.46	1.46	1.49
P	.006	.006	.005	.002	.003	.004
S	.012	.007	.007	.008	.008	.014
Si	.21	.25	.22	.19	.20	.20
Ni	.65	.64	.61	.63	.61	.60
Cr	.05	.03	.05	.02	.02	.03
Mo	.56	.55	.53	.49	.51	.51
Cu	.04	.05	.05	.03	.04	.04
V	.002	.002	.002	.002	.002	.002
Cb	<.01	<.01	.01	<.01	<.01	<.01
Pb	<.001	<.001	<.001	<.001	<.001	<.001
W	<.01	<.01	<.01	<.01	<.01	<.01
As	.014	.018	.012	.011	.009	.010
Sn	<.001	.001	.001	.001	.001	.002
Co	.011	.013	.014	.009	.009	.012
N2	.009	.010	.011	.011	.011	.014
Al	.021	.022	.025	.020	.018	.023
B	<.001	<.001	<.001	<.001	<.001	<.001
Ti	<.01	<.01	<.01	<.01	<.01	<.01
Zr	.001	.001	.001	<.001	<.001	<.001

TABLE Q121.8-2b

SOUTH TEXAS UNIT NO. 2 REACTOR VESSEL BELTLINE REGION WELD CHEMICAL COMPOSITION

Weld	Weld	Control	Weld Wire		Flux		Chemical Composition (%)									
Location	Process	No.	Type	Heat No.	Type	Lot No.	C	Mn	P	S	Si	Ni	Cr	Mo	Cu	V
Inter. and Lower Long Seams	Sub-arc	G3.02	B4	90209	Linde 0091	1054	.14	1.27	.004	.009	.16	.11*	.11	.53	.04*	.006
Inter. To Lower Shell Girth Seam And Lower Shell Long. Seams	Sub-arc	E3.12	B4	90209	Linde 124	1061	.10	1.31	.008	.010	.52	.11*	.08	.50	.04*	.007

* Based on CE NPSD-1039 Rev. 2, "Best Estimate Copper And Nickel In CE Fabricated Reactor Vessel Welds." Sample weighted mean.

TABLE Q121.8-2c

SOUTH TEXAS UNIT NO. 2 REACTOR VESSEL BELTLINE REGION MATERIAL INFORMATION

BELTLINE PLATE MATERIAL

				MAXIMUM END-OF-LIFE									
				Fluence ($10^{19}N/cm^2$)		ΔRT_{NDT}(°F)				ΔUse (Ft-Lb)			
						Inner Wall		1/4 T		Inner Wall		1/4 T	
Plate No.	T_{NDT} °F	RT_{NDT} °F	Average Use Ft-Lb	Inner Wall	1/4 T	RG 1.99	W	RG 1.99	W	RG 1.99	W	RG 1.99	W
R2507-1*	-10	-10	109	1.9	1.1	55	90	50	78	24.0	8	21.5	8
R2507-2*	-10	-10	129	1.9	1.1	55	90	50	78	28.5	10	25.0	10
R2507-3	-40	-40	122	1.9	1.1	55	90	50	78	27.0	10	24.0	10
R3022-1	-30	-30	124	1.9	1.1	55	90	50	78	27.5	6	24.0	6
R3022-2	-40	-40	118	1.9	1.1	55	90	50	78	26.0	8	23.0	8
R3022-3	-40	-40	123	1.9	1.1	55	90	50	78	27.0	8	24.0	8

* Material that will limit the pressure-temperature operating curves at the beginning and end of life.

BELTLINE WELD MATERIAL

					MAXIMUM END-OF-LIFE									
					Fluence ($10^{19}N/cm^2$)		ΔRT_{NDT}(°F)				ΔUse (Ft-Lb)			
							Inner Wall		1/4 T		Inner Wall		1/4 T	
Weld Seam No	Weld Control No.	T_{NDT} °F	RT_{NDT} °F	Average Use Ft-Lb	Inner Wall	1/4 T	RG 1.99	W	RG 1.99	W	RG 1.99	W	RG 1.99	W
101-124A	G3.02	-70	-70	146	.62	.36	50	67	50	58	25	10	22	5
101-124B&C	G3.02	-70	-70	146	1.1	.62	50	78	50	67	28.5	10	25	10
101-142A	E3.12	-70	-70	101	.62	.36	50	67	50	58	17	10	15	5
101-142B&C	E3.12	-70	-70	101	1.1	.62	50	78	50	67	19.5	10	17	10
101-171	E3.12	-70	-70	101	1.9	1.1	55	90	50	78	22	10	19.5	10

Question 121.16

Confirm that the reactor vessel fasteners for Units 1 and 2 will be inspected according to the requirements of Sections III and XI of the ASME Code as supplemented by Regulatory Guide 1.65, "Materials and Inspections for Reactor Vessel Closure Studs."

Response

ASME Section III

During fabrication, the nondestructive examination of the STPEGS Units l and 2 reactor vessel fasteners (studs) was performed in accordance with the requirements of the ASME Code Section III, as supplemented by Regulatory Guide 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." Specifically, the bolting material, including nuts and washers, was ultrasonically examined after heat treatment in accordance with ASME SA-388, "Ultrasonic Examination of Heavy Steel Forgings." The calibration location used to establish the first back reflection for the radial ultrasonic testing was based on good sound representative material; to assure that the material is respresentative, the selection of the reference location was based on a preliminary ultrasonic examination of material representing at least three units of an item. In addition, as stated in Section 5.3.1.3.3 of the STPEGS UFSAR, magnetic particle or liquid penetrant examination was performed on all exterior closure stud surfaces and all nut surfaces after final machining or rolling.

ASME Section XI

During preservice and the first interval of inservice inspections, the reactor vessel closure studs, including nuts and washers, were examined in accordance with ASME Section XI as supplemented by ASME Code Case N-307-1 and Regulatory Guide 1.65. Several NDE methods were used to accomplish examinations as described below.

A surface examination was performed on the entire outside surface of the stud and the inside surface of the stud excluding the 0.625-inch diameter portion of the inside bore and the non-load bearing region of the stud above the threads. Surface examination were performed with Fluorescent MT and PT methods. Examination of the 0.625-inch diameter bore hole is performed with a high angle refracted longitudinal wave UT sound beam. The outer 1/4" of the shaft, threads and "Roto-Lok" lugs were examined with a combination UT45° and UT60° refracted shear wave from the inside surface of the stud (excluding the 0.625-inch bore) and a UT60° refracted shear wave from the 0.625-inch bore.

Response (Continued)

The outside surface of the RV nuts was examined with a Fluorescent MT examination. The inside threaded surface of the nut was not accessible for a technically adequate surface examination. In lieu of the surface examination of the threaded surfaces of the RV nut, an ultrasonic examination was performed on the threaded region from the OD and end surface of the nut. The UT examination provided coverage of the thread root area in two directions. A UT0° examination was performed 360° around the nut end surface to examine the threaded area for circumferential flaws. A UT43° examination from the OD was used to examine the threaded area in clockwise and counterclockwise directions to detect axial flaws. A Relief Request (RR-ENG-12) was approved by the NRC for UT of the threaded area of the RV nuts in lieu of the ASME Section XI required surface examination.

A visual (VT-1) examination was performed on the washers as required by ASME Section XI.

ASME Section XI - Second Inspection Interval

During the second inspection interval, the reactor vessel closure studs, including nuts and washers, are examined in accordance with ASME Section XI as supplemented by ASME Code Case N-307-2. Since the inservice inspection requirements of Regulatory Guide 1.65 (regulatory position C.4) are now addressed in Section XI, the South Texas Project has discontinued its inservice inspection commitment to Regulatory Guide 1.65. The South Texas Project performs PT and/or MT surface examinations on RPV closure studs removed from the vessel flange during refueling outages in accordance with Section XI scheduling requirements. These examinations are evaluated in accordance with Section XI acceptance standards in lieu of the Section III acceptance standards cited in the regulatory guide. The Section XI standards are more appropriate for service-induced flaws or degradation. Several NDE methods are used to accomplish examinations similar to those used during preservice and the first interval inservice inspections.

The above techniques may be modified as necessary if the modified technique can be demonstrated to be equivalent or superior to those already being used. This would be in accordance with ASME Section XI, Paragraph IWA-2240. The above techniques or requirements may also be modified as allowed by later mandated and adopted ASME Section XI Code editions per 10CFR50.55a.

Question 122.7

Verify whether or not the vessel supports, the seal ledge, and the heat lifting lugs are part of the Reactor Coolant Pressure Boundary. If they are, provide the unirradiated mechanical properties to the same extent as requested previously by Part 1 of Question 121.8 for the ferritic materials of the pressure-retaining components in the RCPB. Discuss or tabulate separately the mechanical properties of the components fabricated from SA533 Class 2 material. Also, provide the specific welding materials and their specifications as requested in Item 122.6, above.

Response

The vessel supports, seal ledge, and head lifting bosses are not pressure retaining parts of the reactor vessel. The vessel supports are weld metal buildup of ASME welding material specifications SFA 5.4 and SFA 5.5. The seal ledge is SA516 Gr 70, welded to the reactor vessel flange using ASME welding material specification SFA 5.1. The head lifting bosses for the replacement head on Unit 1 are SA508 Class 3 welded to the replacement head forging using ASME welding material specifications SFA 5.5. CN-2994

Question 122.8

In Table 5.2-2 change Code Case 1432-2 to Code Case 1423-2. The former designation pertains to SA 516 Grade 55 carbon steel plates.

Response

The Code Case 1432-2 designation for reactor coolant piping branch nozzles is a typographical error; this should be Code Case 1423-2.

Question 122.9

Weld cladding procedures do not have to be qualified for use in accordance with Position C.2 of Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Components", when applied to SA 533 Grade B Class 1 plate made to fine-grain practice and heat-treated to develop a fine-grained structure. Provide the grain sizes of the SA 533 material and the forging grade SA 508 Class 3 material for which no qualifications are required by Westinghouse when cladding RCPB ferritic steel components. In addition, give the degree of conformance with Position C.3 of Regulatory Guide 1.43.

Response

The Westinghouse practice regarding qualification weld cladding procedures is not based on specific grain size considerations. Instead, the primary aspect of determining the need for qualification is the susceptibility of a material to underclad cracking. Data have shown that SA533 and SA508 Class 3 materials made to fine grain practice (i.e., addition of aluminum and quenched and tempered resulting in a fine grain structure) exhibit resistance to underclad cracking, while SA508 Class 2 material is susceptible to underclad cracking. Therefore, as stated in Section 5.2.3.3.2, qualification is required for high heat input processes, such as the submerged-arc wide-strip welding process and the submerged-arc 6-wire process, used as SA508 Class 2 material.

Production welding is monitored to ensure that essential variables remain within the limits established by the qualification. If the essential variables exceed the qualification limits, an evaluation will be performed to determine if the cladding is acceptable for use.

Question 122.10

Provide the basis for Westinghouse not applying to Class 2 and 3 ferritic steel components of the RCPB any of the recommendations of Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel".

Response

Westinghouse experience has shown that high integrity low-alloy steel weldment quality is obtainable with proper control of welding materials and variables along with qualification of procedures, as required by the ASME Code Sections III and IX, and without maintaining the preheat temperature until a post weld heat treatment has been performed, as recommended by Regulatory Guide 1.50. Welding of Class 2 and 3 ferritic stee1 components is performed in accordance with the requirements of the ASME Code Sections III and IX.

In addition, it should be pointed out that the development of restrictive preheat requirements in the past has been related primarily to practices used for weldments in thick sections (greater than six inches). These thick section considerations encountered on Class 1 equipment are not generally applicable to Class 2 and 3 ferritic steel components.

Question 122.11

Provide the degree of conformance with the preheat recommendations of the ASME Code, Section III, Appendix D, D 1200, during procedure qualification and production welding of ferritic steel components of the RCPB, the engineered safety features, and the Steam and Feedwater System.

Response

NSSS Scope

Preheat practices utilized on Class 1 reactor coolant pressure boundary components (reactor vessel, steam generators, pressurizer) are in compliance with the recommendations of the non-mandatory Appendix D of the ASME Code, Section III. The recommendations of this non-mandatory appendix are not imposed upon suppliers of Class 2 and 3 auxiliary equipment; furthermore, a survey of vendor manufacturing procedures for Class 2 and 3 equipment has not been performed to determine the degree of conformance with the non-mandatory Appendix D on Class 2 and 3 auxiliary equipment. However, welding procedures for all ASME Code classified equipment comply with all applicable mandatory requiremets of the ASME Code.

BOP Scope

Field Erection Welds: Welding procedures for all ASME Code classified equipment were qualified in accordance with Section IX and all the mandatory requirements of the code. In the development of these procedures, the recommendations found in the nonmandatory preheat procedures (ASME Code Section III, Appendix D) were considered and the specified preheat temperatures comply with the suggested minimum preheat temperatures.

Question 122.12

Provide information on the moisture control for low-hydrogen, covered-arc-welding electrodes when welding ferritic steel components of the RCPB, the engineered safety features, and the Steam and Feedwater System. Give the degree of conformance with the requirements of the AWS Dl.1, "Structural Welding Code".

Response

The requirements of AWS Dl.1, Section 4.5, "Structural Welding Code Electrodes for Shielded Metal Arc Welding", are met. Both Westinghouse and B&R follow the recommendations in AWS Dl.1, Section 4.5.2.1, "Approved Atmospheric Exposure Time Periods", for permissible atmospheric exposure of low-hydrogen electrodes.

Question 122.13

For all applicable components of the RCPB and the engineered safety features, shop-welded or field-welded, of ferritic steel or austenitic stainless steel, give the degree of conformance with the recommendations of Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility".

Response

Westinghouse practice requires welder qualification to ASME Code, Section III and IX requirements. Experience shows that the current Westinghouse shop practice produces high quality welds. Limited accessibility qualification or requalification, as described by Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility", is an unduly restrictive requirement for component manufacture, where the welders' physical position relative to the welds is controlled and does not present any significant problems. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised and monitored. Further assurance of acceptable weld quality is provided by the performance of required nondestructive evaluations.

Field Erection Welds: Field erection welds, including limited access welds, are made by welders and/or welding operators trained and qualified in accordance with ASME Section IX using welding procedures properly qualified to meet the requirements of ASME Section III and Section IX. Before welding, the accessibility is checked and during welding, each limited access production weld is monitored for adherence to the proper welding procedure, parameters and techniques. In addition, the acceptability of production welds is checked by the performance of the required nondestructive examinations.

Question 211.10

In Section 5.2.2 references are made to WCAP-7769. Provide a comparison of South Texas parameters for all parameters listed in Table 2-2. Where differences exist, show that these differences will not affect the conservatism of the results given in WCAP-7769.

Response

WCAP-7769, Revision 1 differentiates between the loss of load transient with the steam dump and Reactor Coolant System (RCS) pressure control systems functioning and the turbine trip event. The transient as discussed in the WCAP (p. 3-35) is the turbine trip event without direct reactor trip. That the UFSAR depicts a higher peak pressure than that shown in the WCAP (Figure 3-24) is due to rod motion delay time. WCAP-7769 assumed one second for rod motion following reactor trip set-point versus two seconds assumed for the UFSAR. The 2-second delay is not unique to South Texas.

Table 2-2 from WCAP-7769 (Table Q211.10-1) is provided with South Texas parameters provided in the far right column.

As stated in the WCAP the pressurizer safety valve is sized based on the peak surge rate into the pressurizer following a complete loss of load without reactor trip and with energy relief only thru the steam generator (SG) and pressurizer safety valves. The actual safety valve capacity must be equal to or greater than the required capacity.

The ratio of the actual safety valve capacity and the peak surge rate is an entry in Table 2-2. If this ratio is greater than the ratio for that type of plant listed in Table 2-2, then the assumptions of the WCAP envelope the plant in question. The value for a 4-loop plant is given as l.056. The value of this ratio for South Texas is 1.l4. That is the capacity of the safety valve is 1.14 times greater than the surge rate into the pressurizer.

Numerous analyses have been performed in support of the EPRI Safety and Relief Valve Test Program (NUREG-0737, Item II.01) where in RCS overpressure protection was addressed similar to that in WCAP-7769. Indeed this particular transient was analyzed for the enveloping (worst case) 4-loop plant and presented in a report "Valve Inlet Fluid Conditions for Pressurizer Safety and Relief Valves in Westinghouse-Designed Plants". EPRI Report NP-2296-LD, March, 1982.

The maximum pressurizer pressure reported for this limiting event, 4-loop plant, was 2555 psia, which agrees quite well with that shown in the UFSAR (approximately 2560 psia). For the enveloping plant, the analysis conducted with the reactor tripping on the second Reactor Protection System (RPS) signal shows a peak pressurizer pressure of 2565 psia. The differences between the two reactor trip points (approximately two seconds) is diluted considering safety valve sizing and the assumptions for safety valve flow rate versus pressure used in the analyses (linear, from 0 to l00 percent over the pressure range of 2500 to 2575 psia).

Response (Continued)

Figure 2-1 of the WCAP shows that only 90 percent of safety valve flowrate is required to turn around the overpressure transient assuming no reactor trip. With l00 percent of safety valve capacity, the pressurizer pressure peaks at less than 2575 psia.

With reactor trip occurring at the first reactor trip setpoint, approximately 60 percent of total safety valve flow rate was required to turn around the overpressure transient.

TABLE Q211.10-1

TYPICAL PLANT THERMAL-HYDRAULIC PARAMETERS

	Units	2-Loop	3-Loop	4-Loop	South Texas
Heat Output, Core	MWt	1,780	2,652	3,411	3,800
System Pressure	psia	2,250	2,250	2,250	2,250
Coolant Flow	gpm	178,000	265,500	354,000	376,400
Average Core Mass Velocity	10^6 lb/hr-ft^2	2.42	2.33	2.50	--
Inlet Temperature	°F	545	544	522.5	560
Core Average T_{mod}	°F	581	580	588	596
Core Length	FT	12	12	12	14
Average Power Density	kw/1	102	100	104	99
Maximum Fuel Temperature	°F	<4100	<4200	<4200	<4200
Fuel Loading	kg/1	2.7	2.6	2.6	2.6
Pressurizer Volume	Ft^3	1000	1400	1800	2100
Pressurizer Volume Ratioed to Primary System Volume		0.157	0.148	0.148	0.150
Peak Surge Rate for Pressurizer Safety Valve sizing Transient	Ft^3/sec	21.8	33.2	41.0	51.5
Pressurizer Safety Valve Flow at 2500 psia - 3+ percent Accumulation	Ft^3/sec	26.1	36.1	43.3	58.7
Ration of Safety Valve Flow to Peak Surge Rate		1.197	1.087	1.056	1.14
Full Power Steam Flow per Loop	lb/sec	1078	1076	1038	1178
Nominal Shell-side Steam Generator Water Mass per Loop	lb	100,300	106,000	106,000	139,000

Question 211.11

Your statement that Brown & Root is responsible for the design and mounting of the supports for the pressurizer safety valves does not provide the necessary assurance that the valve mounts meet the Westinghouse criteria. Discuss the anticipated loads on the safety valve supports and verify that loading due to water relief, including the passage of a water slug and the effects of water hammer have been considered.

Response

Westinghouse now has the responsibility for the design, fabrication, and supervision of installation of the pressurizer safety and relief valve manifold assembly. The design of this assembly, including valve supports, has been completed. Loads due to water relief, including the passage of a water slug and the effects of water hammer have been considered. Stresses are within code allowable limits.

Question 211.12

Your response to Question 211.2 is not acceptable. Per the requirements of BTP RSB 5-2 the low temperature overpressure protection system must be designed to meet the requirements of IEEE 279 and must be designed to function during an operating basis earthquake.

Provisions to allow testing prior to shutdown must be provided to assure operability of the system.

Provide a discussion of a direct current bus failure which would cause isolation of letdown flow (fail closed valves) and initiate an overpressure transient. On some recently reviewed plants, this failure would simultaneously disable a PORV. If the DC bus failure was assumed to be the initiating event, the overpressure protection system would not meet the single failure criteria.

Response

In accordance with the guidelines of BTP RSB 5-2, the cold overpressure protection system is designed to the guidance of IEEE 279 and is designed to function during an operating basis earthquake.

Provisions to allow testing of this cold overpressure protection system are provided.

The STPEGS design is not subject to the postulated failure of a power-operated relief valve (PORV) and simultaneous isolation of letdown by the failure of a DC bus. Two of the three parallel letdown orifice isolation valves are fail-closed valves in the letdown line inside Containment. However these valves are powered from Class 1E AC power, rather than DC. The failure of a DC vital bus may result in the loss of one PORV but will not cause any valve in the letdown line inside Containment to change positions. If the letdown line has been in service when the DC bus failure occurs, causing the loss of a PORV, the valves in the letdown line between the RCS and the letdown relief valve will remain open. Thus, in addition to the unaffected PORV, the letdown relief valve (with a set pressure of 600 psig) is available to provide RCS overpressure protection with one or more charging pumps in operation. In addition, the redundant PORV is on a different DC bus and will be operable at this time.

Question 250.3N - Deleted

Question 250.4N

If the reactor coolant pipe and/or fittings are fabricated from SA351, Grade CF8A (centrifugal cast stainless steel), discuss the effectiveness of your ultrasonic examination procedures and the ability of the instrumentation to detect flaws, if they exist, in the volume of the cast stainless steel weldments required to be examined by the regulations.

Response

The ultrasonic examination procedure which was used to examine welds in SA351, Grade CF8A (Centrifugal Cast Stainless Steel) piping during the preservice inspection (PSI) of STPEGS Unit 1 meets the requirements ASME Code Section XI. This refracted longitudinal wave ultrasonic examination procedure has been acceptable to the NRC in meeting the inservice inspection (ISI) regulatory requirements at several other PWR plants. HL&P is aware that recent studies by research organizations indicate that the acoustic properties of SA351, Grade CF8A material may reduce the effectiveness of some ultrasonic examination procedures for flaw detection. HL&P is currently evaluating potential methods for determining the effectiveness of the procedure which will be used.

Question 250.6N

All preservice examination requirements defined in Section XI of the ASME Code that have been determined to be impractical must be identified and a supporting technical justification must be provided. The relief requests should include at least the following information:

1. For ASME Code Class 1 and 2 components, provide a table similar to IWB-2500 and IWC-2500 confirming that either the entire Section XI preservice examination was performed on the component or relief is requested with a technical justification supporting your conclusion.

2. Where relief is requested for pressure retaining welds in the reactor vessel, identify the specific welds that did not receive a 100 percent preservice ultrasonic examination and estimate the extent of the examination that was performed.

3. Where relief is requested for piping system welds (Examination Category B-J, C-F, and C-G), provide a list of the specific welds that did not receive a complete Section XI preservice examination including drawing or isometric identification number, system, weld number, and physical configuration (e.g., pipe-to-nozzle weld, etc.). Estimate the extent of the preservice examination that was performed. When the volumetric examination was performed from one side of the weld, discuss whether the entire weld volume and the heat-affected-zone (HAZ) and base metal on the far side of the weld were examined. State the primary reason that a specific examination is impractical (e.g., support or component restricts access, fitting prevents adequate ultrasonic coupling on one side, component-to-component weld prevents ultrasonic examination, etc.). Indicate any alternative or supplemental examinations performed and method(s) of fabrication examination.

Response

During and/or after the preservice inspection (PSI) of STPEGS Unit 1, HL&P will identify and document any Section XI examination requirements determined to be impractical and provide technical justification for such determination. Documentation of the compliance of the PSI program with Section XI examination requirements will be provided. Where applicable, requests for relief will be submitted in accordance with the criteria specified in this question.

Question 440.14N

FSAR Section 5.2.2 states that the transient for which the overpressure protection requirements are determined is a complete loss of steam flow to the turbine, no reactor trip, with credit taken for the steam generator safety valves and maintaining main feedwater (MFW) flow. However, WCAP-7769, Rev. 1, which is referenced in the FSAR, also states that for plants having turbine driven MFW pumps another analysis is required, i.e., a simultaneous loss of load and MFW, with credit taken for Doppler feedback and reactor trip (other than reactor trip on turbine trip) and no credit taken for PORV, ADV, and steam dump operation, reactor and pressurizer controls and spray. Discuss whether this analysis was performed for STPEGS, and what the results were.

Response

WCAP-7769 discusses the generic methodology for sizing safety valves. It is intended to relate this methodology to a typical plant. The results presented in the WCAP are not intended to demonstrate that the STPEGS complies with ASME Code requirements. Such compliance is demonstrated in an overpressure protection report specifically for the STPEGS which is prepared in accordance with Article NB-7300 of Section III of the ASME Code. Section 5.2.2 will be modified to clarify this item.

The following additional information may provide more insight into the process employed to verify that adequate Reactor Coolant System (RCS) overpressure protection is provided:

Verification of adequate overpressure protection for the RCS is accomplished in several stages.

Initially, all transients that may cause overpressurization of the RCS are identified. That transient which is anticipated to result in the maximum system pressure and maximum safety valve capacity is then chosen as the design transient for determining the actual safety valve capacity to be provided. This design transient is then analyzed, utilizing input parameters that are conservatively chosen to result in a higher RCS pressure and safety valve capacity requirement. Following selection of the valve capacity, the overpressure transients previously identified are analyzed to verify that the chosen capacity results in peak RCS pressures within that identified in Article NB-7000 of Section III of the ASME Code.

For STPEGS, the protection is afforded for the following events which envelop those credible events which could lead to overpressure of the RCS if adequate overpressure protection were not provided:

1. Loss of Electrical Load and/or Turbine Trip (Sections 15.2.2 and 15.2.3)

2. Uncontrolled Rod Withdrawal at Power (Section 15.4.2)

3. Loss of Reactor Coolant Flow (Section 15.3)

4. Loss of Normal Feedwater (Section 15.2.7)

5. Loss of Offsite Power (LOOP) to the Station Auxiliaries (Section 15.2.6)

Response (Continued)

Review of these transients shows that the turbine trip transient results in the maximum system pressure and the maximum safety valve relief requirements. Therefore, to determine the required safety valve capacity, the turbine trip transient was analyzed, with additional conservatisms included over those considered for Chapter 15 analyses. The sizing of the pressurizer safety valves was based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102 percent of the engineered safeguards design power. In this analysis, feedwater (FW) flow was assumed to be lost; (This is more conservative than maintaining (FW) flow in that it reduces heat transfer capability thereby increasing primary system pressure). No credit was taken for operation of pressurizer power operated relief valves (PORVs), pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steam line (PORVs). The reactor was maintained at full power (no credit for reactor trip), and steam relief through the steam generator (SG) safety valves was considered.

The maximum surge rate into the pressurizer during this transient was identified and a total safety valve capacity in excess of this value was chosen. As no reactor trip was assumed, the safety valves by themselves provide adequate capacity to turn around the overpressure transient.

Following selection of the safety valve size and quantity the overpressure transients listed above were analyzed. These analyses confirmed that the overpressure protection afforded the RCS is in accordance with ASME Code requirements. Discussion of those transients and their results is provided in Chapter 15.

Question 440.17N

Has the delay due to the time it takes to discharge the water from the pressurizer safety valve loop seals been accounted for in the limiting pressure transient? If it has not been accounted for, how would this delay affect the results?

Response

The delay due to the time it takes to discharge the water from the pressurizer safety valve loop seals has been accounted for in the limiting pressure transient.

Question 440.18N

WCAP-7769, Section 3.4 assumes failure of one steam generator safety relief valve per loop. Provide assurance that your remaining safety valves can provide the required minimum capacity.

Response

As stated in the WCAP the maximum steam generator (SG) safety valve required capacity is 78 percent of the provided capacity for the limiting case which is the loss of electrical load transient. Twenty safety valves are provided. If 78 percent of the valves open, 78 percent of the total provided relieving capacity is available. Sixteen valves would provide 80 percent of the total relieving capacity.

Question 440.20N

Section 5.4.13 cites a backpressure compensation feature on the pressurizer safety valves. Provide a discussion of this feature which explains how this function is performed.

Response

Backpressure compensation for the pressurizer safety valves is provided by a balancing bellows and balancing piston. These features are incorporated in Crosby style HB safety valves and were tested as part of the recently completed EPRI safety valve test program (NUREG-0737, Item II.D.1). The results from these tests demonstrated that backpressure has little if any effect on valve performance.

Question 440.21N

For RCS pressure control during low temperature operation, discuss whether the analyses performed to determine the maximum pressure for the postulated worst case mass and heat input events assumed relief by the pressurizer PORVs only or whether credit is also taken for the RHR relief valves. If credit is taken for the RHR relief valves, then demonstrate that the overpressure protection functions would not be defeated by interlocks which would isolate the RHR system, or by common mode failures (e.g., failure of a DC bus). See also Question 440.28N.

Response

No credit is taken for the Residual Heat Removal (RHR) relief valves in the Cold Overpressure Mitigation System (COMS) analysis. In the COMS analysis it is assumed only one power-operated relief valve (PORV) is available for RCS pressure mitigation.

Question 440.22N

In accordance with Section 5.2.2.11.2 the bounding mass input analysis for RCS pressure control during low temperature operation was performed assuming letdown isolation with 2 charging pumps operating. There has been an operating plant incident involving inadvertent SI pump actuation during low temperature conditions. Our position is that the low temperature overpressure protection system (LTOPS) be designed to handle actuation of one high head safety injection (HHSI) pump. Therefore discuss whether the STPEGS LTOPS has sufficient capacity for this type of transient.

Response

In accordance with WCAP-10529, "Cold Overpressure Mitigation System", we assume in the Cold Overpressure Mitigation System (COMS) analysis that a charging/letdown flow mismatch results from the isolation of letdown in coincidence with the inadvertent start of a charging pump, delivering full flow. Consistent with standard Technical Specification 3.5.3 during low temperature operation the high-head safety injection (HHSI) pumps will be locked out of service.

Question 440.24N

In Section 5.2.2.11.1 of the FSAR, you indicate that an auctioneered system temperature is continuously converted to an allowable pressure and then compared to the actual RCS pressure. "This comparison will provide an actuation signal to the PORVs when required, to prevent pressure-temperature conditions from exceeding the allowable limits". Our review of the low temperature overpressure protection design for certain other Westinghouse plants indicates that a failure in the temperature auctioneer for one PORV (signalling it to remain closed) could also fail the other PORV closed (by denying its permissive to open). Address this concern about a potential common mode failure in the low temperature overpressure protection system for STPEGS.

Response

Past Cold Overpressure Mitigation System (COMS) logic called for the output of the temperature auctioneer of either train to serve as a permissive for the other train's power-operated relief valve (PORV). This is not the case for STPEGS. Failure of the temperature auctioneer will only disable the PORV in one train.

Question 440.25N

Provide your limiting Appendix G curve for the first eighteen full power months of operation. Discuss the operational procedures which will minimize the likelihood of an overpressure event.

Response

See the response to MEB Q251.14N and Figures Q251.14N-1 through Q251.14N-4.

Question 440.26N

The staff is concerned that your proposed LTOP system does not adequately protect the reactor vessel during transient events where the vessel wall temperature lags behind the temperature used in the variable setpoint calculator. For example, starting a RCP in a loop with a hot steam generator when the RCS is water solid causes the RCS pressure and temperature to rise. Your LTOP system would automatically raise the PORV setpoint as a function of auctioneered cold or hot leg temperature, but the vessel wall will not be heated in this transient at the same rate. Thus, due to the LTOP system auctioneering scheme, the part of the RCS most vulnerable to brittle fracture may not be adequately protected because the relief valves would open at a higher pressure than what the true vessel wall temperature would allow.

If, during a cooldown, a mass input event occurred, your proposed LTOP system may not protect the coldest location in the vessel since the setpoint would not be based on the coldest fluid temperature.

Address the above concerns by discussing the following:

a. Discuss the events you considered when establishing the worst case scenario for LTOPs evaluation, show how the event selected is worst case regarding vessel temperature, and show how your LTOP system protects the vessel at its coldest location.

b. Include in your analyses the most limiting single active failure, and justify the choice.

c. Include in your analyses the effects of system and component response times, including:

    1. temperature detectors
    2. pressure detectors
    3. logic circuitry

Show the response times that were assumed and the extent of conservatism in the assumed values.

Response

a. The events considered when establishing the worst case scenario for Cold Overpressure Mitigation System (COMS) evaluation are documented in WCAP-10529, "Cold Overpressure Mitigation System". The worst case event from the standpoint of vessel temperature is the heat input transient. In the heat input transient we assume a reactor coolant pump (RCP) is started when the steam generator (SG) is 50°F hotter than the Reactor Coolant System (RCS).

    The conservatism built in to our setpoint determination algorithm ensures the coldest location in the vessel is protected. For any given RCS temperature, setpoints are selected such that the Appendix G pressure limit is satisfied for the RCS temperature 50°F less than the temperature used in the analysis. For example, if selecting setpoints

Response (Continued)

for a RCS temperature of 200°F, we select setpoints that satisfy the Appendix G pressure constraints at 150°F.

b. In the COMS analysis it is assumed one power-operated relief valve (PORV) is inoperative. This results in the availability of only one PORV for RCS pressure mitigation.

c. 1. The response time of the temperature detectors are not considered in COMS analysis for the following reasons:

- In the case of the mass input transient we have isothermal conditions in the RCS, therefore the response time of the temperature detectors is not a factor.

- In the case of the heat input transient the temperature of the RCS is increasing. Delay in temperature detector response will result in a measured temperature that is less than the actual RCS temperature, which is conservative.

2. We assume there is a 0.6 second delay before the PORV starts to stroke. The breakdown is as follows:

- 0.4 sec pressure transmitter delay

- 0.1 sec solenoid actuation delay

- 0.1 sec logic circuitry delay

3. See item 2, above.

Question 121.11

The pressure-temperature limit calculation methods given in the Technical Specifications are those given in Topical Report WCAP-7924A. The NRC staff has reviewed and accepted this report with the following exception. The evaluation stipulated that the method for determining the shift in RT_{NDT} is not acceptable and that an acceptable method must be included in the FSAR. Section 5.3.2.1 of the STPEGS FSAR presented an alternate method of determining the shift in RT_{NDT} as a function of fluence. This method has been evaluated and found unacceptable

It is our position that all of the methods recommended in Revision 1 to Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials" be used to evaluate radiation damage to the reactor vessel materials of STPEGS Units 1 and 2. Revise the FSAR accordingly.

Response

The method used by Westinghouse to evaluate radiation damage to the reactor vessel materials of STPEGS Units l and 2 results in greater shifts in RT_{NDT} than those determined using the method recommended by Revision 1 of Regulatory Guide 1.99, as shown in the response to item (4) of Question 121.8. Therefore, the Westinghouse methodology, which we consider acceptable, results in more conservative RT_{NDT} shifts than the Regulatory Guide 1.99 method for the STPEGS reactor vessel materials.

Question 121.14

Confirm that all bolting and other fasteners, used in the RCPB of STPEGS Units l and 2, with nominal diameters exceeding l inch, meet the minimum requirements of 25 mils lateral expansion and 45 ft-lbs in terms of Charpy V-notch tests conducted at the preload temperature or at the lowest service temperature, whichever is lower (10 CFR Part 50, Appendix G, paragraph IV.A.4).

Response

Reactor vessel bolting material properties are given in Tables 5.3-5 and 5.3-6 for Unit 1 and Unit 2, respectively.

The requirements applicable to the ferritic materials for bolting (with nominal diameters greater than 1 in.) used in pressure retaining applications of the STPEGS Class 1 reactor coolant pressure boundary equipment have been reviewed with regard to the requirements of lOCFR50 Appendix G.

The current lOCFR50 Appendix G, Paragraph IV.A.4, minimum requirements for materials for bolting with nominal diameters exceeding 1 in. are 25 mils lateral expansion and 45 ft-lbs in terms of Charpy V-notch tests. It should be noted that, for bolting with diameters greater than 1 in. to 4 in. the 10CFR50 Appendix G 45 ft-lb requirement exceeds the applicable ASME Code requirements, which include no ft-lb absorbed energy minimum.

With the exceptions discussed herein, the ferritic pressure retaining bolting in the STPEGS Class l reactor coolant pressure boundary equipment is required to meet 25 mils lateral expansion and 45 ft-lbs in terms of Charpy V-notch tests as the lowest preload or service temperature. The only bolting materials on which requirements consistent with 1OCFR50 Appendix G and the ASME Code (specifically the 45 ft-lb requirement for bolting with diameters greater than 1 in. to 4 in.) have not been imposed are the reactor coolant pump No. 1 seal housing bolting material and the reactor coolant pump cartridge seal bolting material. This bolting material satisfies the ASME code requirement of 25 mils lateral expansion at 68°F. Although not required by the ASME Code, Charpy V-notch tests were performed on this bolting material at 68°F; based on a partial review of the available data, the 45 ft-lb minimum is satisfied.

Question 251.2N

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 of Appendix G, 10 CFR Part 50.

Response

The STPEGS Unit 1 reactor vessel was fabricated to ASME Code Section III requirements. Combustion Engineering, Inc. met the requirements of Section III and Paragraph III.B.4 of Appendix G, 10CFR50 by schooling and training of personnel performing fracture toughness tests. The individuals performing fracture toughness tests have demonstrated competency to perform the tests in accordance with the written procedures of Combustion Engineering, Inc. and trained and qualified personnel supervised all testing.

Question 251.3N

To demonstrate compliance with Paragraph III.C.1 of Appendix G, 10 CFR Part 50, provide CVN impact test data and curves for the base metal and welds in the reactor vessel beltline region.

Response

The test data is provided in Tables Q251.3N-1 through Q251.3N-6. Curves are provided in Figures Q251.3N-1 through Q251.3N-6.

TABLE Q251.3N-1

SOUTH TEXAS UNIT 1 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES
INTERMEDIATE SHELL BASE MATERIAL

PLATE R1606-1				PLATE R1606-2				PLATE R1606-3			
Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-40	7	3	0	-40	9	4	0	-10	21	12	5
-40	9	4	0	-40	8	3	0	-10	22	13	5
-40	12	6	0	-40	7	3	0	-10	17	9	0
-10	12	7	0	-10	19	12	5	40	47	30	25
-10	17	11	0	-10	14	7	0	40	40	28	20
-10	18	10	0	-10	13	7	0	40	39	24	20
20	36	23	15	40	52	35	25	60	47	34	25
20	28	20	10	40	58	37	30	60	43	30	20
20	19	12	5	40	29	18	10	60	40	27	20
60	58	31	30	50	43	31	20	70	69	54	50
60	46	39	25	50	45	29	20	70	50	36	30
60	60	23	30	50	49	34	25	70	52	39	30
70	69	44	50	60	60	39	40	100	72	52	50
70	64	42	40	60	63	44	40	100	74	55	50
70	62	41	35	60	54	37	30	100	58	46	40
100	89	60	70	100	81	58	60	160	86	67	80
100	84	57	70	100	69	50	50	160	83	60	80
100	73	50	50	100	78	59	60	160	83	62	80
100	110	74	100	160	91	65	100	212	91	72	100
160	108	78	100	160	98	69	100	212	98	68	100
160	111	79	100	160	93	66	100	212	128	82	100

Plate	T_{NDT}	RT_{NDT}
R1606-1	= -40°F	= 10°F
R1606-2	= -20°F	= 0°F
R1606-3	= -20°F	= 10°F

TABLE Q251.3N-2

SOUTH TEXAS UNIT 1 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES
LOWER SHELL BASE MATERIAL

PLATE R1622-1				PLATE R1622-2				PLATE R1622-3			
Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-40	24	15	5	-40	7	3	0	-40	11	6	0
-40	15	11	0	-40	8	4	0	-40	10	5	5
-40	19	13	0	-40	10	7	0	-40	11	5	0
0	24	20	10	0	36	24	10	0	31	23	5
0	54	40	30	0	36	25	10	0	27	21	5
0	51	36	25	0	28	22	5	0	53	39	20
30	52	36	25	30	50	36	20	30	51	37	25
30	68	47	30	30	61	43	30	30	54	40	25
30	69	49	35	30	60	44	30	30	62	44	30
100	96	66	80	100	78	53	40	100	87	53	40
100	102	68	70	100	83	55	40	100	107	65	50
100	84	59	60	100	55	38	25	100	84	57	40
160	110	64	100	160	113	79	90	160	120	73	90
160	109	70	100	160	114	74	90	160	123	74	90
160	113	73	100	160	115	79	90	160	116	73	90
212	112	70	100	212	120	76	100	212	128	72	100
212	108	73	100	212	122	78	100	212	127	75	100
212	113	68	100	212	124	79	100	212	126	80	100

PLATE R1622-1	PLATE R1622-2	PLATE R1622-3
T_{NDT} = -30°F RT_{NDT} = 30°F 30□F	T_{NDT} = -30°F RT_{NDT} = 30°F	T_{NDT} = -30°F RT_{NDT} = 30°F

TABLE Q251.3N-3

SOUTH TEXAS UNIT 1 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES

INTER & LOWER SHELL LONG. WELD SEAMS CODE NO. G1. 70

Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-110	19	11	0
-110	10	6	0
-110	13	8	0
-80	41	26	20
-80	39	25	20
-80	34	20	15
-40	98	65	60
-40	89	58	50
-40	63	44	30
10	122	72	70
10	131	77	80
10	161	90	100
100	151	80	100
100	162	90	100
100	156	90	100
160	164	91	100
160	155	84	100
160	155	83	100

T_{NDT} = -50°F
RT_{NDT} = -50°F

INTER TO LOWER SHELL GIRTH WELD SEAM CODE NO. E3.13

Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-80	26	17	5
-80	25	16	5
-80	19	12	0
-40	28	22	10
-40	23	17	5
-40	32	26	10
-10	69	54	50
-10	66	53	50
-10	68	54	50
60	94	71	80
60	83	62	70
60	85	64	80
100	97	71	90
100	98	73	90
100	96	74	90
160	101	77	100
160	99	76	100
160	100	79	100

T_{NDT} = -70°F
RT_{NDT} = -70°F

TABLE Q251.3N-4

SOUTH TEXAS UNIT 2 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES
INTERMEDIATE SHELL BASE MATERIAL

PLATE R2507-1				PLATE R2507-2				PLATE R2507-3			
Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-40	13	6	0	-40	13	6	0	-40	11	4	0
-40	12	6	0	-40	6	3	0	-40	13	6	0
-40	11	6	0	-40	12	6	0	-40	10	4	0
30	48	34	25	10	44	27	15	20	60	41	25
30	51	36	25	10	37	25	15	20	51	35	20
30	48	34	25	10	51	32	20	20	53	36	20
40	50	35	25	20	50	35	20	60	74	48	35
40	51	38	25	20	68	45	25	60	92	57	60
40	58	42	25	20	58	38	25	60	75	48	35
50	65	46	30	50	81	56	35	100	70	52	30
50	65	47	30	50	67	46	25	100	93	61	60
50	64	46	30	50	73	50	30	100	90	60	60
60	72	49	30	60	88	55	40	160	121	76	100
60	61	46	25	60	75	48	35	160	124	81	100
60	73	50	30	60	88	54	40	160	120	75	100
100	88	58	60	100	85	58	40	212	122	81	100
100	87	60	60	100	93	61	40	212	123	85	100
100	87	61	70	100	115	74	70	212	122	86	100
160	107	72	100	160	128	79	100				
160	109	72	100	160	130	80	100				
160	100	69	100	160	125	76	90				
212	108	71	100	212	127	81	100				
212	110	72	100	212	130	80	100				
212	110	72	100	215	131	78	100				

PLATE R2507-1	PLATE R2507-2	PLATE R2507-3
T_{NDT} = -10°F	T_{NDT} = -10°F	T_{NDT} = -40°F
RT_{NDT} = -10°F	RT_{NDT} = -10°F	RT_{NDT} = -40°F

TABLE Q251.3N-5

SOUTH TEXAS UNIT 2 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES

LOWER SHELL BASE MATERIAL 5

PLATE R3022-1				PLATE R3022-2				PLATE R3022-3			
Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)	Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-40	13	6	0	-40	13	6	0	-40	11	4	0
-40	12	6	0	-40	6	3	0	-40	13	6	0
-40	11	6	0	-40	12	6	0	-40	10	4	0
30	48	34	25	10	44	27	15	20	60	41	25
30	51	36	25	10	37	25	15	20	51	35	20
30	48	34	25	10	51	32	20	20	53	36	20
40	50	35	25	20	50	35	20	60	74	48	35
40	51	38	25	20	68	45	25	60	92	57	60
40	58	42	25	20	58	38	25	60	75	48	35
50	65	46	30	50	81	56	35	100	70	52	30
50	65	47	30	50	67	46	25	100	93	61	60
50	64	46	30	50	73	50	30	100	90	60	60
60	72	49	30	60	88	55	40	160	121	76	100
60	61	46	25	60	75	48	35	160	124	81	100
60	73	50	30	60	88	54	40	160	120	75	100
100	88	58	60	100	85	58	40	212	122	81	100
100	87	60	60	100	93	61	40	212	123	85	100
100	87	61	70	100	115	74	70	212	122	86	100
160	107	72	100	160	128	79	100				
160	109	72	100	160	130	80	100				
160	100	69	100	160	125	76	90				
212	108	71	100	212	127	81	100				
212	110	72	100	212	130	80	100				
212	110	72	100	215	131	78	100				
T_{NDT} = -10°F RT_{NDT} = -10°F				T_{NDT} = -10°F RT_{NDT} = -10°F				T_{NDT} = -40°F RT_{NDT} = -40°F			

TABLE Q251.3N-6

SOUTH TEXAS UNIT 2 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES 6

INTER & LOWER SHELL LONG. WELD SEAMS CODE NO. G3. 02

Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-100	14	8	0
-100	28	18	10
-100	23	12	5
-80	39	24	20
-80	32	18	15
-80	40	23	20
-40	85	55	50
-40	93	66	60
-40	98	69	60
-10	88	57	60
-10	94	65	60
-10	98	66	60
60	131	80	80
60	146	83	95
60	156	85	100
100	146	87	100
100	145	84	100
100	147	86	100

T_{NDT} = -70°F
RT_{NDT} = -70°F

INTER TO LOWER SHELL GIRTH WELD SEAM CODE NO. E3.12

Temp. (°F)	Energy (ft-lb)	Lat. Exp. (mils)	Shear (%)
-80	22	16	5
-80	25	17	5
-80	22	15	5
-40	48	35	25
-40	30	22	10
-40	43	33	20
-10	52	38	30
-10	58	42	35
-10	63	46	40
30	92	66	80
30	94	66	80
30	92	65	80
60	97	69	90
60	104	71	90
60	88	66	80
100	107	74	95
100	98	68	95
100	92	66	90
160	98	74	100
160	98	75	100
160	106	77	100

T_{NDT} = -70°F
RT_{NDT} = -70°F

Figure Q251.03N-1

Figure Q251.03N-2

Figure Q251.03N-3

Figure Q251.03N-4

Figure Q251.03N-5

Figure Q251.03N-6

Question 251.4N

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

a. Indicate the post-weld heat treatment used in the fabrication of the test welds and the vessel beltline welds.

b. Indicate whether the test specimens for the longitudinal seams were removed from excess material and welds in the vessel shell course following completion of the longitudinal weld joints.

c. Indicate whether the test specimens for the girth seams were prepared using excess material and welds in the vessel shell course following completion of the girth weld joints.

d. If the test specimens mentioned in b and c above were not removed from excess material and welds in the vessel shell course following completion of the longitudinal/girth weld seams, identify the base materials used to fabricate the welds from which the longitudinal and girth weld test specimens were obtained.

Response

Tests specimens for the longitudinal and girth seams were removed from separate weldments per Paragraph NB-2430 of the ASME Code.

The weldment for each vessel was made with the same heat of filler metal and lot of flux and the same welding conditions as used in joining the vessel intermediate and lower shell course weld seam. The following plates and heat treatment were used in fabricating the weldment for each vessel.

Unit 1 Surveillance weld (Plate R1606-2 to Rl606-3)
Unit 2 Surveillance weld (Plate R2507-1 to R2507-2)

Unit 1 Surveillance weld – 1150°F, 13 hr, 15 min, furnace cooled
Unit 1 Girth weld seam - 1150°F, 11 hr, 35 min, furnace cooled

Unit 2 Surveillance weld – 1150°F - 7 hr, 22 min, furnace cooled
Unit 2 Girth weld seam - 1150°F - 7 hr, 50 min, furnace cooled

Question 251.5N

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.

Response

a. RT_{NDT} of the welds which may be limiting for operation of the reactor vessel are as follows:

Weld Seams	Unit 1 RT_{NDT} (°F)	Unit 2 RT_{NDT} (°F)
Intermediate shell longitudinal	-50	-70
Intermediate shell to lower shell girth	-70	-70
Lower shell longitudinal	-50	-70

b. No reactor coolant pressure boundary (RCPB) heat-affected zones require Charpy V-Notch (CVN) impact testing per Paragraph NB-4335.2 of the l977 ASME Code since the weld is not made by electroslag, electrogas, or thermit process; and the joint is postweld heat treated.

Question 251.6N

To demonstrate that the surveillance capsule program complies with Paragraph II.B, Appendix H, 10 CFR Part 50:

a. For the submerged-arc weld surveillance specimens (Code No. E3.13) provide the weld wire type and heat identification, flux type and lot identification, weld process and heat treatment used for the weld sample fabrication.

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

Response

a. Information relative to the fabrication of weld surveillance sample (Code No. E3.13) is as follows:

Weld wire type	B4 (Lo Cu and P)
Weld wire heat no.	89476
Flux type	Linde 124
Flux lot no.	1061
Weld process	Automatic submerged arc
Heat treatment	1150°F - 13 hr, 15 min, - Furnace Cooled

b. See Figure Q251.6N-1.

Figure 251.06-1N

Question 251.7N

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 ¼ wall thickness as measured from the inside diameter.

Response

a. & b. The STPEGS Unit 1 and 2 Reactor Vessel Material Surveillance Capsule Withdrawal Schedule (see Figure Q251.06N-1) is:

Capsule Iden	Vessel Location	Lead Factor	Withdrawal Time
U	58.5°	4.00	1st Refueling
Y	241°	3.69	5 EFPY
V	61°	3.69	9 EFPY
X	238.5°	4.00	15 EFPY
W	121.5°	4.00	Standby
Z	301.5°	4.00	STandby

c. The estimated reactor vessel end-of-life fluence at the ¼ wall thickness is 1.2×10^{19} n/cm² for Unit 1 and 1.1×10^{19} n/cm² for Unit 2.

Question Q251.13N

(SRP 5.3.1)

With regards to fracture toughness requirements of 10CFR50.55a and the May 27, 1983 revisions to Appendices G and H to 10CFR50 (48FR24009; 48FR24011):

a. Identify any ferritic reactor coolant pressure boundary materials that do not comply with these requirements.

b. For any materials that cannot meet these requirements provide alternative fracture toughness data and analyses to demonstrate equivalence to the requirements to 10CFR Part 50.

Response

All reactor coolant pressure boundary materials comply with the requirements of 10CFR50.55a and the May 27, 1983, revisions to Appendices G and H to 10CFR50. (See also the response to NRC Q251.14N).

Question 251.14N

(SRP 5.3.1)

To demonstrate compliance with Appendix G, 10CFR Part 50, as revised May 27, 1983 (48FR24009), submit fracture mechanics analyses, or pressure-temperature limit curves for the closure flange region of the Unit 1 and Unit 2 reactor pressure vessels.

Response

STPEGS Unit 1:

The new 10CFR50 Appendix G rule states that the minimum metal temperature of the closure flange regions should be at least 120°F higher than the limiting RT_{NDT} for these regions when the pressure exceeds 20 percent of the preservice hydrostatic test pressure (621 psig for Westinghouse plants). For STPEGS Unit 1 the minimum temperature of the closure flange and vessel flange regions is 120°F since the limiting RT_{NDT} is 0°F (see Table 5.3-3). The South Texas Unit 1 heatup curve shown in Figure Q251.14N-1 is not impacted by the new 10CFR50 rule. However, the current STPEGS Unit 1 cooldown curve is impacted by the new 10CFR50 rule. A revised Unit 1 cooldown curve which meets the Appendix G requirement (see Figure Q251.14N-2) has been provided in the Technical Specifications.

For STPEGS Unit 2, the minimum temperature of the closure flange and vessel flange regions is 110°F since the limiting RT_{NDT} is –10°F (see Table 5.3-4).

Westinghouse reviewed the reasons for the different curves between Unit 1 and Unit 2. The differences resulted from the very conservative assumptions utilized in the derivation of the Unit 2 curves. Adoption of the assumptions utilized in the derivation of the Unit 1 curves demonstrated that the Unit 1 curves are also applicable to Unit 2 for 32 EFPY. These curves have been incorporated in the Technical Specifications.

Figure Q251.14N-1

Figure Q251.14N-2

Section Question 211.13

Provide assurance that adequate alarms are provided to detect leakage from the RHR in the event of a small leak or a significant pipe break. Specifically, provide the following information:

(1) Demonstration should be provided that the leak detection system will be sensitive enough to initiate (by alarm) operator action, permit identification of the faulted line and isolation of the line prior to 30 minutes and prior to the leak creating undesirable consequences such as flooding of redundant equipment.

(2) It should be shown that the leak detection system can identify the faulted train and that the leak is isolable.

(3) Directions given to the operator to isolate the faulted train and to return the intact train to service should be provided.

(4) The leak detection system should meet the following requirements:

  (a) Control room alarm

  (b) IEEE-279 except single failure requirements

Response

The Residual Heat Removal System (RHRS) is located inside Containment. All leakages originating from RHRS components will be detected by the Reactor Coolant Pressure Boundary Leakage Detection System, as discussed in UFSAR Section 5.2.5. RHRS leakage will be determined by:

  (a) Containment Normal Sump Level and Flow

  (b) Containment air particulate radioactivity

  (c) Reactor containment fan cooler (RCFC) drain flow

  (d) Containment humidity

  (e) RHRS process parameters: RHRS pump discharge flow, RHR Heat Exchanger inlet temperature and pressure, and RHR Heat Exchanger outlet temperature and flow.

(1) The reactor coolant pressure boundary (RCPB) leak detection systems are sufficiently sensitive to assure small increases in leakage can be detected prior to affecting safe plant operation. RCPB leakage is collected and monitored to determine flow rate to an accuracy of 1 gal/min, or its equivalent.

Response (Continued)

Primary monitoring methods:

(a) The containment normal sump is monitored by a differential temperature actuater level device. The rate of level change, is calculated and alarmed for an increasing rate approaching 1 gal/min is generated. Manual calculations may be obtained from control room level indicators.

(b) The Containment air particulate radioactivity monitor is a microprocessor - based system, which is designed to sample a representative isotope, and provide an alarm representative of a 1 gal/min leak to the Containment atmosphere.

(c) RCFC drain flow is monitored by a standpipe and level instrument designed to indicate flow. Flow rate is indicated in the control room, and alarmed by the plant computer at a rate of 1 gal/min above the normal drain flow.

Secondary monitoring methods:

(d) Containment air humidity is measured with a temperature-compensated dew cell. Percent humidity is monitored in the control room.

(2) (a) During normal plant operation the RHRS is not in operation and, therefore, is not considered to be a source of leakage to the containment atmosphere.

The RHRS is isolated on the suction side by motor operated valves XRH0060A, XRH0060B, XRH0060C and XRH0061A, XRH0061B, XRH0061C, and, on the discharge side, by series sets of check valves (Figures 5.4-6, 6.3-1, 6.3-2, 6.3-3, and 6.3-4).

Leakage past the check valves is considered negligible, since check valve leakage testing is performed during power operation.

(b) When the RHRS is in operation, the leaking RHRS train can be identified by the operator as follows:

i. Large pipe break - a large break in an RHRS line will be indicated by abnormal readings from pressure and flow indicators for that train.

ii. Small pipe break - for leakage rates too low to cause significant instrument fluctuations, the operator can identify the faulted train by isolating each train in succession and observing the effect on the RCPB leak detection system. If the leak is in the isolated train, the operator will see a decreasing sump (See Sections 5.2.5.4.2 and 5.2.5.6.2), indicating that the faulted train has been isolated.

Response (Continued)

(c) RHRS single failure analysis and system reliability considerations are presented in Section 5.4.7.2.6. The system is designed in such a manner that three separate flow circuits are available, any one of which satisfies the system design criteria. This allows individual flow isolation for train oriented leak detection.

(3) By interpreting process parameters and alarms, the operator will determine the proper course of action. An RHRS loop may then be isolated, in preparation for maintenance, without affecting the ability of the plant to achieve cold shutdown.

(4) (a) The occurrence of leaks will be alarmed in the control room (See Section 5.2.5).

(b) The RCPB Leakage Detection System was designed to conform with NRC General Design Criterion 30 and Regulation Guide 1.45.

(5) Intersystem leakage between the RHR and CCW systems would be detected by increasing level in the CCW surge tank and a high radiation alarm in the affected CCW loop.

<u>Question 211.14</u>

Describe the consequences of loss of component cooling water flow to the RHR and RCS pumps. Justify the time period that the pumps could operate without CCW. What signals, indicators, and alarms are provided to alert the operator to a loss of component cooling to the pumps?

<u>Response</u>

The RHR pumps operate with cooling water being supplied to the seal coolers. Loss of component cooling water would result in higher seal unit temperature and consequently shorter seal lifetime, but would not cause or require a rapid shutdown of the pumps.

Component cooling water temperature is measured at the outlet of the RHR pump seal cooler and monitored by the plant computer. A high temperature indicates a malfunction or low flow in the cooling water circuit to the pump.

Loss of component cooling water (CCW) to the RCS pumps was previously addressed in the Section 5.4.1.3.3.

Question 211.16

Per the discussion in Section 6.3.2.2 it is indicated that the flow control valves for the RHR systems fail to the maximum cooling position on failure of the nonsafety grade air system. Discuss the potential for this failure and the consequences of thermal shock and technical specification (cooldown limit) violation resulting from this failure.

Response

The potential for failure of the nonsafety grade air system is, of course, dependent on the air system design. However, it is considered highly improbable that the air system failure would occur precisely during the few hours per year that it could cause the cooldown rate to exceed the Technical Specification limit of 100°F/hr.

The cooldown rate depends on several factors, including the RCS temperature, the RHR flow rate, the component cooling water and essential cooling water (ECW) temperatures, and the auxiliary loads on the component cooling water (CCW) system. Under expected conditions, the cooldown rate would not exceed the Technical Specification limit of 100°F/hr, even if the butterfly valves were failed to the maximum cooling position from the moment RHR was initiated. Under the most conservative and severe set of assumptions, with all three RHR trains running and no operator action, the failure would have to occur precisely during the short period of time that the RCS temperature was between 350°F (RHR cut-in) and 250°F, in order to cause a cooldown rate in excess of the Technical Specification limit. Below an RCS temperature of 250°F, even under this severe set of assumptions, the cooldown rate would not exceed the Technical Specification limit.

Plant cooldown can be controlled, even if instrument air is not available. The methods of doing this are listed below in order of preferability:

1. The simplest method of controlled cooldown without instrument air is to put only one RHR train in operation for the first portion of cooldown. Even with the butterfly valve controlling flow through RHR heat exchanger (HX) fully open and the bypass butterfly valve fully closed, the cooldown rate will not even reach 50°F/hr over the first, most critical, hour. If desired, the other trains can be cut in as required to achieve a more efficient cooldown rate, but still remain in compliance with the Technical Specification limit.

2. Another means is by intermittent operation of the RHR pumps for the first part of cooldown, using administrative control to ensure that the cooldown rate does not exceed the Technical Specification limit.

3. A third method is to maintain continuous operation of the RHR pumps while periodically closing valves XRH0031A, XRH0031B, and XRH0031C to prevent the cooled RHR flow from returning to the RCS, thus carrying out the first part of cooldown in a stepwise manner. (With this method, the RHR miniflow lines must be opened.)

Response (Continued)

In summary, the event causing an excessive cooldown rate would have to involve both the air failure occurring precisely during a specific period of just a few hours, and the existence of unusually low ECW and CCW temperatures.Furthermore, there are simple actions which can be taken to control the cooldown rate should this highly unlikely event occur.

Question 282.1N

Provide a summary of operative instructions to be used for the steam generator secondary water chemistry control and monitoring program, addressing the following:

1. Sampling frequency for the critical chemical and other parameters and of control points or limits for these parameters for each mode of operation: normal operation, hot startup, cold startup, hot shutdown, cold wet layup;

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

3. Location of process sampling points;

4. Instructions for the recording and management of data;

5. The program element defining corrective actions for off-control point chemistry conditions detailing time allowed at off-chemistry conditions.

   Branch Technical Position MTEB 5-3 describes an 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).

6. The program element identify (a) the authority responsible for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

Response

The Secondary Water Chemistry Program for South Texas Project Electric Generating Station provides for effective, long-term, reliable operation of the steam generators and secondary side components.

System corrosion will be controlled by feeding all-volatile chemicals to the secondary systems for minimizing dissolved oxygen and maintaining an alkaline pH in the feedwater to each steam generator. All-volatile treatment will also be used for wet layup of secondary systems during periods of unit shutdown.

Impurity ingress into the secondary systems will be controlled by the condensate polishing system, the steam generator blowdown system, and the deaerator.

A sampling and analysis program will be maintained for monitoring the blowdown from each steam generator. Concentration levels for each parameter have been established with specific operational action required in the event that a concentration level is exceeded.

Response (Continued)

1. The sampling frequency and action level requirements will be included in plant procedures. These frequencies and action level requirements will be developed in accordance with industry experience and EPRI TR-102134 "PWR Secondary Water Chemistry Guidelines".

2. Laboratory analyses will be performed using procedures based upon ASTM or Standard Methods for Analysis of Water and Wastewater or by methods demonstrated to be equivalent or better than those listed above.

3. The location of the secondary sampling points are shown in Figure Q282.01N-1.

4. 4. Analytical results are recorded on the appropriate Worksheet, Log Sheet, Data Sheet, or other approved form. Key plant chemistry data is transferred to daily chemistry reports as well as plotted graphically to show abnormal trends of parameters.

5. Plant Chemistry Specifications define corrective action for off-control chemistry conditions and detail time allowed at off-chemistry conditions. These specifications are based upon industry experience and EPRI TR-102134 "PWR Secondary Water Chemistry Guidelines".

6a. Plant Chemistry Specifications identify the Chemistry Manager as the authority responsible for interpreting chemistry data.

6b. When an analysis indicates that a chemical parameter is not within specified limits, appropriate actions are taken as soon as possible. If the sample was taken to satisfy a technical specification surveillance requirement, when the applicable surveillance procedure is consulted to determine the corrective action required. If the sample was not taken to satisfy a technical specification surveillance requirement, then Plant Chemistry Specifications are consulted to determine the corrective action required.

Figure 282.01N-1

Question 410.8N

In considering the event that the rupture disks of the pressurizer relief tank are blown out and become missiles, describe the associated hazards to the safety-related equipment and whether missile protection features are provided.

Response

The rupture disks of the pressurizer relief tank are designed to burst, not blow out as a panel. The hazard associated with this failure mode is lessened. Potential missiles created by these rupture disks would be stopped by structural steel, the pressurizer surge line or by two levels of grating above the pressurizer relief tank.

Question 440.28N

Provide the basis for sizing the RHR relief valves. Also justify using 600 psig as the valve set pressure, in view of the fact that the RHR system design pressure is also 600 psig. Other recent Westinghouse plants, which also have RHR systems designed to 600 psig, utilize 450 psig as the valve setpoint. If the RHR relief valve is utilized for LTOPS purpose, discuss the suitability of the valve capacity and setpoint for this purpose.

Response

As reported in Section 5.4.7.1, each Residual Heat Removal (RHR) subsystem is equipped with a pressure relief valve designed to relieve the combined flow of all the charging pumps at the relief valve set pressure of 600 psig. The potential and capacity for charging pumps to overpressurize the Residual Heat Removal System (RHRS), therefore, represent the sizing basis for the valves.

The reason for the variation in relief valve set pressures between the STPEGS and other Westinghouse designs is that the STPEGS relief valve is in the RHR pump discharge rather than the suction line. In effect, to protect against system overpressurization via a pump suction side relief valve, the developed head of the subject pump must be considered in the establishment of the relief valve set pressure. Consequently, the set pressure variance to effect the same system protection is appropriate.

The STPEGS Cold Overpressure Mitigation System (COMS) does not take credit for the availability or relief capacity of the RHR relief valves

Question 440.29N

Figure 5.4-6 "RHRS Piping Diagram" indicates ESF signals to the RHR inlet valves and does not show the open permissive and auto closure interlocks. Are these interlocks combined with the ESF controls? If so, can the RHR inlet valves be inadvertently opened when the RCS is at high pressure or closed when the plant is on RHR cooldown in the event of an ESF actuation? Figure 5.4.6 should show the interlocks and power diversity as described in the text.

Response

For consistency in representation of signals to equipment, the Engineered Safety Feature (ESF) symbol has been used to represent protection-grade (Class lE) signals to equipment. On Figure 5.4-6, the ESF symbol for the Residual Heat Removal (RHR) inlet isolation valves represents the open permissiveinterlock signal to the valves from the Solid-State Protection System (SSPS), which are Class lE signals. These signals are discussed in Sections 5.4.7 and 7.6.2; the logic diagram for these valves is shown in Figure 7.6-2. As shown on this figure, no other signals are sent to these valves.

The power diversity for these valves is discussed in the above referenced sections, and is also shown on Figures 7.6-2 and 5.4-6.

Question 440.30N

With regard to the information in Appendix 5.4.A "Cold Shutdown Capability" identify the most limiting single failure with regard to cooldown capability and verify that the statement of Table 5.4.A-1 that the auxiliary feedwater storage tank (AFST) "capacity of 500,000 gallons is adequate to support 4 hours at hot standby conditions followed by 10 hours cooldown to RHR cut in condition with a margin for contingencies" considers this failure.

Response

The answer is included into UFSAR Table 5.4A-1 Section VII.

Question 440.32N

For each mode of operation, state whether the RHR inlet valve motor power supply breakers are locked open. If the breakers are locked open during modes 1, 2, and 3, state how the plant is brought to cold shutdown from the control room.

Response

The residual heat removal (RHR) inlet isolation valve motor power supply breakers (one valve in each inlet line) are power locked out with the valves in the closed position during plant modes 1, 2, and 3. These power lockouts preclude simultaneous opening of the two RHR system inlet isolation valves which can be postulated to occur due to control circuitry fire damage; i.e., multiple hot shorts. Operator action outside of the control room is required to close the power supply breakers for the inlet isolation valves prior to establishing RHR system operation. This situation is not in conformance with the guidelines of Branch Technical Position RSB 5-1 because the consequences of simultaneous valve opening has greater safety significance than the ability to be able to perform a shutdown (including opening of the RHR inlet isolation valves) from the control room.

Question 440.33N

a. Table 5.4.A-1 "Compliance Comparison with BTP RSB 5-1" states that during cold shutdown boron sampling is not required. Will boronometers be used for boron concentration measurements, and if so, are they safety grade? We consider periodic boron concentration measurements necessary, particularly if the plant is in natural circulation.

b. Table 5.4.A-1, Item V, indicates that "test data and analysis for a plant similar in design to STPEGS will verify adequate mixing and cooldown under natural circulation conditions." State which plant test would be utilized, and justify why the plant is similar to the STPEGS design, considering possible differences in core and RCS design, T_{avg}, upper head volume and temperature, and other pertinent parameters.

Response

a) STPEGS can periodically measure boron concentration by use of the Post- Accident Sampling System (PASS) (Section 9.3.2). The PASS panel is provided back-up power from the highly reliable TSC Diesel. This shouldbe available in the event of a Loss of Offsite Power (LOOP).

b) STPEGS and Diablo Canyon Unit 1 have been compared in detail to ascertain any differences between the two plants that could potentially affect natural circulation flow and attendant boron mixing. Because of the similarity between the plants, it was concluded that the natural circulation capabilities would be similar. Therefore, the results of prototypical natural circulation cooldown tests conducted at Diablo Canyon will be representative of the capability at STPEGS.

The general configuration of the piping and components in each reactor coolant loop is the same in both STPEGS and Diablo Canyon. The elevation head represented by these components and the system piping is similar in both plants.

To compare the natural circulation capabilities of STPEGS and Diablo Canyon, the hydraulic resistance coefficients were compared. The coefficients were generated on a per loop basis. The hydraulic resistance coefficients applicable to normal flow conditions are as follows:

	Diablo Canyon Unit 1	STPEGS
Reactor Core & Internals	128.4×10^{-10}	149.7×10^{-10} ft/(Loop gal/min)^2
Reactor Nozzles	36.7×10^{-10}	27.3×10^{-10} ft/(Loop gal/min)^2
RCS Piping		
RV Outlet to SG Inlet		4.0×10^{-10} ft/(Loop gal/min)^2

Response (Continued)

	Diablo Canyon Unit 1		STPEGS
SG Outlet to RC Pump Inlet			10.0×10^{-10} ft/(Loop gal/min)^2
RC Pump Discharge To RV Inlet			$\underline{4.0 \times 10^{-10}}$ ft/(Loop gal/min)^2
Total RC Loop	24.0×10^{-10}		18.0×10^{-10} ft/(Loop gal/min)^2
Steam Generator	$\underline{114.5 \times 10^{-10}}$		$\underline{132.1 \times 10}^{-10}$ ft/(Loop gal/min)^2
Total	303.6×10^{-10}		327.1×10^{-10} ft/(Loop gal/min)^2
Flow Ratio Per Loop	$\frac{\text{STPEGS}}{\text{Diablo Canyon}}$	= ~	$\frac{303.6}{327.1}$ - 1/2 = $\underline{0.963}$

The general arrangement of the reactor core and internals is the same in Diablo Canyon and STPEGS. The coefficients indicated represent the resistance seen by the flow in one loop.

The reactor vessel outlet nozzles configuration for both plants is the same. The radius of curvature between the vessel inlet nozzle and downcomer section of the vessel on the two plants is different. Based on 1/7 scale model testing performed by Westinghouse and other literature, the radius on the vessel nozzle/vessel downcomer juncture influences the hydraulic resistance of the flow turning from the nozzle to the downcomer. The Diablo Canyon vessel inlet nozzle radius is significantly smaller than that of STPEGS, as reflected by the higher coefficient for Diablo Canyon.

Steam generator (SG) units were also compared to ascertain any variation that could affect natural circulation capability by changing the effective elevation of the heat sink or the hydraulic resistance seen by the primary coolant. It was concluded that there are no differences in the design of the SGs in the two plants that would adversely affect the natural circulation characteristics.

It is expected that the relative effect of the coefficients would be the same under natural circulation conditions such that the natural circulation loop flowrate for STPEGS would be within five percent of that for Diablo Canyon.

For typical 4-loop plants there are two potential flow paths by which flow crosses the upper head region boundary in a reactor. These paths are the flow nozzles into the upper head and the guide tubes. The flow nozzles provide a flow path between the downcomer region and the upper head region. The temperature of the flow which enters the head via this path corresponds to the

Response (Continued)

cold leg value (i.e., T_{cold}). Fluid may also be exchanged between the upperplenum region (i.e., the portion of the reactor between the upper core plate and the upper support plate) and the upper head region via the guide tubes. Guide tubes are dispersed in the upper plenum region from the center to the periphery. Because of the nonuniform pressure distribution at the upper core plate elevation and the flow distribution in the upper plenum region, the pressure in the guide tube varies from location to location. These guide tube pressure variations create the potential for flow to either enter or exit the upper head region via the guide tubes.

To ascertain any difference between the upper head cooling capabilities between Diablo Canyon and STPEGS, a comparison of the hydraulic resistance of the upper head regions was made. These flow paths were considered in parallel to obtain the following results.

	Diablo Canyon Unit 1	STPEGS
Flow area (ft^2)	0.77	0.788
Loss coefficient	1.51	1.50
Overall hydraulic resistance (ft^{-4})	2.57	2.413
Relative head region flow rate (Based on hydraulic resistance)	1.00	1.03

As indicated above, the effective hydraulic resistance to flow in STPEGS is slightly less than Diablo Canyon. Assuming that the same pressure differential existed in both plants the STPEGS head flow rate would be 103 percent of the Diablo Canyon flow.

It can, therefore, be concluded that the results of the natural circulation cooldown tests performed at Diablo Canyon will be representative of the natural circulation and boron mixing capability of STPEGS. The results of these tests will be reviewed for applicability.

Question 440.35N

Recent plant experience has identified a potential problem regarding the loss of shutdown cooling during certain reactor coolant system maintenance operations. On a number of occasions when the reactor coolant system has been partially drained, improper RCS level control, a partial loss of reactor coolant inventory, or operating the RHR system at an inadequate NPSH has resulted in air binding of the RHR pumps with a subsequent loss of shutdown cooling. Regarding this potential problem, provide the following additional information.

a. Discuss the design or procedural provisions incorporated to maintain adequate reactor coolant system inventory, level control, and NPSH during all operations in which RHR cooling is required.

b. Discuss the provisions incorporated to ensure the rapid detection of air binding of the RHR pumps so that they are not damaged. What provisions are there to vent or otherwise remove the trapped air in the pumps and rapidly put the RHR system back into service prior to excessive core heatup?

c. Discuss the provisions incorporated to provide alternate methods of shutdown cooling in the event of loss of RHR cooling during shutdown maintenance. These provisions should consider maintenance periods during which more than one cooling system may be unavailable, such as loss of steam generators when the reactor coolant system has been partially drained for steam generator inspection or maintenance.

Response

STPEGS responded to the industry issue of shutdown cooling assurance in the response to Generic Letter 88-017, "Loss of Decay Heat Removal".Correspondence ST-HL-AE-3097 dated August 3, 1989, ST-HL-AE-3398 dated March 9, 1990 and ST-HL-AE-3741 dated April 15, 1991 detail the design and administrative provisions to minimize the potential for loss of shutdown cooling.

Question 440.36N

a. Describe the compliance of the reactor vessel head vent system (RVHVS) with NUREG-0737 Item II.B.1 "RCS Vents".Provide an item by item comparison of the NUREG-0737 requirements with the STPEGS RVHVS design.

b. The FSAR indicates that the RVHVS is also used for primary coolant letdown. State during what operational modes the RVHVS would be used for letdown, whether it would be used together with or as an alternate to CVCS letdown, and whether there could be interference between the letdown function and the system's primary function of head venting.

c. Revise Figure 5.1-1 to depict the RVHVS as described in the Amendment 38 submittal, including the existence of redundant remote operated isolation and throttling valves. Also clarify whether the system discharges to the PRT, as stated in Section 5.4.15, or to the reactor coolant drain tank, as shown in Figure 5.1-1.

Response

A.

1. A description of the design, location, size, and power supply for the Head Vent System is provided in Section 5.4.15. As indicated in Section4 5.4.15.3, a break in a vent pipe would be similar to the hot leg break case in WCAP-9600 and the results presented therein are applicable.

2. Westinghouse Emergency Response Guideline FRI-3, "Response to Voids in the Reactor Vessel" provides guidance on the operation of the Head Vent System. STPEGS plant specific procedures relating to the operation of the Head Vent System will be developed by Houston Lighting and Power.

   Also see Appendix 7A, Item II.B.1 for further information.

B. As described in Section 5.4.A.1, the safe shutdown design basis for the STPEGS is hot standby. The cold shutdown capability of the plant has however been evaluated. In this scenario the head vent line may be used as a letdown path should the primary Chemical and Volume Control System (CVCS) letdown path be unavailable.

C. The Heat Vent System discharges to the pressurizer relief tank (PRT). Figure 5.1-1 will be corrected.

Question 440.37N

State what provisions have been made for pressurizer and RCS loop venting.

Response

Noncondensable gases would be expected to collect in the reactor vessel head or the pressurizer. The reactor vessel may be vented via the Reactor Vessel Head Vent System while the pressurizer may be vented via the safety-related power-operated relief valves (PORVs).

Question 440.73N

What relief provisions are provided to accommodate thermal expansion of the water trapped between the two RHR inlet valves during heatup?

Response

Two isolation valves in series are provided in each Residual Heat Removal (RHR) inlet leading from the reactor coolant loop hot legs to the suction of the RHR pumps. The isolation valve nearest to the hot leg is located more than ten feet away from the hot leg connection and below the elevation of the hot leg loop piping. The Reactor Coolant System (RCS) side of the trapped volume in question is therefore not close coupled to the RCS loop piping and is cold trapped, i.e., arranged to preclude the formation of convection currents of hot reactor coolant which could heat the trapped volume.

Given this physical layout, the mechanism by which thermal heat up and expansion of the trapped volume could occur during normal plant operation is limited to the heat up of this volume as the Containment ambient temperature increases during plant heatup. The maximum pressure which would occur in this line segment was calculated based on the following conservative assumptions:

- The line is isolated as the Containment ambient temperature, and trapped water volume temperature, increase from 65°F to 120°F.

- Zero leakage is assumed to occur both past the seats and through the stems of the isolation valves.

The results of the analysis demonstrate that the peak pressure which occurs in the trapped volume is less than the design pressure of the 12-in. schedule 160 piping and the isolation valves at the applicable temperature. It is therefore concluded that overpressure protection is not required for the RHR inlet line to accommodate thermal expansion of the trapped water volume during plant heatup.

Question 440.74N

What is the capacity of the RHR discharge line relief valves downstream of the RHR HX.

Response

This relief valve is for thermal relief only and has a low flow capacity (20 gal/min).

Question 440.75N

Discuss the adequacy of the RHR pump bypass valve manual on-off controls. Other recent Westinghouse plants have automatic recirculation control valve modulation based on total pump flow. Discuss the required operator actions.

Response

Since the Residual Heat Removal (RHR) pump is not used as a safety injection pump on STPEGS an automatic miniflow arrangement has not been provided. The RHR pumps are manually started by the operator when needed for Reactor Coolant System (RCS) cooling.

For pump protection the pump will trip on low flow and operator action is required to open the miniflow valve on a low flow alarm.

Question 440.76N

Will alarms be provided to indicate excessive RHR pump seal temperatures; e.g., component cooling water outlet high temperature alarms?

Response

A temperature element is located downstream of the residual heat removal (RHR) pumps on each component cooling water (CCW) line (Figures 9.2.2-1 through 9.2.2-3). This output signal is transmitted to the plant computer. If the preset temperature setpoint is exceeded it will be alarmed as a computer alarm. The operator then checks the computer to determine what condition has alarmed and takes corrective action.