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CHAPTER 1

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The following information is "**historical, not design/licensing basis information**". This information supported initial licensing decisions. This information is considered redundant to the information required by 10CFR50.34 and found in the regular sections of the UFSAR.

Question 730.1N

The Atomic Safety and Licensing Appeal Board in ALAB-444 determined that the Safety Evaluation Report for each plant should contain an assessment of each significant unresolved generic safety question. It is the staff's view that the generic issues identified as "Unresolved Safety Issues" (NUREG-0606) are the substantive safety issues referred to by the Appeal Board. Accordingly, we are requesting that you provide us with a summary description of your relevant investigative programs and the interim measures you have devised for dealing with these issues pending the completion of the investigation, and what alternative courses of action might be available should the program not produce the envisaged result.

There are currently a total of 26 Unresolved Safety Issues discussed in NUREG-0606. We do not require information from you at this time for a number of the issues since a number of the issues do not apply to your type of reactor, or because a generic resolution has been issued. Issues which have been resolved have been or are being incorporated in the NRC licensing guidance and are addressed as a part of the normal review process. However, we do request the information noted above for each of the issues listed below:

1. Waterhammer (A-1)
2. Steam Generator Tube Integrity (A-3)
3. ATWS (A-9)
4. Reactor Vessel Materials Toughness (A-11)
5. Steam Generator and Reactor Coolant Pump Support (A-12)
6. Systems Interaction (A-17)
7. Seismic Design Criteria (A-40)
8. Containment Emergency Sump Performance (A-43)
9. Station Blackout (A-44)
10. Shutdown Decay Heat Removal Requirements (A-45)
11. Seismic Qualification of Equipment in Operating Plans (A-46)

HISTORICAL INFORMATION

12. Safety Implications of Control Systems (A-47)

13. Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment (A-48)

Responses

In the Safety Evaluation Reports for Virgil C. Summer and Commanche Peak (NUREG-0717 and NUREG-0797), the NRC Staff concluded that those plants could be operated prior to final resolution of the unresolved safety issues. The reasoning that led to these conclusions is applicable to STPEGS. In general, HL&P agrees with the previous NRC staff assessments of these issues. Therefore, it has been concluded that STPEGS can be operated without risk to the health and safety of the public. Programs and measures taken for dealing with these generic issues are discussed below.

Question 730.1N

A-1 Waterhammer

Refer to evaluation in sections 10.4.7 and 10.4.9.

Question 730.2N

A-3 Steam Generator Tube Integrity

Bechtel, HL&P, and Westinghouse are participating in a joint Task Force to examine FW cycle water chemistry control and steam generator options for STPEGS. The purpose of these studies is to determine options available for minimizing the long-term degradation of the steam generators from corrosion.

Question 730.3N

A-9 Anticipated Transients Without Scram

Refer to Sections 4.3.1.7 and l5.8.

Question 730.4N

A-11 Reactor Vessel Materials Toughness

The current Westinghouse specification for reactor vessel materials (which encompasses the STPEGS reactor vessels) limits the amount of copper, phosphorus, and vanadium permitted in order to reduce the effect of radiation on the vessel fracture toughness. Vessels fabricated to these requirements will maintain high fracture toughness properties throughout plant life. For additional information regarding compliance to Appendix G, "Fracture Toughness Requirements", of l0CFR50, refer to Section 5.3 and the responses to NRC questions 121.4, 121.11, and 121.14.

Question 730.5N

HISTORICAL INFORMATION

A-12 Steam Generator and Reactor Coolant Pump Support

The STPEGS steam generator and reactor coolant pump (RCP) supports were designed to meet the requirements of ASME Section III, Subsection NF. Refer to Sections 3.8.3.4.3 and 5.4.14. Westinghouse has concluded that compliance with Subsection NF is sufficient to resolve the concerns expressed in NUREG-0577. As of October 1983, in accordance with the staff recommendation in NUREG-0577 (Rev. 1), no further actions are required for operating PWRs and for current CP and OL applicants. It was concluded that no safety benefit would be derived from the verification of material fracture resistance, and other corrective measures were not justified on the basis of arguments presented and supported by the value-impact analysis.

HISTORICAL INFORMATION

Question 730.6N

A-17 Systems Interaction

The fundamental plant design philosophy at STPEGS dictates that safety-related systems be redundant, independent, and provided with adequate isolation to preclude unacceptable systems interaction. An STPEGS Systems Interaction Design Guide is being developed and will include guidance for separation and consideration of fire, flooding, seismic II/I, missiles, single failure, and pipe break effects.

Question 730.7N

A-40 Seismic Design Criteria

As discussed in Section 3.7, STPEGS has been designed to meet the project commitments for seismic design.

Question 730.8N

A-43 Containment Emergency Sump Performance

The STPEGS Containment emergency sump design bases are described in Section 6.2.2.1.2. Performance of the sumps has been evaluated in accordance with RG 1.82 proposed Revision 1, May 1983.

Question 730.9N

A-44 Station Blackout

STPEGS is evaluating the reliability of the AFW given a loss of all AC power. This evaluation is being performed in response to the March 10, 1982 NRC letter and has been submitted to the NRC at a later date. A response to Generic Letter 81-04, discussing emergency procedures and training, was provided by letter from J. H. Goldberg to Darrel G. Eisenhut, May 12, 1982.

Question 730.10N

A-45 Shutdown Decay Heat Removal Requirements

STPEGS has addressed the capability to achieve cold shutdown as identified by Branch Technical Position RSB 5-1. This capability is discussed in Appendix 5.4.A.

Question 730.11N

A-46 Seismic Qualification of Equipment in Operating Plant

STPEGS will be evaluating safety-related equipment on a case-by-case basis regarding the impact of qualifying equipment to the newer NRC positions in Regulatory Guide (RG) 1.100 which calls out IEEE 344-1975. A decision can then be made to determine what type of action, if any, is desirable.

Question 730.12N

A-47 Safety Implications of Control Systems

STPEGS has been designed with the goal of ensuring that control system failures will not prevent automatic or manual initiation and operation of any safety equipment required to trip the plant or to maintain the plant in a safe shutdown following any "anticipated operational occurrence" or "accident". STPEGS accomplishes this by the use of independence between safety and nonsafety systems or by providing qualified isolation devices between safety and nonsafety systems. The independence of redundant safety-related systems is discussed in Section 7.1.2.2. With reference to nonsafety-related instrumentation, STPEGS is presently finalizing the design of the nonsafety related instrumentation power distribution system. A failure modes and effects analysis will be performed on this system and will be presented at a later date as part of answers to NRC questions 032.42, 032.44, and 032.45.

The failure modes and effects analysis presented in Chapters 7 and 8 for safety-related instrumentation illustrates that failures of individual sensors, losses of power to protection separation groups, etc., all result in events which are bounded by the Chapter 15 analyses.

Question 730.13N

A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

The Combustible Gas Control System is discussed in Section 6.2.5. This system is designed to meet the source term assumptions of RG 1.7 (Rev. 1). For these source terms hydrogen burn is not considered credible since system design will maintain hydrogen concentration below 4 percent.

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Question 312.16

You imply that the public will use your heavy-haul road to obtain access to the public launch facilities at the end of this road. Please clarify this point. If the public is to use this road, also discuss your provisions for access control during routine operations and emergencies.

Response

Section 2.1.1.2 no longer contains the implication that the heavy haul road will be used for access to public launch facilities located on the site. HL&P no longer intends public launch facilities to be available on the site. For these reasons, provisions for public access control, beyond that described in the STPEGS Security Plan, are not necessary.

Question 312.1

Regarding the possible purchase of property near the north boundary of the STPEGS site for industrial development, provide an estimate of the distance of the development to the nearest plant safety-related structure and discuss the planned size of the development, the type of industry most likely to locate there, and any zoning or other restrictions which might apply.

Response

Contacts with the property owners, Union Carbide and Dow Chemical, indicate that no definite plans for the property are available and the owners will not speculate on possible development options at this time.

Question 372.1

The data period for determination of tornado frequencies (discussed on pages 2.3-3 and 2.3-4 of the FSAR) ended in 1972. Identify tornadoes that have occurred in the vicinity of the site since 1972, and provide estimates of the maximum wind speeds (based on observed structural damage), path lengths, and path areas.

Response

In the period January 1973 through June 1978 a total of 24 tornadoes were reported within a 50-mile radius of the STPEGS site, an average of 4.36 tornadoes per year (NOAA, 1978). Six complete reports of path lengths and widths were available and the average computed tornado path area for the data period was 0.0725 square miles. Most of the incomplete or missing reports implied "short and narrow" tornado path dimensions. Wind speeds of 72 mph, and over 100 mph, were reported, but no severe-damage reports were documented for the 5.5 year period. Section 2.3 has been amended to incorporate the recent data. The Table Q372.1-1 sumarizes the data for the January 1973 through June 1978 period.

TABLE Q372.1-1

TORNADO DATA FROM NOAA "STORM DATA"
(PERIOD OF RECORD JANUARY 1973 THROUGH JUNE 1978)

No.	Place/County	Date	Path Length (mi)	Path Width (yd)	Path Area (mi^2)	Property Damage ($)	Comments
1.	Brazoria County	June 5, 1973	2	50	0.057	0	Tornado observed on ground 10 miles NE of Freeport. Area was open marsh so no damage occurred.
2.	Garwood Colorado County	June 13, 1973	Short	Narrow	-	0	Duration was short, several trees uprooted but no property damage occurred.
3.	Hillje Wharton County	June 13, 1973	7	Narrow	-	$500 to $5000	Tornado touched ground briefly uprooting trees and knocking one home from its foundation. The funnel lifted and moved HE and was sighted 3 mi NE of El Campo.
4.	Calhoun County	June 13, 1983	8	Narrow	-	$500 to $5000	The tornado was first reported on the ground on a ranch near Green Lake. It lifted as it moved NNE, then touched down briefly near Kamey, damaging a mobile home.
5.	Ganado Jackson County	April 30, 1974	1	?	-	$50 to $500	Tornado damaged trailer, loud roaring noise.
6.	Angleton Brazoria County	September 13, 1974	?	?	-	0	Tornado touched down briefly about 10 miles north of Angleton. No visible signs were found in area.
7.	Midfield Matagorda County	September 28, 1974	?	?	-	0	Tornado was observed to touch ground briefly. No damage reports were received.
8.	Sargent Matagorda County	June 25, 1975	?	?	-	0	Tornado reported near Sargent. No damage over marshland.
9.	Freeport Brazoria County	June 27, 1975	?	?	-	$50 to $500	Tornado touched down briefly near Surfside; minor damage.
10.	Victoria Victoria County	May 27, 1975	?	?	-	0	72 mph winds and pea-size hail were reported. Several unconfirmed reports of tornadoes were reported. No reported damage.

TABLE Q372.1-1 (Continued)

TORNADO DATA FROM NOAA "STORM DATA"
(PERIOD OF RECORD JANUARY 1973 THROUGH JUNE 1978)

No.	Place/County	Date	Path Length (mi)	Path Width (yd)	Path Area (mi^2)	Property Damage ($)	Comments
11.	Victoria Victoria County	October 15, 1975	?	?	-	$50 to $500	Tornado reported 3 miles east of Victoria Victoria County Airport, moving south at 15 mph. Some minor damage to a few buildings.
12.	Middle and Upper Texas Coast	December 24, 1975	1	440	0.250	$3500	A line of thunderstorms with one tornado moved rapidly southeastward off Texas Coast. Funnel cloud touched down 1600 hours 2 miles south of Ganado, Jackson county, damaging house and trailer.
13.	Matagorda County	August 3, 1975	?	?	-	0	Tornado reported 10 miles west of Matagorda. No damage reported.
14.	Victoria Victoria County	August 4, 1975	?	?	-	0	Tornado 10 miles SE of Victoria moving NW. No reported damage.
15.	Telfener Victoria County and Edna Jackson County	May 7, 1976	6	30	0.102	$5000 to $50,000	First signed as a funnel over downtown Victoria moving NE. Touched down briefly between Telfener and Inez. Touched down again SE of Edna and moved toward Ganado for approximately 6 miles.
16.	Pierce Wharton County	July 14, 1976	Short	Narrow	-	0	Tornado touched down 15 miles SE of Pierce.
17.	Richmond Fort Bend County	September 2, 1976	?	?	-	0	Touched down briefly in an isolated area.
18.	Alvin Brazoria County	September 26, 1976	1/2	20	0.006	0	Moved from SW to NE. Touched down south of Alvin moving NE and lifted off ground 1/4 mile east of Alvin.
19.	Bay City Matagorda County	September 26, 1976	1/2	20	0.006	$5000 to $50,000	Funnel touched down briefly and damaged fences, outbuildings and windows.
20.	College Park Matagorda County	April 16, 1977	Short	Narrow	-	0	Funnel cloud touched down briefly near College Park.

TABLE Q372.1-1 (Continued)

TORNADO DATA FROM NOAA "STORM DATA"
(PERIOD OF RECORD JANUARY 1973 THROUGH JUNE 1978)

No.	Place/County	Date	Path Length (mi)	Path Width (yd)	Path Area (mi^2)	Property Damage ($)	Comments
21.	Wadsworth Matagorda County	September 10, 1977	?	?	-	0	Funnel cloud touched down briefly in open country.
22.	El Campo Hungerford Wharton County	November 8, 1977	?	150	-	$500 to $5000	A tornado from a fast moving thunderstorm touched down south of El Campo. El Campo airport registered over 100 mph winds at the time.
23.	East Bernard Wharton County	December 13, 1977	1/2	50	0.014	$50,000 to $5,000,000	Tornado touched down on outskirts of East Bernard. House was moved 20 ft from foundation. A 50 ft x 30 ft metal shed destroyed, damaging farm machinery inside the shed.
24.	South Ganado Jackson County	April 22, 1978	Short	20	-	$5000 to $50,000	One barn destroyed, power lines broken, numerous trees uprooted, severely damaged crops in area.

Question 372.3

Recent operating experience has identified various failures of systems from freezing temperature. Identify the design basis maximum and minimum air temperature (including frequency and duration) considered in the designs of systems and components such as heating and air conditioning systems, impulse lines, service water valves, steam isolation valves, etc. Also discuss the designs of systems and components with respect to combinations of phenomena such as moisture buildup coincident with freezing temperature.

Response

The STPEGS HVAC design basis maximum and minimum outside ambient air temperatures are 95°F and 29°F, respectively. These design conditions are based on ASHRAE data.*

Plant systems and components are protected from the effects of freezing temperatures by the following means:

1. Components are located in buildings or structure where the HVAC systems maintain the building environment above freezing temperatures by means of duct or unit heaters (refer to Section 9.4). Such components include, but are not limited to the main steam isolation valves (located in the MSIV structure) and the essential cooling water (ECW) pumps, strainers, and certain valves (located in the ECW intake structure), or

2. Components are located below ground (e.g., buried ECW piping), or

3. Certain components, such as instrument lines, which are directly exposed to potentially freezing conditions, are heat traced and insulated.

Another example of system design to prevent failures due to freezing conditions is illustrated in the Instrument Air System. As discussed in Section 9.3.1.2.2, the dual-tower, no-heat regenerative dryers for the Instrument Air System provide air at a design dew point of (-)40°F thus precluding the possibility of condensation and subsequent freezing.

* American Society of Heating, Refrigerating and Air Conditioning Engineers, Inc., ASHRAE Handbook & Produce Directory - 1972 Fundamentals, N.Y., (1972).

Question 372.4

The valves of solar radiation presented in FSAR Table 2.3-22 appear to be incorrect. The maximum daily solar radiation available in the area of the site at the beginning of July is about 975 cal. cm^{-2}, which is equivalent to about 3600 Btu. ft^{-2}. The daily solar radiation amounts presented in Table 2.3-22 exceed the maximum daily solar radiation available by over a factor of two, and exceed the average daily solar radiation for San Antonio in July by a factor of three. Clarify the solar radiation data used for preparation of Table 2.3-22, and discuss the effect of using incorrect solar radiation data in the calculation of minimum water cooling for the ultimate heat sink.

Response

The values in Table 2.3-22 resulted from an assumption that the maximum hourly value occurs for the entire 24-hr period rather than from summing hourly values for each day.

The effect of using higher solar radiation values would result in higher equilibrium temperature, resulting in higher pond temperatures. The use of higher solar radiation results in a conservative calculation of minimum water cooling for the ultimate heat sink.

Question 372.5

Identify the dates of initiation and completion of the filling of the cooling reservoir, and the program proposed to examine possible effects of the reservoir on local meteorological conditions (e.g., fogging, icing, temperature, and humidity).

Response

The cooling reservoir water level is currently being maintained at 28.0 MSL. During August 1985, filling operations will be initiated to raise the water level to 35.0 MSL. Subsequent filling operations have not been scheduled.

The response to Q372.6 discusses the status of programs related to predicting reservoir impacts on local meteorological conditions.

Question 372.6

Indicate if a monitoring program for occurrences of fog at the STPEGS site has been operation or if such a program is planned for operation to confirm the estimates of increased fogging and icing resulting from the cooling reservoir.

Response

As discussed in Section 5.1.5.1 of the STPEGS Environmental Report-Construction Permit Stage (ER-CP), approximately one-third of the land occupied by the STPEGS cooling reservoir was used in rice farming each year and was therefore flooded from March through October. Thus, it is expected that the increase in low visibility fogging occurrences from the cooling reservoir will be minimal and localized to the immediate lake vicinity where only very lightly travelled transportation routes might be briefly affected. However, calculations were made using the CRFP fogging model with meteorology from Victoria which has been shown to be representative of the site. The CRFP model has been verified (see ER-CP Section 6.1.3.2.3) using data gathered from studies performed at Dresden Nuclear Power Station in Illinois and Four Corners Power Plant in Arizona.

Because the assessment of measured fogging at the STPEGS site has been performed using a twice verified model, there are no plans to assess the onsite occurrence during operation of fog of the cooling reservoir by performing a comprehensive onsite study.

Question 372.7

FSAR Section 2.3.2.2 indicates that 3 years (February 1953 - January 1956) of meteorological data from Victoria, Texas, were used to provide estimates of increased frequency of fog resulting from operation of the cooling reservior.

1. Discuss the representativeness of the 3 years of Victoria data with respect to long-term conditions expected at the STPEGS site.

2. Four years (July 21, 1973, through September 30, 1977) of onsite meteorological data, including solar radiation information, are now available. Discuss utilization of these high-quality onsite meteorological data in the modeling of predicted impacts resulting from operation of the cooling reservoir.

Response

(1) Ten years of data, from January 1, 1968, through December 31, 1977, for Victoria, Texas, were used to determine the representativeness of the three-year period of Victoria data (February 1953 through January 1956) used in the analysis of fog potential related to the STPEGS Cooling Reservoir. Comparisons were also made to STPEGS data collected onsite as presented in Section 2.3 of the STPEGS UFSAR (Ref. 1). The conclusion of this study is that the February 1953 to January 1956 data used in the fog predictor model are representative of long-term conditions at the STPEGS site.

Presented in Figures Q372.7-1, Q372.7-2, and Q372.7-3 are annual wind roses for Victoria, Texas for three time periods: February 14, 1953, to January 31, 1956; July 21, 1973, to September 30, 1977; and January 1, 1968, to December 31, 1977, respectively. Figure Q372.7-1 is based on the data period used in the fog predictor model; Figure Q372.7-2 based on the concurrent data period with the onsite STPEGS data presented in Section 2.3 of the UFSAR; and Figure Q372.7-3 represents a 10-year long-term average. Agreement between the three periods of record is good. Winds occur most frequently from the south for the long-term and site-concurrent periods (Figures Q372.7-2 and Q372.7-3) and from the south-southeast for the 1953-1956 period (Figure Q372.7-1). Calms occurred with a frequency of 2.46 percent for the site-concurrent period, and 6.67 percent for the period used in the fog study. The high frequency of calms recorded at Victoria as compared to the STPEGS onsite data (0.28 percent) is the result of the relatively high-threshold wind instruments at Victoria. From Figures Q372.7-2 and Q372.7-3 it is concluded that the wind data for the July 21, 1973, to September 30, 1977, period coinciding with the STPEGS onsite program are representative of long-term conditions. Comparison of Figure Q372.7-1 with the STPEGS wind rose for July 21, 1973, to September 30, 1977, (Figure Q372.7-4) yields to the conclusion that the Victoria wind data used in the fog predictor model are representative of the STPEGS site region. The annual average wind speed at Victoria was 9.6 mph for the February 14, 1953, to January 31, 1956, period compared to 10.7 mph at STPEGS for the July 21, 1973, to July 20, 1977, period. Monthly and annual average wind speeds for the three periods of Victoria data are presented in Table Q372.7-1.

Presented in Table Q372.7-2 are monthly and annual averages of ambient temperature and dewpoint temperature for the three periods of Victoria data (February 14, 1953, to January 31, 1956; July 21, 1973, to September 30, 1977; and January 1, 1968, to
Response (Continued)

December 31, 1977) and for the STPEGS onsite data (July 21, 1973, to July 20, 1977). Agreement between average ambient temperatures and dewpoint temperatures for both sites is good, as presented in Table Q372.7-2. The differences are slightly cooler temperatures and higher dewpoints at the STPEGS site, because it is closer to the coast of the Gulf of Mexico than is Victoria.

Table Q372.7-3 presents monthly and annual values of average daily maximum and minimum temperatures and average diurnal temperature ranges for the three periods of Victoria data. Temperatures are slightly warmer and the diurnal range slightly larger for the 1953 to 1956 period than for the later periods.

The monthly and annual stability class frequency distributions for Victoria are presented in Table Q372.7-4 for the three periods discussed in previous sections. For comparison, STPEGS annual stability class distributions are presented in Table Q372.7-5, which contains the information provided in Table 2.3-13 of the STPEGS UFSAR for the period July 21, 1973, to September 30, 1977. Differences between offsite and onsite distributions can be attributed to the different methods of stability classification. The stability distributions determined from Victoria data are based on the Pasquill-Turner approach (Ref. 2), which involves utilization of factors such as cloud cover, isolation, time of day, and wind speed to determine the stability class. The stability distribution determined from STPEGS data is based on the measured vertical temperature gradient, and classified in accordance with Regulatory Guide 1.23. Table Q372.7-4 shows that the Victoria data for the site-concurrent period are representative of long-term conditions. On an annual basis the occurrences of all stability classes are similar for each of the three periods.

Based on comparisons of Victoria data and of available STPEGS onsite data, it is concluded that the Victoria data for the period February 14, 1953, to January 1, 1956, are representative of long-term conditions and that Victoria data are representative of the four years of onsite STPEGS data. It is therefore concluded that the three years of Victoria data used by the Cooling Reservoir Fog Predictor (CRFP) model are representative of long-term conditions expected at the STPEGS site.

(2) The CRFP model, as described in Section 2.3 of the UFSAR, inputs National Weather Service (NWS) observations of wind speed, wind direction, dry bulb temperature, wet bulb temperature, and cloud cover for use in calculations of the dissipation of heat from the thermally loaded reservoir and of the formation of elevated visible plumes and ground-level fog. In addition, solar and longwave radiant energy are

Response (Continued)

calculated for each time period. The solar radiation term is calculated from an algorithm based upon the latitude of the reservoir, day of year, time of day, and cloud cover. The longwave radiant fluxes are calculated from the pond surface temperature and meteorological data including cloud cover.

The onsite meteorological data set contains all parameters necessary for analyses of the Cooling Reservoir except for cloud cover, which would be required in the longwave radiation calculations. However, there are other factors influencing solar radiation received at the ground, such as atmospheric particulates and fog.

References

1. Updated Final Safety Analysis Report - South Texas Project Units 1 & 2, Vol. 2, Docket Nos. STN 50-498 and STN 50-499.

2. Turner, D. Bruce, "A Diffusion Model for an Urban Area", J. App. Meteorol., Vol. 3, No.1 (February 1964), pp.83-91.

TABLE Q372.7-1

MONTHLY AND ANNUAL AVERAGE WIND SPEED
AT VICTORIA, TEXAS, FOR THREE PERIODS OF RECORD

(mph)

	Period of Record		
Month	February 14, 1953 to January 31, 1956	July 21, 1973 to September 30, 1977	January 1, 1968 to December 31, 1977
January	11.2	10.2	10.5
February	12.0	11.1	10.9
March	11.5	12.4	11.9
April	9.7	12.0	11.9
May	9.7	10.1	10.4
June	9.7	9.7	9.8
July	8.2	8.3	8.8
August	7.4	8.0	8.2
September	6.5	8.8	8.8
October	8.3	9.1	9.0
November	10.8	9.9	9.9
December	10.8	9.9	10.0
Annual	9.6	9.9	10.0

TABLE Q372.7-2

MONTHLY AND ANNUAL AVERAGE TEMPERATURE (T)
AND DEW POINT TEMPERATURE (T_d) FOR VICTORIA AND STP

(°F)

Period of Record	Victoria						STPEGS	
	February 14, 1953, to January 31, 1956		July 21, 1973, to September 30, 1977		January 1, 1968, to December 31, 1977		July 21, 1973, to July 20, 1977	
	T	T_d	T	T_d	T	T_d	T	T_d
January	56	47	52	44	53	45	53	47
February	58	46	58	46	56	45	58	48
March	65	54	65	55	63	53	64	57
April	71	62	70	60	70	60	68	62
May	76	67	76	67	75	66	74	68
June	82	71	80	71	80	71	79	72
July	84	73	81	72	82	72	81	74
August	83	73	81	72	82	72	80	73
September	80	70	77	69	78	70	75	68
October	72	61	69	60	71	61	69	61
November	62	50	61	53	61	51	63	55
December	56	45	54	45	56	47	54	46
Annual	71	60	69	60	69	59	68	61

TABLE Q372.7-3

MONTHLY AND ANNUAL VALUES OF AVERAGE DAILY MAXIMUM (MAX), AVERAGE DAILY MINIMUM (MIN), AND AVERAGE DIURNAL TEMPERATURE RANGE FOR VICTORIA, TEXAS

(°F)

Period of Record	February 14, 1953 to January 31, 1956			July 21, 1973 to September 30, 1977			January 1, 1968 to December 31, 1977		
	Max	Min	Range	Max	Min	Range	Max	Min	Range
January	67.0	47.1	19.9	62.5	44.3	18.2	62.7	45.3	17.4
February	69.2	49.3	19.9	69.6	48.7	20.9	66.9	47.6	19.3
March	75.7	57.4	18.3	74.5	57.3	17.2	72.8	54.9	17.9
April	81.3	63.8	17.5	78.5	62.5	16.0	78.5	62.4	16.1
May	85.2	68.4	16.8	83.7	69.2	14.5	83.4	68.0	15.4
June	91.6	73.7	17.9	88.3	73.4	14.9	88.1	73.4	14.7
July	94.1	76.3	17.8	90.3	75.0	15.3	90.9	75.3	15.6
August	93.3	75.9	17.4	90.5	74.8	15.7	91.0	74.9	16.1
September	90.6	72.0	18.6	86.8	70.6	16.2	87.0	71.4	15.6
October	83.3	63.0	20.3	80.1	61.1	19.0	81.0	62.4	18.6
November	73.2	52.7	20.5	72.0	52.9	19.1	71.7	52.1	19.6
December	66.9	46.8	20.1	65.1	45.1	20.0	66.7	47.6	19.1
Annual	81.1	62.4	18.7	79.0	61.9	17.1	78.4	61.3	17.1

TABLE Q372.7-4

MONTHLY AND ANNUAL STABILITY CLASS DISTRIBUTIONS FOR VICTORIA, TEXAS

(%)

1 = February 14, 1953, to January 31, 1956
2 = July 21, 1973, to September 30, 1977
3 = January 1, 1968, to December 31, 1977

Stability Class Based on Pasquill-Turner Method

		A	B	C	D	E	F	G
January	1	0.0	1.70	5.47	66.04	13.80	8.74	4.26
	2	0.10	2.92	6.65	63.91	11.09	12.00	3.33
	3	0.04	2.38	6.41	67.62	10.65	10.36	2.54
February	1	0.12	2.46	6.63	65.43	12.62	9.68	3.05
	2	0.22	2.88	6.53	61.95	11.39	14.16	2.88
	3	0.09	2.12	6.67	65.11	11.09	12.63	2.30
March	1	0.18	2.87	6.68	72.18	8.24	8.02	1.84
	2	0.10	1.61	5.14	78.23	7.06	6.45	1.41
	3	0.28	1.85	5.52	72.98	8.87	8.83	1.65
April	1	1.16	4.35	12.22	57.45	7.96	9.31	7.55
	2	0.31	2.81	8.65	69.27	7.40	9.17	2.40
	3	0.42	2.92	6.87	71.08	8.25	8.42	2.04
May	1	1.30	5.60	13.36	53.65	8.29	9.50	8.29
	2	0.71	4.44	9.58	64.52	8.87	9.88	2.02
	3	0.56	5.20	9.88	63.51	9.44	9.56	1.85
June	1	1.71	4.31	17.69	40.76	14.17	12.92	8.43
	2	1.35	6.87	13.02	48.12	14.27	13.96	2.40
	3	0.92	5.25	12.71	53.21	14.08	11.87	1.96
July	1	2.69	7.44	17.66	35.72	11.52	12.55	12.42
	2	2.69	7.13	18.89	37.69	15.09	15.56	2.96
	3	1.57	5.73	16.77	43.10	14.76	15.60	2.46
August	1	3.81	7.89	17.11	32.44	12.23	12.28	14.25
	2	2.10	8.71	16.53	34.27	14.19	20.16	4.03
	3	1.61	8.67	15.12	36.37	14.92	19.11	4.19
September	1	1.57	9.73	16.35	26.35	7.50	22.14	16.35
	2	1.50	7.58	11.00	40.17	14.17	21.50	4.08
	3	1.17	6.62	10.71	41.58	15.21	21.08	3.62
October	1	0.40	5.74	14.48	33.89	16.27	17.26	11.97
	2	0.30	3.93	10.08	43.95	15.85	21.98	3.93
	3	0.12	4.03	10.00	44.27	15.77	21.29	4.52

TABLE Q372.7-4 (Continued)

MONTHLY AND ANNUAL STABILITY CLASS DISTRIBUTIONS FOR VICTORIA, TEXAS

(%)

1 = February 14, 1953, to January 31, 1956
2 = July 21, 1973, to September 30, 1977
3 = January 1, 1968, to December 31, 1977

Stability Class Based on Pasquill-Turner Method

		A	B	C	D	E	F	G
November	1	0.19	3.29	8.06	56.60	16.95	9.59	5.33
	2	0.10	2.08	7.60	53.54	13.65	16.98	6.04
	3	0.04	2.37	7.75	52.54	14.50	17.46	5.33
December	1	0.09	2.78	6.27	60.62	16.13	9.05	5.06
	2	0.0	2.42	7.56	55.34	15.22	15.02	4.44
	3	0.0	2.10	7.06	59.96	13.59	13.59	3.71
Annual	1	1.12	4.89	11.92	49.84	12.14	11.77	8.32
	2	0.85	4.62	10.34	53.41	12.45	14.98	3.35
	3	0.57	4.12	9.65	55.89	12.60	14.16	3.02

TABLE Q372.7-5

STABILITY CLASS DISTRIBUTIONS BASED ON ΔT (195 ft-33 ft)
FOR THE STPEGS SITE (JULY 21, 1973 - JULY 20, 1977) TEXAS

Period	Stability Class						
	A	B	C	D	E	F	G
July 21, 1973 – July 20, 1974	12.3	2.9	7.5	29.4	22.8	15.3	9.9
July 21, 1974 - July 20, 1975	12.8	2.7	6.5	32.2	23.1	12.6	10.0
July 21, 1975 – July 20, 1976	13.4	3.6	7.7	26.2	22.4	15.6	11.2
October 1, 1976 – September 30, 1977	4.5	2.2	6.1	40.9	24.0	12.9	9.5
July 21, 1973 – July 20, 1977	10.7	2.9	6.9	32.2	23.1	14.1	10.1

Figure Q372.7-1

(See Q&R Figures)

Figure Q372.7-2

Figure Q372.7-3

Figure Q372.7-4

Question 372.8

Identify the primary data recording system (analog or digital) and indicate the fraction of data recorded by the analog and digital systems.

Response

The primary data recording system is digital via magnetic tape. During the first year of operation of the Onsite Meteorological Program, the digital system was not operational and data was extracted from the analog recordings. Approximate data utility from each recording device is shown in the table below.

Data Collection Rates by Device

Time Period	Percent Digital	Percent Analog[1]
July 21, 1973 – November 30, 1974		100
December 1, 1974 – November 30, 1974	NA[2]	NA
July 21, 1975 – December 31, 1975	89.0	11.0
1976[3]	86.4	13.6
1977[4]	67.3	32.7

1. Includes Data Records Indicated as Missing

2. NA - Not Available from Existing Records

3. Includes Period of Limited Maintenance

4. Through September 30, 1977

Question 372.10

Deleted.

Question 372.11

Deleted.

Question 372.12

Provide the results of the calibration findings, including adjustments and/or replacements of components in the data collection and recording system.

Response

Standard calibration procedures include recording "as found" values. Any significant discrepancies are corrected and the sensor recalibrated using standard calibration techniques. "As left" values are then recorded. Significant adjustments and replacement of components are listed as follows:

Calibration Date	Item	Action
November 4, 1974	Translator Card 30-10 DT	Replaced and calibrated card; unable to reach calibration with old card.
January 21, 1975	30 M DT Probe	Replaced probe; ice bath indicated -0.1°F error from true.
	Pryanometer	Replaced sensor; old sensor required new dessicant.
April 9, 1975	60-10 DT	Ice bath off -0.1°F; recalibrated card.
	30-10 DT	Ice bath off +0.1°F; recalibrated card.
	Pyranometer	Electrical short; replaced sensor.
July X, 1975	30 M DT Probe	Ice bath off -0.2°F; replaced sensor
November 12, 1975	No problems	
January 20, 1976	10 M WD	Unacceptable changeover on dual potentiometer; replaced sensor.
April 8, 1976	60 M WD	Cable cover weathered; replaced cable.
	10 M WD	Cable cover weathered; replaced cable.
	60 M WS	Cable cover weathered; replaced cable.
	60 M WS	Cable cover weathered; replaced cable.

Response (Continued)

Calibration Date	Item	Action
	10 M AT	Slight leakage to ground; replaced sensor.
September 29, 1976		

Station had no routine maintenance during period of IBEW strike. Tower was completely recalibrated.

	10 M WD	Sensor had no signal; replaced sensor.
	60 M DT	Ice bath off 0.2°F; replaced probe.
January 18, 1977	60 M WD	Unable to determine "as found" values due to pulled shaft when installing calibrator; replaced sensor.
	30-10 DT	Ice bath indicated -0.2°F error. Replaced probe at 30 M.
April 13, 1977	No problems	
July 19, 1977	30 M DT	Ice bath indicated defective probe; replaced sensor
November 2, 1977	No problems	

Abbreviations:
DT - Delta Temperature
AT - Ambient Temperature
WD - Wind Direction
WS - Wind Speed

Question 372.13

Data recovery for the onsite meteorological program has been extraordinarily high. Indicate if data from other levels have been used to substitute for data at the "primary" levels (i.e., wind speed and direction at the 10m level, and vertical temperature gradient between the 10m and 59.4m levels), and, if so, describe the procedures used for the substitutions.

Response

Data were not substituted from other levels to enhance data recovery. The high percentage data recovery is attributed to an intensive maintenance program including quarterly calibrations and three site visits per week by qualified instrument technicians. Generally, any problems encountered were solved immediately upon discovery or within 72 hours, resulting in minimal data loss.

Question 372.14

Provide the dates and times of significant instrument outage, the causes of the outage, and the corrective action taken. Also discuss the reasons for the limited maintenance performed on the data collecting equipment during the July 21, 1976, through September 30, 1976, period.

Response

Dates and times of significant instrument outage in excess of 24 hrs and the corrective action taken for resolution of the outage are shown in Table Q372.14-1.

Limited maintenance was performed on the data-collecting equipment during the period July 21, 1976, through September 30, 1976, because of a strike by local union workers. No calibrations or routine site visits were performed during this period.

TABLE Q372.14-1

SIGNIFICANT INSTRUMENT OUTAGES

Days	Problem	Resolution	Approximate Hrs of Data Lost
11/237/75 – 10/241/75	Rain gauge out	Replaced Potentiometer	95
10/332/75 – 11/335/75	60m wind speed failure	Replaced Sensor	73
14/334/75- 11/335/75	60m wind direction failure	Replaced Sensor	22
3/10/76 - 10/20/76	10m wind direction failure	Replaced Sensor	123
8/63/76 - 12/70/76	Solar radiation failure	Replaced Sensor	173
0/218/76 - 16/219/76	End of tape *	Replaced Tape	41
0/242/76 - 14/243/76	End of tape *	Replaced Tape	39
15/249/76 - 14/251/76	End of tape *	Replaced Tape	48
5/260/76 - 11/266/76	End of tape *	Replaced Tape	184
4/269/76 - 9/273/76	End of tape *	Replaced Tape	101
12/266/76 - 10/274/76	10 m wind direction failure	Replaced Sensor	190
10/333/76 - 11/334/76	10 m wind speed stopped due to freezing precipitation	Natural Thaw	26
8/333/76 - 11/334/76-	60m wind speed stopped due to freezing precipitation	Natural Thaw	28

TABLE Q372.14-1 (Continued)

SIGNIFICANT INSTRUMENT OUTAGES

Days	Problem	Resolution	Approximate Hrs of Data Lost
20/366/76 - 10/5/77	60m wind speed defective	Replaced Sensor	65
11/45/77 - 7/115/77	30-10 T defective	Replaced Sensor	1700
9/49/77 - 8/52/77	60m wind speed defective	Replaced Sensor	72
18/161/77 - 16/201/77	30-10 T defective	Replaced Sensor	958
7/165/77 - 11/168/77	Precipitation	Replaced Potentiometer	76
18/252/77 - 18/264/77	Dewpoint off scale	Adjust Dewpoint	289

* End of Tape - Limited Maintenance Period

Question 372.16

The atmospheric dispersion model and procedures used to evaluate dispersion conditions to be used in an assessment of the consequences of design basis accidents described in Section 2.3.4 of the FSAR are based on Regulatory Guide 1.4 and Section 2.3.4 of the Standard Review Plan. After review of the results of recent atmospheric dispersion field experiments, we have developed a modified procedure for calculating short-term relative concentration (χ/Q) values which considers the following:

1. Lateral plume meander
2. Atmospheric dispersion conditions as a function of direction
3. Wind direction frequencies
4. Exclusion area boundary distances as a function of direction

Enclosed is a copy of DRAFT Regulatory Guide 1.XXX, "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants" (9/23/77), which describes the new procedure in detail. We believe that this model will provide an improved characterization of atmospheric dispersion conditions around the STPEGS site.

Enclosed is the interim branch technical position concerning use of these two models. During our review, we will examine χ/Q values for appropriate time periods for design basis accident evaluations using the modified model described in the enclosed DRAFT Regulatory Guide, and compare them with χ/Q values calculated using the model described in Regulatory Guide 1.4 and the procedures described in Section 2.3.4 of the Standard Review Plan. Therefore, provide exclusion area boundary distances as a function of direction using the procedure described in the DRAFT Regulatory Guide. Also provide a large-scale (for independent measurement) map of the site, similar to Figure 2.3-12, that also identifies the exclusion area boundaries, true north, and includes a scale of distances.

Response

The table below presents exclusion area boundary distances as a function of direction. A large-scale map of the site is provided under separate cover. (ST-HL-AE-295).

Response (Continued)

Direction	Distance * (meters)	Distance Used in Calculations (meters)
N	1430	1430
NNE	1430	1430
NE	1471	1430
ENE	1512	1430
E	1524	1430
ESE	1512	1430
SE	1471	1430
SSE	1430	1430
S	1430	1430
SSW	1430	1430
SW	1540	1430
WSW	1722	1430
W	1853	1430
WNW	1722	1430
NW	1540	1430
NNW	1430	1430

* Minimum within ± 22.5 degrees of the sector centerline

Question 372.17

The effects of spatial and temporal variations in atmospheric transport and diffusion conditions is of importance in describing the dose consequences of airborne routine releases of radioactivity. Sea breeze penetration at the STPEGS site is discussed on pages 2.3-14 and 2.3-15 of the FSAR with the conclusion that, because of the low frequency of occurrence of sea breeze penetration to the site, "the impact of sea breeze upon dose estimates for the STPEGS is expected to be insignificant". However, assessments of dose consequences to the population out to a distance of 80 km from the plant is required by Appendix I to 10 CFR Part 50, and the calculations of these doses may be affected by local circulation patterns such as the sea breeze in the area of the STPEGS site. Provide additional discussion of the effects of spatial and temporal variations in airflow of the estimates of annual average relative concentration (χ/Q) and relative deposition (D/Q) values out to a distance of 80 km from the site, and provide estimates of adjustments to χ/Q and D/Q values for consideration of these variations.

Response

Comparison of χ/Q values for STPEGS with those for the Allens Creek Nuclear Generating Station (HL&P, 1973), located 110 km inland (97 km north of STPEGS), indicates long-term dispersion conditions tend to decrease (χ/Q increases) farther inland (see Tables Q372.17-l and Q372.17-2). A portion of this difference can be attributed to sea breeze.

Under conditions favoring closed circulation, it is likely that a helical streak line, which moves northward up the coast line in time, will occur. This phenomenon results from (a) the sea breeze veering (turning to the right) with time due to the Coriolis effect, and (b) the amount of veering decreasing with height because the return flow is weaker than the onshore flow beneath; i.e., the return flow veers less than the surface flow. A helical streak line resulting from a sea breeze has not been observed. The sea breeze modeling results of McPherson (1968), however, clearly demonstrate a helical pattern such as described above.

There is currently no methodology available to accurately account for sea breeze effects not already present in the STPEGS meteorological record.

References

1. ss, S. L., 1959: Introduction to Theoretical Meteorology, Henry Holt and Company, New York, pp. 201.

2. Houston Lighting & Power Company, 1973: "Preliminary Safety Analysis Report - Allens Creek Nuclear Generating Station", submitted to the Nuclear Regulatory Commission, Washington, D. C.

3. McPherson, R. D., 1968: "A Three-Dimensional Numerical Study of the Texas Coast Sea Breeze", Report No. 15, Atmospheric Science Group, The University of Texas, Austin, pp. 252.

4. McPherson, R. D., 1970: " A Numerical Study of the Effect of a Coastal Irregularity on the Sea Breeze", Journ. Appl. Met., 9, pp. 767-777.

TABLE Q372.17-1
AVERAGE METEORLOGICAL RELATIVE
CONCENTRATION
DATA PERIOD: 7/21/73 TO 9/30/77

TABLE Q372.17-1
AVERAGE METEOROLOGICAL RELATIVE
CONCENTRATION
DATA PERIOD: 7/21/73 TO 9/30/77

NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N
SITE BOUNDARY DISTANCES															
4.1E-07	3.4E-07	2.1E-07	2.7E-07	0.5E-08	4.0E-08	7.2E-08	1.0E-07	1.2E-07	2.4E-07	2.9E-07	6.0E-07	6.6E-07	1.0E-06	1.1E-06	1.0E-06
3.4E-07	2.9E-07	1.9E-07	2.4E-07	7.0E-08	3.0E-08	5.5E-08	7.8E-08	8.9E-08	1.9E-07	2.3E-07	5.1E-07	5.7E-07	8.7E-07	9.6E-07	8.8E-07
2.0E-09	1.3E-09	6.4E-10	7.9E-10	2.7E-10	1.1E-10	3.1E-10	4.8E-10	3.7E-10	7.6E-10	8.7E-10	2.0E-09	2.8E-09	6.3E-09	8.4E-09	7.7E-09
4.1E-07	3.3E-07	2.1E-07	2.7E-07	8.4E-08	3.9E-08	7.1E-08	9.9E-08	1.1E-07	2.4E-07	2.8E-07	5.9E-07	6.6E-07	1.0E-06	1.1E-06	1.0E-06
4.1E-07	3.3E-07	2.1E-07	2.7E-07	8.4E-08	4.0E-08	7.2E-08	1.0E-07	1.1E-07	2.4E-07	2.8E-07	5.9E-07	6.6E-07	1.0E-06	1.1E-06	1.0E-06
3.6E-07	2.9E-07	1.8E-07	2.4E-07	6.9E-08	2.9E-08	5.4E-08	7.6E-08	8.6E-08	1.9E-07	2.3E-07	5.0E-07	5.7E-07	8.6E-07	9.6E-07	8.7E-07
3.6E-07	2.9E-07	1.9E-07	2.4E-07	7.0E-08	3.0E-08	5.5E-08	7.7E-08	8.7E-08	1.9E-07	2.3E-07	5.1E-07	5.7E-07	8.7E-07	9.8E-07	8.8E-07
1555.	1586.	1600.	1567.	2971.	6889.	6420.	5936.	6360.	4426.	3419.	2160.	1889.	1792.	1631.	1521.
LOW POPULATION ZONE DISTANCE (4800 METERS)															
8.4E-08	7.0E-08	4.5E-08	5.6E-08	4.4E-08	6.5E-08	1.1E-07	1.4E-07	1.0E-07	2.2E-07	1.0E-07	2.0E-07	1.8E-07	2.5E-07	2.4E-07	2.0E-07
6.6E-08	5.5E-08	3.5E-08	4.4E-08	3.5E-08	5.1E-08	8.5E-08	1.1E-07	1.4E-07	1.7E-07	1.4E-07	1.6E-07	1.4E-07	2.0E-07	1.9E-07	1.5E-07
4.3E-10	2.1E-10	1.0E-10	1.2E-10	1.2E-10	2.1E-10	5.1E-10	6.9E-10	6.3E-10	6.6E-10	4.9E-10	5.2E-10	5.0E-10	1.2E-09	1.4E-09	1.1E-09
8.2E-08	6.9E-08	4.3E-08	5.4E-08	4.3E-08	6.4E-08	1.1E-07	1.3E-07	1.7E-07	2.2E-07	1.8E-07	1.9E-07	1.8E-07	2.4E-07	2.4E-07	1.9E-07
8.3E-08	7.0E-08	4.4E-08	5.5E-08	4.4E-08	6.5E-08	1.1E-07	1.4E-07	1.8E-07	2.2E-07	1.8E-07	2.0E-07	1.8E-07	2.5E-07	2.4E-07	2.0E-07
6.5E-08	5.4E-08	3.4E-08	4.3E-08	3.4E-08	5.0E-08	8.4E-08	1.1E-07	1.4E-07	1.7E-07	1.4E-07	1.5E-07	1.4E-07	1.9E-07	1.9E-07	1.5E-07
6.6E-08	5.5E-08	3.5E-08	4.4E-08	3.5E-08	5.1E-08	8.4E-08	1.1E-07	1.4E-07	1.7E-07	1.4E-07	1.5E-07	1.4E-07	2.0E-07	1.9E-07	1.5E-07
4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.	4000.
0.5 MILES (805 METERS)															
1.1E-06	9.0E-07	6.3E-07	7.7E-07	6.1E-07	9.2E-07	1.5E-06	1.9E-06	2.4E-06	3.1E-06	2.5E-06	2.7E-06	2.4E-06	3.4E-06	3.2E-06	2.7E-06
1.1E-06	9.0E-07	5.8E-07	7.1E-07	5.6E-07	8.4E-07	1.4E-06	1.8E-06	2.2E-06	2.8E-06	2.3E-06	2.5E-06	2.2E-06	3.1E-06	3.0E-06	2.4E-06
8.2E-09	4.0E-09	1.9E-09	2.3E-09	2.3E-09	4.0E-09	9.7E-09	1.3E-08	1.2E-08	1.3E-08	9.3E-09	9.9E-09	1.1E-08	2.3E-08	2.6E-08	2.2E-08
1.1E-06	9.0E-07	6.3E-07	7.7E-07	6.1E-07	9.2E-07	1.5E-06	1.9E-06	2.4E-06	3.1E-06	2.5E-06	2.7E-06	2.4E-06	3.2E-06	3.2E-06	2.7E-06
1.1E-06	9.0E-07	6.3E-07	7.7E-07	6.1E-07	9.2E-07	1.5E-06	1.9E-06	2.4E-06	3.1E-06	2.5E-06	2.7E-06	2.4E-06	3.3E-06	3.2E-06	2.7E-06
1.0E-06	8.9E-07	5.7E-07	7.0E-07	5.6E-07	8.4E-07	1.4E-06	1.7E-06	2.2E-06	2.8E-06	2.3E-06	2.5E-06	2.2E-06	3.1E-06	3.0E-06	2.4E-06
1.1E-06	9.0E-07	5.8E-07	7.1E-07	5.6E-07	8.4E-07	1.4E-06	1.8E-06	2.2E-06	2.8E-06	2.3E-06	2.5E-06	2.2E-06	3.1E-06	3.0E-06	2.4E-06
805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.	805.
1.5 MILES (2415 METERS)															
2.2E-07	1.8E-07	1.2E-07	1.4E-07	1.1E-07	1.7E-07	2.8E-07	3.6E-07	4.6E-07	5.7E-07	4.7E-07	5.1E-07	4.7E-07	6.5E-07	6.4E-07	5.1E-07
1.8E-07	1.5E-07	9.8E-08	1.2E-07	9.7E-08	1.4E-07	2.4E-07	3.0E-07	3.9E-07	4.8E-07	4.0E-07	4.3E-07	3.9E-07	5.5E-07	5.4E-07	4.4E-07
1.4E-09	6.6E-10	3.2E-10	3.9E-10	3.0E-10	6.6E-10	1.6E-09	2.2E-09	2.0E-09	2.1E-09	1.6E-09	1.6E-09	1.9E-09	3.9E-09	4.4E-09	3.6E-09
2.2E-07	1.8E-07	1.1E-07	1.4E-07	1.1E-07	1.7E-07	2.8E-07	3.6E-07	4.6E-07	5.6E-07	4.7E-07	5.0E-07	4.6E-07	6.5E-07	6.4E-07	5.1E-07
2.2E-07	1.8E-07	1.2E-07	1.4E-07	1.1E-07	1.7E-07	2.8E-07	3.6E-07	4.6E-07	5.7E-07	4.7E-07	5.1E-07	4.7E-07	6.5E-07	6.4E-07	5.1E-07
1.8E-07	1.5E-07	9.6E-08	1.2E-07	9.6E-08	1.4E-07	2.4E-07	3.0E-07	3.8E-07	4.8E-07	3.9E-07	4.2E-07	3.9E-07	5.5E-07	5.4E-07	4.3E-07
1.8E-07	1.5E-07	9.7E-08	1.2E-07	9.7E-08	1.4E-07	2.4E-07	3.0E-07	3.9E-07	4.8E-07	4.0E-07	4.3E-07	3.9E-07	5.5E-07	5.4E-07	4.3E-07
2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.	2415.

TOTAL OBS -35014 TOTAL INV OBS - 262 CALMS UPPER LEVEL - 0.00 CALMS LOWER LEV -112.00

KEY ENTRY 1 RELATIVE CONCENTRATION - XDQ (S/M**3)
ENTRY 2 DEPLETED RELATIVE CONCENTRATION (S/M**3)
ENTRY 3 RELATIVE DEPOSITION RATE (1/M**2)
ENTRY 4 DECAYED XDQ (S/M**3) - HALF LIFE 2.26 DAYS
ENTRY 5 DECAYED XDQ (S/M**3) - HALF LIFE 8.00 DAYS
ENTRY 6 DEC+DPL XDQ (S/M**3) - HALF LIFE 2.26 DAYS
ENTRY 7 DEC+DPL XDQ (S/M**3) - HALF LIFE 8.00 DAYS
ENTRY 8 - DISTANCE IN METERS

TABLE Q372.17-1 (Continued)
AVERAGE METEOROLOGICAL RELATIVE CONCENTRATION
DATA PERIOD: 7/21/73 TO 9/30/77

NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	N
2.5 MILES			(4024 METERS)												
1.1E-07	8.8E-08	5.6E-08	7.0E-08	5.6E-08	8.2E-08	1.4E-07	1.7E-07	2.2E-07	2.8E-07	2.3E-07	2.5E-07	2.3E-07	3.2E-07	3.1E-07	2.5E-07
8.5E-08	7.1E-08	4.5E-08	5.7E-08	4.5E-08	6.6E-08	1.1E-07	1.4E-07	1.8E-07	2.2E-07	1.9E-07	2.0E-07	1.8E-07	2.6E-07	2.5E-07	2.0E-07
5.6E-10	2.6E-10	1.4E-10	1.6E-10	1.2E-10	2.0E-10	6.8E-10	9.4E-10	8.5E-10	8.9E-10	6.6E-10	7.0E-10	7.0E-10	1.6E-09	1.9E-09	1.5E-09
1.0E-07	8.7E-08	5.5E-08	6.9E-08	5.5E-08	8.1E-08	1.4E-07	1.7E-07	2.2E-07	2.7E-07	2.3E-07	2.5E-07	2.3E-07	3.1E-07	3.1E-07	2.5E-07
1.1E-07	8.8E-08	5.6E-08	7.0E-08	5.6E-08	8.2E-08	1.4E-07	1.7E-07	2.2E-07	2.6E-07	2.3E-07	2.5E-07	2.3E-07	3.2E-07	3.1E-07	2.5E-07
8.4E-08	7.0E-08	4.4E-08	5.5E-08	4.4E-08	6.5E-08	1.1E-07	1.4E-07	1.8E-07	2.2E-07	1.8E-07	2.0E-07	1.8E-07	2.5E-07	2.5E-07	2.0E-07
8.5E-08	7.1E-08	4.5E-08	5.6E-08	4.5E-08	6.6E-08	1.1E-07	1.4E-07	1.8E-07	2.2E-07	1.8E-07	2.0E-07	1.8E-07	2.5E-07	2.5E-07	2.0E-07
4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.	4024.
3.5 MILES			(5634 METERS)												
6.7E-08	5.7E-08	3.6E-08	4.5E-08	3.6E-08	5.3E-08	8.6E-08	1.1E-07	1.4E-07	1.8E-07	1.5E-07	1.6E-07	1.5E-07	2.0E-07	1.9E-07	1.6E-07
5.2E-08	4.4E-08	2.8E-08	3.5E-08	2.8E-08	4.1E-08	6.7E-08	8.4E-08	1.1E-07	1.4E-07	1.1E-07	1.2E-07	1.1E-07	1.5E-07	1.5E-07	1.2E-07
3.2E-10	1.6E-10	7.7E-11	9.2E-11	9.1E-11	1.6E-10	3.8E-10	5.3E-10	4.8E-10	5.0E-10	3.7E-10	3.9E-10	4.4E-10	9.2E-10	1.0E-09	8.6E-10
6.6E-08	5.5E-08	3.5E-08	4.4E-08	3.5E-08	5.1E-08	8.5E-08	1.1E-07	1.4E-07	1.7E-07	1.5E-07	1.6E-07	1.4E-07	2.0E-07	1.9E-07	1.5E-07
6.7E-08	5.6E-08	3.6E-08	4.5E-08	3.5E-08	5.2E-08	8.6E-08	1.1E-07	1.4E-07	1.8E-07	1.5E-07	1.6E-07	1.4E-07	2.0E-07	1.9E-07	1.6E-07
5.1E-08	4.3E-08	2.7E-08	3.4E-08	2.7E-08	4.0E-08	6.6E-08	8.3E-08	1.1E-07	1.4E-07	1.1E-07	1.2E-07	1.1E-07	1.5E-07	1.5E-07	1.2E-07
5.2E-08	4.4E-08	2.8E-08	3.4E-08	2.7E-08	4.0E-08	6.6E-08	8.4E-08	1.1E-07	1.4E-07	1.1E-07	1.2E-07	1.1E-07	1.5E-07	1.5E-07	1.2E-07
5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.	5634.
4.5 MILES			(7244 METERS)												
4.8E-08	4.1E-08	2.6E-08	3.2E-08	2.5E-08	3.7E-08	6.1E-08	7.7E-08	1.0E-07	1.3E-07	1.1E-07	1.1E-07	1.0E-07	1.4E-07	1.4E-07	1.1E-07
3.6E-08	3.1E-08	1.9E-08	2.4E-08	1.9E-08	2.8E-08	4.6E-08	5.8E-08	7.6E-08	9.3E-08	8.0E-08	8.6E-08	7.7E-08	1.1E-07	1.0E-07	8.4E-08
2.1E-10	1.0E-10	5.0E-11	5.9E-11	5.9E-11	1.0E-10	2.5E-10	3.4E-10	3.1E-10	3.2E-10	2.4E-10	2.5E-10	2.9E-10	6.0E-10	6.7E-10	5.5E-10
4.7E-08	3.9E-08	2.5E-08	3.1E-08	2.5E-08	3.6E-08	6.0E-08	7.5E-08	9.9E-08	1.2E-07	1.0E-07	1.1E-07	1.0E-07	1.4E-07	1.3E-07	1.1E-07
4.8E-08	4.0E-08	2.6E-08	3.2E-08	2.5E-08	3.7E-08	6.1E-08	7.8E-08	1.0E-07	1.3E-07	1.1E-07	1.1E-07	1.0E-07	1.4E-07	1.4E-07	1.1E-07
3.5E-08	2.9E-08	1.9E-08	2.3E-08	1.8E-08	2.7E-08	4.5E-08	5.6E-08	7.4E-08	9.4E-08	7.8E-08	8.3E-08	7.5E-08	1.0E-07	1.0E-07	8.2E-08
3.6E-08	3.0E-08	1.9E-08	2.4E-08	1.9E-08	2.8E-08	4.6E-08	5.7E-08	7.5E-08	9.5E-08	7.9E-08	8.5E-08	7.7E-08	1.0E-07	1.0E-07	8.3E-08
7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.	7244.
7.5 MILES			(12073 METERS)												
2.4E-08	2.1E-08	1.3E-08	1.6E-08	1.3E-08	1.9E-08	3.1E-08	3.8E-08	5.1E-08	6.5E-08	5.4E-08	5.8E-08	5.2E-08	7.0E-08	6.8E-08	5.6E-08
1.7E-08	1.4E-08	9.2E-09	1.1E-08	9.0E-09	1.3E-08	2.1E-08	2.7E-08	3.6E-08	4.5E-08	3.8E-08	4.1E-08	3.6E-08	4.9E-08	4.7E-08	3.9E-08
8.6E-11	4.2E-11	2.0E-11	2.4E-11	2.4E-11	4.2E-11	1.0E-10	1.4E-10	1.3E-10	1.3E-10	9.8E-11	1.0E-10	1.2E-10	2.4E-10	2.7E-10	2.3E-10
2.3E-08	2.0E-08	1.2E-08	1.5E-08	1.2E-08	1.8E-08	3.0E-08	3.7E-08	4.9E-08	6.3E-08	5.2E-08	5.6E-08	5.0E-08	6.7E-08	6.6E-08	5.4E-08
2.4E-08	2.0E-08	1.3E-08	1.6E-08	1.3E-08	1.9E-08	3.0E-08	3.8E-08	5.1E-08	6.4E-08	5.4E-08	5.8E-08	5.1E-08	6.9E-08	6.7E-08	5.5E-08
1.6E-08	1.4E-08	8.6E-09	1.1E-08	8.5E-09	1.3E-08	2.1E-08	2.6E-08	3.4E-08	4.4E-08	3.6E-08	3.9E-08	3.5E-08	4.7E-08	4.6E-08	3.7E-08
1.7E-08	1.4E-08	9.0E-09	1.1E-08	8.8E-09	1.3E-08	2.1E-08	2.6E-08	3.5E-08	4.5E-08	3.7E-08	4.0E-08	3.6E-08	4.8E-08	4.7E-08	3.8E-08
12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.	12073.

TOTAL OBS -35014 TOTAL INV OBS - 262 CALMS UPPER LEVEL - 0.00 CALMS LOWER LEV -112.00

KEY ENTRY 1 RELATIVE CONCENTRATION - XOQ (S/M**3)
ENTRY 2 DEPLETED RELATIVE CONCENTRATION (S/M**3)
ENTRY 3 RELATIVE DEPOSITION RATE (1/M**2)
ENTRY 4 DECAYED XOQ (S/M**3) - HALF LIFE 2.26 DAYS
ENTRY 5 DECAYED XOQ (S/M**3) - HALF LIFE 8.00 DAYS
ENTRY 6 DEC+DPL XOQ (S/M**3) - HALF LIFE 2.26 DAYS
ENTRY 7 DEC+DPL XOQ (S/M**3) - HALF LIFE 8.00 DAYS
ENTRY 8 - DISTANCE IN METERS

TABLE Q372.17-2

ALLENS CREEK NUCLEAR GENERATING STATION
ANNUAL AVERAGE DILUTION FACTORS (SECONDS/METER^3
AT THE MID-POINT OF THE STANDARD DISTANCES
GROUND RELEASE

Affected Sector	Distance (Miles)									
	0-5	1.5	2.5	3.5	4.5	7.5	15	25	35	45
N	4.9E-6	9.6E-7	4.7E-7	3.0E-7	2.1E-7	1.0E-7	4.1E-7	2.1E-8	1.4E-8	1.0E-8
NNE	3.4E-6	6.5E-7	3.2E-7	2.0E-7	1.4E-7	7.1E-8	2.8E-8	1.5E-8	9.7E-9	7.1E-9
NE	2.0E-6	3.8E-7	1.9E-7	1.2E-7	8.3E-8	4.1E-8	1.6E-8	8.5E-8	5.6E-9	4.1E-9
ENE	1.4E-6	2.6E-7	1.3E7	8.2E-8	5.8E-8	2.9E-8	1.1E-8	5.9E-8	3.9E-9	2.9E-9
E	1.5E-6	2.8E-7	1.4E-7	8.9E-8	6.3E-8	3.2E-8	1.3E8	6.7E-9	4.4E-9	3.3E-9
ESE	1.4E-6	2.6E-7	1.3E-7	8.4E-8	6.0E-8	3.0E-8	1.2E-8	6.4E-9	4.2E-9	3.1E-9
SE	1.9E-6	3.6E-7	1.8E-7	1.2E-7	8.3E-8	4.2E-8	1.7E-8	8.8E-9	5.8E-9	4.3E-9
SSE	2.8E-6	5.2E-7	2.6E-7	1.6E-7	1.2E-7	5.8E-8	2.3E-8	1.2E-8	7.9E-9	5.8E-9
S	4.6E-6	8.7E-7	4.3E-7	2.7E-7	1.9E-7	9.6E-8	3.8E-8	2.0E-8	1.3E-8	9.6E-9
SSW	3.6E-6	6.8E-7	3.3E-7	2.1E-7	1.5E-7	7.4E-8	2.9E-8	1.5E-8	1.0E-8	7.4E-9
SW	3.7E-6	7.1E-7	3.5E-7	2.2E-7	1.6E-7	7.8E-8	3.1E-8	1.6E-8	1.1E-8	7.7E-9
WSW	3.3E-6	6.35-7	6.1E-7	2.0E-7	1.4E-7	7.1E-8	2.8E-8	1.5E-8	9.7E-9	7.2E-9
W	2.9E-6	5.7E-7	2.8E-7	1.8E-7	1.3E-7	6.3E-8	2.5E-8	1.3E-8	8.5E-9	6.2E-9
WNW	2.8E-6	5.4E-7	2.7E-7	1.7E-7	1.2E-7	5.8E-8	2.3E-8	1.2E-8	7.8E-9	5.7E-9
NW	4.9E-6	9.8E-7	4.8E-7	3.0E-7	2.1E-7	1.1E-7	4.2E-8	2.2E-8	1.4E-8	1.1E-8
NNW	4.1E-6	8.2E-7	4.0E-7	2.5E-7	1.7E-7	8.6E-8	3.4E-8	1.7E-8	1.1E-8	8.4E-9

Question 372.18

From the discussion of extreme winds presented in Section 2.3.1.2.1, of the FSAR it appears that the design wind velocity at 30 feet above ground with a 100-year recurrence interval should be 125 mph. As stated on page 2.3-3 of the FSAR, this value, when used with a gustiness factor of 1.3, provides an estimate of the highest instantaneous gust expected once in 100 years of 163 mph. Clarify the apparent discrepancy between the selection of the design wind velocity and gust factor used in Section 3.3.1 and the discussion of extreme winds and gust factors presented in Section 2.3.1.2.1.

Response

The recorded 125 mph wind velocity (as was experienced by Corpus Christi during Hurricane Celia) is not considered to have occurred at the STPEGS site due to the reduction of wind velocity which occurs when hurricanes traverse over land (STPEGS PSAR Section 3.3.1.2). It is estimated that a wind velocity of 120 mph occured at the STPEGS site during Celia.

Question 372.19

The response to Request No. 372.3 states that "The STPEGS design basis maximum and minimum outside ambient temperatures are 96°F and 29°F, respectively." Climatological data presented in Tables 2.3-14 through 2.3-20 indicate an observed maximum temperature of 110°F at Victoria, with observed extreme maximum temperatures ranging from 101°F to 105°F at other climatological stations in the area. Temperatures in excess of 90°F may be expected on an average of about 100 days each year. Similarly, an extreme minimum temperature of 8°F has been observed at Galveston, with observed extreme minimum temperatures ranging from 9°F to 13°F at other climatological stations in the area. Temperatures of 32°F or lower may be expected on an average of about 10 days each year. Provide further justification of the selected design basis maximum and minimum ambient air temperatures considering that extreme temperatures observed in the area are significantly different than the selected design basis values. Also discuss the effects on safety-related systems and components resulting from persistent (e.g., on the order of several hours) temperatures significantly different than the selected design basis values.

Response

As described in the revised response to Question 372.3, the heating, ventilating and air conditioning (HVAC) design basis maximum and minimum outside ambient temperatures are 95°F and 29°F, respectively. These design conditions are based on ASHRAE data and are 99 percent (winter) and 1 percent (summer) temperature levels for Bay City, Texas. The summer design basis of 95°F will be exceeded only 1 percent of the time in a normal summer and conversely there will be temperatures lower than 29°F only 1 percent of the time in a normal winter.

The outside design temperatures for safety-related HVAC, auxiliary systems, and components (95°F and 29°F) are considered long-term, steady state values. They are conservatively assumed to occur continuously during summer and winter, while extreme maximum and minimum temperatures are transient values of short duration.

Because of thermal inertia and due to the conservative design of HVAC systems, it is expected that persistent (e.g., on the order of several hours) temperatures outside the design basis values will have no impact on the normal temperature ranges delineated in Table 9.4-1. Thus, there will be no impact on safety-related systems and components located in structures served by HVAC systems.

As described in the response to Question 372.3, components such as instrument lines that are located outside and hence are exposed to freezing conditions are heat traced and insulated. Therefore, there will be no impact on these components resulting from persistent temperatures different than the design basis values.

Question 372.21

The annual frequencies of occurrence of moderately stable and extremely stable conditions (Pasquill types "F" and "G", respectively) are very important in the determination of relative concentration (χ/Q) values to be used in assessing the consequences of design basis accidents. A significant decrease (about 60 percent) in the annual frequency of extremely stable conditions at Victoria was observed for the period July 1973 through June 1977 (Table 2.3-12) compared to the annual frequency of these conditions observed for the period September 1953 through August 1958 (Table 2.3-11), particularly during the summer and fall seasons. Discuss possible explanations for this decrease in the occurrence of extremely stable conditions at Victoria, and discuss the significance of this decrease on the representativeness and conservatism of the onsite data collected during the period July 1973 through September 1977.

Response

The stability frequency distributions presented in Tables 2.3-11 and 2.3-12 were produced by the so-called "STAR" technique. This method of estimating thermal atmospheric stability is indirect, using wind speed, total amount of cloud cover, incoming solar radiation and time of day. With respect to moderately and extremely stable conditions (which can occur only at night) only wind speed and cloud cover are of interest. The scheme to estimate Pasquill "F" (moderately stable) and "G" (extremely stable) is shown below:

	Cloud Cover	
Wind Speed	≥50%	<50%
Very low (0-3 knots)	F	G
Low (4-6 knots)	E	F

Therefore, to produce an increase in "G" frequencies, an increase in occurrence of very low wind conditions or a decrease in amount of cloud cover must occur.

There are three possible explanations for these conditions:

1. Observations were reported once every three hours in the later period (7/73 - 6/77), whereas they were reported hourly in the earlier period (9/53 - 8/58). The later observations could produce biased low wind speed and/or cloud cover conditions.

2. A change in technique and/or instruments used to measure wind speed and cloud cover could have occurred between the two periods.

3. A real change in the meteorology could have occurred between the periods, indicating that one or both of the periods were not representative of the climatology of Victoria.

Response (Continued)

Each of these possibilities will be discussed below.

1. Three-hourly vs Hourly Observations - In a study performed by the National Climatic Center of NOAA (Ref. 1) the percentage distributions of stabilities produced by the "STAR" method using hourly data and three-hourly data were compared. Using several statistical techniques, they concluded there were no significant differences between the frequencies produced by three-hourly and hourly data.

2. Change in Techniques and/or Instruments - Upon closer inspection of the two frequency distributions, a large decrease in the percentage of very low wind speeds (0-3 knots), and particularly in the percentage of calms, was found in the later data period. As shown above, this decrease in very low wind speeds would produce a decrease in the extreme stable conditions. Table 1, below, shows the change in percent of wind speed classes from the earlier data period and the later.

Table 1
Wind Speed Class (Knots)

Period	Calm	0-3	4-6	7-10	11-16	17-21	>21
Annual	-6.0	- 8.8	10.1	-2.6	2.9	-0.9	-0.6
Winter	-2.5	- 3.1	10.3	-3.2	0.2	-2.3	-1.8
Spring	-5.3	- 7.7	4.1	-2.9	6.1	0.9	-0.5
Summer	-9.7	-11.3	16.1	-3.5	-0.5	-0.9	0.1
Autumn	-6.8	-13.5	9.8	-0.8	5.8	-0.9	-0.3

A large annual decrease (8.8 percent)[1] is observed in the frequency of very low wind speeds from the earlier to the later period. The majority of the decrease can be attributed to a decrease in the frequency of calms (6.0 percent).[2] Also, it should be noted that there was a corresponding increase in the 4-6 knot frequency class, suggesting the lowest frequencies were "shifted" up one class. This shift of wind speed may have occurred as a result of different techniques in reporting calms or from changing to an anemometer with a lower threshold speed.

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1. A threefold decrease between the earlier and later periods.
2. A twofold decrease between the earlier and later periods.

Response (Continued)

Examination of the station history revealed that the Air Force operated the Victoria station during the earlier period and that it was turned over to the National Weather Service in 1961. Mr. Steve Doty of the National Climatic Center stated to us that, although it would be very difficult to document, he has found that Air Force stations tend to report a higher percentage of calms than do comparable National Weather Service stations.

3. Meteorological Differences Between the Two Periods - Finally, in order to determine if the changes in the frequencies of stable conditions were produced by real changes in the meteorology, a longer period of record from Victoria[3] was examined. Although the frequency distribution did not separate stability classes F and G, the percentages of low wind speeds can be compared to those of the two other data periods. The frequencies of wind speed classes for each of the data periods are shown in Table 2, below.

Table 2
Wind Speed Class (Knots)

Period	Calm	0-3	4-6	7-10	11-16	17-21	>21
9/53-8/58 (Earlier, 5 yr)	8.7	16.2	22.3	33.4	20.1	6.2	1.7
7/73-6/77 (Later, 5 yr)	2.7	7.4	32.4	30.8	23.0	5.4	1.1
1/65-1/74 (Longer, 10 yr)	2.8	7.0	30.4	32.2	24.2	5.2	1.0

As can be seen, the later period (7/73-6/77) corresponds very closely with the longer period of record.

Conclusions - The investigation suggests that the shift of very stable conditions (G) to moderately stable conditions (F) from the earlier data period to the later period is a result of fewer calm conditions being reported during the later period. The decrease in calm conditions could be real or the result of changes in techniques and/or instruments used in determining wind speed; the evidence presented indicates the latter. Moreover, whether the differences are real meteorological changes or not, the later period is considered to be more representative of Victoria's climate because of its similarity to the longer 10-year record.

3. January 1965 through December 1974 period (three-hourly observations).

Reference

1. Doty, S. R., B. L. Wallace, and G. C. Holzworth, "A Climatological Analysis of Pasquill Stability Categories Based on 'STAR' Summaries", National Climatic Center, Federal Building, Asheville, NC, 1976.

Question 372.22

A preliminary examination of onsite data for the period July 21, 1973, through September 30, 1977, provided on magnetic tape, indicates an inordinate number of occurrences of moderately unstable (Pasquill type "B") conditions defined by the vertical temperature gradient measured between the l0m and 30m levels. Although this interval of temperature gradient measurement is not the primary source of atmospheric stability information, the distribution of atmospheric stability conditions defined for this interval should generally resemble the distribution of stability conditions defined by the measurement of vertical temperature gradient between the l0m and 60m levels. Discuss the differences in the distribution of atmospheric stability conditions defined by these two intervals of measurement and indicate if problems with the data collection program are suspected.

Response

Since the air near the ground (at l0m in this case) will respond more quickly to heating and cooling fluxes than air at either the 30m or 60m level, the lower temperature gradient measurements (i.e., the lower interval) will tend to respond quicker to temperature changes and indicate greater frequencies of very unstable atmosphere or (to a lesser extent) a more stable atmosphere. This is illustrated with data for the July 21, 1973, through September 30, 1977, data period in Table Q372.22-1. The data in this table compares the 30m to l0m temperature gradient classifications with the 60m to lOm temperature gradient classifications. As expected, the 30m to l0m level experiences more extremely unstable classes at the expense of the less unstable and neutral conditions. Unstable and neutral conditions account for approximately 53 percent of the observations at both levels of measurement, indicating that both levels are experiencing the same effects. Similarly, the extremely stable cases are more numerous at the 30m to l0m level than at the other level.

Furthermore, the routine used to derive the frequency of various stabilities by use of RG 1.23 criteria has such a narrow range for "B" stability, that, for the 30m to l0m temperature gradients, "B" stability was not attainable at recording accuracies of 0.1 F (See Table Q372.22-2). For the 30m to l0m interval, only the (-)0.6°F reading falls into a classification that is other than extremely unstable or neutral for temperature gradient readings of less than 0.0°F.

TABLE Q372.22-1

TEMPERATURE STABILITY CLASSIFICATION

July 21, 1973 - September 30, 1977*
[Frequency (%)]

[60m - 10m Level]

	A	B	C	D	E	F	G	TOTAL	(30m - 10m)
A	11.03	2.67	6.15	8.65	0.53	0.13	0.02	29.18	
B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.57%
C	0.06	0.04	0.27	3.80	0.12	0.01	0.00	4.30	
D	0.24	0.08	0.29	15.23	4.09	0.14	0.02	20.09	
E	0.11	0.03	0.07	3.30	13.54	1.48	0.13	18.66	
F	0.16	0.00	0.01	0.40	4.10	7.54	0.89	13.10	
G	0.02	0.00	0.00	0.04	0.11	4.97	9.45	14.59	
Total	11.62	2.82	6.79	31.42	22.49	14.27	10.51	99.92**	
(60m -, 10m)	52.65%								

* Period July 21, 1976, through September 30, 1976, omitted due to limited maintenance.

** Not 100.00 due to round-off error.

TABLE Q372.22-2

LAPSE RATE CLASSIFICATION SCHEME

Stability Class	Lapse Rate C/100m	Temperature Gradients Included (°F) 30m - 10m (67 ft)	60m - 10m (162 ft)
A	$\Delta T < -1.9$	$\Delta T < -.698$	$\Delta T < -1.698$
B*	$-1.9 < \Delta T < -1.7$	$-.698 < \Delta T < -.625$	$-1.698 < \Delta T < -1.511$
C**	$-1.7 < \Delta T < -1.5$	$-.625 < \Delta T < -.551$	$-1.511 < \Delta T < -1.333$
D	$-1.5 < \Delta T < -0.5$	$-.551 < \Delta T < -.018$	$-1.333 < \Delta T < -.044$
E	$-0.5 < \Delta < 1.5$	$-.018 < \Delta T < .551$	$-.044 < \Delta T < 1.333$
F	$1.5 < \Delta T < 4.0$	$.551 < \Delta T < 1.470$	$1.333 < \Delta T < 3.555$
G	$4.0 < \Delta T$	$1.470 < \Delta T$	$3.555 < \Delta T$

* This interval not attainable for 30m - 10m (67 ft) at accuracies of 0.1°F.

** Only -0.6°F will be classified into this category for the 30m - 10m interval at accuracies of 0.1°F.

Question 372.24

During plant operation, the onsite meteorological tower should provide measurements of wind speed, wind direction, and atmospheric stability for estimates of atmospheric dispersion conditions from the point of release to the exclusion area boundary and LPZ distances during and following accidental and routine releases.

Meteorological measurements, particularly wind speed and vertical temperature gradient, at the present tower location during winds from the south clockwise through south-southwest could be used to provide non-representative or misleading estimates of atmospheric dispersion, during and following accidental and routine releases, because of the long over-water fetch for airflow from these directions. Discuss the representativeness of the location of the onsite meteorological tower for describing atmospheric dispersion conditions from the point of release to the exclusion area boundary and LPZ distances, with particular attention to measurements of wind speed and vertical temperature gradient when winds are from the south clockwise through south-southwest directions. Indicate if the monitoring program identified in the response to Request No. 372.6 will be used to evaluate the representativeness of measurements at the current tower location.

Response

During plant operation, the presence of the cooling reservoir is expected to result in decreased mechanically-generated turbulence (decreased $\sigma\theta$) and increased surface wind speed directly above, and for some distance downwind of, the reservoir. The magnitude of the changes in mechanically-generated turbulence and wind speed will depend upon several factors; e.g., fetch over the reservoir, distance and roughness characteristics downwind of the reservoir, and thermal stability.

The upward flux of heat (convection) will decrease the vertical temperature gradient (decreased ΔT) within the air over the reservoir, resulting in destabilization of the air nearest the water[1]. The effect will be greatest near the outfall where the flux of heat is largest, and will decrease away from the outfall. When the wind speed is small, the effect will be limited to the vicinity of the reservoir. When the wind speed is not small, the effect will extend downwind of the reservoir. Both effects will diminish in space as the air becomes mixed with ambient air. These two effects are expected for any wind direction. However, when winds are from the south clockwise through south-southwest, the over-water fetch is longest with respect to the meteorological tower. It follows, then, that the probability of their detection at the meteorological tower will be greatest for these wind directions.

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1. Except, perhaps, near ground level, immediately downwind of the reservoir on a hot summer day.

Response (Continued)

The effects of operation of the cooling reservoir, namely, increased wind speed and decreased atmospheric stability near the ground, would produce better atmospheric dispersion conditions (i.e., lower concentrations for ground level releases) than would exist in the ambient air without its operation. As the air moves away from the vicinity of the reservoir, the effects would diminish as the air mixes with ambient air until atmospheric dispersion conditions finally become that of the ambient air.

For winds from south clockwise through south-southwest, assume that the effects influence dispersion near the plant, but are not detected at the tower located 1.0 mi northeast of the plant; i.e., ambient conditions are measured at the tower. Because atmospheric dispersion conditions would be better near the plant than indicated by the tower measurements, ground level concentrations based on tower-measured wind speed and atmospheric stability would be:

1. overestimated from the point of release to the exclusion area boundary (0.9 mi); and

2. overestimated from the point of release to the LPZ distance (3.5 mi) because of the enhanced initial dilution taking place near the plant.

Next, assume that the effects influence dispersion near the plant, and are also detected at the tower (although mixing with ambient air would have diminished their influence at the tower distance); i.e., better-than-ambient dispersion conditions are measured at the tower. Item l, above, would still hold, and item 2, above, would generally hold. However, better-than-ambient atmospheric conditions measured at the tower (considered alone) would yield underestimates of ground level concentrations at the LPZ distance. If this condition dominated net dispersion such that the enhanced dilution taking place near the plant was cancelled out, underestimated ground level concentrations could result somewhere between the tower and the LPZ distance, and item l would not hold. It is anticipated that in any case, operation of the Cooling Reservoir will have little, if any, measurable effect on ground level concentrations beyond the LPZ.

The monitoring system for the fog model verification program will not be used to assess the impact of the reservoir on dispersion conditions. However, prior to completion of reservoir-filling operations, more than seven years of meteorological data will have been collected. Data collected following reservoir filling and operation of the plant will be evaluated to determine any significant changes in dispersion meteorology with respect to winds from the south and south-southwest sectors.

Question 372.25

The control room display of meteorological parameters will include utilization of the Unit 1 and Unit 2 computers for CRT display or digital print-out. The response to Request No. 372.8 indicates a significant reliance (32.7%) on the analog data recording system for the period January through September 1977. Discuss the problems encountered in the digital data recording system and indicate if these difficulties would impair the reliability of the control room access to meteorological information.

Response

The current digital recording system is a Climet CI-100 data logger coupled with a Kennedy 1600 Incremental tape recorder. The loss of digital data has been associated with the data logger's IBM encoder circuitry. A simultaneous problem with the tape drive caused difficulty in determining the exact nature of the problem.

The present data logging system will not be used during plant operation. The data channels will be scanned and the data processed into hourly averages by the plant computer. The data will be transmitted from the meteorological tower to the plant computer via hard-wired telemetry. The current problems with the digital system should, therefore, have no impact on future digital data collection reliability. CN-3229

Question 240.4N

Provide a discussion of flood protection measures employed at STPEGS to preclude floodwater from entering safety-related buildings or areas; i.e., flood doors, hatches, covers, vent pipes (fuel oil), etc. The design basis flood for STPEGS results from the failure of the MCR embankment which would not allow any warning time to implement flood protection. Therefore, an alarm system is required to insure that flood closure mechanisms are normally closed. Provide a discussion of the alarm system. Also, all closure mechanisms must open into the direction of the flood water such that the force of the flood water will hold the door or cover in the closed position. Please discuss. Are there any emergency procedures associated with the flood protection measures? If so, please discuss.

Response

As indicated in the response to NRC Question 240.1N, a detailed assessment of the Main Cooling Reservoir (MCR) facing the STPEGS Category I structures has demonstrated that the MCR embankment remains stable under all credible failure modes.

The instantaneous MCR breach is not considered a credible event; therefore the provision of single water-tight doors and other flood protection features (discussed in Section 3.4 and the responses to NRC Questions 240.1N through 240.3N) provide adequate protection against any credible flood. With respect to fuel oil vent pipes, these are more than 30 ft above the maximum design basis flood level. The water-tight doors will be under administrated control so they can be secured if conditions require (no alarm system is provided). (Note: the exterior doors are designed such that they open into the direction of the flood water.)

Ductbanks entering safety-related areas of Category I structures will be sealed at the manhole to block the flood path of flood waters.

Question 240.5N

Considering the existing or proposed reservoirs upstream of STP with storage capacities (top of dam) of 400,000 ac-ft or more, are there any of these dams that cannot safety pass (without overtopping) 40 percent of the PMF (or SPF) followed in 3 to 5 days by a PMF? If any of the larger upstream dams would be overtopped during the above postulated scenario, then you need to discuss the effects on other downstream reservoirs and/or STPEGS, considering concurrent rainfall (or SPF) on the intervening drainage areas.

Response

See revised Section 2.4.

Question 240.12N

In determining ground-water velocity you used a gradient of 2.6×10^{-4} ft/ft for the lower shallow aquifer and 6.9×10^{-4} ft/ft for the upper shallow aquifer. How were these values determined?

Response

Section 2.4.13.3.2.1.1 has been revised in Amendment 44 to reflect anticipated post-construction hydraulic gradients for purposes of spill analysis. The gradients questioned in Q240.12N were based on pre-construction conditions and are no longer used in Section 2.4.13.3.

A revised gradient of 1.58×10^{-3} ft/ft is used for the lower shallow aquifer. This gradient is computed using an assumed hydraulic head at the power block equal to ground surface (E1. 27), and a head of E1. 2 feet at the Colorado River. The distance used to compute the gradient is three miles, or 15,840 ft, the shortest distance from the Mechanical-Electrical Auxiliaries Building (MEAB) to the river. This gradient is believed to be conservative (greater than what could be expected to occur) because the piezometric surface in the lower shallow aquifer at the power block is expected to stabilize between E1. 17 ft and 26 ft.

No gradient is determined for accidental spill in the upper shallow aquifer because the stabilized water level in the upper shallow aquifer will be lower at the power block than in the surrounding area (See response to Q240.19N).

Question 240.15N

You state that no significant erosion is expected in the spillway discharge channel due to flood flows. What is the expected velocity of flow in this channel? Provide assurance that the grassed channel will withstand this velocity.

Response

The maximum expected mean velocity in the spillway channel is about 5.6 ft/sec. This corresponds to spillway flows resulting from probable maximum precipitation (PMP) on the Main Cooling Reservoir (MCR). The spillway discharge channel is grassed with a mixture of Bermuda grass, Bahia, and Gulf Rye. The soil is cohesive and erosion resistant. The permissible velocity under such conditions is about 8 ft/sec, which is well in excess of the maximum expected velocity in the spillway channel. No significant erosion of the spillway channel is, therefore, expected.

Question 230.1N

Provide a map showing the locations of all proposed and existing geothermal wells within 15 miles of the site. Examine if fluid injection or withdrawal may cause small magnitude earthquakes (Yerkes and Castle, 1976, Engineering Geology, v. 10, pp. 151-167). If the occurrence of these events is deemed reasonable, discuss ground motion resulting from such small earthquake(s) within 5 miles of the site and examine the effect upon estimate of earthquake hazard at the site and exceedence of the SSE response spectra.

Response

Based on information from the Texas Railroad Commission, the responsible regulatory agency, no geothermal wells exist or are proposed within 15 miles of the site. The site is located on the northern edge of a geopressured, geothermal fairway in the Frio Formation in Matagorda County (Gustavson and Kreitler, 1976) which is unsuitable for geothermal development. As reported by Bebout, et al. (1978) this is due to "...limited lateral extent of reservoirs and lack of sufficient thickness of permeable sandstones." Therefore, future geothermal exploration within the STPEGS site vicinity is not anticipated.

Although the occurrence at the site of such earthquakes is not deemed reasonable, historically the earthquakes associated with fluid injection or withdrawal have been shallow and of small magnitude. Ground motions associated with such small magnitude earthquakes, even within five miles of the site, would not have an effect on the design basis for the STPEGS.

The low intensity seismic effects which accompany fluid extraction studied by Yerkes and Castle (l976) are attributed to differential compaction at depth, but they note that the relative effects of fluid extraction followed by injection are not easily separated. The nature and occurrence of the seismicity and faulting associated with this differential compaction is chiefly a function of: "... (l) the pre-exploitation strain regime, and (2) the magnitude of contractional horizontal strain centered over the compacting materials relative to that of the surrounding annulus of extensional horizontal strain ..."

Based on data presented in Section 2.5.2.4 it has been concluded that the Cenozoic and upper Mesozoic sequence underlying the site vicinity is incapable of storing significant amounts of strain energy. The magnitude of contractional horizontal strain is directly related to the extent of fluid withdrawal. Since the potential fluid withdrawal in the vicinity of the site is small, based on data presented in Section 2.5.l.l.6.6.7.2, it is concluded that the magnitude of contractional horizontal strain is also small. Therefore, since the chief functions of seismicity associated with fluid withdrawal or injection are small, it is expected that the seismicity will be of small magnitude. An earthquake of this small magnitude would not have an effect on the design basis for the STPEGS.

Response (Continued)

A paragraph that reports the absence of geothermal wells and summarizes the potential for geothermal development in the STPEGS site vicinity has been included in Section 2.5.1.1.6.6.7.2. Section 2.5.2.3 has been amended to include a discussion of the potential for ground motion due to fluid injection.

References

1. Bebout, D.G., R. G. Loucks, and A. R. Gregory, "Frio Sandstone Reservoirs In The Deep Subsurface Along The Texas Gulf Coast - Their Potential For Production of Geopressured Geothermal Energy", Bureau of Economic Geology, Report Investigation No. 91, University of Texas, Austin, 1978.

2. Gustavson, Thomas C., and Charles W. Kreitler, "Geothermal Resources Of The Texas Gulf Coast - Environmental Concerns Arising From The Production And Disposal Of Geothermal Waters", Bureau Of Economic Geology, Geologic Circular 76-7, University Of Texas, Austin, 1976.

3. Yerkes, R. F., and R. O. Castle, "Seismicity And Faulting Attributable To Fluid Extraction", Engineering Geology, Vol. 10 (1976), pp. 151-167.

Question 230.3N

Examine and provide the interpretation including figures of any seismic reflection lines which may have been shot within five miles of the site, Post CP Safety Evaluation Report.

Response

Sections 2.5.1.2.5 and 2.5.4.4 have been updated to include seismic information obtained in l983 and its interpretation. The sharper definition of the newer seismic lines have reinforced the earlier interpretation and only changed minor details off-site in the geologic structure. (Figures 2.5.1-6 through 2.5.1-12 have also been added.)

Question 230.4N

In the FSAR, you have indicated that growth faults are not a source of earthquakes. Provide a discussion, including supporting basis which you have used to support your statement. Discuss this in light of the article by Mauk, Sorrel's and Kimball, 1981. (Fifth Geopressured Geothermal Energy Conference, Baton Rouge, La).

Response

Growth "faults" are not associated with seismic activity capable of generating earthquakes which could cause damaging ground motion at STPEGS. As noted in Section 2.5.2.4:

> "The microseismic ground motion which may result from nontectonic sources such as growth "faults" is considered insignificant in relation to the ground shaking that may result from tectonic sources in basement rocks... The upper Mesozoic and Cenozoic sequence in which growth "faults" are known to occur are incapable of storing significant amounts of strain energy."

Based on an evaluation Texas Gulf Coastal Plain geology, growth "faults" flatten at depth and do not extend into basement rock, which is evidence that they are not caused by tectonic forces nor are they an extension upward of basement faults. It is therefore concluded that growth "faults" are the result of gravitational forces acting on the poorly consolidated sediments overlying downwarping basement rock (Section 2.5.1.1.6.6.6). Mauk, et. al. report microearthquake activity associated with growth "faults" in Brazoria County, Texas and Parcperdue, Vermillion Parish, Louisiana. This activity may be either high-stress-drop microearthquakes associated with the top of a geopressured zone* or low-stress-drop microearthquakes associated with gravity slide phenomenon. In either case this activity is: "... very low and the size (magnitude) of the events is very small. No events have been recorded with magnitudes larger than 1.5 (Mauk, et al, P. 106)."

Therefore, it is concluded that ground motion that might be generated by growth "faults" will not result in shaking which will affect plant design at the STP site.

Section 2.5.1.1.6.6.6 has been revised to reflect this conclusion. The observation that nontectonic, microseismic activity may be associated with growth "faults" is clarified in revised Section 2.5.2.4.

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* A geopressured zone exists where fluid pressure in the aquifer exceeds normal hydrostatic pressure of 0.465 pounds per square inch per foot of depth.

Question 230.5N

Recent installations of seismic networks in the Central U. S. have resulted in significant additions to the history of the site area (of East Texas Seismic Network operated by the University of Texas). Many of the earthquakes listed in Tables 2.5.2-3 and 2.5.2-4 of the STP PSAR have been relocated and/or reevaluated. For instance the 1964 earthquakes in the vicinity of Hemphill, East Texas are considered a swarm of events with approximately the same epicenter, the largest of which had an estimated magnitude of 4.4 (m_b) (Ref. 1). On November 5, 1963 an earthquake occurred in the Gulf of Mexico with a magnitude of $m_b = 4.8$ (determined from instrumental data).

Update the above earthquake listings and maps to show the most recent information regarding both historical and instrumental seismicity. Include magnitude estimates wherever possible. Sources include references 1, 2, 3 and 4.

Response

See revised Section 2.5.2 which incorporates the updated seismic history.

Most of the data on earthquakes in the PSAR and UFSAR have been superseded by these more recent catalogs. For those few events for which no updated source information was found, the original PSAR and UFSAR source was retained. In particular, this includes events for which the best current information is DOC (Docekal, 1970).

STR is a compilation of earthquake data cataloged by state by Stover of the U.S. Geological Survey. Other source information from the USGS is designated GS.

EQH represents the updated Earthquake History of the United States published by NOAA (1982). Finally, the Oklahoma Gelophysical Observatory has a compilation of local events which inlcude sources OKO (their own event locations) and OKU (epicenter information taken from U. S. Earthquakes).

In combining all the different catalogs, a hierarchy was developed so that the best information was always retained. In order of most to least preferred, this hierarchy is: DEG,; PEN, CAR; NUT, SLU; EUS, STR; OKU, OKO, BOL; EQH; CGS, PDE, GS, G-R; and DOC, where sources within a common set of semicolons have comparable weights.

No change resulting from this reevaluation results in a change in the arguments leading to the Project design basis earthquake.

References

1. Barstowm, N. L., K. G. Brill, O. W. Nuttli, P. W. Pomeroy. "An Approach to Seismic Zonation for Siting Nuclear Electric Power Generating Facilities in the Eastern United States" (NUREG/CR-1557), May 1981.

2. Carlson, Steven M., "Investigations of Recent and Historical Seismicity in East Texas". MA thesis May, 1984 University of Texas, Austin Texas.

3. Dewey, J. W. and D. W. Gordon, 198, "Seismicity of the Eastern United States and Adjacent Canada, 1925-1976"; to be published as a U. S. Geological Survey Professional Paper.

4. NGSDC, National Geophysical and Solar-Terrestrial Data Center, 1981 Earthquake Data File listing of magnetic tape.

5. Coffman, J. L. and C. A. Von Hake, Earthquake History of the United States, Publication 41.1, revised edition (through 1970), 1982 reprint with supplement (1971-1980), U. S. Department of Commerce, NOAA.

6. Pennington, W. D. and S. M. Carlson, "Observations from the East Texas Seismic Network", Bureau of Economic Geology, University of Texas, Austin, Texas 1984.

TABLE Q230.05N-1

ALL TECTONIC EARTHQUAKES WITHIN 200 MILES OF THE SITE

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	Dist Mi
1873	5	1	4	30	0.0	30.25	97.60	3.6	4.0	CAR	137.4
1887	1	5	17	57	0.0	30.15	97.06	3.6	5.0	CAR	111.8
1887	1	31	22	14	0.0	30.53	96.30	3.8I	4.0	CAR	120.7
1902	10	9	18	0	0.0	30.10	97.60	3.6	5.0	CAR	130.1
1910	5	8	17	30	0.0	30.10	96.00	3.6	4.0	CAR	90.1
1910	5	12	0	0	0.0	30.10	96.00	3.6	0.0	NUT	90.1
1914	12	30	1	0	0.0	30.50	95.90	3.5	4.0	CAR	117.9
1925	0	0	0	0	0.0	29.60	94.80	3.8I	4.0	CAR	93.4
1952	10	17	15	48	0.0	30.10	93.80	3.8	4.0	CAR	162.4
1956	1	7	0	0	0.0	29.30	94.80	3.8I	4.0	EUS	82.9
1956	1	8	0	35	0.0	29.30	94.80	3.8	0.0	NUT	82.9
1959	10	15	15	45	0.0	29.80	93.10	3.8	0.0	NUT	190.6
1964	6	3	9	37	0.0	31.00	94.00	3.6	4.0	NUT	195.3
1966	3	24	23	45	0.0	30.00	94.00	3.0	0.0	NUT	148.6
1970	2	3	0	0	0.0	31.00	97.00	3.8	0.0	NUT	162.5
1973	12	25	2	46	0.0	28.82	98.20	3.8N	4.0	CAR	130.9
1974	4	20	23	46	0.0	28.80	98.20	0.0	0.0	CAR	130.9
1974	6	24	18	3	0.0	28.80	98.20	0.0	0.0	CAR	130.9
1974	8	1	13	34	0.0	28.80	98.20	0.0	0.0	CAR	130.9
1975	10	26	21	41	0.0	28.80	98.20	0.0	0.0	CAR	130.9
1982	3	28	23	24	32.9	28.83	98.19	3.0	0.0	CAR	130.3
1983	7	23	15	24	39.1	28.83	98.19	3.4	5.0	CAR	130.3
1983	7	23	22	41	0.0	28.83	98.19	3.3I	3.0	CAR	130.3

NOTE: All reported magnitudes are mb or its equivalent mblg unless otherwise noted.

I - After magnitude indicates that the magnitude value has been calculated from intensity based on Nuttli (1974): mb = 1.75 + 0.5*Io.

N - Indicates magnitude from Nuttli's catalog in Barstow et al. (1981).

TABLE Q230.05N-2
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	DistMi
1699	12	25	13	0	0.0	35.20	90.00	4.3I	5.0	EUS	566.0
1780	2	6	0	0	0.0	30.40	87.20	4.8I	6.0	STR	543.4
1843	1	5	2	45	0.0	35.50	90.50	6.0	8.0	NUT	564.6
1843	2	17	5	0	0.0	35.50	90.50	4.8	5.0	NUT	564.6
1873	5	1	4	30	0.0	30.25	97.60	3.6	4.0	CAR	137.4
1875	10	28	3	0	0.0	35.10	90.00	3.8	0.0	NUT	560.8
1879	9	26	3	10	0.0	35.30	90.30	3.9	4.0	NUT	560.6
1880	7	14	2	30	0.0	35.30	90.30	4.1	4.0	NUT	560.6
1881	10	7	16	52	0.0	35.10	90.00	3.8	4.0	NUT	560.8
1882	10	22	22	15	0.0	34.00	96.00	5.5	6.0	CAR	358.7
1883	6	11	18	16	0.0	35.10	90.00	4.2	6.0	NUT	560.8
1883	12	5	15	20	0.0	36.30	91.20	4.6	5.0	NUT	589.2
1884	11	30	5	0	0.0	35.50	89.70	4.0	4.0	NUT	592.8
1886	2	5	1	0	0.0	32.80	88.00	5.3I	5.0	EQH	551.9
1887	1	5	17	57	0.0	30.15	97.06	3.6	5.0	CAR	111.8
1888	11	3	0	0	0.0	35.40	90.40	3.8	4.0	NUT	562.5
1889	7	20	1	32	0.0	35.20	90.00	3.8	6.0	NUT	566.0
1891	1	8	6	0	0.0	31.70	95.20	3.8	6.0	CAR	206.5
1891	1	14	0	0	0.0	35.10	90.00	3.6	4.0	NUT	560.8
1898	1	27	1	35	0.0	34.60	90.60	3.8	4.0	NUT	512.5
1899	12	1	18	50	0.0	36.80	94.40	3.8	4.0	NUT	560.0
1900	12	0	0	0	0.0	36.00	96.80	3.8	4.0	NUT	498.6
1902	10	9	18	0	0.0	30.10	97.60	3.6	5.0	CAR	130.1
1905	2	3	0	0	0.0	30.50	91.10	4.3I	5.0	STR	319.6
1907	1	11	7	45	0.0	37.10	97.00	3.8	4.0	NUT	575.2
1910	5	8	17	30	0.0	30.10	96.00	3.6	4.0	CAR	90.1
1910	5	12	0	0	0.0	30.10	96.00	3.6	4.0	NUT	90.1
1911	3	31	16	57	0.0	33.80	92.20	4.3	6.0	NUT	413.0
1911	3	31	18	10	0.0	33.80	92.20	3.8	5.0	NUT	413.0
1914	12	30	1	0	0.0	30.50	95.90	3.5	4.0	NUT	117.9
1915	10	8	16	50	0.0	35.70	95.30	3.7	3.0	NUT	477.9
1917	3	24	0	0	0.0	35.30	101.20	4.2	5.0	NUT	540.7
1917	3	27	19	56	0.0	35.30	101.30	3.8	6.0	NUT	544.0
1917	3	28	13	56	0.0	35.30	101.30	4.8I	6.0	DOC	544.0
1917	3	28	17	38	0.0	35.30	101.30	4.8I	6.0	DOC	544.0
1917	6	29	20	23	0.0	32.69	87.50	4.3I	5.0	BOL	574.5
1917	6	30	1	23	0.0	32.70	87.50	4.3I	5.0	EQH	574.8
1918	0	0	0	0	0.0	35.50	97.70	3.6	3.3	NUT	472.2
1918	9	10	16	30	0.0	35.50	98.00	3.6	6.0	NUT	476.1
1918	9	11	8	0	0.0	35.51	97.95	4.8I	6.0	DOC	476.1
1918	9	11	6	30	0.0	35.50	97.90	3.6	6.0	NUT	474.8
1918	10	4	9	21	0.0	34.70	91.70	4.4	5.0	NUT	480.5
1918	10	13	9	30	0.0	36.10	91.00	3.8	0.0	NUT	583.1
1918	10	16	3	30	0.0	35.20	89.20	4.3I	5.0	EQH	596.5
1919	4	8	12	30	0.0	36.20	91.30	3.6	4.0	NUT	580.5

TABLE Q230.05N-2 (Continued)
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	DistMi
1919	11	3	20	40	0.0	36.30	91.00	3.6	5.0	NUT	594.9
1923	3	27	8	0	0.0	34.60	89.70	3.9	4.0	NUT	547.1
1923	10	28	17	10	0.0	35.50	90.40	4.5	7.0	NUT	568.0
1923	11	26	23	25	0.0	35.50	90.40	4.1	4.0	NUT	568.0
1924	1	1	1	5	0.0	35.40	90.30	4.6	5.0	NUT	566.0
1925	1	27	22	42	0.0	36.20	91.70	3.8	3.0	NUT	569.7
1925	7	8	16	0	0.0	36.20	93.20	3.9	4.0	NUT	536.6
1925	7	29	11	30	0.0	34.50	101.20	3.8	4.0	NUT	496.8
1925	7	30	8	0	0.0	34.50	100.30	4.2	5.0	NUT	466.3
1925	7	30	12	17	0.0	35.40	101.30	4.9	6.0	NUT	549.6
1926	1	20	0	0	0.0	35.60	94.90	4.2	5.0	NUT	473.8
1926	6	20	14	20	0.0	35.60	94.90	4.2	5.0	NUT	473.8
1927	5	7	8	28	0.0	35.70	90.60	4.8	7.0	NUT	572.5
1927	11	13	16	21	0.0	32.30	90.20	3.8	4.0	NUT	423.7
1927	12	15	4	30	0.0	28.90	89.40	3.9	4.0	NUT	402.6
1928	11	1	4	12	49.0	27.00	105.50	6.3	0.0	G-R	591.3
1928	11	10	6	20	0.0	36.10	91.10	3.8C	4.0	NUT	580.2
1928	12	26	3	25	0.0	36.10	91.10	3.8	4.0	NUT	580.2
1929	7	28	17	0	0.0	28.90	89.40	3.8	4.0	NUT	402.6
1929	12	28	0	30	0.0	35.50	97.90	4.0	6.0	NUT	474.8
1930	1	26	21	0	0.0	36.10	91.10	3.8	4.0	NUT	580.2
1930	3	27	8	56	0.0	35.10	90.10	3.5	4.0	NUT	557.1
1930	10	19	12	12	0.0	30.10	91.00	4.2	6.0	NUT	316.9
1930	11	16	12	30	0.0	34.30	92.80	3.3	5.0	NUT	424.8
1931	8	16	11	40	21.0	30.60	104.10	5.8C	8.0	NUT	500.1
1931	8	19	1	36	0.0	30.60	104.10	4.2	5.0	NUT	500.1
1931	12	17	3	36	0.0	34.10	89.80	4.7	7.0	NUT	519.0
1932	4	9	10	17	0.0	31.70	96.40	3.9	6.0	CAR	201.4
1933	8	19	19	30	0.0	35.50	98.00	3.4	6.0	NUT	476.1
1933	12	9	8	50	0.0	35.80	90.20	3.2	6.0	NUT	591.3
1934	4	11	17	40	0.0	33.90	95.50	3.9	5.0	NUT	353.3
1934	7	3	3	10	41.0	35.20	90.00	3.8	4.0	NUT	566.0
1936	3	14	17	20	0.0	34.00	95.20	3.6	5.0	NUT	362.2
1936	6	20	3	24	3.5	35.31	100.77	4.5	5.0	D&G	527.6
1937	5	17	0	49	46.0	36.10	90.60	4.3	5.0	NUT	595.2
1937	6	8	14	26	0.0	35.30	96.90	3.6	4.0	NUT	451.2
1938	4	26	5	42	0.0	34.20	93.50	3.8	4.0	NUT	401.6
1938	9	18	3	34	28.3	35.41	90.25	4.8	5.0	D&G	568.3
1939	6	1	7	30	0.0	35.00	96.40	4.3	4.0	NUT	428.2
1939	6	19	21	43	12.0	34.10	92.60	4.3	5.0	NUT	418.3
1940	12	2	16	16	0.0	33.00	94.00	3.8	4.0	NUT	314.2
1941	6	28	18	30	0.0	32.30	90.80	3.6	4.0	NUT	394.9
1941	10	18	7	48	0.0	35.40	99.00	3.2	5.0	NUT	487.1
1941	11	15	3	7	0.0	35.10	90.00	3.8	4.0	NUT	560.8
1941	11	17	3	8	0.0	35.50	89.70	4.7	6.0	NUT	592.8

TABLE Q230.05N-2 (Continued)
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	DistMi
1942	6	12	4	50	0.0	36.40	97.90	3.7	3.0	NUT	535.2
1947	9	20	21	30	0.0	31.90	92.60	4.0	4.0	NUT	296.8
1947	12	15	3	27	0.0	35.60	90.10	4.0C	5.0	NUT	583.8
1950	3	20	13	23	0.0	33.30	97.80	3.8	4.0	CAR	327.5
1950	9	17	5	48	0.0	35.70	89.90	3.8	4.0	NUT	596.2
1951	6	20	19	37	10.0	35.00	102.00	4.5	6.0	NUT	552.5
1952	4	9	16	29	29.0	35.40	97.80	5.1	7.0	NUT	466.7
1952	4	11	20	30	0.0	35.40	97.80	3.9	4.0	NUT	466.7
1952	4	16	5	58	0.0	35.40	97.80	3.9	3.0	NUT	466.7
1952	4	16	6	5	0.0	35.40	97.80	3.9	5.0	NUT	466.7
1952	6	16	0	30	0.0	35.40	97.80	3.8	4.0	NUT	466.7
1952	7	17	0	30	0.0	35.40	97.80	3.6	4.0	NUT	466.7
1952	7	17	2	0	0.0	35.40	97.80	3.6	4.0	NUT	466.7
1952	8	14	21	40	0.0	35.40	97.80	3.8	4.0	NUT	466.7
1952	10	8	4	15	0.0	35.10	96.50	3.8	4.0	NUT	435.4
1952	10	17	15	48	0.0	30.10	93.80	3.8	4.0	CAR	162.4
1953	3	16	12	50	0.0	35.40	97.90	3.4	3.0	NUT	468.1
1953	3	17	13	12	0.0	35.60	98.00	3.8	5.0	NUT	482.8
1953	3	17	14	25	0.0	35.60	98.00	4.2	6.0	NUT	482.8
1953	5	12	18	50	0.0	35.60	90.30	3.8	4.0	NUT	576.9
1953	6	6	17	40	0.0	34.70	97.70	3.8	4.0	NUT	408.8
1954	4	11	0	0	0.0	35.00	96.40	3.8	4.0	NUT	428.2
1954	4	12	23	5	0.0	35.00	96.403	3.8	4.0	NUT	428.2
1954	4	13	18	48	0.0	35.10	96.40	3.8	4.0	NUT	435.1
1954	4	27	2	9	27.0	35.10	90.00	4.3I	5.0	EUS	560.8
1954	4	27	4	9	0.0	35.10	90.00	4.4	5.0	NUT	560.8
1955	1	27	0	37	0.0	30.60	104.50	3.8	4.0	NUT	523.4
1955	2	1	14	45	0.0	30.40	89.10	4.4	5.0	NUT	432.1
1956	1	8	0	35	0.0	29.30	94.80	3.8	4.0	NUT	82.9
1956	2	16	23	30	0.0	35.40	97.30	4.1	6.0	NUT	461.2
1956	4	2	16	3	18.0	34.20	95.60	3.7	5.0	NUT	373.4
1956	9	27	14	15	0.0	31.90	88.40	3.8	4.0	NUT	504.0
1956	10	30	10	36	0.0	36.20	95.90	4.2	7.0	NUT	510.5
1957	3	19	0	16	38.0	32.00	95.00	4.1	5.0	OKU	229.5
1957	3	19	16	37	38.0	32.60	94.70	4.3	5.0	CAR	274.2
1958	1	26	16	56	0.0	35.20	90.00	4.3I	5.0	EQH	566.0
1958	5	20	1	25	0.0	35.50	90.40	3.8	4.0	NUT	568.0
1958	11	6	23	8	0.0	29.90	90.10	3.8	4.0	NUT	366.5
1958	11	19	18	15	0.0	30.50	91.20	3.3	5.0	NUT	314.1
1959	2	10	20	5	0.0	35.50	100.90	4.5	5.0	NUT	542.6
1959	6	15	12	45	0.0	34.70	96.70	4.0	5.0	NUT	408.8
1959	6	17	10	27	10.6	34.64	98.05	4.3	6.0	D&G	419.8
1959	10	15	15	45	0.0	29.80	93.10	3.8	4.0	NUT	190.6
1960	5	4	16	31	32.0	34.20	92.00	3.8	4.0	NUT	442.3
1961	1	11	1	40	0.0	34.90	95.50	3.8	5.0	NUT	422.0

TABLE Q230.05N-2 (Continued)
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	DistMi
1961	4	26	7	5	0.0	34.60	95.00	3.8	3.0	NUT	404.8
1961	4	27	7	30	0.0	34.90	95.30	4.1	5.0	NUT	423.0
1963	9	10	19	40	8.3	28.90	104.00	4.2	0.0	CGS	482.4
1963	9	13	10	51	57.9	29.10	105.90	4.7	0.0	D&G	597.2
1963	11	5	22	45	3.4	27.49	92.58	4.8	0.0	D&G	299.5
1964	2	2	8	23	0.0	35.10	99.70	4.2	5.0	NUT	484.7
1964	4	24	1	20	54.2	31.38	93.81	3.7	5.0	D&G	222.8
1964	4	24	7	33	51.9	31.42	93.81	3.7	4.0	D&G	225.0
1964	4	28	0	30	45.7	31.40	93.82	3.4	53.0	D&G	223.5
1964	4	28	21	18	35.0	31.20	93.90	4.0N	5.0	CAR	209.7
1964	5	7	20	1	39.0	31.20	94.00	3.2	5.0	CAR	206.1
1964	6	2	23	0	0.0	31.30	94.00	4.2	5.0	CAR	211.6
1964	6	3	0	0	0.0	31.30	94.00	4.2	5.0	CAR	211.6
1964	6	3	9	37	0.0	31.00	94.00	3.6	4.0	CAR	195.3
1964	7	23	23	57	55.1	20.10	96.40	4.2	0.0	PDE	598.4
1964	8	16	11	33	31.0	31.40	93.80	3.0	5.0	NUT	224.2
1965	4	13	9	35	46.0	30.30	105.10	4.2	0.0	NUT	555.0
1965	8	30	5	17	38.0	32.10	102.30	3.5	4.0	NUT	437.3
1966	3	11	10	24	20.3	21.70	95.40	4.7	0.0	PDE	489.6
1966	7	20	9	4	58.8	35.64	101.33	3.8	5.0	D&G	564.1
1966	8	14	15	25	52.0	31.70	103.10	4.3	6.0	NUT	467.0
1966	8	19	4	15	44.6	30.30	105.60	4.1	0.0	CGS	584.6
1966	8	19	7	38	53.6	30.20	105.70	3.9	0.0	CGS	589.6
1966	8	19	8	38	21.9	30.30	105.60	4.0	0.0	CGS	584.6
1966	8	20	6	36	2.7	30.10	105.50	4.3	0.0	CGS	576.9
1966	8	21	2	57	25.2	30.00	105.60	4.1	0.0	CGS	582.1
1966	11	28	2	20	57.3	30.40	105.40	3.8	0.0	CGS	573.8
1966	12	5	10	10	37.8	30.40	105.40	4.2	0.0	CGS	573.8
1967	6	4	16	14	12.6	33.55	90.84	4.5	6.0	D&G	449.7
1967	6	29	13	57	6.5	33.55	90.81	4.0	5.0	D&G	450.9
1968	1	4	0	0	0.0	34.90	95.50	3.8	4.0	NUT	422.0
1968	6	4	22	13	18.0	27.33	102.96	4.4	0.0	CGS	434.2
1968	10	14	14	42	54.0	34.00	96.80	3.5	6.0	NUT	361.5
1969	1	1	23	35	38.7	34.99	92.69	4.5	6.0	D&G	470.2
1969	4	13	6	27	51.0	34.20	96.30	3.5	0.0	NUT	372.8
1969	5	2	11	33	21.7	35.29	96.31	4.0	5.0	D&G	447.9
1969	10	19	11	51	34.3	30.81	105.76	3.8	0.0	D&G	599.8
1970	1	7	17	45	0.0	35.20	89.90	3.8	4.0	NUT	569.7
1970	2	3	0	0	0.0	31.00	97.00	3.8	4.0	NUT	162.5
1971	3	14	17	27	54.6	33.18	87.84	3.9	0.0	D&G	572.6
1971	3	15	14	53	22.0	32.80	88.30	3.5	0.0	NUT	536.5
1971	3	16	2	37	28.0	32.80	88.30	3.7	0.0	NUT	536.5
1971	7	31	14	53	49.4	31.65	103.12	3.8	4.0	D&G	466.7
1971	10	1	18	49	38.5	35.77	90.49	4.1	6.0	D&G	580.0
1973	1	8	9	11	37.0	33.80	90.60	3.5	3.0	NUT	471.7

TABLE Q230.05N-2 (Continued)
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	DistMi
1973	12	25	2	46	0.0	29.00	98.30	3.8	4.0	NUT	137.6
1974	2	15	13	33	49.2	36.40	100.69	4.6	5.0	D&G	589.9
1974	2	15	22	32	38.2	34.04	92.98	3.6	3.0	D&G	404.2
1974	2	15	22	35	46.6	34.07	93.12	3.6	3.0	D&G	402.4
1974	2	15	22	49	4.4	34.03	93.04	4.0	5.0	D&G	402.0
1974	11	28	3	35	20.5	32.31	104.14	3.9	0.0	GS	539.9
1974	12	10	6	1	32.7	31.35	87.47	3.0	5.0	PDE	542.6
1974	12	13	5	3	58.0	34.70	91.90	3.4	5.0	NUT	474.3
1974	12	30	8	5	27.1	30.92	103.11	3.7L	0.0	STR	448.8
1975	6	24	11	11	36.6	33.70	87.84	3.8	4.0	D&G	591.2
1975	8	1	7	27	43.8	30.57	104.49	4.8	0.0	D&G	522.4
1975	9	13	1	25	5.6	34.13	97.22	3.4	4.0	D&G	374.2
1975	11	29	14	29	44.9	34.68	97.42	3.5	4.0	D&G	413.6
1976	1	16	19	42	56.9	35.90	92.16	3.3	5.0	D&G	539.7
1976	1	25	4	48	28.5	31.90	103.09	4.1	5.0	D&G	472.1
1976	3	25	0	41	20.0	35.60	90.50	5.0	6.0	NUT	570.2
1976	3	25	1	0	12.0	35.60	90.50	4.5	0.0	D&G	570.2
1976	3	25	23	5	7.1	20.62	99.09	5.0	0.0	PDE	593.8
1976	4	19	4	42	46.9	36.06	99.79	3.5	4.0	D&G	545.2
1976	9	25	14	6	55.8	35.58	90.47	3.6	5.0	D&G	570.1
1977	2	12	6	51	44.6	28.34	105.13	3.7	0.0	GS	553.1
1977	5	4	2	0	24.3	31.95	88.44	3.6	5.0	D&G	503.5
1977	6	2	23	29	10.6	34.56	94.17	4.0	6.0	D&G	412.3
1977	6	7	23	1	25.0	33.13	100.94	3.5	0.0	D&G	416.8
1977	11	28	1	40	50.5	32.95	100.84	3.5	0.0	PDE	404.0
1978	3	2	10	4	53.0	31.55	102.50	3.5L	0.0	D&G	430.5
1978	5	3	23	35	15.2	25.79	103.05	4.4	0.0	PDE	477.8
1978	6	16	11	46	56.0	32.99	100.88	4.4	5.0	D&G	407.6
1978	7	24	8	6	16.9	26.38	88.72	4.9	0.0	D&G	478.7
1978	8	31	0	31	0.3	33.61	89.42	3.5	5.0	PDE	513.5
1978	9	23	7	34	3.7	33.96	91.92	3.2	5.0	D&G	431.3
1978	12	11	2	6	50.1	31.91	88.47	3.5	5.0	D&G	500.5
1979	2	27	22	54	54.8	35.96	91.20	3.4	6.0	D&G	569.0
1979	3	14	4	37	0.0	35.50	97.80	4.3I	5.0	EQH	473.5
1979	6	25	17	11	13.8	35.56	90.45	3.0	5.0	D&G	569.6
1979	7	25	3	16	0.0	34.00	97.60	4.3I	5.0	EQH	370.3
1980	6	9	22	37	0.0	35.50	101.10	4.3I	5.0	EQH	548.9
1980	11	2	10	1	0.0	35.50	97.80	4.3I	5.0	EQH	473.5
1980	11	13	23	55	48.2	34.37	97.08	2.7	5.0	OKO	389.1
1981	6	26	8	33	27.0	35.85	90.08	3.6	5.0	SLU	598.1
1981	7	11	21	9	21.8	34.85	97.73	3.5	5.0	OKO	429.0
1981	11	6	12	36	41.0	31.92	95.20	3.2C	5.0	PEN	221.2
1982	1	4	16	56	8.1	31.18	102.49	3.9	3.0	PDE	420.0
1982	1	20	14	1	30.6	35.22	92.20	3.5	3.0	PDE	496.8
1982	1	21	0	33	54.3	35.18	92.25	4.5	5.0	SLU	493.1

TABLE Q230.05N-2 (Continued)
ALL TECTONIC EARTHQUAKES WITHIN 600 MILES OF THE SITE
WITH INTENSITY V AND GREATER MAGNITUDE 3.5 AND GREATER

Year	Date Mo	Dy	Hr	Time (GMT) Mn	Sec	Lat	Lon	Mag	Int	Sou	Dist Mi
1982	1	21	15	45	39.0	35.18	92.15	4.1	0.0	SLU	495.8
1982	1	22	23	54	22.6	35.25	92.29	3.7	0.0	SLU	496.3
1982	1	24	3	22	45.2	35.22	92.18	4.3	5.0	SLU	497.4
1982	2	24	19	27	15.3	35.30	92.25	3.9	5.0	SLU	500.4
1982	3	1	0	12	11.7	35.20	92.11	4.3	5.0	SLU	498.0
1982	3	21	9	39	16.0	25.18	101.05	4.4	0.0	PDE	396.3
1982	5	3	7	54	48.6	33.99	96.47	3.0	6.0	OKO	358.9
1982	5	31	17	49	19.9	35.20	92.24	3.6	4.0	PDE	494.6
1982	5	31	18	21	19.4	35.20	92.25	3.6	0.0	PDE	494.3
1982	7	5	4	14	50.1	35.19	92.23	3.8	0.0	SLU	494.2
1982	9	25	23	17	5.5	35.21	92.23	3.5	0.0	SLU	495.4
1983	7	23	15	24	39.1	28.83	98.19	3.4	5.0	CAR	130.3

Note: All reported magnitudes are mb or its equivalent mblg unless otherwise noted.

I - After magnitude indicates that the magnitude value has been calculated from intensity based on Nuttli (1974): mb = 1.75 + 0.5*Io.

L - After magnitude indicates that the magnitude value is local magnitude M1 as defined by Richter (1958).

C - Indicates magnitude from Carlson (1984).

N - Indicates magnitude and intensity from Nuttli's catalog in Barstow (1981).

Figure Q230.05N-1

Figure Q230.05N-2

Question 230.6N

Carlson (Reference 1) reports that the 1932 Mexia earthquake (31.7N96.4W; m_b = 3.9), the 1957 Gladewater earthquake (32.6N94.7W; m_b = 4.3) and the 1983 Fashing earthquake (28.83N98.19W; m_b = 3.0) occurred near large oil and/or gas fields, suggesting that a relation between seismicity and fluid withdrawal could exist. In what ways were the conditions which led to these or other "induced" earthquakes similar to or different from those in the oil/gas fields surrounding the site. What is the potential of ground motion at the site from induced shallow earthquakes.

Response

Carlson (Reference 2.5.2-45) discusses low level seismicity possibly associated with fluid withdrawal and fluid injection. He indicates the proximity of several small earthquakes (Mexia, 1932; Gladewater, 1957; and Fashing, 1932) to large oil and/or gas fields suggests a possible relationship to fluid withdrawal. Carlson also suggests the possibility of a correlation of small events with fluid injection for secondary or enhanced recovery of hydrocarbons or salt water.

The mechanism proposed by Carlson is stick-slip failure along normal faults near or within oil/gas fields. Failure is proposed to occur either because of increased shear stress along the faults or increased resistance to sliding along the fault surface associated with a decrease in pore pressure. The second mechanism is essentially the opposite of that proposed to explain injection-induced seismicity.

As Carlson acknowledges, evidence for such a mechanism at Mexia and Gladewater is circumstantial at best. Rough coincidence of these earthquakes with the area of highest hydrocarbon production is the strongest argument in favor of some casual association. However, small earthquakes are noted in the Mexia area that are not associated with oil fields, and the size and felt area of the Gladewater events argue for a focal depth well below the oil producing horizons. Carlson does not rule out the possibility of a tectonic origin for either.

Although some instrumental data is available for the 1983 Fashing earthquake, its location is again principally dependent on a survey of felt effects. Carlson postulates a shallow focal depth (about 3.5 km), not far below gas producing depths. Pore pressure has decreased in this field from 1956 to 1982, and Carlson proposes that gradual movement occurring aseismically on the Fashing-Edwards fault nearby may now be occurring episodically and causing small earthquakes.

The general geologic setting and the oil/gas production characteristics of the site area can be compared to those areas discussed by Carlson; however, an evaluation of the potential for similar events due to similar causes near the site must necessarily be qualified. Both the phenomenon of induced by fluid withdrawal earthquakes and the proposed mechanism causing them, if they do in fact occur, are conjectural.

Response (Continued)

Total and annual hydrocarbon production rates at the times of the earthquake clusters reviewed by Carlson are substantially greater than for any fields near the site. For example, by 1932, Mexia field production was running three million barrels annually, 90 million barrels total; annual production for 1983 from the Fashing gas field was over 16,000,000 mcf. In contrast, the total combined 1983 production for all fields within approximately seven miles of the Plant Site was 7,500,000 mcf of gas and 28,000 barrels of oil.

Hydrocarbon extraction in those fields with possible induced seismicity discussed by Carlson is from relatively more component, Cretaceous rocks of the Ouachita Seismotectonic Province, and the hydrocarbon traps occur along faults which is part of that province's structural system.

The most important difference between the site area and those cases studied by Carlson is that there are no known earthquakes near the site area oil/gas fields. This lack of seismicity together with the small magnitudes of all the earthquakes considered by Carlson indicate that the current seismic design basis is adequate to supersede any fluid withdrawal induced events in the site area.

References

1. Carlson Steven M., (1984) "Investigations of Recent and Historical Seismicity in East Texas". MA thesis (May 1984) University of Texas at Austin

Question 230.7N

The site is considered to be located in the Gulf Coast Seismotectonic province (FSAR Figure 2.5.2-4). The historic earthquake with the highest intensity within this province was determined to be the October 19, 1930, Donaldsonville, Louisiana earthquake. Table 2.5.2-3 of the STP PSAR lists the intensity as VII (Rossi-Forel). Barstow (Reference 2) list the intensity as VI (Modified Mercalli) and the magnitude as 4.7 (mb). The largest instrumentally recorded earthquake within this province is November 5, 1963 event located in the Gulf of Mexico (magnitude $m_b = 4.8$).

In discussing the maximum earthquake potential specific mention is made that local soil conditions probably influenced the reported intensities of the 1930, Donaldsonville earthquake (of FSAR pp. 2.5.2-15, 19, 20). Ground motion estimates for the seismic design of the STP were based on intensity-peak acceleration relationships (Reference FSAR p. 2.5.2-18). Selecting the appropriate maximum earthquake based on magnitude estimates, and using distances of 10 to 15 km, compare the South Texas Design Spectrum to spectra derived from published magnitude-acceleration/velocity relationships such as Nuttli et at (References 5 and 6). To obtain the appropriate spectral acceleration and velocity ordinates refer to amplification factors proposed by Newmark and Hall (Reference 7). Compare design spectra to the 84th percentile ground motion estimates and discuss the significance of exceedances if any.

Response

The southern boundary of the Gulf Coast Seismotectonic Province is generally not well defined and may, in fact, exclude the November 5, 1963, earthquake located in the Gulf of Mexico. Frolich (1982) considers a number of earthquakes in the Gulf of Mexico and concludes that they may be caused by flexure of the deep crust due to loading of the lithosphere by Mississippi River deltaic sediments. There is no evidence that such a mechanism is characteristic of the Gulf Coast Seismotectonic Province where the South Texas Project site is located. The crustal stress regime implied by a focal mechanism solution from an earthquake in the Gulf of Mexico in 1978 is shallow thrusting along planes parallel to the Gulf Coast. This is exactly the opposite of the shallow stress regime implied by coastal geologic structures.

Appropriate maximum magnitudes for the Gulf Coast Seismotectonic Province are in the 4.6 to 4.8 range (m_b scale) independent of whether these magnitudes are based on an interpretation of the 1930 Donaldsonville earthquake or the 1963 Gulf of Mexico event. The appropriate focal depth are about 10 km (see Section 2.5.1.1.6.3.2).

Nuttli and Herrmann (1984) give the following attenuation formulas:

$$\log_{10} a_h \text{ (cm/sec}^2) = 0.57 + 0.50\, m_b - 0.83\log_{10}(R^2+h^2)^{1/2} - 0.00069R$$

$$\log_{10} v_h \text{ (cm/sec)} = -3.60 + 1.00\, m_b - 0.83\log_{10}(R^2+h^2)^{1/2} - 0.00033R$$

Response (Continued)

Where a_h and v_h are arithmetic averages of peak horizontal acceleration and velocity and R and h (distance and depth) are in kilometers. Substituting h = 10 km, R = 10, 15 km, and m_b = 4.8, the results are a_h ranges 0.08 to 0.10g and v_h ranges 1.42 to 1.74 cm/sec. Average values are a_h = 0.09g and v_h = 1.58 cm/sec.

These peak values may be multiplied by appropriate amplification factors using the method of Newmark and Hall (1978) to derive 84 percent response spectra. For 5 percent critical damping these factors are 2.71 and 2.30 for acceleration and velocity, respectively. The transition from amplified peak acceleration to amplified peak velocity takes place, according to Newmark and Hall, at about 8 Hz.

The South Texas Design Spectrum is clearly conservative at all frequencies and is particularly conservative at long periods (Figure Q230.7N-1).

For completeness it should be noted that the peak acceleration value obtained above depends in part on convention in the derivation of design values. For example, details of regression method and formula application can affect the derived value and, especially at very small distances, there are inadequate data to resolve all uncertainty. Fundamentally, however, it is worth emphasizing that the design earthquake at South Texas is essentially one of intensity VI on the Modified Mercalli scale and that this intensity is not expected to cause any damage to any safety-related structures designed to the criteria of STPEGS.

References

1. Frohlich, Cliff (1982). "Seismicity of the Central Gulf of Mexico. Geology", V. 10, p. 103-106.

2. Newmark, N. M. and W. J. Hall (1978). "Development of Criteria for Seismic Review of Selected Nuclear Power Plant", NUREG/CR-0098

3. Nuttli, O. W. and R. B. Herrmann (1984). "Strong Ground Motion of Mississippi Valley Earthquakes", Journal of Technical Topics in Engineering Vol 110 No.1 May 1984

Figure 230.07N-1

Question 231.1N

Present a summary, with conclusions, of Houston Lighting and Power Company's post-CP Safety Evaluation Report geologic and seismologic efforts relative to updating the South Texas Project FSAR through November l981. This summary is to include information derived/produced by both the applicant as well as by others. Please revise appropriate sections of the FSAR (Sections 2.5.1, 2.5.2, 2.5.3 and relevant appendices) accordingly.

Response

Chapter 2.5 has been revised to incorporate additional data including information developed during post-CP Safety Evaluation Report (SER) efforts undertaken in response to NRC Questions. The additional information has been incorporated in the appropriate subsection or appendix of the UFSAR and is summarized below.

The geologic and seismologic data acquired subsequent to the CP SER and incorporated in Chapter 2.5 through November l98l continues to support the original conclusion presented in the CP SER.

Geologic data generated by post-CP SER efforts and incorporated in Section 2.5.1 concern the following topics and are summarized below:

- Strain energy in Gulf Coast sediments.
- Update and indicate significance of oil and gas production within 15 miles of the site.
- Seismic reflection geophysical data.

The sedimentary units in the vicinity of the site have been evaluated in regard to elastic properties and capability to store strain energy. It is concluded that there are effective mechanisms for plastic release of stresses within all elements of the sedimentary rock sequence, precluding the possible accumulation of elastic strain energy even within the more elastic stratigraphic units. This evaluation supports the conclusion that geologic units that are younger and shallower than the Jurassic basement in the Texas Gulf Coast do not provide the conditions required for the storage and release of strain energy sufficient to produce an earthquake of engineering significance to the STPEGS site.

The UFSAR has been updated to provide information on oil and gas production in the site area through December 1983. The significance of this production in terms of regional subsidence has also been considered. This survey indicates a decline in production in the immediate vicinity of the site (South Duncan Slough and Petrucha fields). This production has no effect on plant safety or operation. There has been no subsidence in Matagorda County attributed to the withdrawal of oil and gas as of 1983. (The discussion of oil and gas production in the site vicinity has been updated in response to NRC Q23l.02N).

Response (Continued)

The subsurface geological model at the site, developed from seismic reflection geophysical data, paleontological data, and well log analyses, has been evaluated through comparison with copyrighted and proprietary structural contour maps purchased from geological data services. The data service maps substantiate the broad interpretations of the model. Additional seismic reflection lines, shot subsequent to the CP SER, are being examined and compared with PSAR data. The corresponding section of the UFSAR has been updated in response to NRC Q230.03N.

In addition, portions of the UFSAR text on regional stratigraphy were revised to refine nomenclature and description.

Section 2.5.2 has been revised to clarify terminology and to incorporate additional data on seismic history and new evaluations of earthquake intensity/ground acceleration relationships.

The seismic history for the site has been updated through December 3l, 1982. The post-CP SER update indicated that no earthquakes were recorded or reported within a 200-mile radius of the STPEGS site. The site seismologic design bases have not changed. (The seismic history has been updated through December 31, 1982, in response to NRC Q230.2N).

Intensity/ground acceleration relationships proposed subsequent to the CP SER have been evaluated for the STPEGS site. This evaluation has not altered the conclusions regarding the seismic analysis. In summary, the earthquake producing the maximum vibratory ground motion at the site is conservatively estimated to be of Intensity VI (Modified Mercalli). The epicentral acceleration associated with an intensity VI (Modified Mercalli) earthquake is 0.07g.

Question 231.8N

Provide a general summary of the near site oil and gas exploration/production that has taken place in the site area since December, 1982. Designate by appropriate text and FSAR figure revision the locations of any completed or newly-permitted exploratory test wells and seismic reflection lines and any changes in the structural interpretation of the site area resulting from these new data. Include in this response the completion dates of all post-CP exploratory wells and seismic reflection surveys including the four TXO/Sies Pros Inc. lines shown on FSAR Figure 2.5.1-6.

Response

Near site oil and gas production information is periodically updated upon issuance of the Texas Railroad Commission Oil and Gas Division Annual Report each June. Section 2.5.1.1.6 has been revised to present production data through December, 1985.

Section 2.5.1.1 has been revised to include data on Post-CP hydrocarbon exploration including test and production wells and seismic exploration. Information such as locations and dates are provided on Table 2.5.1.1 and Figure 2.5.1-1A.

Other seismic reflection lines near the Plant Site have been shot subsequent to 1982. Two lines are of a quality that makes them potentially useable data. These lines are identified on Figure 2.5.1-1A as Jaecon 1984 and Southwest Minerals. The most recent review of seismic data for the response to NRC Q230.3N resulted in only minor revisions to the interpretation northwest of the site, and no changes at the site itself. It is concluded that the Jaecon 1984 line is in essentially the same location as previously obtained data, and the Southwest Minerals line is located in an area surrounded by previously interpreted data. Any refinement that the Southwest Minerals line would provide will not affect the basic geologic structural interpretation under the plant area.

The response to NRC Q231.7N provides information on the post-1975 oil/gas exploration and production drilling.

Question 231.18N

Since much of the information presented in Appendix Geotechnical Monitoring, has not been amended for some time (for example, Figure 2.5.C-25B, Regional Subsidence and Deep Aquifer Piezometer Differential Decline, has not been revised since March 1983), please update this appendix and other appropriate FSAR sections to reflect the most current data and conclusions.

Response

The geotechnical monitoring portions of the UFSAR are currently updated on an annual basis through June of each year and submitted to the NRC during the first quarter of the following year. Review of the various monitoring data has indicated that the performance of Category I foundations is within criteria, and there is no unusual or unexpected behavior in any of the various geotechnical elements monitored.

Question 231.19N

Using guidance contained in the Standard Review Plan conduct a lineament analysis of an area within at least five miles of the site using imagery derived from Landsat, Skylab and other appropriate sources not included in the PSAR lineament study (PSAR Figure 2.5.1-44). In addition to identification, discuss the possible origin and address the safety significance of any lineament which may be structurally controlled. Conduct field truth investigations as required. As indicated by the Standard Review Plan, provide the staff with a copy of the imagery used in your analysis.

Response

Section 2.5.1.2.5.5 has been revised to incorporate the results of a lineament study conducted Summer, 1985, using post CP imagery. Lineaments identified during this study were reviewed using field checks and comparison with other project data. None of the lineaments identified are correlated with geological structure. Section 2.5.1.2.5.5 describes the scope of the study and provides a location map (Figure 2.5.1-15) of the lineaments.

The 1985 lineament study was performed as a confirmatory review to supplement the extensive CP multi-spectral study. The present study used NASA U-2 false-color infrared imagery flown in 1979, based on the evaluation that these data provide the best overview of the five-mile radius study area.

Other post-CP imagery was identified. Several Landsat Multispectral Scanner scenes obtained subsequent to 1975 are available (February 1976; December 1976, October 1980; and April 1984, with site area at edge); however, as in the CP study (refer to PSAR Figures 2.5.1-44 and 2.5.1-44A) this imagery was not considered to be appropriate to review within the five mile study radius because of its scale. Side-looking airborne radar imagery was flown along the Texas coast by Litton Aerospace in late 1976 for speculation. This imagery in the form of a composite mosaic was reviewed. Given the mosaic scale (1:400,000) and the relatively low relief of the terrain, it was concluded that the 1976 radar imagery does not represent an improvement over the site-specific radar flown with multiple look-directions for the STP site in 1973. High-altitude black and white photography of approximately the same scale as the false-color U-2 imagery was flown for the ASCS in 1979. The U-2 imagery were considered to provide the better coverage over the low-relief site area. The false-color photography are also a better tool for identifying surface soil tonal, soil moisture, and vegetation features than black and white photography. Aerial photography in the form of black and white sheets at an approximate scale of 1:12,000 flown in 1981 for the USDAs "Agriculture Stabilization and Conservation Service" (ACSC) as well as color-slides at an approximate scale of 1:8000 flown annually for crop monitoring is on file at the ASCS in Matagorda County. This photography was not used in the lineament analysis but the black and white photographs and the slides from 1985 were inspected during a field review of the previously identified lineaments. No new lineaments were observed on these photographs.

This information was previously provided to the NRC in letter ST-HL-AE-1499 dated October 31, 1985. It should be further noted that remote sensing images were transmitted in ST-HL-AE-1262 dated June 5, 1985.

Question 240.16N

No sustained pumping (from the deeper aquifer) is permitted within a 4,000 ft radius of the plant area. What is the purpose of this restriction? Is any pumping (other than sustained) permitted.

Response

The 4,000 ft sustained pumping exclusion radius is to restrict the withdrawal of significant amounts of groundwater from directly beneath the plant area in order to minimize the potential for regional subsidence resulting from lowering of the groundwater level in the deep aquifer. The relationship between subsidence and groundwater withdrawal is discussed in Section 2.5.1.2.9.6.1.

One deep aquifer well is located about 3,200 ft due east of Unit 1. The well (680 ft deep) is to provide the potable water supply and fire training water supply at the Emergency Operations Center (EOC). Water requirements are low and intermittent. Average pumping rate for normal use is anticipated to be 2 gal/min; there is no sustained pumping from this well. Groundwater usage from the EOC well will not have a significant impact on regional subsidence.

Question 241.1N

The measured settlement data given in Appendix 2.5.C of the South Texas Project FSAR is provided only up to June 1979. Provide time vs. settlement plots of up-to-date settlement data obtained for all Category I structures where settlements are being monitored. Tabulate values of the measured maximum differential settlements and show comparisons of the measured data with anticipated settlements assumed in the analysis of these structures and their appurtenances, and evaluate the impact of any differences between the measured and anticipated settlements on the design and construction of these structures and appurtenances. Staff requires that the settlement of safety related structures and appurtenances be monitored for a period of at least five years after the issuance of the operating license and the impact of observed settlement, if any, on the design limits of category I structures be evaluated periodically. (6 months, 2 years and 5 years after OL issuance).

Response

The evaluation of settlement monitoring data is periodically updated and is provided in Section 2.5.4 and Appendix 2.5.C.

The experienced differential movements between buildings are plotted on Figures 2.5.C-11 and 2.5.C-11A for Unit 1, and on Figures 2.5.C-12 and 2.5.C-12A for Unit 2. The differential movements within individual buildings are shown on plots for representative dates on FSAR Figures 2.5.C-13A and 2.5.C-13B for Unit 1, and on Figures 2.5.C-14 and 2.5.C-14A for Unit 2.

The design criterion for allowable differential movements between buildings is defined in Section 2.5.4.11 (item 1) as one-inch, which is applicable after the pipe installation. Recording of differential movements between buildings started when adjacent portions of two building foundations had been completed. The differential movement plots and tabulations should, therefore, not be directly compared with the design criteria, and they only provide geotechnical information of the relative settlement behavior of the adjacent foundations and allow evaluations of the trends of movements. For purpose of evaluation of measured settlement, January 1985 will be the assumed date of pipe connection.

(Note: The previously described evaluation of Unit l Essential Cooling Water System piping installation at the Mechanical-Electrical Auxiliary Building [MEAB] has been deleted [see amended Section 2.5.C.4.6] as the pipes have been disconnected).

The design criteria for allowable tilt across individual buildings are defined in Section 2.5.4.11 (item 3). The tilt criteria applies to piping after final installation and connections.

Notwithstanding that the design criteria are not applicable in the early part of building construction and before installation of interconnected systems, as described above, it is an objective to minimize deviations throughout the construction period in order to avoid adverse trends. For this reason the effects of actual settlement behavior have been analyzed for the Unit 2 MEAB (see amended Figure 2.5.C-14A, section Q_3, June 1980). The tilt and curvature

Response (Continued)

of the foundation have been conservatively derived, as described above, and this case is recognized as the most severe situation experienced. However, the differential movements were found not to have any detrimental effect on the building. Category I piping systems were only partially installed in the Unit 1 MEAB in 1979, and no piping installations had been made in Unit 2 MEAB in 1980.

The excursion within Unit 2 MEAB, as discussed above, was corrected by load modifications as described in letter to NRC on February 3, 1981 (ST-HL-AE- 616). An excursion is also noted within the Unit 1 MEAB in June 1979 which was "self-correcting" in the normal course of construction.

The predicted heave/settlements are shown in comparison to the actual movements for the Reactor Containment, Fuel Handling and Mechanical-Electrical Auxiliary Buildings of Unit l on amended Figure 2.5.C-9 and 2.5.C-9A. The actual heave/settlement for the Unit 2 buildings are shown on Figure 2.5.C-10 and 2.5.C-10A.

Settlement monitoring for safety related structures and appurtenances after the issuance of the operating license will be performed as requested. Existing Table 2.5.C-1 in the UFSAR defines the monitoring frequency which meets the requirements of Question 241.1N.

The following Sections, and Figures have been revised.

Sections:	2.5.4.11 2.5.C.3 2.5.C.4 2.5.C.4.5 2.5.C.4.6
Figures:	2.5.C-9, 9A, 10, 10A, 11, 11A, 12, 12A, 13A, 13B, 14, 14A, 15

TABLE Q241.01N-1

MEASURED DIFFERENTIAL SETTLEMENT

Between Buildings	Date Started	Measured Diff. Settlement (in.)				
		Oct. 1978	June 1979	Dec. 1980	Oct. 1982	Apr. 1983
Unit 1						
FHB vs RCB	July 1976	0	0.2	0.1	0.4	0.3
MEAB vs RCB	Oct. 1977	0.1	0.3	0.3	0.2	0.1
MEAB vs FHB	Oct. 1977	0.1	0.1	0.6	0.5	0.6
MEAB vs DGB	Dec. 1979	-	-	0.2	0.1	0.0
IVC vs RCB	Dec. 1977	0.6	0.6	0.1	0.1	0.2
Unit 2						
FHB vs RCB	March 1977	0.3	0.6		0.5	-
MEAB vs RCB	April 1979	0.4	0.1		0.6	-
MEAB vs FHB	May 1979	0.1	0.2		0.5	-
MEAB vs DGB	Dec. 1982 (1)	-	-		-	-
IVC vs RCB	July 1979	0.3	0.2		0.4	-

1. DGB-2 mat constructed December 1982.
2. See Figure 2.5.C-11 and 2.5.C-11A for Unit 1 differential movement plots.
3. See Figure 2.5.C-12 and 2.5.C-12A for Unit 2 differential movement plots.

TABLE Q241.01N-2
MEASURED END-TO-END TILT)

Buildings	Direction	Measured End-to-End Tile (in.)				
		Oct. 1978	June 1979	Dec. 1980	Oct. 1982	Apr. 1983
Unit l						
RCB	E-W	0.3	0.4	0.3	0.2	0.l
RCB	N-S	0	0.l	0.2	0.3	0.2
FHB	E-W	0	0	0	0.l	0.2
FHB	N-S	0.3	0	0.4	0.4	0.4
MEAB	E-W N Portion	0.6	0.6	0.5	0.6	0.7
MEAB	E-W S Portion	0.3	0.2	0.4	0.4	0.4
MEAB	N-S E Portion	0.4	0.7	0.5	0.2	0.2
MEAB	N-S W Portion	00	.l	0.l	0.l	0.l
DGB	E-W	(l)	(l)	0	0	0.l
DGB	N-S	(l)	(l)	0	0.2	-
Unit 2						
RCB	E-W	0.2	0.3	0.2	0	-
RCB	N-S	0	0	0	0.l	-
FHB	E-W	0	0.l	0.2	0	-
FHB	N-S	0.2	0.7	0.7	0.8	0.7
MEAB	E-W N Portion	0.l	0.2	0.2	0.7	0.4
MEAB	E-W S Portion	0.2	0.2	0.7	0	-
MEAB	N-S E Portion	0.7	0.7	0.l	0.l	0.0
MEAB	N-S W Portion	0.l	0.l	0.l	0.2	-
DGB	E-W	(2)	(2)	(2)	(2)	-
DGB	N-S	(2)	(2)	(2)	(2)	-

l. DGB, Unit l, construction started in December l979.
2. Construction of DGB, Unit 2 started December l982.
3 See Figures 2.5.C-l3A and 2.5.C-l3B for differential movement profile within Unit l buildings.
4 See Figure 2.5.C-l4 and 2.5.C-l4A for differential movement profile within Unit 2 buildings.

Question 361.8

Piezometric level declines (deep aquifer) experienced at the STPEGS site generally exceed the estimates shown on PSAR Figure 2.5.1-15G. This figure indicates a projected six foot decline between January 1973 and June 1978. The actual decline, utilizing the data presented in PSAR Figure 2.5.1-16D and FSAR Figure 2.5.C-22, ranges from 7 ft at Piezometer 607 to 27 ft at Piezometer 604. Eleven feet of decline has occurred directly beneath the plant site in a 2-1/2 year period (November 1975 to June 1978). Discuss the impact of this rapid groundwater decline (especially directly beneath the structures area) on the subsidence estimates given on FSAR page 2.5.1-125. Discuss the significance, if any, of this decline with respect to site safety.

Response

The regional decline in the piezometric level within the deep aquifer has been, on the average, 11 ft between 1973 and 1979. The projected decline shown on PSAR Figure 2.5.1-16G is 11.5 ft. Withdrawals occur on a cyclic basis because of seasonal needs. Evaluations must, therefore, be made at the same cyclic points from year to year. For example, Piezometer 607 shows a decline of about 4 ft between March 1975 and March 1978. Localized larger drawdown has been experienced near the well which has been pumped since the spring of 1976 for construction purposes (near Piezometer 604, as described in Sections 2.5.C.5.5.5, 2.5.C.5.6, and 2.5.4.6.8). This localized drawdown is temporary and will recover when construction withdrawal is reduced and normal plant operation begins. A further interpretation of the current (March 1979) groundwater conditions within the deep aquifer is provided by amendment to Sections 2.5.C.5.5.5 and 2.5.C.5.6. The changes in groundwater elevations with regard to regional subsidence and site safety are addressed in the response to Question 361.10.

Question 361.10

Provide a composite figure incorporating subsidence contours derived from observations taken from the monuments shown on FSAR Figure 2.5.C-1 and piezometric levels derived from the deep aquifer piezometers shown on FSAR Figure 2.5.C-18. The 1973 piezometric levels (PSAR Figure 2.5.1-16D) are to be used as a base for the piezometric decline. We request that revisions to this figure be submitted periodically to coincide with the submittal of the combined Horizontal Strain-Regional Subsidence Monitoring data described in Request No. 361.9, above. With each subsequent submittal, describe the suspected relationship between the observed subsidence and the deep aquifer piezometric level decline.

Response

FSAR Figure 2.5.C-25 has been developed as requested by the NRC. The figure shows the subsidence within the plant area as contours superimposed on piezometric decline contours. Although Question 361.10 addresses decline since 1973, the 1975 data obtained from plant area piezometers are more applicable. The 1973 groundwater data were obtained from other less site-sensitive sources. It is also important that the subsidence and groundwater data are derived for the same time period. The drawdown contours presented on Figure 2.5.C-25 reflect a bias due to the regional cycle of pumping and rebound. The January sampling period falls within a portion of the rebound cycle of the aquifer. The magnitude of the rebound cycle varies from year to year due to variations in the amount of pumping during the late fall of the previous year. The southwesterly trend of apparent differential drawdown at the site for this sampling period reflects a temporary late pumping cycle northwest of the site in the fall of 1978 and drawdown due to pumping of a site well (approximately 7000 ft southeast of the plant area) used for construction purposes.

The interpreted subsidence contours reflect a regional subsidence of about 1.00 to 1.25 inches over the monitoring period (approximately three years). The net subsidence in the plant area has been less, due to heave associated with the construction excavation and rebound of the shallow aquifer due to rewatering. The interpretation of the regional near-surface subsidence monitoring is further addressed in UFSAR Section 2.5.C.5.5.2. It is evident that the construction activities have had overriding effects on the near-surface subsidence monitoring observations, in particular at monuments I, H, F, G, J, and L. These activities include heave caused by plant area excavation and other more local activities such as Cooling Reservoir embankment construction, material stockpiles, ECP, and ECP pipeline excavations. It is anticipated that the above identified monuments will continue to show deviating behavior due to ongoing plant construction, reservoir filling, and return of groundwater conditions to a natural state. The subsidence has not had any recognizable effects on the heave/settlement behavior of the plant structures as described in FSAR Section 2.5.C.4.5.

Question 361.12

The Cambe Geological Service Map No. T-7, provided in response to Request No. 361.1, indicates an additional site well not shown on PSAR Figure 2.5.1-32. This previously unidentified well (Robbins No. 1) is located approximately one mile east of Well No. 16 (PSAR Figure 2.5.1-32). Provide all pertinent data relative to the Robbins No. 1 Well. Revise appropriate portions of the FSAR accordingly.

Response

The well identified as Robbins No. 1 represents a location registered with the Texas Railroad Commission. However, the well was never drilled and the location should be classified as abandoned.

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Question 210.6N

In Table 3.2.B-1, page 3.2-50, the code edition and addenda of Section III of the ASME Boiler and Pressure Vessel Code reactor coolant pressure boundary (RCPB) components are inconsistent with those identified in Table 5.2-1 for RCPB components. Resolve this inconsistency.

Response

The ASME Code editions and addenda dates listed in Table 5.2-1 are the versions used in the design and fabrication of the components as identified on the Code Data form. The Code edition and addenda mentioned in note 12, page 3.2-50, represent the earliest version of the Code to which the STPEGS RCPB equipment could have been designed and fabricated in accordance with the appropriate regulations and HL&P/Westinghouse requirements. Note that this does not limit the Code versions to those specifically mentioned in note 12 as the last sentence of the note indicates. This is consistent with the NRC regulation, 10CFR50.55a, which allows the use of Code Editions and Addenda that are later versions than those established by the regulation. The Code Edition and Addenda mentioned in note 12 meet 10CFR50.55a and the actual ones used for the equipment also meet the regulation by virtue of their component order dates. However, note 12 has been revised to eliminate the apparent discrepancy.

Question 210.7N

Identify all ASME Code Cases including those that are listed as acceptable in Regulatory Guides 1.84 and 1.85 that are used in the construction of each Quality Group A (Safety Class 1) component 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. A number of Code Cases in Regulatory Guides 1.84 and 1.85 are identified as conditionally acceptable to the NRC staff. Verify that in those instances where conditionally acceptable coded cases have been applied in the construction of components you are in compliance with the additional conditions applicable to each conditionally approved Code Case.

Response

Table Q210.07N-1 lists the code cases used on NSSS Class 1 components with their revision. Table Q210.07N-2 lists the cases' titles. Three of the code cases, 1528, N-242-1 and 1423, have NRC conditional approval and those conditions have been met. Note that the NRC condition for use of N-242-1 is to identify the paragraphs used. For code case N-242-1 paragraphs 1.0 through 4.0 were used.

Tables Q210.07N-3 and Q210.07N-4 list the code cases used on non-NSSS Class 1 systems and components and the code case titles. The NRC conditional approval for code cases N-242, N-242-1, N-274, N-275, all revisions of 1644 (N-71), 1734 (N-116), 1818 (N-175), N-249-1, and N-411, have been met. For code case N-242 and N-242-1, paragraphs 1.0 through 4.0 were used.

TABLE Q210.7N-1

ASME CODE CASES USED ON NSSS CLASS 1 COMPONENTS

Component	Unit 1	Unit 2
Steam Generator	2142-1, 2143-1, N-20-3, N-474-1	2142-1, 2143-1, N-20-3, N-474-1
Pressurizer	1528	none
RC Pump	1739*	1739*
CRDM	none	none
RC Pipe	1423-2	1423-2
Reactor Vessel	1557, 1605, N-514	1557, 1605, N-514
Valves	N-242-1, 1553-1, 1649, 1769	N-242-1, 1567, 1649, 1769

* Refer to Note 42 from Table 3.12-1. The applicable code cases for the reactor coolant pumps will be confirmed upon finalization of the ASME III documentation for the pumps.

TABLE Q210.7N-2

CODE CASE TITLES FOR ASME CODE CASES
USED ON NSSS CLASS 1 COMPONENTS -

1423-2	Wrought 304 and 316 with Nitrogen Added, Sections I, III, VIII
1484	SB-163 Nickel-Chromium-Iron Tubing at Specified Minimum Yield Strength of 40.0 Ksi Section III, Division 1, Class 1
1528	High Strength SA-508 cl 2 and SA-541, cl 2 forgings, Section III, Class 1
1553-1	Upset Heading and Roll Threading of SA-453 for Bolting, Section III
1557	Steel Products Refined by Secondary Remelting
1567	Testing Lots of Carbon and Low Allow Steel Covered Electrodes
1605	CR-Ni-Mo-V Bolting Material for Section III, Class 1 Components
1649	Modified SA 453-GR660 for Class 1, 2, 3 and CS Construction
1739	Pump Internal Items, Section III, Division 1, Class 1, 2, and 3
1769	Qualification of NDE Level III Personnel, Section III Division 1
N-242-1	Materials Certification, Section III, Division 1, Classes 1, 2, 3, MC, CS
2142-1	F - Number grouping for Ni-Cr-Fe, Classification UNS N 06052 Filler Metal, Section 1X (Applicable to all Sections including Section III, Division 1, and Section XI).
2143-1	F - Number grouping for Ni-Cr-Fe, Classification UNS W 86152 Welding Electrode, Section IX (Applicable to all Sections including Section III, Division 1 and Section XI).
N-514	Low Temperature Overpressure Protection, Section XI, Division 1.

TABLE Q210.7N-3

ASME CODE CASES FOR NON-NSSS CLASS 1 SYSTEMS AND COMPONENTS -

System or Component	Code Case No.
● RHRS	N-242
● SIS	N-242-1
● RCS	N-274
● CVCS	N-275
ASME III	
● Gate/Globe/Check	N-242
● Steel Plug Valves	N-242-1
ASME III	
● Butterfly Valves	N-242
● Steel Ball Valves	N-242-1
ASME III	
● Butterfly Valves	1733 (N-115)
● Pipe Supports for ASME III Piping	1644-5 1644-6 1644-7 (N-71-7) 1644-8 (N-71-8) 1644-9 (N-71-9) N-71-10 N-71-11 N-71-12 1683-1 1686 (N-86) 1729 (N-111) 1734 (N-116) 1741-1 (N-120) 1818 (N-175) N-225 N-242-1 N-247 N-249-1 N-249-2 N-309 N-413
● RCS Component Supports and Other NF Steel Items	1644-5 N-71-9 N-71-10 1741
● ASME III Piping	N-411

TABLE Q210.7N-4

CODE CASE TITLES FOR ASME CODE CASES USED ON NON-NSSS CLASS 1 COMPONENTS 4 -

N-242	Material Certification, Section III, Division 1, Classes 1, 2, 3, MC and CS Construction
N-242-1	Material Certification, Section III, Division 1, Classes 1, 2, 3, MC and CS
N-274	Alternative Rules for Examination of Weld Repairs Section III, Division 1
N-275	Repair of Welds, Section III, Division 1
1733 (N-115)	Evaluation of SSE Loadings for Section III, Division 1, Class MC Containment Vessels
1683-1	Bolt Holes for Section III, Class 1, 2, 3 and MC Component Supports
1686	Furnace Brazing, Section III, Subsection NF, Component Supports (N-86)
1644-5	Additional Materials for Component Supports and Alternate
1644-6	Design Requirements for Bolted Joints Section III, Division 2, Subsection NF Class 1, 2, 3 and MC Construction
1644-7 (N-71-7)	Additional Materials for Component Supports Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC (Component Supports)
1644-8 (N-71-8)	Additional Materials for Component Supports Section III, Division 1, Subsection NF Class 1, 2, 3, and MC (Component Supports)
1644-9 (N-71-9)	Additional Materials for Component Supports Section III, Division 1, Subsection NF Class 1, 2, 3, and MC (Component Supports)
N-71-10	Additional Materials for Component Supports Fabricated by Welding Section III, Division 1, Subsection NF Class 1, 2, 3, and MC (Component Supports)
N-71-11	Additional Materials for Component Supports Fabricated by Welding Section III, Division 1, Subsection NF Class 1, 2, 3, and MC (Component Supports)
N-71-12	Additional Materials for Component Supports Fabricated by Welding Section III, Division 1, Subsection NF Class 1, 2, 3, and MC (Component Supports)

TABLE Q210.7N-4 (Continued)

CODE CASE TITLES FOR ASME CODE CASES USED ON NON-NSSS CLASS 1 COMPONENTS

1729 (N-111)	Minimum Edge Distance - Bolting for Section III, Division 1, Class 1, 2, 3 and MC Construction of Component Supports
1734 (N-116)	Weld Design for Use for Section III, Division 1, Class 1, 2, 3 and MC Construction of Component Supports
1741-1 (N-120)	Interim Rules for the Required Number of Impact Tests for Rolled Shapes, Section III, Division 1, Subsection NF, Component Supports
1818 (N-175)	Welded Joints in Component Standard Supports, Section III, Division 1
N-225	Certification and Identification of Material for Component Supports, Section III, Division 1
N-247	Certified Design Report Summary for Component Standard Supports, Section III, Division 1, Class 1, 2, 3, and MC
N-249-1, 2	Additional Materials for Subsection NF Class 1, 2, 3, and MC Component Supports Fabricated without Welding Section III, Division 1
N-309	Identification of Material for Component Supports, Section III, Division 1
N-411	Alternative Damping Values for Seismic Analysis of Classes 1, 2, and 3 Piping, Section III, Division 1, Class 1, 2, and 3 Construction
N-413	Minimum Size of Fillet Welds for Linear Type Supports, Section III, Division I, Subsection NF

Question 130.2

Justify the use of a maximum (70 mph) and minimum (5 mph) translational velocity for the tornado wind load criteria. Specifically, state why you propose a maximum and minimum value and how you arrived at the quantitative values for the two limits.

Response

Maximum (70 mph) and minimum (5 mph) translational velocities for the tornado are obtained from NRC Regulatory Guide 1.76, Table I, for tornado intensity Region I. Reasons for the use of these values are discussed in the Regulatory Guide. For structural design, the maximum translational velocity of 70 mph is used.

Question 130.6

State how the tornado wind, pressure effects and missiles will be combined directly in a manner such as to be conservative for the structural element being considered.

Response

The tornado wind, pressure effects, and missiles are combined in such a manner that the effect of any compensating loads that reduce the missile loads is deleted from the combination.

Question 220.2N

Confirm that the transformation of tornado parameters into effective loading has been done according to SRP Section 3.3.2.II.3. If not, justify the deviation.

Response

A review of the design of the structures has confirmed that the transformation of tornado parameters into effective loading has been done in accordance with Standard Review Plan (SRP) Section 3.3.2.II.3.

Question 010.16

Your response to our Request 010.3 is not complete. Figure 1.2-3 indicates that the Essential Cooling Water Piping System is located outdoors. Provide a discussion to show how this safety-related piping system is protected from tornado missiles. If this piping is located underground, state how deep it is buried.

Response

The Essential Cooling Water Piping System is protected from tornado missiles, being buried below grade between the Mechanical Auxiliary Building and the Essential Cooling Water System Intake and Discharge Structures. The burial depth is approximately 14 ft at the Mechanical Auxiliary Building and approximately 6 ft outside the Essential Cooling Pond dike.

The pipes enter the Essential Cooling Water Intake Structure horizontally 6 ft below grade. The pipes rise vertically to centerline El. 31 ft-9 in. at the Essential Cooling Water Discharge Structure. The grade is at El. 26 ft-0 in. The raised portion is protected from tornado missiles by a concrete structure entirely enclosing the pipes. The structure is designed in accordance with Regulatory Guide 1.76 as described in Section 3.8.4. Furthermore, the pipes are embedded in granular backfill material within the protective structure.

Question 220.4N

For concrete barriers against turbine generated missile, the modified Petry formula is used. Compare the penetration depths using modified NDRC formula and make sure that you have provided barriers having equivalent conservatism to that required by the modified NRC formula. A copy of the revised SRP Section 3.5.3 covering the subject (Attachment 1) is provided for your information.

Response

The modified Petry formula is not utilized in the STPEGS to establish the thicknesses or probability of failure of concrete barriers against turbine-generated missiles. In the STPEGS the Chang Semi-Analytical Formula (SAF) for scabbing and the CEA-EDF Formula for perforation were used for the evaluation of barriers against the turbine-generated missiles. As explained in the following paragraphs, that approach is consistent with the intent of SRP Section 3.5.3, II.1.a which states that "For turbine missile barriers, penetration and scabbing predictions should be based on empirical equations such as the modified NRC formula or the results of a valid test program".

The Chang SAF for predicting scabbing resistance is based upon the principles of engineering mechanics with coefficients which are determined from test data. Reference 1 provides detailed information regarding the derivation of the formula and the determination of the coefficients used with the formula. The accuracy of the CEA-EDF formulations for perforation resistance are evaluated in Reference 2.

The test data used in Reference 1 were the only suitable data available at the time. These data were obtained based on cylindrical steel missiles impacting on concrete barriers. Later, full scale and reduced scale turbine missile tests were conducted by Sandia Laboratories and SRI International, in France were utilized in an independent assessment of the accuracy of the existing formulas. The results were reported in Reference 2 where it is concluded that the Chang SAF and the CEA-EDF formulas provide accurate predictions of scabbing and perforation, and that any deviation from the test results are on the conservative side.

Recently the authors of Reference 2 investigated the damage probability of turbine missile impact as reported in Reference 3 and selected the Chang SAF as the most applicable formula for concentrate scabbing prediction and quantified the conservatism contained in the SAF.

For information purposes the STPEGS has performed supplementary analyses to determine the probability of damage to concrete barriers of the entire plant using the modified NDRC formulas for scabbing and perforation prediction. The resulting critical probability from those analyses would be 1.26×10^{-7}. The governing walls and roof slabs of the Diesel Generator Building were considered to be 29 in. instead of the actual 24 inches.

Response (Continued)

This recalculated probability is introduced simply as a reference value to assess implications of using the alternate NDRC formula which has been demonstrated by tests to be conservative. The critical probability using the Chang SAF and the CEA-EDF formulations as reported in the Section 3.5, Table 3.5-8 is 0.83×10^{-7}. This probability value is maintained as the design basis for STPEGS since the value is determined on a sound analytical basis through accepted formulations proven to be reliable by observed test results and it satisfies the prescribed limit of 1.0×10^{-7}.

References

1. Chang, W.S., "Impact of Solid Missiles on Concrete Barriers", Journal of the Structural Division, ASCE, February, 1981.

2. Wolde-Tinsae, A.M., et al., "NRC Review of Impact Damage", Proceedings of Seminar on Turbine Missile Effects in Nuclear Power Plants, published by Electrical Power Research Institute, Palo Alto, Calif., October 1982.

3. Gopalakrishna, H.S. and Wolde-Tinsae, A.M., "Damage Probability of Turbine Missile Impact", Journal of the Structure Division, ASCE, December 1984.

Question 410.1N

The FSAR states that the auxiliary and main feedwater pump turbines are protected from overspeed by redundant overspeed trips and that neither turbine is considered to be a source of missiles. Regardless, provide the results of an analysis which shows safe shutdown will not be affected by such missiles.

Response

If the efficacy of the overspeed trips on the auxiliary and main feedwater pump turbines is disregarded there are nevertheless sufficient barriers to protect essential equipment from postulated turbine fragment missiles. Missiles arising from a postulated failure of the auxiliary feedwater pump turbine wheel due to 120 percent overspeed would not have enough energy to penetrate the turbine housing. In addition, each train of main steam, main feedwater, and auxiliary feedwater equipment in the isolation valves cubicle (including the auxiliary feedwater pump) is separated from the other trains by 2-ft-thick concrete walls. Turbine blades postulated to be ejected from the main feedwater pump turbine wheel due to 120 percent overspeed and to penetrate the turbine housing would not have sufficient energy remaining to penetrate or spall the exterior walls of Category I structures. Therefore, the ability to shutdown safely would not be affected by postulated missiles from these turbines.

Question 210.23N

Discuss how jet impingement effects on target piping systems and components were evaluated, specifically the criteria used in determining the acceptability of the target piping systems and components.

Response

Section 3.6.2.3.1 addresses methods of analysis for jet impingement. A detailed explanation of analyses performed for the reactor coolant loop (RCL) is included in Section 3.6.2.3.2. Regarding RCL breaks, please refer to the response to Question 210.20N.

The effects of jet impingement on safety-related piping other than the RCL are analyzed using criteria established in References 3.6-5, 3.6-6, and 3.6-9. The following sentence has been added to item 14 of Section 3.6.1.1:

"For essential piping, jet impingement loads are evaluated regardless of the ratio of impinged and postulated broken pipe sizes."

Once target piping systems and components have been identified and jet impingement loads have been calculated, the piping is statically analyzed under two conditions:

1. Transient loading using a dynamic load factor of 2.0 and incorporating the effects of any dynamic supports attached to the piping.

2. Steady state loading using a dynamic load factor of 1.0 and neglecting the effects of any dynamic supports.

Piping response (stresses, deflections, and support reaction loads) generated using these two conditions are enveloped and compared to the appropriate faulted allowables as defined in Section 3.9.1.1.4 and Tables 3.9-7, 3.9-7A, 3.9-7B, and 3.9-7C. Load combinations for this event are presented in Tables 3.9-2.3, 3.9-2.3A, and 3.9-2.4.

Direct jet impingement on valves and other components connected to a piping system is identified and essential targets are either requalified for jet impingement or protected for the jet impingement. Reaction end loads on valves and components due to jet impingement on piping are calculated and combined with other appropriate loads in qualifying the valves or components to the vendor's allowables.

Question 210.24N

The staff finds that there is insufficient information describing the jet expansion model used for evaluation of jet impingement effects of steam, saturated water or steam-water mixtures. Provide additional information to assure that the criteria described in SRP 3.6.2 Section III.3 have been met for analysis of jet impingement forces.

Response

The jet expansion model used for the evaluation of impingement effects of steam, saturated water or steam-water mixtures is described in "Design for Pipe Break Effects", Topical Report BN-TOP-2, Rev. 2, May 1974, Bechtel Power Corporation, San Francisco, California as indicated in Section 3.6.2.3. The NRC staff has previously evaluated and accepted Topical Report BN-TOP-2, Revision 2, May 1974 as documented in the staff's letter dated June 17, 1974 from R.W. Klecher to R.M. Collins of Bechtel Corporation.

Following is a brief description of the analytical methods used in generation of the BN-TOP-2, Rev. 2 jet expansion model.

1. Discharging fluids with superheated, two-phase, saturated or subcooled conditions at the exit plane of the pipe are expanded with the Moody model. The distance to the asymptotic plane is calculated according to the Moody methodology. However, this distance is limited to no less than five pipe diameters for longitudinal and full-separation circumferential breaks, and five times the axial separation distance for limited separation circumferential breaks.

2. Subcooled fluid with a small void fraction ($\alpha<0.001$) or cold water (enthalpy less than the enthalpy of a saturated liquid at ambient pressure) conditions at the exit plane of the pipe are expanded at a uniform 100 half-angle.

Question 210.27N

Provide a listing of those postulated pipe breaks where limited displacements have been used to reduce break areas.

Response

Limited displacements have not been used to reduce break areas for piping on STPEGS.

Question 210.29N

Provide the loads, load combinations, and stress limits that were used in the design of pipe rupture restraints. Include a discussion of the design methods applicable to the auxiliary steel used to support the pipe rupture restraint. Provide assurance that the pipe rupture restraint and supporting structure cannot fail during a seismic event.

Response

Refer to paragraph 3.6.2.1.1.1a. RCL pipe breaks have been eliminated thereby eliminating the need for RCS loop restraints.

Pipe whip restraints are designed as a combination of an energy-absorbing element (EAE) and a supporting (auxiliary) structure capable of transmitting the resistance load from the EAE to the main building structures (concrete walls, slabs, and steel structures). The EAE usually is either thin gauge cellular crushable material (energy-absorbing material, [EAM]) or stainless steel U-bars. The design limits for EAEs are specified in Section 3.6.2.3.4.1.2.

The supporting structures are designed to the loads, load combinations, and stress limits as specified in Section 3.8.3.3 and Tables 3.8.3-2 and 3.8.4-2. For supporting structures designed to respond elastically, stress limits are set in accordance with Part I of the AISC specification with stress increase factors as given under the STRENGTH heading of Tables 3.8.3-2 and 3.8.4-2. Alternatively, supporting structures may be designed to respond inelastically as stated in Note (f) of the Tables 3.8.3-2 and 3.8.4-2. In this case, the design is limited by the ductility ratios given in Tables 3.5-13, items 5, 6, and 7.

Both the Operating Basis Earthquake (OBE) and the Safe Shutdown Earthquake (SSE) seismic events are specifically included in the loading combinations prescribed for the structural integrity of the pipe whip restraints. The restraints and their structures are treated as structural subsystems whose seismic response is determined from their frequency characteristics and the appropriate floor response spectra. In all cases, the design for load components due to seismic response is subject to stress limits set in accordance with Part I of the AISC specification as described above. For the cases where pipe rupture loads force the structure into the inelastic range and the SSE loading is a non-governing component, the stress limits are not applicable and the ductility factors as described above are used to control the design.

Question 210.32N

No discussion could be found in the FSAR regarding design stress limits for Class 1 piping in the break exclusion zone. If there are any Class 1 lines in the break exclusion zone, provide the required design limits.

Response

There is no Class 1 piping in the break exclusion zone for STPEGS.

Question 210.34N

Provide assurance that 100 percent volumetric inservice examination of all pipe welds in the break exclusion zone will be conducted during each inspection interval as defined in IWA-2400, ASME Code, Section XI.

Response

As discussed in Section 6.6.8, circumferential and longitudinal pipe welds within the break exclusion zone of high energy fluid system piping at containment penetrations will either be 100 percent volumetrically examined during the preservice examination and during each inspection interval of the inservice inspection program in accordance with ASME Code Section XI and SRP 6.6 or exceptions (e.g., due to access limitations) will be documented in the ISI program.

Question 130.11

Compare the response of the simplified finite element structural model incorporated in soil-structure interaction analysis with the detailed lumped mass mathematical models of Category I structures used to obtain time histories at floor elevations.

Response

In the soil-structure interaction analysis, structures are first modeled by simplified finite elements to be incorporated in the integrated soil-structure model. This overall integrated model is then subjected to seismic excitation to obtain the motion of the foundation, including the soil-structure interaction effect. The purpose of this step of analysis is to include the essential dynamic characteristics of the structure in the calculation of the foundation motion, but not the response of the structure at higher elevations. The response of the structure at various elevations is obtained by subjecting the detailed three-dimensional lumped mass structural model to the calculated foundation motion. In the detailed structural model, torsional soil springs and eccentricities are incorporated and the structure is represented by a more refined mathematical model. Only results from the analysis of the detailed model are used in the structural design and in the qualification of safety-related equipment. Since the response of the detailed three-dimensional model includes many additional effects (e.g., torsional response and localized amplification [or reduction]), no direct comparison should be made between the two responses.

Question 130.14

State if rocking is a general consideration for all seismic Category I structures. Also, described the manner in which you have accounted for any accidental torsional effects of earthquakes for the Category I structure that you considered as axisymmetric.

Response

Rocking degrees of freedom have been taken into account in the analysis of the lumped mass model of each structure. Thus, rocking is a general consideration for all Category I structures including rocking motion at the base of the structures.

Of all the Category I structures, only the auxiliary feedwater tank is axisymmetric. No accidental torsional effects of earthquake have been considered in the design of the tank since the structure and the loads are both axisymmetric.

Question 130.15

State your criteria for the determination of an adequate selection of the number of lumped masses based on their relationship with any change in the response of a system with a greater number of masses from that of a system with fewer lumped mass representation.

Response

The following are our criteria for the determination of adequacy in selection of number of lumped masses:

1. Total number of degrees of freedom is more than twice the number of modes with frequencies less than 33 cycles per second.

2. The inclusion of additional modes does not result in more than a 10 percent increase in responses.

Question 130.16

State if the fundamental frequency of the subsystems is controlled to be greater than twice or less than one-half the dominant frequency of the supporting system.

Response

The subsystems are designed to avoid resonance with the supporting structure, to the extent possible. In any case, the subsystems and components are analyzed and designed so that the resulting stresses are within allowable limits dictated by the applicable codes.

Question 220.6N

Confirm that the frequency intervals used for floor spectra generation are small enough that their reduction does not result in more than ten (10) percent change in the computed spectral values.

Response

Response spectra calculations parallel to the original Brown & Root (B&R) calculations, incorporating the prescribed frequency intervals per Regulatory Guide (RG) 1.122 and other minor modifications, were performed in order to resolve the frequency-interval concern and to evaluate the original seismic dynamic analyses. The results indicate that the only significant difference associated with the frequency interval pertains to the sparseness of the intervals used for the spectral response calculation detected at frequencies below 2.5 Hz and only for the Reactor Containment Building (RCB). For the higher frequency range, the frequency intervals used are adequate and the original response spectra is conservative; refer to Figures Q220.6N-1 through Q220.6N-4. For a comparison of the frequency intervals per RG 1.122 with those used in the original calculation, refer to Table Q220.6N-1. From the tabulation the sparseness of the original frequency intervals is evident.

The UFSAR does not define the frequency intervals used for the calculation of floor response spectra. In Section 3.7.1.2 the frequency range/no. of points data tabulated pertains to the calculation of spectra performed to confirm the artificial spectra. The tabulated data does not apply to floor response spectra calculations. In Section 3.7.2.5 only the frequency range for floor response spectra calculations was stated as 0.1 Hz to 33 Hz, which subsequently has been corrected to 0.5 to 33 Hz.

The distinctly higher peaks of the B&R solution compared to the Bechtel solution are attributed to (1) the method used by B&R to combine response spectra along parallel directions due to orthogonal input, and (2) slight variations in the structural model configurations. However, for response spectra comparisons, the fact that there are no frequency shifts and that similar high-frequency range and zero-period accelerations are preserved is a more meaningful basis for comparison than on the basis of similitude of peak values.

The sparseness of the frequency intervals of the original calculations diminished the resolution of the spectral calculation and contributed to the under-representation of spectral response in the low frequency range identified in the response to Q220.8N pertaining to the elastic-half-space (EHS) method for soil/structure interaction (SSI). The spectral response calculated using the RG 1.122 frequency intervals exceeds slightly the original spectra and extends the range of resolution into the low frequency range. The resultant spectra, however, is consistently enveloped by the EHS spectra addressed in the cited response; refer to Figure Q220.6N-1. Therefore, the frequency-interval implications on the spectral response are analogous and bounded by the EHS implications and are similarly dispositioned.
Also see UFSAR Section 3.7.2.5.

TABLE Q220.6N-1

FREQUENCY INTERVALS USED TO CALCULATE FLOOR RESPONSE SPECTRA -

NRC RG 1.122 (used by Bechtel)	B&R	NRC RG 1.122 (used by Bechtel)	B&R	NRC RG 1.122 (used by Bechtel)	B&R
.2		3.8		16.0	
.3		4.0	4.0	17.0	17.0
.4		4.2		18.0	
.5	.5	4.4			19.0
.6			4.5	20.0	
.7		4.6			21.0
.8		4.8		22.0	
.9		5.0	5.0		23.0
1.0	1.0	5.25		25.0	25.0
1.1		5.5	5.5		27.0
1.2		5.75		28.0	
1.3		6.0	6.0		29.0
1.4		6.25		31.0	31.0
1.5	1.5	6.5	6.5		33.0
1.6		6.75		34.0	
1.7		7.0	7.0		35.0
1.8		7.25		TOTAL 75.0	TOTAL 36.0
1.9		7.5	7.5		
2.0	2.0	7.75			
2.1		8.0	8.0		
2.2		8.5	8.5		
2.3		9.0	9.0		
2.4		9.5	9.5		
2.5	2.5	10.0	10.0		
2.6		10.5	10.5		
2.7		11.0	11.0		
2.8		11.5	11.5		
2.9		12.0	12.0		
3.0	3.0	12.5			
3.15		13.0	13.0		
3.30		13.5			
3.45		14.0			
	3.5	14.5			
3.60		15.0	15.0		

Figure Q220.06N-1

Figure Q220.06N-2

Figure Q220.06N-3

Figure Q220.06N-4

Question 220.7N

You have mentioned that l0 percent damping value was used in the qualification of safety-related cable trays in some instances. Give more detail of those instances and justify the use of 10 percent damping. Note that the staff position as reflected in the RG 1.61 suggests use of lower damping value.

Response

The 10 percent damping mentioned for the qualification of safety-related cable trays in some instances pertains to the reduction of data obtained as part of the tests performed for the seismic justification. Trays fully loaded with cable, supported at 6-ft and 10-ft spans were subjected to dynamic testing by harmonic motion input. The response recorded from the test was used to derive equivalent damping ratios from 3 percent to 14 percent in vertical direction and 6 percent to 37 percent in lateral direction. These damping values were compiled for information only, and were not used as a basis for seismic qualification of the tray system by analysis. The seismic qualification of the tray system was accomplished by equivalent static analysis utilizing the seismic accelerations dictated by the floor response spectra (at 4 percent maximum damping) for the corresponding natural frequencies determined from dynamic testing of trays. Therefore, the given damping values are simply a report of test findings, and are not subject to the damping limits per RG 1.61 since the given damping values were not used in dynamic analyses for seismic qualification of the cable trays and support structures. The seismic analysis and design of cable trays and supports as an integrated structural system incorporates damping values ranging from 7 percent to 15 percent depending on the zero-period acceleration at the locations within structures. Currently the generic design of typical cable tray supports is in progress and a maximum damping value of 7 percent has been used for SSE. Nongeneric designs of supports for specific cases may involve damping values near the maximum of 15 percent. The stated damping values are consistent with the cable tray support design practice based on experimental research advocated by Bechtel and submitted to the NRC for consideration.

See Sections 3.7.1.3 and 3.7.3B.15.

Question 220.8N

In the meeting of August 7, l971 on SSI of STPEGS, after having explained the technical basis for the SEB SSI related position and discussed with the applicant on South Texas SSI issues, the SEB staff suggested that among various options available to the applicant for the resolution of the SSI issue, the use of the following approach to meet the intent of the SEB SSI position would be acceptable:

Use Elastic Half Space Method of Analysis without reducing the input motion due to embedment of structure in soil. Apply the RG 1.60 motion properly anchored at the OBE/SSE "g" values in the free field at the foundation level and compare the resulting response spectra with those of Finite Element Method. The applicant should demonstrate that at least the intent of the following position is fully met:

> Methods for implementing the soil structure interaction analysis should include both the half space and finite element approaches. Category I structures, systems, and components should be designed to responses obtained by any one of the following methods:
>
> (a) Envelop the results of both EHS and FEM;
>
> (b) Results of one method with conservative design considerations of effects from use of the other method; and
>
> (c) Combination of (a) and (b) with provisions of adequate conservatism in design.

The above mentioned comparison of floor response spectra needs to be done only for key structures at key levels e.g., 6 key levels of Reactor Containment Building, 4 key levels of auxiliary building, etc.

The SEB staff mentioned that if the actual design floor response spectra are compared with those obtained by enveloping the spectra resulting from the FEM and EHS methods of analysis, there may not be any appreciable change in the design of structural elements, because HL&P and Brown & Root have mentioned that enough conservatism is already built in the design by using Finite Element Method. However, there may be cases where the components and equipments may not meet the seismic criteria based upon the enveloped response spectra. HL&P may need to look into these cases and study the specific impact of NRC's current position on the cases in order to qualify them for the seismic criteria.

If the floor response spectra obtained by enveloping are higher than those used for actual design, HL&P still has a choice to justify that the additional stresses resulting from the enveloped spectra are acceptable and overall design adequacy is maintained by considering the actual as-built-strength of the structure. For concrete structures, the as-built yield strength will be the average of compressive strength established by tests. For both reinforcing and structural steel, the as built yield strength will be the average of the actual tested yield strength, but in no case shall it be greater than 70 percent the ultimate strength. The scope and the extent of

Question 220.8N (Continued)

test program and resulting test data shall be submitted for review and approval by the staff.

Other approaches for demonstrating the seismic design adequacy of Category I structures and systems which meet the intent of this position are also acceptable if reviewed and accepted by the staff. For example, if enough seismic data for the South Texas site and other sites having similar regional and local seismicity characteristics are available, then the site specific spectra approach may be a viable option to be considered.

Response

A study of the STPEGS design-basis seismic response spectra was performed to compare the soil/structure interaction (SSI) analyses by the two-step finite element method (FEM) with the elastic-half-space (EHS) method. The results of this study were summarized in Reference (l).

Specific responses addressing the concerns and suggestions stated in NRC Question 220.8N are presented herein. This response also updates the response to previous NRC Ql30.l2.

The free-field input motion used by Bechtel in the EHS SSI analyses was applied at the base of all structures without resorting to any reduction due to the embedment of structures in soil, which is consistent with the NRC's position.

The FEM spectra envelopes the EHS spectra for the frequency range that is relevant for the design and/or qualification of structural elements, and essentially all equipment and components. The most significant difference is restricted to the low frequency range (f<4 Hz, generally), corresponding to SSI frequencies where the EHS spectral response for horizontal directions in some buildings is distinctly higher than the FEM spectra. This difference prevails and is significant only in the Reactor Containment Building (RCB). In the Fuel Handling Building (FHB) and the Diesel Generator Building (DGB) the difference is evident to an insignificant extent, and in the Mechanical Electrical Auxiliaries Building (MEAB) it is essentially nonexistent (see Figures Q220.8N-1, Q220.8N-2, Q220.8N-3, and Q220.8N-4). Therefore, the difference is well bounded and suitable for systematic assessment by natural-frequency segregation of the limited number of items susceptible to the higher seismic response developed exclusively in the low frequency range.

A program for the systematic segregation and evaluation of affected equipment and components is defined in Attachment (1). The program has been implemented as a specific task to verify the adequacy of all the prior and future seismic designs and/or qualifications based on the original STPEGS floor response spectra augmented by the EHS solution in the low frequency range. The results of the initial implementation of the program on a selected sampling of susceptible items is presented in Table Q220.8N-1. The results confirm the anticipated trend that very few items have natural frequencies within the low range of concern, and

Response (Continued)

that the limited number of items in that range have sufficient design margin to accommodate the moderately higher seismic load predicated by the EHS-augmented spectra.

The comparison of FEM and EHS response spectra has been performed for the RCB, MEAB, FHB, and DGB for the Operating Basis Earthquake (OBE) and Safe Shutdown Earthquake (SSE) events for all levels and locations.

The EHS spectra do not result in higher zero-period accelerations nor in higher peak amplifications than those obtained from the FEM spectra. Therefore, the seismic designs of all the superstructures and most of the structural subsystems, which invariably have frequencies higher than 4 Hz or are already designed for near peak seismic response, are not affected by the EHS-augmented spectra. Accordingly, there is no need to rely on a justification of structures by means of existing design margins nor by means of the actual as-built material strengths as suggested in Q220.8N.

Supplementary information pursuant to the presentation of Reference (1) material to the NRC is also submitted herein as follows:

The original FEM response spectra calculated by Brown & Root (B&R) included parametric studies involving the average, upper and lower bound soil properties. The response spectra, issued as the seismic design basis, represent the envelope of the three soil-property solutions and include a ±l0 percent frequency-based broadening to further account for uncertainties in structural materials and modelling techniques. It is noted that the enveloping of soil properties was specifically performed only for the OBE along the finite element model cross-sections 1 and 2 as defined in Figure Q220.8N-l0. For the OBE along cross-section 3 and for the SSE analysis, the soil property parametric study was not performed. Instead, a higher broadening of ±15 percent was applied to the spectra calculated on the basis of average soil properties.

The EHS response spectra calculated by B&R and by Bechtel for comparative purposes are based on average soil properties and include a ±15 percent frequency-based broadening in lieu of a soil property parametric study. It was considered that the full scope parametric study, while warranted for the design-basis spectra, was not necessary for the comparative-study spectra and, accordingly, it was not incorporated in the EHS solutions.

As stated previously, in the EHS solution performed by Bechtel the free-field surface ground motion was applied directly as input without any reduction to account for the embedment depth of the RCB and FHB structures. This direct application is conservative and avoids the controversial reduction of surface input motion. Accordingly, the Bechtel EHS response spectra solutions are consistently higher than the B&R solutions which are based on reduced input motions; refer to Figures Q220.8N-4 through Q220.8N-9 for

Response (Continued)

typical comparisons. Aside from input motion, the Bechtel and B&R EHS solutions are nearly identical in method. Both solutions are based on the same structural model, which has been reviewed by Bechtel, and utilize the same soil impedances (springs and dampers) developed by Woodward-Clyde Consultants (WCC) as described in Reference (2). The equivalent springs and dampers used are a frequency-independent mechanical analog of the foundation impedances based on EHS theory.

In conclusion, the original seismic response spectra calculated by two-step FEM SSI are reaffirmed to be adequate seismic design bases for the STPEGS, subject to verification of the related seismic design and/or qualification of the limited number of items affected by the discrepant spectral response confined to the low frequency range.

Also see UFSAR Section 3.7.2.4.

References

1. Soil-Structure Interaction Outline-A presentation by HL&P and Bechtel delivered to the NRC on December 7, 1982.

2. "Computations of Spring and Damping Coefficients for Category I Structures, STPEGS, Units 1 and 2", by Woodward-Clyde Consultants, April 1980.

TABLE Q220.8N-1

PROGRAM FOR THE EVALUATION OF AFFECTED EQUIPMENT AND COMPONENTS -

Equipment or System	Fundamental Frequencies (Hz)/ Method of Seismic Qualification	Remarks	(see sheet 3 for code number definition)
Diesel Generator and Diesel Generator Control Panels	17.0; 17.5; 22.0/Test	1	
Hydrogen Monitoring System; Remote Control Panel	29.2; 34.4/Test & Analysis	2	
Electrical Panels MCC	8.75; 10/Test	2	
Containment Electrical Penetration	11.0; l6/Test & Analysis	1	
Load Center Enclosed Switchgear Assembly	10.0; 11.3; 13.4; 15.5; 15.7/Test & Analysis	2	
1000 & 2000 kVA Transformers Load Center	2.0; 2.5; 3.5/Test	2	
Low Head Safety Injection Pump	Higher than 33/Test & Analysis	1	
2" & 3" dia. RTD Lines Loop 2 & 3	8.903; 12.903; 13.510; 14.167; 15.464/Analysis	1	
2" dia. Seal Water Injection Loop 2	12.120; 12.457; 15.266 15.477; 15.741/Analysis	1	
12" & 14" dia. RHR/SI Suction Line	11.886; 14.549; 18.931 19.597; 21.390/Analysis	1	
2" & 4" dia. Normal Letdown	15.200; 16.206; 17.155; 17.37; 17.599/Analysis	1	
16" dia. RCS Pressurizer Surge Line	9.514; 13.876; 16.464 21.063; 26.393/Analysis	1	
8"; l0" & l2" dia. RHR/SI Cold Leg Injection Lines	7.l53; 11.857; 12.323 12.902; 13.599/Analysis	1	
6" & 8" dia. SI Cold Leg Injection Line and CS Pump Discharge Line	4.203; 5.064; 5.431 6.562; 8.844/Analysis	1	

TABLE Q220.8N-1 (Continued)

PROGRAM FOR THE EVALUATION OF AFFECTED EQUIPMENT AND COMPONENTS

Equipment or System	Fundamental Frequencies (Hz)/ Method of Seismic Qualif.	Remarks
HVAC Ducts a) MEAB b) FHB	21.0/Analysis	1
Duct Supports a) MEAB b) FHB, DGB & RCB	4.89; 9.28/Analysis	3
Cable Tray Support	4.8; 5.3; 3.3; 4.1/Analysis	3
Cable Trays	15 (Vert); 13.2 (Trans)/Test	3
Existing Cable Tray System in Switchgear Rooms	5.4/Analysis	2
RCB Polar Crane Runway Girder and Bracket	1.64; 2.21; 5.61; 6.84/Analysis	4
RCB Orbital Service Bridge	1.55 (Radial); 2.8 (Tang.); 6.0 (Tang.)/Analysis	5
FHB 150 Ton Crane	0.28; 2.95; 6.48; 9.81; for out-of-plane motion, of supporting wall: about 6 Hz/Analysis	4

1. Frequency above 4 Hz, out of range - No effect.

2. FEM spectra envelopes the EHS spectra for MEAB, where equipment is located - No effect.

3. Generic design is based on seismic acceleration levels in the range of peak amplification, which is not increased by EHS spectra - No effect.

4. Enough margin in existing design - No effect.

5. Enough margin was found in the existing support embedment - No effect. A definitive analysis has confirmed that the members are adequate, and that the structural integrity of the equipment is not compromised by the EHS augmented seismic response spectra.

Figure Q220.08N-1

Figure Q220.08N-2

Figure Q220.08N-3

Figure Q220.08N-4

Figure Q220.08N-5

Figure Q220.08N-6

Figure Q220.08N-7

Figure Q220.08N-8

Figure Q220.08N-9

Figure Q220.08N-10

Criteria for the Verification of Seismic Qualification and/or Design of Equipment and Components with Respect to the Floor Response Spectra Augmented by Elastic-half-space (EHS) Soil-structure Interaction (SSI) Analysis

References: (A) Floor Seismic Acceleration Response Spectra Design Basis for STPEGS, Bechtel Drawings indexed in Drawing No. 4N16-9-S-39150 and listed in Table 1.

(B) Floor Seismic Acceleration Response Spectra augmented by EHS SSI Analysis for STPEGS, Sketches No. SKC-5 through SKC-254.

1.0 The seismic qualification and/or design of all seismic Category I equipment, components and piping shall be reviewed and verified, if required, in accordance with the steps defined in this criteria.

2.0 Establish the latest and governing seismic qualification and/or design document for the equipment/component/piping. Verify that the seismic qualification and/or design document is based on the appropriate response spectra selected from Reference (A) in accordance with the installed location(s) of the equipment/component/piping with the respective building(s).

Any seismic qualification and/or design which is found to be based on response spectra other than that of Reference (A) shall be referred to the Seismic Group of the Civil/Structural Discipline for specific evaluation and disposition.

3.0 The floor seismic acceleration response spectra as modified by the EHS SSI analysis are characterized with respect to the design-basis spectra by five cases defined below. When the EHS-modified spectra exceed the design-basis spectra, the EHS spectra hereafter will be referred to as the EHS-augmented spectra defined by Reference (B).

(1) The EHS-modified spectra are essentially enveloped by the design-basis spectra over the whole frequency range. The instances where the EHS-modified spectra exceed the design-basis spectra are restricted to the vertical response in the RCB, for which some spectral response peaks exceed the design-basis spectra by no more than 10 percent at isolated frequency points of less than 5 Hz.

(2) Design-basis spectra were not previously issued for the basement locations of the Reactor Containment Building (RCB), the Mechanical Electrical Auxiliary Building (MEAB), and the Diesel Generator Building (DGB), as well as El. 83 ft of the RCB interior structure, the pressurizer support points in the RCB and the enveloped spectra for the power block buildings. Therefore the EHS-modified spectra are henceforth adopted as the design-basis spectra for these locations.

(3) The EHS-augmented spectra exhibit a narrow frequency band where a distinct spectral response peak exceeds the design-basis spectra. The peak is confined to the low frequency range, and in all instances the EHS-augmented spectra exceed the design-basis spectra only at frequencies below 4 Hz.

(4) The EHS-augmented spectra exhibit a narrow frequency band where the spectral response exceeds the design-basis spectra defined by a "valley" between two peaks on the design-basis spectra. This trait is confined to the low frequency range, below 8 Hz, and is in addition to the Case (3) trait.

(5) The EHS-augmented spectra exceed the design-basis spectra over a wide frequency range. This case is restricted to the basement locations of the Fuel Handling Building, where a very limited number of equipment/component/piping are housed.

Table 1 is a listing by drawing number of the Reference (A) design-basis spectra. In the last column of the table the case number, as defined above, is given for each spectra drawing.

4.0 Select the next step of this criteria that must be implemented in accordance with the case number assigned in Table 1 to the spectra that governs the seismic qualification and/or design of the equipment/ component/piping.

4.1 If the installed location(s) of the equipment/component/piping dictates Case (1) spectra, the equipment/component/piping are not affected by the EHS-augmented spectra; proceed to Section 8.0. This is the case for all equipment/component/piping located in the MEAB and several other locations as designated in Table 1.

4.2 If the installed location(s) of the equipment/component/piping dictates Case (2) spectra, start a data sheet (Form A) for the equipment/ component/piping if it was subject to prior seismic qualification and/or design. If the spectra used in the prior seismic qualification and/or design of the equipment/component/piping envelop the design-basis spectra per Reference (A), proceed to Section 8.0. If the prior seismic qualification and/or design of the equipment/component/piping was based on spectra different than the corresponding spectra from Reference (A), and the differences are characterized as in Case (3) or Case (4), proceed to scrutinize the natural frequencies reported in the seismic qualification and/or design in accordance with Section 4.3 or Section 4.4, respectively. Otherwise, if the differences between the spectra used for seismic qualification and/or design and the Reference (A) spectra are more pronounced or over a broad frequency range, refer the case to Civil/Structural for specific evaluation and disposition.

4.3 If the installed location(s) of the equipment/component/piping dictates Case (3) spectra, the equipment/component/piping may be affected by the EHS-augmented spectra, depending on the natural frequency range of the equipment/component/piping. Scrutinize the natural frequencies reported in the seismic qualification and/or design for the equipment/component/ piping. Establish the nature and direction of the modal response corresponding to the low frequency range (less than 4 Hz*) if such information

is available from the seismic qualification and/or design. Ascertain that the low frequencies as reported are (1) representative and valid for the equipment/component/piping system, (2) correspond to horizontal direction of response for the installed position of the equipment/component/piping, and (3) are not related to irrelevant subsystems within the equipment/component/piping.

If the lowest natural frequency is 4 Hz* or higher, the equipment/ component/piping is not affected by the EHS-augmented spectra; proceed to Section 8.0. Equipment/component/piping's with natural frequencies lower than 4 Hz* are potentially affected; proceed to Section 5.0.

It must be noted that for the cases where devices (such as switches, relays or breakers) are mounted within control panels or cabinets, and the natural frequencies associated with the mounting and/or functionality of the devices are not specifically defined in the seismic qualification and/or design of the panel or cabinet, it is appropriate to consider such frequencies to be above the governing limit of 4 Hz*. This onsideration is based on (1) the inherent frequency characteristics of these internally-mounted devices typically higher than 4 Hz*, and (2) the observation that for low frequencies the corresponding free oscillation amplitudes are beyond the range anticipated for such devices; i.e., 0.6 inch amplitude for 4 Hz, 2.4 inches for 2 Hz (the peak-response frequency). However, if specific frequency data from the seismic qualification and/or design of the panel, cabinet or device indicates mounting and/or functionality frequencies below 4 Hz*, such cases should be referred to Civil/Structural for specific evaluation and disposition on the possible need for requalification.

4.4 If the installed location(s) of the equipment/component/piping dictates Case (4) spectra, the equipment/component/piping may be affected by the EHS-augmented spectra, depending on the natural frequency range of the equipment/component/piping and the seismic qualification and/or design method used. Scrutinize the natural frequencies reported in the seismic qualification and/or design for the equipment/component/piping. Establish the nature and direction of the modal response corresponding to the low frequency range (less than 8 Hz*) if such information is available from the seismic qualification and/or design. Ascertain that the low frequencies as reported are (1) representative and valid for the equipment/component/piping system, (2) correspond to horizontal direction of response for the installed position of the equipment/ component/piping, and (3) are not related to irrelevant subsystems within the equipment/component/piping.

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* When scrutinizing seismic qualifications performed by a test utilizing the TRS method, these frequency limits should be adopted as 5 Hz instead of 4 Hz and as 10 Hz instead of 8 Hz. These broadenings allow increase of the cut-off frequencies by at least 1/3 octave.

If the lowest natural frequency is 8 Hz* or higher, the equipment/ component/piping is not affected by the EHS-augmented spectra; proceed to Section 8.0. Equpiment/component/piping's with natural frequncies lower than 8 Hz* are potentially affected; proceed to Section 5.0.

It must be noted that for the cases where devices (such as switches, relays or breakers) are mounted within control panels or cabinets and the natural frequencies associated with the mounting and/or functionality of the devices are not specifically defined in the seismic qualification and/or design of the panel or cabinet, such frequencies cannot be properly considered to always be higher than the governing limit of 8 Hz*. However, for the cases of seismic qualification of panels or cabinets with internal devices, it is anticipated that the seismic qualification, including the devices, was performed by test utilizing the test response spectra (TRS) method. The TRS is based on the original design basis spectra and normally does not represent the "valleys" between peaks of the design-basis spectra. Therefore, since the TRS does not include the low-points of the "valleys", it will invariably envelope the EHS spectra augmented at the "valleys" in between peaks of the design-basis spectra. Such observation, applicable only to seismic qualification by TRS, must be specifically confirmed in order to designate the equipment/component corresponding to this Case (4) as not affected by the EHS-augmented spectra.

The foregoing simplification applies only to seismic qualification performed by test utilizing a TRS that envelop the EHS-augmented spectra. Other cases should be referred to Civil/Structural for specific evaluation and disposition on the possible need for requalification.

4.5 If the installed location(s) of the equipment/component/piping dictates Case (5) spectra, the equipment/component/piping is anticipated to be affected by the EHS-augmented spectra. Start a data sheet (Form A) for the equipment/component/piping, fill in data for columns (A) thru (D), and submit to Civil/Structural for specific evaluation and disposition.

5.0 Start a data sheet (Form A) for the equipment/component/piping, fill-in data for columns (A) thru (C) and/or a checklist (Form B) for the equipment/component only. If the seismic qualification and/or design of the equipment/component/piping is by analysis proceed to Section 6.0, if by test equipment/component only proceed to Section 7.0. For the case of piping system, where testing normally is not applicable for seismic qualification and/or design, disregard Section 7.0. However, for piping-mounted devices or components (valves), proceed to Section 7.2.

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* When scrutinizing seismic qualifications performed by a test utilizing the TRS method, these frequency limits should be adopted as 5 Hz instead of 4 Hz and as 10 Hz instead of 8 Hz. These broadenings allow icnrease of the cut-off frequencies by at least 1/3 octave.

6.0 Establish frequency bands of $0.9f_n$ to $1.1f_n$ for each natural frequency below the lower limit frequency (4 Hz for Case (3); 8 Hz for Case (4)). Read the spectral acceleration corresponding to the established frequency band(s) from the selected Reference (B) spectra. If, at corresponding frequencies, any spectral acceleration derived from Reference (B) spectra is higher than the acceleration by Reference (A) spectra, proceed to Section 6.1; otherwise, if none is higher, the equipment/component/piping is not affected by EHS-augmented spectra; proceed to Section 8.0.

6.1 By review of the analysis, establish the maximum lateral acceleration value for which the equipment/component/piping was qualified and/or designed; denote the value as S_{amax} and enter in column (D) of Form A. Establish the augmented spectral acceleration level from the Reference (B) spectra by performing the square root of the sum of the squares (SRSS) of each of the maximum spectral accelerations corresponding to each frequency band established in Section 6.0; denote S_{aEHS}.

Compare S_{aEHS} to S_{amax}, if $S_{aEHS} < S_{amax}$ the equipment/component/piping is considered adequate insofar as the effect of EHS-augmented spectra is concerned, proceed to Section 8.0. If $S_{aEHS} > S_{amax}$, evaluate the analysis and design to establish whether the available seismic design margin is adequate to accommodate the higher seismic load indicated by S_{aEHS}. If the existing seismic qualification and/or design analysis for the equipment/component/piping does not permit the foregoing scrutiny, or if the results indicate inadequate margin or are inconclusive, refer the case to Civil/Structural Discipline for specific evaluation and disposition on the possible need for reanalysis.

7.0 Establish the method of testing used. If the test response spectra (TRS) method was used, proceed to Section 7.1. If the required input motion (RIM) test method, such as harmonic input (sine-beat) was used, proceed to Section 7.2.

7.1 Establish the TRS used. Compare the TRS to the corresponding EHS-augmented spectra from Reference (B). If the TRS envelopes the Reference (B) spectra, the equipment/component is considered adequate; proceed to Section 8.0.

If the Reference (B) spectra exceed the TRS, proceed to calculate the augmented spectra acceleration level, S_{aEHS}, as defined in Section 6.1. Establish the qualification acceleration level for the equipment/ component from the seismic report or from the TRS by performing the SRSS of the spectral accelerations corresponding to each natural frequency of horizontal modes; denote it is S_{aT}. Compare the S_{aEHS} to S_{aT}; if $S_{aEHS} < S_{aT}$ the equipment/component is considered adequate, proceed to Section 8.0. If $S_{aEHS} > S_{aT}$ refer the case to Civil/Structural Discipline for specific evaluation and disposition.

7.2 The equpiment/component is not affected since the RIM represents the upper-bound acceleration response determined by dynamic analyses at the locations of line-mounted devices or components. However, verify in accordance with Section 4, if the EHS-augmented spectra have to be incorporated in the dynamic analysis of piping system, HVAC duct and cable tray support systems.

8.0 All of the seismic Category I equipment/component shall be documented with data sheet, (Form A) completed in accordance with notes (A) through (D) stated herein, if applicable, and/or the checklist (Form B) for equipment/component.

The disposition per column (E) of Form A or per Form B shall be completed in all cases and the following code for predefined dispositions may be used:

Code	Definition of Disposition
(1)	The spectra corresponding to the installed location of equipment/component/piping are not affected by the EHS-augmented spectra, as designated by the Case (1) spectra in Table 1. Form B can be used for disposition of equipment/component.
(2)	For the installed location of the equipment/component/ piping there was no specific previous design-basis spectra. The spectra used for the seismic qualification and/or design exceed the EHS-augmented spectra which have been incorporated as the design basis; therefore, the equipment/component/piping is adequate. Form B can be used for disposition of equipment/component.
(3)	The equipment/component/piping natural frequencies are over 4 Hz*, above which there is no effect due to EHS-augmented spectra.
(4)	The equipment/component/piping natural frequencies are over 8 Hz*, above which there is no effect due to EHS-augmented spectra.
(5)	The spectral responses specifically determined from the EHS-augmented spectra at the equipment/component/ piping frequencies in the low frequency range does not exceed the design basis spectral response.
(6)	The spectral response specifically determined from EHS-augmented spectra at the equipment/component/ piping frequencies in the low frequency range exceeds the design basis response, but there is adequate margin in the existing design.

* When scrutinizing seismic qualifications performed by a test utilizing the TRS method, these frequency limits should be adopted as 5 Hz instead of 4 Hz and as 10 Hz instead of 8 Hz. These broadenings allow increase of the cut-off frequencies by at least 1/3 octave.

Code	Definition of Disposition
(7)	The equipment/component was qualified by test utilizing a TRS that envelopes the EHS-augmented spectra. Form B can be used for disposition of equipment/component.
(8)	The equipment/component was qualified by test utilizing a TRS that does not envelop the EHS-augmented spectra. However, the spectral response specifically determined from the EHS-augmented spectra at the equipment/component frequencies in the low frequency range is below the qualification acceleration level of the TRS, therefore the equipment/component is adequate.
(9)	The equipment/component is adequate since single- frequency testing with RIM which envelopes the EHS acceleration response was used. Form B can be used for disposition of equipment/component.

Other, non-predefined dispositions must be specifically stated. The case referred to Civil/Structural Discipline for specific evaluation and disposition, as well as any cased dispositioned for re-analysis or retesting, must be specifically defined.

References

(A) Floor Seismic Acceleration Response Spectra Design Basis for STPEGS listed in Bechtel Drawing Nos. 4N16-9-S39150.

(B) Floor Seismic Acceleration Response Spectra augmented by EHS SSI Analysis for STPEGS C/S Calculation No. CC-9150, Sketches No. SK C-5 thru SK C-254.

(Sheet 1 of 2)

SEISMIC CATEGORY I
EQUIPMENT COMPONENT
DATA SHEET -

Equipment (A) or System	Method of (B) Seismic Qualification	Fundmental (C) Frequencies	Qualification (D) Acceleration Level	(for notes (A) through (D) see Sheet 2) Remarks/Disposition (E)

FORM A

(Sheet 2 of 2)

Notes to Attachment 1

(A) Descriptive name of equipment or system. Include weight, size, capacity, etc. as applicable, and B&R or Bechtel Specification No. and Purchase Order No.

(B) Indicate if method is by Analysis or by test.

If by Analysis, define method such as: Modal Response Spectra or Equivalent Static

If by Test indicate: Test Response Spectra, or Required Input Motion

(C) Indicate source: Analysis or test. Give numerical values, include the lower 4 or 5 frequencies, and indicate if they correspond to lateral or vertical modes.

(D) Attach all the Floor Response Spectra used for the qualification, and define the governing cases if the information is available from qualification package.

Define acceleration value for Required Input Motion or Status methods. Attach the test response spectra, when used.

FORM B
(SHEET 1 of 2)

VERIFICATION OF SEISMIC QUALIFICATION OF EQUIPMENT TO THE FLOOR RESPONSE SPECTRA AUGMENTED BY ELASTIC-HALF-SPACE (EHS) SOIL-STRUCTURE INTERACTION (SSI) ANALYSIS

Equipment Name _____

Base Report Log Number _____

_____

Is qualification of the equipment still valid using the EHS-augmented spectra?

[ ] YES [ ] NO

Verification:

1. Qualification Method:

[ ] Analysis [ ] Test [ ] Combination

2. Seismic Input:

[ ] RIM [ ] RRS

If seismic input is RIM, see Paragraph 4 below.

3. Required Response Spectra (RRS) specified for the qualification:

[ ] (1) The EHS-modified spectra are essentially enveloped by the design-basis spectra over the whole frequency range. The instances where the EHS-modified spectra exceed the design-basis spectra are restricted to the vertical response in the RCB, for which some spectral response peaks exceed the design-basis spectra by no more than 10% at isolated frequency points of less than 5 Hz.

[ ] (2) Design-basis spectra were not previously issued for the basement locations of the Reactor Containment Building (RCB), the Mechanical-Electrical Auxiliary Building (MEAB), and the Diesel Generator Building (DGB), as well as El. 83 feet of the RCB interior structure, the pressurizer support points in the RCB, and the enveloped spectra for the power block buildings. Therefore, the EHS-modified spectra are henceforth adopted as the design basis spectra for these locations.

[ ] (3) The EHS-augmented spectra exhibit a narrow frequency band where a distinct spectral response peak exceeds the design-basis spectra. The peak is confined to the low frequency range, and in all instances the EHS-augmented spectra exceed the design-basis spectra only at frequencies below 4 Hz.

FORM B
(SHEET 2 of 2)

[ ] (4) The EHS-augmented spectra exhibit a narrow frequency band where the spectral response exceeds the design-basis spectra defined by a "valley" between two peaks of the design-basis spectra. This trait is confined to the low frequency range, below 8 Hz, and is in addition to the Case (3) trait.

[ ] (5) The EHS-augmented spectra exceed the design spectra over the wide frequency range. This case is restricted to the basement locations of the Fuel Handling Building, where a very limited number of equpment/component are housed.

a. If RRS is either (1) or (2), see Paragraph 4, below.

b. If RRS is either (3) or (4), does TRS or the response spectra used for analysis envelop the EHS-augmented spectra? (attach TRS or response spectra for anlaysis)

[ ] YES [ ] NO

If yes, see Paragraph 4 below.

c. If RRS is (5), does TRS or the response spectra used for analysis envelop Design Basis Spectra (Drawing No. 4N16-9-S-39150)? (attach TRS or response spectra for analysis)

[ ] YES [ ] NO

If yes, see Paragraph 4 below.

4. <u>The qualification is not affected by EHS-augmented spectra</u>.

5. If the above comparison of seismic input does not resolve the effects of EHS-augmented spectra, the design criteria (TPNS No. 4A010SQ1004) is followed to determine the adequacy of the qualification. (Attach all data for the determination and conclusion.)

TABLE 1

LISTING OF DESIGN BASIS SPECTRA
(Including Designation of Case Number for the EHS SSI Effects)

Description		Drawing No.	ESH-Modified Spectra Case Number
Floor Design Response Spectra			
1. REACTOR CONTAINMENT BUILDING (RCB); CONTAINMENT STRUCTURE			
At El. (-)13.25 ft.	E-W Horizontal (OBE)	4N169S-39000	(2)
	N-S Horizontal (OBE)	-39001	(2)
	Vertical (OBE)	-39002	(2)
At El. 37.0 ft	E-W Horizontal (OBE)	-39003	(4)
	N-S Horizontal (OBE)	-39004	(4)
	Vertical (OBE)	-39005	(1)
	E-W Horizontal (SSE)-39006	(3)	
	N-S Horizontal (SSE)	-39007	(4)
	Vertical (SSE)	-39008	(1)
At El. 68.0 ft.	E-W Horizontal (OBE)	-39009	(4)
	N-S Horizontal (OBE)	-39010	(4)
	Vertical (OBE)	-39011	(1)
	E-W Horizontal (SSE)	-39012	(3)
	N-S Horizontal (SSE)	-39013	(4)
	Vertical (SSE)	-39014	(1)
At El. 108.0 ft.	E-W Horizontal (OBE)	-39015	(3)
	N-S Horizontal (OBE)	-39016	(3)
	Vertical (OBE)	-39017	(1)
	E-W Horizontal (SSE)	-39018	(3)
	N-S Horizontal (SSE)	-39019	
	Vertical (SSE)	-39020	(1)
At El. 153.0 ft.	E-W Horizontal (OBE)	4N169S-39021	(3)
	N-S Horizontal (OBE)	-39022	(3)
	Vertical (OBE)	-39023	(1)
	E-W Horizontal (SSE)	-39024	(3)
	N-S Horizontal (SSE)	-39025	(3)
	Vertical (SSE)	-39026	(1)
At El. 203.75 ft.	E-W Horizontal (OBE)	-39027	(3)
	N-S Horizontal (OBE)	-39028	(3)
	Vertical (OBE)	-39029	(1)
	E-W Horizontal (SSE)	-39030	(3)
	N-S Horizontal (SSE)	-39031	(3)
	Vertical (SSE)	-39032	(1)

TABLE 1 (Continued)

LISTING OF DESIGN BASIS SPECTRA
(Including Designation of Case Number for the EHS SSI Effects)

Description		Drawing No.	ESH-Modified Spectra Case Number
2. RCB; INTERNAL STRUCTURE			
At El. 19.0 ft.	E-W Horizontal (OBE)	-39033	(3)
	N-S Horizontal (OBE)	-39034	(3)
	Vertical (OBE)	-39035	(1)
	E-W Horizontal (SSE)	-39036	(3)
	N-S Horizontal (SSE)	-39037	(3)
	Vertical (SSE)	-39038	(1)
At El. 37.0 ft.	E-W Horizontal (OBE)	-39039	(3)
	N-S Horizontal (OBE)	-39040	(3)
	Vertical (OBE)	-39041	(1)
	E-W Horizontal (SSE)	-39042	(3)
	N-S Horizontal (SSE)	4N169S-39043	(3)
	Vertical (SSE)	-39044	(1)
At El. 52.0 ft.	E-W Horizontal (OBE)	-39045	(3)
	N-S Horizontal (OBE)	-39046	(3)
	Vertical (OBE)	-39047	(1)
	E-W Horizontal (SSE)	-39048	(3)
	N-S Horizontal (SSE)	-39049	(3)
	Vertical (SSE)	-39050	(1)
At El. 68.0 ft.	E-W Horizontal (OBE)	-39051	(3)
	N-S Horizontal (OBE)	-39052	(3)
	Vertical (OBE)	-39053	(1)
	E-W Horizontal (SSE)	-39054	(3)
	N-S Horizontal (SSE)	-39055	(3)
	Vertical (SSE)	-39056	(1)
At El. 83.0 ft.	Horizontal (OBE)	4N169S-39072	(2)
	Vertical (OBE)	-39073	(2)
	Horizontal (SSE)	-39074	(2)
	Vertical (SSE)	-39075	(2)
3. MECHANICAL-ELECTRICAL AUXILIARY BUILDING (MEAB)			
At All Elevations	Vertical (OBE)	4N169S-39081	(1)
	Vertical (SSE)	-39082	(1)
At El. 95.0 ft.	E-W Horizontal (OBE)	4N169S-39147	(1)
	N-S Horizontal (OBE)	-39148	(1)
	E-W Horizontal (SSE)	-39149	(1)
	N-S Horizontal (SSE)	-39151	(1)

TABLE 1 (Continued)

LISTING OF DESIGN BASIS SPECTRA
(Including Designation of Case Number for the EHS SSI Effects)

Description		Drawing No.	ESH-Modified Spectra Case Number
At El. 96.0 ft.	E-W Horizontal (OBE)	-39152	(1)
	N-S Horizontal (OBE)	-39153	(1)
	E-W Horizontal (SSE)	-39154	(1)
	N-S Horizontal (SSE)	-39155	(1)
At El. 85.0 ft.	E-W Horizontal (OBE)	-39083	(1)
	N-S Horizontal (OBE)	-39084	(1)
	E-W Horizontal (SSE)	-39085	(1)
	N-S Horizontal (SSE)	-39086	(1)
At El. 69.5 ft.	E-W Horizontal (OBE)	-39087	(1)
	N-S Horizontal (OBE)	-39088	(1)
	E-W Horizontal (SSE)	-39089	(1)
	N-S Horizontal (SSE)	-39090	(1)
At El. 51.0 ft.	E-W Horizontal (OBE)	-39091	(1)
	N-S Horizontal (OBE)	-39092	(1)
	E-W Horizontal (SSE)	-39093	(1)
	N-S Horizontal (SSE)	-39094	(1)
At El. 35.0 ft.	E-W Horizontal (OBE)	-39095	(1)
	N-S Horizontal (OBE)	-39096	(1)
	E-W Horizontal (SSE)	-39097	(1)
	N-S Horizontal (SSE)	-39098	(1)
At El. 21.0 ft.	E-W Horizontal (OBE)	-39099	(1)
	N-S Horizontal (OBE)	-39100	(1)
	E-W Horizontal (SSE)	-39101	(1)
	N-S Horizontal (SSE)	-39102	(1)
At El. 10.0 ft.	E-W Horizontal (OBE)	-39167	(2)
	N-S Horizontal (OBE)	-39168	(2)
4. FUEL HANDLING BUILDING (FHB)			
At All Elevations	Vertical (OBE)	4N169S-39103	(1)
	Vertical (SSE)	-39104	(1)
At El. 119.0 ft.	E-W Horizontal (OBE)	-39105	(1)
	N-S Horizontal (OBE)	-39106	(1)
	E-W Horizontal (SSE)	-39107	(1)
	N-S Horizontal (SSE)	-39108	(1)

TABLE 1 (Continued)

LISTING OF DESIGN BASIS SPECTRA
(Including Designation of Case Number for the EHS SSI Effects)

Description		Drawing No.	ESH-Modified Spectra Case Number
At El. 68.0 ft.	E-W Horizontal (OBE)	-39109	(1)
	N-S Horizontal (OBE)	-39110	(1)
	E-W Horizontal (SSE)	-39111	(1)
	N-S Horizontal (SSE)	-39112	(1)
At El. 48.0 ft.	E-W Horizontal (OBE)	-39113	(1)
	N-S Horizontal (OBE)	-39114	(1)
	E-W Horizontal (SSE)	-39115	(1)
	N-S Horizontal (SSE)	-39116	(1)
At El. 30.0 ft.	E-W Horizontal (OBE)	-39117	(1)
	N-S Horizontal (OBE)	-39118	(4)
	E-W Horizontal (SSE)	-39119	(1)
	N-S Horizontal (SSE)	-39120	(4)
At El. 4.0 ft.	E-W Horizontal (OBE)	-39121	(1)
	N-S Horizontal (OBE)	-39122	(5)
	E-W Horizontal (SSE)	-39123	(1)
	N-S Horizontal (SSE)	-39124	(5)
At El.-29.0 ft.	E-W Horizontal (OBE)	-39125	(1)
	N-S Horizontal (OBE)	-39126	(5)
	E-W Horizontal (SSE)	-39127	(1)
	N-S Horizontal (SSE)	-39128	(5)
5. DIESEL GENERATOR BUILDING (DGB)			
At El. 107.0 ft.	E-W Horizontal (OBE)	4N169S-39129	(3)
	N-S Horizontal (OBE)	-39130	(3)
	Vertical (OBE)	-39131	(1)
At El. 100.0 ft.	E-W Horizontal	(OBE)-39132	(3)
	N-S Horizontal (OBE)	-39133	(3)
	Vertical (OBE)	-39134	(1)
At El. 82.0 ft.	E-W Horizontal (OBE)	-39135	(3)
	N-S Horizontal (OBE)	-39136	(1)
	Vertical (OBE)	-39137	(1)
At El. 55.0 ft.	E-W Horizontal (OBE)	-39138	(3)
	N-S Horizontal (OBE)	-39139	(1)
	Vertical (OBE)	-39140	(1)

TABLE 1 (Continued)

LISTING OF DESIGN BASIS SPECTRA
(Including Designation of Case Number for the EHS SSI Effects)

Description		Drawing No.	ESH-Modified Spectra Case Number
At El. 25.0 ft.	E-W Horizontal (OBE)	-39169	(2)
	N-S Horizontal (OBE)	-39170	(2)
	Vertical (OBE)	-39171	(2)
6. ENVELOPED FLOOR DESIGN SPECTRA FOR ALL BUILDINGS			
At All Elevations	Horizontal (OBE)	4N169S-39176	(2)
	Vertical (OBE)	-39177	(2)
	Horizontal (SSE)	-39178	(2)
	Vertical (SSE)	-39179	(2)
7. ENVELOPED FLOOR DESIGN SPECTRA FOR THE RCB			
At El. up to 153 ft.	Horizontal (OBE)	4N169S-39180	(2)
	Vertical (OBE)	-39181	(2)
	Horizontal (SSE)	-39182	(2)
	Vertical (SSE)	-39183	(2)
8. ENVELOPED FLOOR DESIGN SPECTRA FOR THE MEAB			
At All Elevations	Horizontal (OBE)	4N169S-39184	(2)
	Vertical (OBE)	-39185	(2)
	Horizontal (SSE)	-39186	(2)
	Vertical (SSE)	-39187	(2)
9. ENVELOPED FLOOR DESIGN SPECTRA FOR THE FHB			
At El. up to 68 ft.	Horizontal (OBE)	4N169S-39188	(2)
	Vertical (OBE)	-39189	(2)
	Horizontal (SSE)	-39190	(2)
	Vertical (SSE)	-39191	(2)
10. ENVELOPED FLOOR DESIGN SPECTRA FOR THE DGB			
At All Elevations	Horizontal (OBE)	4N169S-39192	(2)
	Vertical (OBE)	-39193	(2)

Question 220.10N

Discuss and provide, for staff's review, the structural details of circulating water screen house, its model for seismic analysis, assumptions used in the model definition, procedures considered in the soil-structure interaction analysis, and the results of the analysis.

Response

The STPEGS design does not include a circulating water screen house but does include a circulating water intake structure. The circulating water intake structure is not a safety-related structure. A dynamic analysis to estimate seismic loads is, therefore, not required.

Question 220.11N

You have stated that the strain-compatible shear modulus and damping values are used for each element representing soil strata. Indicate, for each layer, what strain-levels these values correspond to. Also, give numerical values of the soil properties and corresponding strains for each layer of soil. Provide this information for both horizontal and vertical analysis. In the staff's opinion the soil properties used should be those corresponding to low strain levels which are consistent with the realistic soil strains developed during the earthquake. Use of high strain parameters needs to be adequately justified.

Response

The soil conditions at the STPEGS site consist of alternating layers of stiff to hard clays and dense silts and sands that extend to depths of several thousand feet (Section 6.1 of Ref. l). The soils in the upper approximately 330 ft have been categorized into thirteen general layers and five material types (Ref. 2). The dynamic shear moduli or shear wave velocities of the in situ soils, applicable to very low shear strain (approximately 10^{-4} percent), were determined from a detailed program of cross-hole shear wave measurement at the site utilizing a down-hole impact hammer (Ref. 2). The results are shown in Figure Q220.11N-l and Table Q220.11N-1. Figure Q220.11N-1 also presents the upper bound and lower bound values of shear wave velocity that were used in the SSI analysis. The upper bound soil properties were defined by increasing values of shear modulus at very low shear strains by 50 percent (equivalent to increasing values of shear wave velocity by 22 percent); the lower bound soil properties were defined by decreasing values of shear modulus at very low shear strains by 40 percent (equivalent to decreasing values of shear wave velocity by 23 percent).

The variations of shear modulus with shear strain were determined using the data from the shear wave measurements at very low strain levels and data from laboratory dynamic tests at higher strain levels, while the variations of damping ratios with strain were obtained from laboratory dynamic tests. The laboratory testing program, the test results and the development of the modulus reduction and damping curves are presented in Reference 2. Figures Q220.11N-2 through Figure Q220.11N-7 show the variations of shear modulus and damping ratio with shear strain for each material type.

The strain-compatible dynamic soil properties for cases involving the horizontal excitation were obtained by simulating the nonlinear behavior of soils by the equivalent linear method (Ref. 3). The equivalent linear method provides an approximate nonlinear solution when the modulus and damping values used in the analysis are compatible with the effective shear strain amplitudes (The effective shear strain amplitudes were defined as 0.65 times the peak shear strain in each element.) The results of a research study (Ref. 4) indicate that the use of average modulus and damping values based on average strains (i.e., equivalent linear technique) is sufficiently accurate for seismic analysis of nuclear power plant structures.

Response (Continued)

Values of the effective shear strain for each soil layer in the free-field shown in Figure Q220.11N-l are presented in Figures Q220.11N-8, -9 and -10

for cases of average, upper-bound, and lower-bound soil properties, respectively. The shear strains developed in these analyses were low, generally ranging from about 0.4 to 1 x $l0^{-2}$ percent for upper-bound properties to 1 to 2 x 10^{-2} percent for lower-bound properties. Values of strain-compatible shear wave velocity of a soil column in the free-field and below the Reactor Building and the Auxiliary Building for the cases of average, upper-bound, and lower-bound soil properties are shown in Figures Q220.11N-11, -l2 and -13, respectively (Ref. 1). It is noted that shear wave velocities of the cohesionless soil layers below the Reactor Building are higher than those in the free-field due to higher confining pressures and lower strain levels beneath the structure than in the free-field. The soil column beneath the Auxiliary Building shown in Figures Q220.11N-11 through Q220.11N-13 includes 22 ft of structural backfill. Thus, the shear wave velocities in the upper 22 ft correspond to those of the backfill. Comparisons of the shear wave velocities of the soil column beneath the Auxiliary Building with those of the soil layers in the free-field shown in Figures Q220.11N-11 through Q220.11N-13 indicate that the values of strain-compatible shear wave velocity of the backfill are equal to or higher than those in the free-field.

As shown in Figure Q220.11N-14, for upper-bound analyses, the strain compatible shear wave velocities are about equal to the very-low-strain (approximately 10^{-4} percent) shear wave velocities measured in the field. Therefore, the analyses for horizontal excitation have essentially included cases using very-low-strain soil properties.

Values of damping ratio for the cases of average, upper-bound, and lower-bound soil properties are presented in Figure Q220.11N-15, -16, and -17, respectively (Ref. 1). In all cases, damping ratios of the soil layers beneath the structures are lower than those in the free-field due to lower strain levels beneath the structures. Damping ratios are generally small, equal to or less than about 0.06 for cases of upper-bound soil properties.

For cases involving vertical excitation, the dynamic soil properties were selected such that they would be compatible with the measured compression wave velocities at the site (Ref. 1). The compression wave velocity between depths of approximately 5 to 80 ft was about 5,500 ft/sec. Between depths of approximately 80 to 400 ft, the compression wave velocity was about 6,000 ft/sec. In the upper 5 ft of the soil profile (above the water table), values of compression wave velocity for vertical excitation were selected using the strain-compatible moduli obtained from the analysis for horizontal excitation. The variation of the compression wave velocities with depth is shown in Figure Q220.11N-18 (Ref. 1). These compression wave velocities were used as a basis for assigning constant (strain-independent) moduli, since compression strains developed during vertical excitation were very small, indicating that there would be little tendency for reduction in modulus. Note that the strain-compatible damping ratios from the corresponding cases for horizontal excitation were used for the cases involving vertical excitation (Ref. 1).

REFERENCES to Q220.llN

1. Woodward-Clyde Consultants (1976), "Soil-Structure Interaction Studies, STPEGS, Units 1 & 2", Report prepared for Brown & Root, Inc.

2. Woodward-Clyde Consultants (1975), "Basic Soil Data: STPEGS", Report prepared for Brown & Root, Inc.

3. Seed, H. B. and I. M. Idriss, "The Influence of Soil Conditions on Ground Motions During Earthquakes", Journal of Soil Mechanics and Foundation Division ASCE, Vol. 94, No. SM 1 (1969), pp. 99-139.

4. D'Appolonia Consulting Engineers, Inc. (1979), "Seismic Input and Soil-Structure Interaction", Report prepared for the U.S. Nuclear Regulatory Commission, NUREG/CR-0693.

TABLE Q220.11N-1

MATERIAL PROPERTIES OF IN SITU SOILS
HORIZONTAL ANALYSIS CASES FOR AVERAGE PROPERTIES***

Soil Layer ID	Sublayer Number	Depth Range (ft)	Material Type Number	Average Shear Wave Velocity Vs * (fps)	Maximum** Shear Modulus, G_{max} (ksf)	Modulus Reduction and Damping Curves (Figure Number)	Total Unit Weight, t (pcf)	Poisson's Ratio, 1
	1	0-6	1	610	1329	6	115	0.42
A	2	6-11	1	610	1444	6	125	0.42
	3	11-16	1	625	1516	6	125	0.42
	4	16-22	1	790	2423	6	125	0.42
	5	22-29.5	2	900	3144	7	125	0.42
B	6	29.5-36.5	2	910	3215	7	125	0.42
C	7	36.5-44	3	910	3215	8	125	0.35
	8	44-50	4	840	2761	9	126	0.42
D	9	50-59.5	4	1150	5175	9	126	0.42
	10	59.5-70.5	3	1150	5175	8	126	0.35
E	11	70.5-81.5	3	1160	5265	8	126	0.35
	12	81.5-91	4	1280	6564	9	129	0.42
F	13	91-100	4	1280	6564	9	129	0.42
	14	100-109	4	1220	5963	9	129	0.42
	15	109-119.5	4	1460	8540	9	129	0.42
H	16	119.5-132	3	1560	9674	8	128	0.35
	17	132-172	5	1229	5909	10	126	0.42
J	18	172-212	5	1173	5384	10	126	0.42
K	19	212-232	3	1541	9581	8	130	0.35

TABLE Q220.11N-1 (Continued)

MATERIAL PROPERTIES OF IN SITU SOILS
HORIZONTAL ANALYSIS CASES FOR AVERAGE PROPERTIES***

Soil Layer ID	Sublayer Number	Depth Range (ft)	Material Type Number	Average Shear Wave Velocity Vs * (fps)	Maximum** Shear Modulus, G_{max} (ksf)	Modulus Reduction and Damping Curves (Figure Number)	Total Unit Weight, t (pcf)	Poisson's Ratio, 1
L	20	232-281	5	1271	6431	10	128	0.42
M	21	281-291	3	1520	8969	8	125	0.35
N	22	291-331	5	1324	6915	10	127	0.42
--	23	331-346	3	1585	9758	8	125	0.35

* Refer to Figure Q220.11N-1 for plot of field shear wave velocity data obtained at Units 1 and 2.

** "Maximum" denotes shear modulus at very low shear strain levels (i.e. approx. 10^{-4} percent). The values of maximum shear modulus shown in the table correspond to the values of average shear wave velocity shown in the table.

*** From Table C.2-1 of Ref. 12

(G) Material type number is used to refer to a specific variation of modulus with strain (i.e. modulus reduction curves) and damping with strain shown in Figures Q220.11N-2 through Q220.11N-7.

Figure Q220.11N-1

Figure Q220.11N-2

Figure Q220.11N-3

Figure Q220.11N-4

Figure Q220.11N-5

Figure Q220.11N-6

Figure Q220.11N-7

Figure Q220.11N-8

Figure Q220.11N-9

Figure Q220.11N-10

Figure Q220.11N-11

Figure Q220.11N-12

Figure Q220.11N-13

Figure Q220.11N-14

Figure Q220.11N-15

Figure Q220.11N-16

Figure Q220.11N-17

Figure Q220.11N-18

Question 220.13N

To account for the effect of accidental torsion, NRC staff's position requires that an additional eccentricity of 5 percent of the maximum building dimension at the level under consideration shall be assumed over the actual geometrical eccentricity of Category I structures. Copy of revised SRP 3.7.2 (Attachment 2) is provided for your reference. Confirm that this staff position is fully complied with in your Category I structural design and analysis.

Response

The additional 5 percent eccentricity was not included in the initial design, only the actual geometric eccentricity between the center of mass and the center of rigidity was considered in the initial seismic analyses. Subsequent analyses for Category I structures have been performed to account for the effect of accidental torsion in accordance with the NRC position. The results of the confirmatory analyses summarized in Table 220.13N-1 indicate that the existing design of all Category I structures is adequate.

TABLE Q220.13N-1

RESULTS OF THE CONFIRMATORY ANALYSES -

Building/Structure Description of Key Shear Walls	Calculated Shear Force, k/ft., 5% Accidental Torsion: Excluded	Calculated Shear Force, k/ft., 5% Accidental Torsion: Included	Allowable, Shear Load, k/ft. Concrete Alone, No Reinforcing	Reinforcement For In-Plane Shear Sq.-in./ft.: Required Vertical	Required Horizontal	Available Vertical	Available Horizontal
Reactor Containment Building (RCB)							
Primary Shield Walls							
El. (-) 13'-3" to 12'-1"	128	130	290	None	None	-	-
12'-1" to 19'-0"	246	249	422	None	None	-	-
19'-0" to 38'-6 1/2"	332	334	390	None	None	-	-
Secondary Shield Walls							
Southwest, El. (-) 5'-3"	122	124	125	None	None	2.6	7.6
North, El. (-) 5'-3"	443	445	179	4.42	4.42	5.2	7.6
Containment Shell							
El. (-) 13'-3" (basement)	38	40	138	None	None	2.1	1.7
El. 38'-9"	31	33	0	None	0.84	2.8	0.90
El. 74'-9"	25	27	0	None	0.44	2.8	0.90
El. 133'-0" (Springline)	8.8	9.7	151	None	None	2.8	1.5

Building/Structure Description of Key Shear Walls	Calculated Shear Force, k/ft., 5% Accidental Torsion: Excluded	Calculated Shear Force, k/ft., 5% Accidental Torsion: Included	Allowable, Shear Load, k/ft. Concrete Alone, No Reinforcing	Reinforcement For In-Plane Shear Sq.-in./ft.: Required	Provided
Mechanical Electrical Auxiliary Building (MEAB)					
East Exterior Wall El. 10'-0"	72	78	86	1.03 (Min.)	1.60
North Exterior Wall El. 35'-0"	59	66	75	0.90 (Min.)	1.60
East Exterior Wall El. 60'-0"	22	24	75	0.90 (Min.)	1.60

TABLE Q220.13N-1 (Continued)

RESULTS OF THE CONFIRMATORY ANALYSES

Building/Structure Description of Key Shear Walls	Calculated Shear Force, k/ft., 5% Accidental Torsion		Allowable, Shear Load, k/ft. Concrete Alone, No Reinforcing	Reinforcement For In-Plane Shear Sq.-in./ft.	
	Excluded	Included		Required	Provided
East Exterior Wall El. 80'-0"	19	21	75	0.90 (Min.)	1.60
Fuel Handling Building (FHB)					
East Exterior Wall El. (-) 29'-0" to 4'-0"	135	153	85	1.30	2.40
North Exterior Wall El. (-) 29'-0" to 4'-0"	184	198	46	2.90	3.10
South Exterior Wall El. 21'-11" to 30'-0"	124	130	62	1.30	1.70
South Exterior Wall El. 4'-0" to 21'-11"	140	142	62	1.60	1.70
South Exterior Wall El. 68'-0" to 119'-0"	114	119	46	1.40	1.60
Diesel Generator Building (DGB)					
West Exterior Wall El. 25'-0" to 55'-0"	30	35	58	0.72 (Min)	1.60
South Exterior Wall El. 25'-0" to 55'-0"	80	81	55	0.72 (Min)	1.60
Essential Cooling Water Intake Structure (EWIS)					
East Exterior Wall El. 10'-0"	37	42	31	0.72 (Min)	1.20
West Exterior Wall El. 34'-0"	47	54	46	1.08 (Min)	1.20

TABLE Q220.13N-1 (Continued)

RESULTS OF THE CONFIRMATORY ANALYSES

Building/Structure Description of Key Shear Walls	Calculated Shear Force, k/ft., 5% Accidental Torsion		Allowable, Shear Load, k/ft. Concrete Alone, No Reinforcing	Reinforcement For In-Plane Shear Sq.-in./ft.	
	Excluded	Included		Required	Provided
North and South Exterior Wall El. 34'-0"	41	47	46	1.08 (Min)	1.20
Interior Wall East to West El. 10'-0"	32	33	31	1.08 (Min)	1.20

Question 220.15N

When seismic Category I piping is directly connected to the nonseismic Category I piping, confirm that the attached nonseismic Category I piping, up to the first anchor beyond the interface, are designed in a manner that earthquake of SSE intensity will not cause failure of seismic Category I piping.

Response

In the case described above, the nonseismic Category I piping up to the first anchor beyond the interface is seismically analyzed and designed with the seismic Category I piping to withstand an Safe Shutdown Earthquake (SSE) level earthquake.

Question 220.16N

The analysis procedures used for composite damping calculation seem not consistent with those of the SRP Section 3.7.2.II.15. Discuss the basis for your deviation and justify the adequacy of the method used.

Response

The approach described in UFSAR Section 3.7.3.15 is conservative, since the lowest element damping is arbitrarily assigned to all elements through the uniform damping assignment to all modes. The damping values based on testing programs were not used in the dynamic analysis of piping systems except in the case of the Reactor Coolant Loop.

Question 220.22N

Has buckling been considered in design of containment building? If yes, provide a discussion of the manner with which the adequacy of the building design is assured.

Response

Because of the massive dimensions of the containment shell (4-ft wall and 3-ft dome) and the relative magnitude of compressive stresses, buckling is not considered to be a possible mode of failure for the Reactor Containment Building.

Question 220.25N

State if the concrete is assumed to be cracked under any load combination involving axisymmetric and non-axisymmetric loadings. If so, by what method have you considered the cracking and the basis thereof?

Response

The structural analyses for the determination of design moments, forces, and shears under all loads are performed on the basis of linear elastic analysis. Nonlinear analyses involving iterative processes to account for concrete cracking are not used under any load combination involving axisymmetric or nonaxisymmetric loadings. The cracking of concrete is considered in the design of the individual concrete sections, for which the amount of reinforcing steel is provided without relying on the concrete to resist any tension. For the design of reinforced concrete sections under thermal loading, the state-of-stress under nonthermal loads is determined first, and if necessary, the reductions in thermal stresses are calculated based on concrete cracking, reinforcement yielding (within allowable limits), compatibility of state-of-stress and strain, and boundary conditions. The foregoing reductions of thermal stresses operate on the design loads calculated by linear elastic analyses, and do not represent nonlinear iterative analyses devised to account for concrete cracking.

Question 220.28N

In Section 3.8.1.5.1.1 of FSAR it is mentioned that allowable stresses may be increased by 33-1/3 percent when temperature effects are combined with other loads. SRP Section 3.8.1.II.5 requires that no 1/3 increase in allowable stresses is permitted for load combinations including OBE or wind loads. Please confirm that this position has been fully complied with or justify the deviation.

Response

The one-third allowable stress increase referred to in UFSAR Section 3.8.1.5.1.1 pertains exclusively to the case when the loading combination includes thermal loads. The design of the reinforcement for the STPEGS Reactor Containment Building could rely on the one-third allowable stress increase only when thermal loads are present in combination with Operating Basis Earthquake (OBE) and wind loads.

Question 220.29N

Confirm that the materials of construction are in accordance with Article CC-2000 of ASME-ACI 359 Code, augmented by Regulatory Guide 1.103, 1.107 and 1.136. If not, identify the deviations and justify same.

Response

The materials of construction for the containment are in accordance with Article CC-2000 of the ASME-ACI 359 Code. As stated in Section 3.12, STPEGS conforms with Regulatory Guide (RG) 1.103. RG 1.107 is not applicable to STPEGS since the Containment does not use grouted tendons. RG 1.136 is not applicable to STPEGS due to its implementation date.

Question 220.30N

The staff presently accepts the use of ACI-349 as augmented by Regulatory Guide 1.142 in the design of Category I concrete structures other than containment. FSAR Sections 3.8.3, 3.8.4, and 3.8.5 have mentioned the use of ACI-318 Code for Concrete Structure. Evaluate and assess the impact of using ACI-349 as augmented by Regulatory Guide 1.142. Identify specific deviations from the staff position and the areas where use of ACI-318 Code results in less conservative design. Also discuss specific means for disposition of these less conservative design areas or justify their design adequacy.

Response

The only significant difference between the ACI-318 and ACI-349 codes is in the load combination equations. The STPEGS load combinations comply with the Standard Review Plan (SRP) requirements, which are the same as the ACI-349 loading combinations as modified by RG 1.142. Therefore, the STPEGS structural design satisfies the current NRC acceptance criteria.

Other differences are:

1. Provisions regarding quality assurance (QA)

2. Provisions of Appendix A, B, and C of the ACI-349 Code (these appendices are not included in the ACI-318 Code).

With regard to Item 1, STPEGS criteria require compliance with the applicable QA requirements including 10CFR50 Appendix B which is referenced in ACI-349, and no discrepancy arises with respect to the ACI-349 Code.

With regard to item (2), the STPEGS criteria for thermal considerations and for impulsive and impactive effects are the same as, or more conservative than those prescribed in the Code in Appendix A and Appendix C, respectively.

With regard to Appendix B of the Code, the STPEGS design criteria differs from the Code provisions in the following respects:

a) For the welded anchor studs of standard embedded plates used for miscellaneous supports, and for ductile-type undercut expansion anchors (Drillco Maxibolts), the interaction equation prescribed by the STPEGS criteria for combined tension and shear is:

$$\frac{t}{T}^{5/3} = \frac{s}{S}^{5/3} \leq 1.0$$

Response (Continued)

instead of the linear equation implied by the Code (Subsection B.6.3.2):

$$\frac{t}{T} + \frac{s}{S} \leq 1.0$$

where:

t, s = design tension load and shear load, respectively
T, S = allowable tension load and shear load, respectively (allowable leads based on ultimate loads)

b. For grouted rock-bolts (Williams), the interaction equation prescribed by the STPEGS criteria for combined tension and shear is:

$$\frac{t}{T}^2 + \frac{s}{S}^2 \leq 1.0$$

instead of the linear equation implied by the Code.

c. Anchor bolts for certain applications are allowed to be provided with embedment lengths that result in ultimate load capacities that satisfy the required design load with the prescribed load factors, but do not necessarily satisfy the generic Code provision to develop the full tensile strength of the steel bolts, implied in Subsection B.4.2.

Discussion

Items a and b

The foregoing interaction equation (with 5/3 and 2.0 exponents) are allowed by the STPEGS criteria only for the cases where the tension and shear ultimate loads of the stud/bolts represent ductile behavior governed by the steel material strength. For the Maxibolts, the hole drilled into the concrete is undercut (conically enlarged in diameter at its base) in order to provide a positive mechanical anchorage for the expanded head of the bolt. This positive anchorage, plus the prescribed deep embedment and wide separation between bolts, preclude slippage and/or concrete cone failure so that the full strength of the steel bolt is invariably developed as demonstrated by tests. Similarly, for the rock-bolts, the combination of an effective head expanded by torquing upon initial installation, followed by grouting by injection of a high-strength non-shrink mix through an axial hole in the bolt, plus the prescribed deep embedment, assures the development of the full strength of the steel bolts. That means that the concrete ultimate load capacities, which are calculated in accordance with the ACI-349 code for the above

bolts with a specific embedment and spacing, exceed and fully develop the steel material ultimate load of the bolts. Therefore, in these cases the relevant interaction mechanism is that
Response (Continued)

applicable to steel bolts as opposed to the interaction associated with concrete anchorage or cone failure represented by the linear interaction. For steel studs in concrete the ultimate load capacities and interaction behavior have been extensively evaluated by tests as reported in References (1) and (3), where the interaction equation with 5/3 exponents is recommended. For steel bolts the interaction behavior recognized by the AISC in Reference (2) is defined by an elliptical relationship which is equivalent to the interaction equation with an exponent of 2.0. It is noted that the interaction equation with exponents of 2.0 (AISC) is the upper bound analytical expression derived from tests, and it envelops the more conservative equation with 5/3 exponents.

The foregoing approach, whereby the implied linear interaction is recognized for the design of anchor studs/bolts which are proportioned to fully develop the steel material strength so that slippage and/or concrete cone failure do not govern, is also mentioned in Reference (3). In this reference paper the elliptical shear/tension interaction is recognized as valid, but it is conditionally recommended for the reassessment of existing designs rather than for generic use in new designs. This is actually the case for the STPEGS since the designs affected by the elliptical interactions equations are mostly the earlier designs based on the original STPEGS criteria established prior to the ACI-349 Code. The subsequent new designs for embedded plate anchors performed by Bechtel are in accordance with the Code.

For the cases of anchor studs/bolts where the concrete ultimate load capacity governs because of allowed reductions in embedment and/or spacing, the STPEGS criteria reverts to the linear interaction equation implied by the ACI-349 Code.

Therefore, based on the foregoing clarifications and on consideration of Reference (3), it is regarded that the interaction equations as prescribed by the STPEGS criteria are adequate to assure the structural integrity of the anchor studs/bolts under combined tension and shear, and are consistent with an interpretation of the Code supported by the ASCE paper of Reference (3).

References

1. Design Data 10 - Embedment properties of headed studs by TRW, Nelso Division, 1977. (Refer to section 1.0 and 6.0, and references cited therein).

2. Commentary on the specification for the design, fabrication and erection of structural steel for buildings, AISC, November 1, 1978. (Refer to subsection 1.6.3).

3. State-of-the-art report on steel embedments, by ASCE Nuclear Structures and Materials Committee, June 1984. (Refer to subsection 3.3.3.2 and 4.1.2.3).

Item c

In some instances, the anchor bolt size (diameter) provided for equipment mounting is based on the bolt hole size specified in the equipment manufacturer drawings. The resultant bolt size is verified by the STPEGS engineer to be adequate for the calculated design loads, and the bolt anchorage into the concrete (as governed by the bolt embedment, spacing and head or anchor plate at the end of the bolt) is designed to satisfy the calculated design loads. Often in these cases the bolt size as derived from the manufacturer's standardized drawing is actually oversized with respect to the calculated loads. Therefore, it is not necessary to extend the overdesign into the bolt anchorage by attempting to fully develop the ultimate tensile strength of bolts whose function does not demand loads close to the ultimate load range.

In these cases of oversized bolts, it is considered sufficient to design the bolt anchorage (using the ACI-349 Code formulations) to develop the calculated factored design load for the specific bolts rather than to develop the generic bolt ultimate load.

In view of the above discussion, the design procedures and construction practices used in the STPEGS ensure that the structures are adequate for the specified conditions prescribed by the current NRC criteria.

In accordance with the request made during the NRC structural audit, the impact of the NRC positions as stated in RG 1.142 has been evaluated. The following table compares the NRC and STPEGS positions on the twelve items included in RG 1.142.

TABLE Q220.30N-1

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)" -

1. Structures required to withstand pressures and to maintain a certain degree of leak-tightness during operating and accident conditions will be reviewed in accordance with specific provisions of Standard Review Plan 3.8.3.	1. The requirements for leak-tightness specified to Standard Review Plan 3.8.3 are applicable to PWR ice-condenser containment internal structures and to BWR containment internal structures, and therefore are not applicable to STPEGS, which has PWR dry containment internal structures.
2. When concrete structures are used to provide radiation shielding, provisions of ANSI/ANS 6.4-1977 (see Appendix A) are applicable to the extent that they enhance the radiation shielding function of these structures. Reduction in shielding effectiveness due to embedment, penetrations, and openings should be fully evaluated.	2. Concrete structures which are used as radiation shields are analyzed for shielding effectiveness utilizing the methods addressed in Section 12.3. Reductions of shielding effectiveness such as shielding discontinuities, penetrations and opening (e.g., doors and access hatches), are reviewed for impact on radiation dose rate zoning. Additional shielding in the form of penetration seals or labyrinths is provided as necessary to ensure operating personnel exposures are maintained ALARA.
3. The Code lacks specific requirements to ensure the ductility of concrete moment frames. Adherence to the requirements of Appendix A to ANSI/ACI 318-77 is acceptance.	3. The STPEGS Category I structures do not utilize concrete moment frames, and therefore this position is not applicable to STPEGS design.
4. In addition to the requirements of Section 1.3.1 of the Code, the inspectors should have sufficient experience in reinforced and prestressed concrete practice as applied to the construction of nuclear power plants. The examiners/ inspectors qualified to Appendix VII of Section III, Division 2, of the ASME Boiler and Pressure Vessel Code (ACI 359) are acceptable as inspectors.	4. Inspectors involved with concrete related work on the STPEGS are qualified in accordance with ANSI N45.2.6, "Qualifications of Inspection, Examination and Testing personnel for Nuclear Power Plants," a widely accepted standard in nuclear construction.

TABLE Q220.30N-1 (Continued)

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)"

5. In lieu of the frequency of compressive strength testing required by Section 4.3.1 of the Code or that required by ANSI N45.2.5 as endorsed by Regulatory Guide 1.94, the following is acceptable: Samples for strength tests of concrete should be taken at least once every shift for each class of concrete placed or at least once for each 100 cu yd of concrete placed. When the standard deviation for 30 consecutive tests of a given class is less than 600 psi, the amount of concrete placed between tests may be increased by 50 cu yd for each 100 psi the standard deviation is below 600 psi, except that the minimum testing rate should not be less than one test for each shift when concrete is placed on more than one shift per day or less than one test for each 200 cu yd of concrete placed. The test frequency should revert back to each 100 cu yd placed as soon as the test data of any 30 consecutive tests indicate a higher standard deviation than the value controlling the decreased test frequency.	5. Concrete for the STPEGS is tested every 100 cu yds (or at least once a day during production). This test frequency meets or exceed both ACI 318 and ANSI N45.2.5 requirements. The provisions to reduce testing frequencies outlined in this position have not be exercised.
6. The load factors used in Section 9.3.1 of the Code are acceptable to the staff except for the following: a. In load combination (9), (10), and (11), $1.3T_o$ should be used in place of $1.85T_o$.	6. The load combinations and the associated load factors used in the STPEGS design meet the minimum requirements specified in Standard Review Plan Sections 3.8.3 and 3.8.4 and therefore are consistent with the

TABLE Q220.30N-1 (Continued)

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)"

b. In load combination (6), $1.5P_a$ should be used in place of $1.25P_a$.	modifications to the load factors outlined in this position.
c. In load combinations (7), $1.25P_a$ and $1.25E_o$ should be used in place of $1.15P_a$ and $1.15E_o$, respectively.	
d. In load combination (2), and (10), $1.9E_o$ and $1.4E_o$ should be used in place of $1.7E_o$ and $1.3E_o$, respectively.	
7. When the lateral and vertical pressures of liquids are due to the normal groundwater variation in the soil surrounding the structure, the load factors of H loading of Section 9.3.1 should be applied to these forces or their related internal moments and forces.	7. In the STPEGS design, the load factors used to computer the water pressure resulting from the groundwater table are, as a minimum, those applicable to the dead load of the structure. The design water table used to calculate hydraulic forces on structures which extend below the water table is based on a high water table elevation. Since the unit weight of water is well defined and the design is based on the high water table elevation corresponding to 1 foot below grade, the groundwater loads are actually defined with a high level of certainty and are not subject to adverse variation. Therefore the load factors applicable to well defined loads, such as dead load, are considered appropriate.
8. In Section 9.3.2 the effects of differential settlement should be included in load combinations (1) through (11).	8. In the STPEGS design, the effects of differential settlement would have been included, had significant differential settlement been anticipated. However, the natural soild and Category I backfill, which support all Category I structures, have been

TABLE Q220.30N-1 (Continued)

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)"

	investigated and evaluated to ensure that differential settlements within structures will remain within tolerable limits. As part of an ongoing program, settlement in the structures is monitored to ensure that this is the case. Differential settlements within structures observed to date are considered negligible.
9. The consideration of loads due to pool dynamics for the concrete structures in pressure-suppression containments will be evaluated on a case-by-case basis.	9. Because STPEGS does not utilize pressure-suppression contain-ments, this position is not applicable to the STPEGS design.
10. The local exceedance of section strengths in accordance with Appendix C of the code is acceptable in analyses for impactive or impulsive effects of Y_r, Y_j, and Y_m in load combinations (7) and (8), and those of tornado-generated missiles in load combination (5) except for the following: a. The deformation and degradation of the structure resulting from such an analysis will not cause loss of function of any safety-related structures, systems, or components. b. The section strengths should be adequate to satisfy these load combinations without the impactive or impulsive.	10. The STPEGS design is in compliance with this position.

TABLE Q220.30N-1 (Continued)

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)"

c. In Section C.3.4, the permissible ductility ratios (u) when concrete structure is subjected to a pressure pulse due to compartment pressurization or external explosion (blast) loading should be as follows:

   1) For the structure as a whole u ≤1.0.

   2) For a located area in the structure u ≤3.0.

d. In Section C.3.7, where shear controls the design, the permissible ductility ratios should be as follows:

   1) When shear is carried by concrete alone, u ≤1.0.

   2) When shear is carried by combination of concrete and stirrups or bent bars, u ≤1.3.

11. The local exceedance of section strengths in accordance with Appendix C of the Code is also acceptable under the impactive and impulsive loadings associated with aircraft impact, turbine missiles, and a localized pressure transient during an explosion, subject to the applicable exceptions of regulatory position C.10.

11. The STPEGS design is consistent with this position.

12. The generic criteria of Appendix A "Thermal Consideration", of the Code are acceptable for the analysis of structures under T_o and T_a.

12. The STPEGS design considers thermal effects for Category 1 reinforced concrete structures. In general, the OPTCON computer code is used for determining the thermal effects on the design of reinforced concrete sections.

TABLE Q220.30N-1 (Continued)

STPEGS POSITIONS ON REGULATORY GUIDE 1.142 "SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)"

	Even though the method outlined in Appendix A of the ACI 349 code has not been used, OPTCON reflects the state-of-the-art methodology in reinforced concrete design, incorporating an equally acceptable procedure for computing the thermal effects. OPTCON is one of the modules of the Bechtel Structural Analysis Program, Post Processor described in Appendix 3.8.A. (Refer to the response to Q220.25N for a more detailed discussion on the consideration of cracked sections in the STPEGS structural analysese.)

Question 220.32N

The Fuel-Handling Building contains a spent fuel pool. A copy of "Minimum Requirements for Design of Spent Fuel Racks" is enclosed (Attachment 3). Provide the information as required and discuss your compliance with this position.

Response

HL&P has evaluated the long term need for increased spent fuel storage at STPEGS through the use of higher density spent fuel racks and decided to purchase higher density racks, these new racks will comply with Appendix D to Standard Review Plan (SRP) 3.8.4.

The present racks will be used only for the initial fuel delivery, low-power testing and the early part of Cycle 1. The analysis of these 14-in. center-to-center spent fuel racks was performed using the load combinations and acceptance limits outlined in Table Q220.32N-1 (attached). These load combinations and acceptance limits are taken from the paper "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications", dated April 14, 1978, with modifications dated January 18, 1979, and have been used consistently by Westinghouse for the evaluation and recent license amendments for spent fuel racks at other plants.

The load combinations and acceptance limits for the seismic and thermal loads are from the table on page IV-6 of the January 18, 1979 modifications. The load combinations for the stuck fuel incident and the fuel drop accident are taken from the text of the paper. Although these load combinations and acceptance limits are not exactly the same as those stated in Appendix D of SRP 3.8.4, the intent of Appendix D has been met.

TABLE Q220.32N-1

STORAGE RACK LOADS AND LOAD COMBINATIONS -

Load Combination	Acceptance Limit
D + L	Normal Limits of NF 3231.1a
D + L + P_f	Normal Limits of NF 3231.1a
D + L + E	Normal Limits of NF 3231.1a
D + L + T_o	Lesser of $2S_y$ or S_u stress range
D + L + T_o + E	Lesser of $2S_y$ or S_u stress range
D + L + T_a + E	Lesser of $2S_y$ or S_u stress range
D + L + T_o + P_f	Lessor of $2S_y$ or S_u stress range
D + L + T_a + E'	Faulted condition limits of NF 3231.1c (see Note 3)
D + L + F_d	The functional capability of the fuel racks shall be demonstrated

1. The abbreviations in the table above are those used in Standard Review Plan (SRP) Section 3.8.4 where each term is defined except for T_a, which is defined here as the highest temperature associated with the postulated abnormal design conditions. F_d is the force caused by the accidental drop of the heaviest load from the maximum possible height, and P_f is the upward force on the racks caused by a postulated stuck fuel assembly.

2. The provisions of NF-3231.1 of ASME Section III, Division I, shall be amended by the requirements of Paragraphs c.2, 3, and 4 of Regulatory Guide 1.124, entitled "Design Limits and Load Combinations for Class A Linear-Type Component Supports".

3. For the faulted load combination, thermal loads were neglected when they are secondary and self-limiting in nature and the material is ductile.

Question 220.33N

With regard to your submittal on masonry walls (Reference letter from G. W. Oprea to D. G. Eisenhut, dated September 4, l980) the following information is requested.

The staff has established a position on the evaluation of safety-related masonry walls. A copy of this position is attached herewith (Attachment 4) for your assessment of masonry wall design at South Texas Project. Compare the staff's criteria with the criteria which you used in the design of STPEGS masonry walls. Identify and provide justification for all deviations from the staff's criteria. The justification provided should be based on experimental tests and/or analytical considerations, as appropriate.

Specific questions on the submittal with the above reference are as follows:

(1) Provide detailed calculations for three representative masonry walls at least one wall being of multiwythe construction if any and one in the Reactor Building which experience all the loads identified in Attachment 2 and 3 of the enclosure to your letter of September 4, 1980. If there are walls which experience loads such as LOCA, and thermal, as indicated in the Attachment 2 and 3 referenced above, provide detailed calculations for one of these walls also. The calculations should identify all the load and load combinations. Provide response spectra and damping values used. Also provide details and the actual mechanism in the field.

(2) Submit the examples with discussion on:

(a) The effects of three components of earthquake loading

(b) The mechanism through which composite action of multiwythe walls (if any) is assumed to occur

(c) Seismic drifts effects

(d) Attachment of walls to the columns and floors to demonstrate the adequacy of the assumptions used in analysis

Response

Safety-related concrete masonry unit (CMU) walls are not planned to be used inside any of the seismic Category I structures. If safety-related CMU walls are determined to be necessary, the walls will be designed in conformance with the referenced evaluation criteria (Standard Review Plan [SRP] Section 3.8.4 Appendix A), refer to revised Section 3.8.4.4. Therefore, the requested information describing deviations from the staff's criteria and sample calculations are not considered necessary since presently on STPEGS there are no safety-related CMU walls.

Question 220.34N

Prepare for the structural design audit scheduled for the week of January 11, 1982 by completing the design audit forms (Attachment 5) before the audit date. The subject of structural design audit is discussed in Appendix B to SRP Section 3.8.4 (Attachment 6).

Response

The structural design audit forms were transmitted by letter to Mr. Thomas Novak on June 30, l983 (Correspondence serial number ST-HL-AE-967). A revision to the structural design audit forms were transmitted by letter to Mr. Thomas Novak on December 19, 1984 (Correspondence serial number ST-HL-AE-1162). The stresses at key sections of Containment shell and mat are given in Table 3.8.1-7. Governing stress ratios for principal steel members are given in Table 3.8.3-4.

Question 110.2

Subparagraph NCA-1130(b) of the ASME B&PV Code Section III requires non-code mechanical or electromechanical devices such as valve operators to be covered by the code when these devices act as component supports. Provide a commitment to insure that the design of devices which become attachment points for component supports, thus providing component support load path, will adequately consider these support loadings.

Response

The STPEGS does not currently use devices such as valve structures as supports, restraints, or attachment points for supports and restraints. However, should such devices be used in this manner, the design of these devices will adequately consider all support loadings.

Question 110.3

Describe the allowable buckling loads for Class 1, 2 and 3 component supports subjected to normal, upset, emergency, and faulted load combinations.

Response

For normal, upset, emergency, and faultd conditions, all Class 1, 2, and 3 component supports are designed in accordance with the criteria as specified in Subsection NF or ASME Section III.

Question 110.4

Provide the basis for selecting the location, required load capacity, and structural and mechanical performance parameters of safety-related hydraulic snubbers in order to achieve a high level of operability assurance, including:

1. A description of the analytical and design methodology utilized to develop the required snubber locations and characteristics.

2. A discussion of design specification requirements to assure that required structural and mechanical performance characteristics and product quality are achieved.

3. Procedures, controls to assure correct installation of snubbers and checking the hot and cold settings during plant start-up tests.

4. Provisions for accessibility for inspection, testing, and repair or replacement of snubbers.

Response

The only application of hydraulic snubbers is for the upper support structures for the steam generators. Appropriate preliminary design stiffnesses for these supports (as well as stiffnesses for all other Reactor Coolant System [RCS] supports) are included in the reactor coolant loop model so that loads can be generated at all support locations for all applicable loading conditions. Loads at the steam generator upper supports are then used to verify adequacy of the support structure, including snubbers.

The RCS snubbers provided for STPEGS Units 1 and 2 are the hydraulic shock arrestor type and are designed and manufactured in accordance with ASME Section III, Subsection NF. Additionally, all snubbers are subjected to a thorough testing program which verified their capability to function properly before, during, and after upset and faulted condition loadings. All aspects of design and manufacture are in accordance with accepted Westinghouse quality assurance procedures (Quality Control Standard 1, QCS-l; Ref: WCAP-8370 "NES Quality Assurance Program", approved by NRC 12/31/74). Instruction manuals are provided with the snubbers and contain detailed procedures for installation which assure proper installation and checkout during plant start-up testing. Also, precautions are taken to assure accessibility to the snubbers for purposes of inspection and testing. All snubbers have the capacity for in-place testing.

Question 110.14

Provide the following information regarding the stress limits to be used for bolting materials:

1. For ASME Class l components, provide stress limits to be used for bolting materials for faulted condition loading. Neither ASME Section III nor Appendix F to ASME Section III contains faulted stress (Level D Service Limit) limits for bolts.

2. For ASME Class l, 2, and 3 component supports, provide stress limits for bolting materials for both emergency and faulted condition loading. Neither Section III, Appendix XVII nor Appendix F contain emergency of faulted stress (Level C or D Service Limit) limits for component support bolts.

Response

1. Stress limits used for Class l component bolting for the faulted condition are as follows:

   Reactor Vessel Closure Studs

   $P_m \leq 2.4\ S_m$ or $0.7\ S_u$

   $P_m + P_b \leq 3.6\ S_m$ or $1.05\ S_u$ (whichever is lower)

   Reactor Coolant Pump Main Flange Bolting

   $P_m \leq 0.7\ S_u$

   $P_u + P_b \leq 1.05\ S_u$

   Steam Generator Manway Cover Bolting (loaded in tension only)

   $P_m \leq 2.0\ S_m$

2. Stress limits used for Class l, 2, and 3 component support bolting are those of ASME Section III Appendix XVII (XVII-2460) and/or ASME Code Case 1644, increased according to the provisions of ASME Section III (XVII-2110[a]) for emergency conditions and F-1370(a) of Appendix F for faulted conditions.

   NOTE: The Replacement Steam Generators were fabricated to the 1989 edition of the ASME code, which now addresses faulted stress limits for bolts. The code requirements were applied.

Question 110.18

For active pumps and valves, and for all other components (including piping and vessels) required for safe shutdown of the plant, provide assurance that the design criteria; i.e., stress limit, deformation limit, etc., which have been utilized to evaluate the acceptability of each such component under exposure to its worst case postulated loading environment, will provide for sufficient component dimensional stability to assure its system functional capability as has been assumed in the FSAR Chapter 15 analyses. Acceptable criteria for piping are provided in Attachment 110-1.

Response

Active pumps and valves are qualified for operability by test and/or analysis. This testing and/or analysis verifies that active pumps and valves will perform their safety function when subjected to the must severe loads which would be imposed by the SSE coincident with the maximum faulted plant condition nozzle loads. The maximum nozzle loads imposed by the piping systems and the seismic accelerations imposed due to building location and/or piping system design are confirmed to be less than the maximum nozzle loads and seismic loads used for component design. Thus, active pumps and valves are qualified for loads which are at least as severe as the maximum loads which are expected to occur as a result of faulted condition loadings.

The stress limits which are applied to active pumps (Tables 3.9-4A and 3.9-4B) are only nominally higher than Level B stress limits and less than Level C stress limits. This assures that the pumps will not experience permanent deformation or otherwise be damaged during the short duration of the faulted condition event. Likewise, stress limits for active valves are presented in Tables 3.9-5 and 3.9-5A (Class 1) and 3.9-6 and 3.9-6A (Class 2 and 3). In addition, the stress limits imposed on the non-ASME Code extended structures of active valves assure that the extended structures do not experience permanent deformation or damage and that the functional capability of the valves is not impaired.

The design procedures for Level C and D stress limits delineated in Section III of the ASME Code provide adequate assurance that structural discontinuities in piping, tanks, and vessels will retain their specified geometric configuration during the improbable emergency and faulted condition events. These procedures provide adequate margins to assure the primary pressure boundary of components and the function of component supports. Conservative stress indices and intensification factors based upon analytical and experimental results as specified in the Code are used for analysis in the area of structural discontinuity of piping, tanks, and vessels. The use of these proven procedures and conformance with ASME III requirements provide an acceptable basis to assure the functional capability of these components.

Question 110.19

Provide the following information with regard to buckling loads:

1. Provide the bases for the allowable buckling loads, including the buckling allowable stress limit, under faulted conditions for all NSSS and BOP ASME Class 1 component supports.

   Also describe the analytical techniques used in determining both the calculated buckling loads under faulted conditions and the critical buckling loads of the ASME Class 1 and 2 component supports.

2. In FSAR Section 3.9.1.4.7, you state that for all NSSS Class l component supports, loads shall not exceed 0.90 times the critical buckling strength. We require that Class l component supports meet the following criteria which are consistent with Regulatory Guides 1.124 and 1.130, and F-1370 of the ASME Code.

   Whenever the design of component supports permits loads in excess of 0.67 times the critical buckling strength, verification of the support functional adequacy shall be established by full scale experimental testing (II.1252(b)). The results of such tests shall be submitted for NRC review on an individual case basis. It is our understanding that the design criteria for component supports in Appendix F to ASME Section III is currently being reevaluated by the applicable code committee and that some changes to the existing criteria may be made. As an alternative to full scale testing, we will consider any revised criteria after approval by the ASME for inclusion in Appendix F. State your intent with regard to this position.

3. Provide the allowable buckling loads under faulted conditions for Class 2 and safety-related Class 3 component supports. Criteria consistent with the staff position for Class l supports in Item 2 above will be acceptable.

<u>Response</u>

1. For Class 1 supports within Westinghouse scope, member critical buckling loads (P_{CR}) are calculated in the following manner:

$$P_{CR} = \left(1 - \frac{(kl/r)^2}{2\,C_c^2}\right) S_y A$$

where

$$C_c = \frac{2\pi^2 E}{S_y}$$

Response (Continued)

Member compressive axial loads are limited to 2/3 P_{CR}, in accordance with ASME Boiler & Pressure Vessel Code Section III, Appendix F. For BOP Class l Supports, the ASME Boiler and Pressure Vessel Code Section III is followed.

2. Item 3 of Section 3.9.1.4.7 has been deleted per response to NRC Question 110.1.

3. Allowable buckling loads under faulted conditions for safety-related Class 2 and Class 3 component supports are calculated in the same manner as for Class l supports as stated above, except where buckling loads are negligible due to the configuration of equipment such as pumps, etc.

Question 110.22

Criteria are provided in Section 3.9.3.3 of the FSAR for the design and installation for mounting of pressure relief devices. The information provided discusses compliance with Regulatory 1.67 and Code Case 1569. Also reference is made to ASME Class 2 and 3 safety valve installations. Section 5.2.2.5 of the FSAR references Section 3.9.3.3 as applicable for the design of the "mounting" of ASME Class l pressure relief devices. The information provided in Section 3.9.3.3 is not applicable for the design of closed discharge pressure relieving systems such as that used for the pressurizer safety and relief valves on the STPEGS units. Both the Regulatory Guide and the Code Case referenced, while providing acceptable criteria for the design of open discharge systems, do not contain criteria for the design of closed discharge systems. Provide a description of the methodology used for the design of ASME Class l, 2, and 3 closed discharge systems, specifically including a description of how valve discharge reaction forces for the pressurizer ASME Class 1 safety valves are determined and limited as necessary so as not to exceed the loads used by the NSSS supplier for the design of the safety valve mounting brackets on the pressurizer.

Response

A piping system analysis is performed which considers the effects of pressure, gravity, thermal expansion and anchor movement, seismic, seismic anchor movement, loss of coolant accident, design basis accident, thermal transient loadings, and shock loads caused by safety and relief valve actuation.

Shock loading of the pressurizer relief piping system of a PWR unit can be induced by the opening of any or all of two relief valves and three safety valves. The activation of these valves allows the discharge of high pressure fluid from the pressurizer into the discharge piping, causing pressure and momentum transients throughout the piping system. These transients create signficant time-varying unbalanced forces in each straight run of the piping until steady-state flow is achieved. The analysis to obtain the structural response of the system following the sudden opening of the valves consists of a thermal-hydraulic analysis to obtain the force histories acting on the piping system as a result of the high pressure fluid flow, and a dynamic structural analysis to determine the response of these transient forces. The method of analysis consists of the following steps:

1. Development of a thermal-hydraulic model of the system.

2. Performance of thermal-hyraulic analysis to determine transient state histories at discrete locations throughout the system.

3. Integration of transient state histories to develop force histories applicable to bends and straight sections of the piping system.

4. Development of a lumped mass structural model of the piping system.

5. Performance of structural dynamic analysis of the system with the forces developed in Step 3.

Response (Continued)

Subsequent to the performance of individual load case analyses, a code compliance analysis is performed. This analysis combines the results of all loads, including shock loads in accordance with code and design specification requirements. Resultant piping restraint design loads are used for the design of individual pipe supports. The support design scheme used for the STPEGS does not utilize the safety valve mounting brackets of the pressurizer.

Question 110.24

The exception taken to position C.2.a.(2) and C.2.a.(4) of Regulatory Guide 1.121 in Section 3.2.1 of the FSAR is unacceptable without further justification. The Regulatory Guide recommendation for a 300-percent margin against burst failure, based on normal operating pressure differential, should be satisfied for all types of defects. This margin of safety may be demonstrated either analytically or experimentally. Test data submitted by Westinghouse for certain types of through wall defects have indicated that additional margin remained in the tube beyond the point where bulging occurs. A lower margin of safety may be applicable to these test data, provided it is shown that the remaining strength beyond bulging to gross rupture provides an equivalent margin of safety as recommended in Regulatory Guide 1.121.

On this basis, provide additional information that substantiates the equivalency of the Westinghouse 200 percent margin, based on Westinghouse performed tests, to the 300 percent margin recommended by the Regulation Guide which is related to a somewhat less conservative definition of tube failure. This equivalency must be justified for all types of tube defects. It is our understanding that the STPEGS term "margin of safety" is to be considered equivalent to "factor of safety" used in Regulatory Guide 1.121.

Response

STPEGS will not be taking exception to positions C.2.a.(2) and C.2.a.(4) of Regulatory Guide 1.121. See UFSAR Section 3.12.1.

Question 110.31

Recent operating reactor experience indicates that vibratory loads associated with the operation of positive displacement pumps have contributed to high cycle fatigue pipe failure. Such failures are known to occur on both the suction and discharge sides of positive displacement pumps in PWR charging systems.

Describe the measures that are proposed to be taken at the STPEGS facility to absorb these vibratory loads originating from the positive displacement charging pumps. If pulsation dampers or other mechanical devices are to be used in the pumps' vicinity, furnish a description of such devices; i.e., manufacturer, type, size, location, and effectiveness of the device. In case pulsation dampers or other mechanical devices are not employed to dampen vibratory loads:

1. Describe the vibratory loads origination at the positive displacement pump and transmitted to the discharge and suction pipe and associated pipe supports.

2. Describe in some detail how the maximum vibratory loads were established for calculating the maximum alternating stress in the design of the pipe runs and associated supports. Also describe the analytical procedure to determine the fatigue stresses in the affected piping system.

3. Furnish an isometric sketch of the pipe-affected piping system showing the location of the pipe supports and the peak alternating stresses. Also indicate the locations which will be monitored for vibration during the preoperational piping vibration and dynamic effects test program.

<u>Response</u>

Pulsation dampeners provided at the positive displacement charging pump suction and discharge to minimize piping vibration. These pulsation dampers are described as follows:

Manufacturer: Associated Piping and Engineering Company

Model

- Suction: SOCN 3-10
- Discharge: PDSN 2-16T

Type

- Suction: Variable vapor volume
- Discharge: Fluid kinetic

Size

- Suction: 10-inch-diameter, 30-inch height

Response (Continued)

- Discharge: 16-inch-diameter sphere

Maximum operating pressure

- Suction: 15 psig
- Discharge: 2500 psig

Maximum pressure variation

- Suction: 4 psi
- Discharge: 50 psi

Refer to revised Section 3.9.2.1.2 for a description of the vibratory test program.

Question 210.38N

Justify not considering the following primary system transients for normal conditions listed in FSAR Section 3.9.1.1.6.

1. Reactor coolant pumps startup and shutdown

2. Reduced temperature return to power.

Response

The design transients for STPEGS are based on Westinghouse internal design criteria documents, Systems Standard Design Criteria 1.3, Rev. 2, and 1.3, Appendix A. These documents do not include reactor coolant pumps (RCPs) startup and shutdown or reduced temperature return to power transients. These two transients were not specifically considered for Westinghouse plants designed during the time frame for which these documents are in effect.

However, in the case of the first transient, i.e., RCPs startup and shutdown, W assumes that variations in Reactor Coolant System (RCS) primary side temperature and in pressurizer pressure and temperature are negligible and that the steam generator secondary side is completely unaffected. It is considered by Westinghouse that due to the overall number of transient events considered in the design of STPEGS, not including this transient in the design has a minimal effect.

Reduced temperature return to power is not considered in the RCS design basis for STPEGS, therefore that transient is prevented from occurring by operational limitations contained in the proposed technical specifications.

The NRC MEB has reviewed and approved similar plants (Comanche Peak and Byron) which do not consider these two transients.

Question 210.40N

Identify components for which inelastic analysis has been used. If any, provide details of methods used.

Response

Inelastic analysis has not been used to qualify any components including piping. Inelastic analysis is sometimes used to evaluate plant response due to pipe break as discussed in Section 3.6.

Question 210.46N

On page 3.7-21 of the FSAR, it is stated that in certain cases, such as with auxiliary piping connected to the reactor coolant loop, multiple spectra have been used to reduce the excessive conservatism in supplying enveloped spectra over the entire length of piping. Discuss how multiple spectra are used.

Response

1. NSSS Scope

   For piping and components supported at multiple elevations Westinghouse uses the most limiting spectra in performing seismic analysis.

   Multiple spectra are not used in Westinghouse scope analyses.

2. BOP Scope

   Multiple response spectra are used when use of an enveloped spectra results in an excessively conservative design. In such cases supports, anchors, and nozzles are excited by their corresponding response spectra. For example, a piping system connected to the reactor coolant loop (RCL) and supported by the internal structure will have two response spectra as the forcing functions. The RCL spectrum is applied at the RCL-auxiliary piping interface and the Reactor Containment Building internal structure spectrum is used at the support locations. The responses due to multiple spectra are combined by absolute summation followed by modal summation for each direction, then combination for directions. Modal and directional summation is in accordance with Regulatory Guide (RG) 1.92. Bechtel computer program ME101 "Linear Elastic Analysis of Piping Systems" is used for multiple response spectra analysis. This computer program is discussed further in Section 3.9.1.2.2.1.

Question 210.47N

SRP Section 3.9.2.III.2.a.(2)(c) states that to obtain an equivalent static load on equipment or component which can be represented by a simple mode, a factor of 1.5 is applied to the peak acceleration of the applicable floor response. FSAR Section 3.7.3B.1.7 does not comply with this guidance. Provide justification for not using a factor of 1.5.

Response

SRP Section 3.7.2 agrees with the above statement concerning a factor of 1.5 applied to the peak acceleration but also notes that a value less than 1.5 may be used if justified.

For rigid equipment, since there is no resonance or magnification of the floor response, no additional factors are applied to the high frequency acceleration levels of the applicable floor response when calculating the seismic acceleration coefficient.

Limited Flexible Equipment is defined as having only one (1) predominant mode in the frequency range subject to possible amplification (<33 Hz). In performing the static analysis as defined in Section 3.7.3B.1.7, the total weight of the equipment or component is multiplied by the amplified response at its calculated fundamental natural frequency. This provides a conservative equivalent static load for this equipment or component.

For flexible equipment and piping Westinghouse uses dynamic analyses.

Question 210.48N

Provide additional information to justify the use of a multiplication factor of 1.0 in the equivalent static load method for design of cable tray hangers and heating, ventilating, and air conditioning (HVAC) duct supports.

Response

As stated in Section 3.7.3A.1.2 dynamic analyses using the modal response spectrum method were performed for typical cable tray and HVAC support systems. The seismic force and moment response obtained from the dynamic analyses is established to be less than the corresponding response from the equivalent static method using a factor of 1.0 times the peak acceleration of the applicable floor response spectra. Therefore, use of the multiplication factor of 1.0 in analyses by equivalent static method is justified.

This approach was reviewed by the Structural Engineering Branch during the STPEGS audit during the week of January 7, 1985.

Question 210.49N

SRP 3.9.2.II.2.h specifies criteria for using constant vertical static factors. The use of constant vertical static factors is acceptable only if it can be justified that the structure is rigid in the vertical direction. Provide assurance that this guidance has been used.

Response

1. NSSS Scope

   Constant vertical static factors are not used by Westinghouse.

2. BOP Scope

   Constant vertical load factors are not used to obtain vertical response loads for the seismic design of Category I structures, systems, and components. Multimass dynamic analyses for both horizontal and vertical directions of excitation are performed to obtain the seismic responses and floor response spectra.

   For subsystems within structures, when the floor response spectra are used to define vertical input motion and/or loads for the Seismic Qualification and/or design of equipment and components, the rigidity of the structural subsystems is taken into consideration. Parametric analyses have been performed to determine the minimum subsystem frequencies required to assure effectively-rigid subsystems behavior that justifies use of the floor vertical response spectra directly without any additional amplification to account for subsystem flexibility. The established frequency limits are implemented in the Project as a specific requirement for the design of structural subsystems that support safety-related equipment. Subsystems identified to have low frequencies, if any, are stiffened to comply with the established frequency limits. Section 3.7.2.10 has been revised to reflect this response.

   This approach was reviewed by the Structural Engineering Branch during the STPEGS audit during the week of January 7, 1985.

Question 210.51N

Provide the basis used for the design of piping anchors which separate seismically designed piping and nonseismic Category I piping. Include in your discussion, the loads and load combinations used and how the local pipe wall stresses are considered.

Response

In the case where an anchor is used to separate seismic Category I piping systems from piping systems where seismic qualification is not required, the anchor is designed to meet seismic Category I requirements. This is in agreement with RG 1.29, paragraph C.3 which states, "seismic Category I design requirements should extend to the first seismic restraint beyond the defined boundaries. Those portions of structures, systems, or components that form interfaces between seismic Category I and nonseismic Category I features should be designed to seismic Category I requirements".

Loading conditions and load combinations for qualification of piping, components, and supports are specified in Table 3.9-2.4. In the case of an anchor, the piping analysis for the piping on each side of the anchor is performed independently using the appropriate loading conditions. Anchor loads are generated for both the upstream and downstream piping runs. Anchor loads for the nonseismic Category I side include either seismic loads due to Safe Shutdown Earthquake (SSE) or piping collapse loads. The loads from the two piping runs are then combined and used for the anchor design. Dynamic loads from the two sides are combined by square root of the sum of the squares (SRSS). Resultant static and dynamic loads are combined absolutely as required for the appropriate plant condition as defined in Table 3.9-2.4.

Local pipe wall stresses are considered in accordance with ASME Section III, subsection NC, ND, or ANSI B31.1 as appropriate. The applicable subsection is determined by the pipe class. No seismic boundary anchors are placed on ASME Class 1 piping.

Question 210.52N

FSAR Table 1.3-1, Comparison with Similar Facility Design, states that the new design of the reactor vessel head closure system and lower internals are different from the Comanche Peak plant. Provide additional information which describes the differences in lower internals design between STPEGS and Comanche Peak. Specifically, describe any changes in the reactor internals design which may have resulted from utilization of the rapid refueling concept at STPEGS. If such changes exist, discuss the effects of these changes on the response of the reactor internals to flow-induced excitation and provide the basis for meeting the guidelines of RG 1.20 and maintaining Indian Point, Unit 2 as the prototype plant for STPEGS.

Response

No changes were made to the STPEGS reactor internals resulting from the utilization of the rapid refueling concept that would impact the vibratory response of the internals. The utilization of lifting rods in the upper internals to facilitate the removal of the upper internals with the upper head has no impact on the internals vibratory response. In fact the vibration assessment, based on flow turbulence, is only concerned with the region below the upper support plate in the lower guide tube region, inlet nozzle, downcomer and outlet nozzle locations.

The STPEGS plant is based on the four loop Nuclear Steam Supply System (NSSS) design of Indian Point insofar as Regulatory Guide (RG) 1.20 is concerned. In addition, the STPEGS plant incorporates such design enchancements as have already been reviewed and approved by the NRC staff such as neutron pad versus thermal shield and the inverted top hat design. One additional modification concerns the change to the reactor internals to permit the use of a 14-ft core. To account for this the fuel no longer rests on a lower core plate but simply rests on the lower support plate. An analytical flow-induced vibration assessment has been performed and documented for the STPEGS plant. It has been concluded that the vibrational response of this plant obtained from scale model tests and instrumented plant tests, shows that the internals vibration levels are low and that the STPEGS reactor internals design is adequate to assure structural integrity against flow induced vibrations.

Question 210.53N

FSAR Section 5.3.1.7 describes the Roto-Lok reactor vessel head closure system which is used for the STPEGS Units 1 and 2 reactor vessel head. It also states that a prototype Roto-Lok closure system has been tested to verify this closure design. Results of these tests are presented in the WCAP-8447, December, 1974. However, Section 7 of WCAP-8447 states that, "Also, it should again be noted that the program described in this report was for development hardware and testing only. The final design and analysis for a particular vessel is performed by the vessel supplier when the Roto-Lok is actually applied by production vessels." The staff's review of the WCAP-8447 as provided in a letter from J.F. Stoltz to C. Eicheldinger dated September 2, 1977, determined that WCAP-8447 provides an acceptable basis for the preliminary design of the Roto-Lok closure system. Furthermore, in that evaluation, the staff required that for the first reactor vessel to use this closure system (STPEGS Plant) the results of final design and analysis of the closure system be provided in the FSAR. The applicant is requested to provided this information. Include in your discussion how the assumptions presented in WCAP-8447 are applicable to the STPEGS Units 1 and 2 plant specific reactor vessels.

Response

The STPEGS reactor vessel Roto-Lok closure system configuration is shown in Figure Q210.53N-1. This closure assembly used the sawtooth lug design discussed in Chapters 6 and 7 of WCAP-8447 (proprietary) with the following modifications:

1. Stud fillet radii at the top of the lug to shank junctures were increased from 0.187 in. to 0.250 in.,

2. Insert fillet radii at the bottom of the lug to cylindrical inside diameter junctures were reduced from 0.187 in. to 0.125 in.,

3. The length of each lug was increased from 1.975 in. to 2.095 in. at the shank on each stud, and

4. The lug length was increased the same amount at the cylindrical inside diameter of each insert.

The final Roto-Lok closure region design was analyzed by the STPEGS reactor vessel vendor (Combustion Engineering) using the ANSYS three-dimensional finite element computer program. The assumptions used in the proprietary WCAP-8447 (see pages 3-5 through 3-7 and 6-1) are still applicable to this analysis with the following revisions:

1. The specified stud preload is 110 percent of the design pressure blow-off load during normal operation or 110 percent of the hydrostatic blow-off load during the hydrotest versus the 120 percent factor used in the WCAP.

2. The full length of the closure stud was used in the analysis instead of just the portion in the vessel and closure flanges.

Response (Continued)

3. The crown portion of the closure head was modelled with two elements through the thickness in lieu of one layer.

4. The closure region was modelled as a 5 degree wedge with the width consisting of three elements. The effect of the stud holes in the circumferential direction was also handled in a more refined fashion than in the WCAP.

5. The reactor vessel's internal surfaces in contact with the primary coolant were assumed to have an infinite heat transfer coefficient instead of a finite film coefficient associated with turbulent flow.

6. Heat transfer by conduction, radiation, and convection in lieu of just convection was assumed to occur across the air gaps between the vessel components and the studs and nuts.

7. The strength reduction factor in the fatigue analysis was increased from 3.75 to 4.0.

The results of the vessel vendor's analysis of the Roto-Lok stud assembly are presented along with the corresponding ASME code allowables in the following table. This table shows the code allowable limits are met.

Category	Governing Value	ASME Code Allowable
Design Stud Membrane Stress Intensity	34.73 ksi	34.8 ksi
Maximum Average Stud Service Stress Intensity	54.3 ksi	84.0 ksi
Maximum Stud Service Stress Intensity	76.8 ksi	126.0 ksi
Usage Factor	0.502	1.0

Figure 210.53N-1

Question 210.54N

The staff finds that there is insufficient information describing the design of safety-related HVAC ductwork and supports. Provide the design basis used for qualifying the HVAC ductwork and support structural integrity.

Response

HVAC ducts are fabricated from sheet metal and/or steel plate. The duct supports are fabricated from rolled structural shapes. All ducts and supports are galvanized.

Safety-related ducts and duct supports are designed for combinations of gravity, pressure, and seismic loads utilizing allowable stresses that maintain the response within the elastic range. The seismic analysis of ducts and duct supports is based on the equivalent static method as stated in Section 3.7.3A.1.2 and 3.7.3A.3.3. Codirectional seismic responses due to longitudinal, transverse, and vertical earthquakes are combined by the SRSS method or the component factor method. The component factor method is equivalent to the SRSS method, and in certain types of analyses is more practical than the SRSS method for combining codirectional responses from the three components of earthquakes. The component factor method is widely used in the industry for the design of structures, systems, and components of nuclear power plants. The maximum error possible by the use of the component factor method is less than one percent with respect to the SRSS method.

The rationale for the use of the component factor method is attached. Section 3.7.3A.6 has been revised to identify the use of the component factor method as an acceptable option in addition to the SRSS method with the exception that the component factor method is not used for piping analysis.

Tables Q210.54N-1 and Q210.54N-2 give the load combinations and allowable stresses used in the design of duct and duct supports.

Expansion anchors (Hilti Kwik-bolts) are used occasionally in supports for safety-related HVAC ducts. As explained in response to Q210.62N, the design allowable loads are based on tested ultimate load capacities with an applied factor of safety of four or higher. Design allowable loads are not increased for faulted or abnormal/extreme environmental loading combinations. The integrity of the expansion anchors is not compromised by normal operational vibratory motion due to the low amplitude nature of the vibration.

In specific isolated instances, as determined from pipe break analyses and/or tornado depressurization analyses, the loads due to compartment pressurization/depressurization and/or jet impingement are included in the design of safety-related ducts. The loads due to pipe break are considered as additive to the loads of combinations (2) and (3) of the above tables.

Response (Continued)

Safety-related HVAC ducts are designed using analytical guidelines established from testing results. Following are the principal codes and standards used in the design:

1. AISC - "Specification for the Design Fabrication and Erection of Structural Steel for Buildings", 1969, including Supplements 1 and 2.

2. AISC - "Code of Standard Practice for Steel Building and Bridges", 1976.

3. AISI - "Specification for the Design of Cold-Formed Steel Structural Members", 1968 and AISI - "Supplementary Information on the 1968 Edition of the Design of Cold-Formed Steel Structural Members", 1971.

   Exception: Section 2.3.4 of AISI 1968 states that the ratio h/t of the webs of flexural members shall not exceed 500. Actual tests performed on HVAC ducts substantiate the use of w/t and h/t ratios of up to 1500 for ducts. The STPEGS approach allows these ratios to exceed 500, but restricts these values to less than 1500.

4. AWS - Structural welding code AWS D1.1, 1977 and code for welding zinc-coated steel AWS 19.0.

5. OSHA - Department of Labor, Volume 37, Number 202, Part II - Applicable sections on platforms, handrails and ladders.

6. SMACNA - Sheet metal and air conditioning contractor's national association high pressure duct construction standards and low-pressure duct construction standards.

Supports for safety-related HVAC ducts are designed by the working stress method using the AISC specification, 1969 edition.

TABLE Q210.54N-1

LOAD COMBINATIONS FOR HVAC DUCTS -

Load Case	Loading Combination	Allowable Stress
(1)	D + P	0.6 Fy
(2)	D + P + E	0.6 Fy
(3)	D + P + E_s	0.9 Fy
(4)	D + P + W_{tp}	0.9 Fy

Symbols used in load combinations:

D - Dead weight of duct
P - Maximum operating pressure inside duct
E - Operating basis earthquake load
E_s - Safe shutdown earthquake load
Fy - Minimum specified yield strength of duct material
W_{tp} - Tornado differential pressure

TABLE Q210.54N-2

LOAD COMBINATIONS FOR HVAC DUCTS -

Load Case	Loading Combination	Allowable Stress
(1)	D	F_s
(2)	D + E	F_s
(3)	D + E_s	1.5 F_s or 0.9 Fy, whichever is smaller

Symbols used in load combinations:

D - Dead load
E - Operating basis earthquake load
E_s - Safe shutdown earthquake load
F_s - Allowable stress for support material governed by AISC or AISI as applicable
Fy - Minimum specified yield strength of support material

VALIDITY OF THE COMPONENT FACTOR METHOD

In the component factor method, the following equation is used to determine the total seismic load:

$$R_{total} = R_i + 0.4R_j + 0.4R_k \qquad (1)$$

In the following, adequacy of the above equation is demonstrated. First, consider a combined response, R' defined as follows:

$$R' = R_i + 0.414R_j + 0.318R_k \qquad (2)$$

In which

$$R_i \geq R_j \geq R_k \geq O \qquad (3)$$

Let

$$R_j = R_j + R_k \quad (R_j = O \text{ if } R_j + R_k)$$

$$R_i = R_i + R_j = R_i + R_j + R_k \quad (R_i = O \text{ if } R_i = R_j) \qquad (4)$$

The SRSS method gives:

$$R = \{(R_i + R_j + R_k)^2 + (R_j + R_k)^2 + R^2_k\}^{1/2}$$

$$= \{3R^2_k + 2R^2_j + R^2_i + 2R_i(R_j + R_k) + 4R_jR_k\}^{1/2} \qquad (5)$$

According to Eq. (2)

$$R' = (R_i + R_j + R_k) + 0.414(R_j + R_k) + 0.318R_k$$

$$R' = 1.732R_k + 1.414R_j + R_i = \{[1.732R_k + 1.414R_j + R_i]^2\}^{1/2}$$

$$R' = \{3R^2_k + 2R^2_j + R^2_i + 2R_i(1.414R_j + 1.732R_k) + 4.9R_jR_k\}^{1/2} \qquad (6)$$

Comparing Eqs. (5) and (6), it is obvious that the combined response calculated according to Eq. (2) is always more conservative than the combined response by the SRSS method. In the special case that $R_i = R_j = R_k$, they become identical to each other, i.e., $R = R' = 3R_k$.

For convenience of engineering applications, Eq. (2) can be simplified by replacing the factors 0.414 and 0.318 by common factor of 0.4. This reduces Eq. (2) to Eq. (1). By inspection, the maximum probable error of Eq. (1) with respect to the SRSS method is less than 1 percent. This maximum error occurs when $R_k = 0$ and $R_i = R_j$. In this special case, the SRSS method gives $R = 1.41R_i$ and Eq. (1) gives $R = 1.4R_i$.

VALIDITY OF THE COMPONENT FACTOR METHOD

In implementing Eq. (1), permutations of the component factors (1.0, 0.4, 0.4) and, positive and negative values of the seismic stresses are taken into account. The resulting 24 sub-combinations will contain the most critical case (i.e., the maximum absolute value of the total seismic response) and will be combined with stresses due to other loads using proper sign. The most critical case, thus identified, forms the basis of the final design.

Question 210.55N

Provide the basis for assuring the ASME Code Class 1, 2, and 3 piping systems are capable of performing their safety function under all plant conditions. Describe the methodology used to assure the functional capability of essential piping system when service limits C or D are specified.

Response

Loading combinations for the various plant conditions (i.e., normal, upset, emergency, faulted) and the corresponding stress limits for ASME Code Class 1, 2, and 3 piping and pipe supports are given in the Section 3.9. These stress limits are in compliance with the code requirements and form the basis for assuring that the piping systems are capable of performing their safety functions under specified plant conditions.

NSSS Scope

For essential piping systems, functional capability has been satisfied by analysis using the following method:

Component	Limit	Calc Method
Straight pipe, welds, reducers	1.8 Sy	NB-3650, Eq. (9)
Branches, tees	2.0 Sy	NB-3650, Eq. (9)
Elbows, 5D bends	1.8 Sy	NB-3650, Eq. (9)*

* B_1 and B_2 indices are replaced as follows:

$$0 \le B_1 = -0.1 + 0.4h \le 0.5$$

and $B_1 = 0.5$ for $B_2 = 1.0$

$$B_2 = \begin{cases} \dfrac{1.3}{h^{2/3}} & \text{, for } \alpha_o > 90^o \\ \dfrac{0.895}{h^{0.9122}} & \text{, for } \alpha_o = 90^o \\ 1.0 & \text{, for } \alpha_o = 0^o \end{cases} \quad \text{and } B_2 \ge 1.0$$

Linear interpolation for $0 < \alpha_o < 90^o$

Where:

$$h = \frac{tR}{r^2_m}$$

R = bend radius
r_m = mean pipe radius
t = nominal wall thickness

Response (Continued)

The applicable loading cases for the Class 1 piping components to meet the functional capability limits for reactor coolant loop and the pressurizer safety and relief system are:

P_o + DWT + SSE

Where:

P_o = design pressure

DWT = deadweight

SSE = safe shutdown earthquake

To assure the functional capability of a Class 1 system not larger than 1-in. diameter which is analyzed to ASME Code Class 2 rules, the following stress limits have been used to supplement the level D requirements for ASME Class 2 stainless steel elbows.

$$B_1 \frac{PD}{2t} + B_2 \frac{Mj}{Z} \leq 1.8\ Sy$$

Where: $B_1 = (-0.1 + 0.4h)$ and $0 \leq B_1 \leq 0.5$

and $B_1 = 0.5$ for $B_2 = 1.0$

$$B_2 = \begin{pmatrix} 1.3/(h^{2/3}) \text{ for } \propto_o > 90^o \\ 0.895/(h^{0.9122}) \text{ for } \propto_o = 90^o \\ 1.0 \text{ linear for } \propto_o = 0 \end{pmatrix} \quad \text{and } B_2 \geq 1.0$$

Linear interpolation for $0 < \propto_o < 90^o$

Where: $h = \frac{tR}{r^2_m}$ and $\propto_o$ is the angle of the bend in degrees.

Other terms are as defined in NC-3600 of Section III of the ASME Code. There are no Class 2 stainless steel elbows or bends with Do/t > 50.

The loading combination for the reactor vessel head vent system is:

P_o + DWT + SSE

BOP Scope

For essential piping systems, the functional capability has been satisfied by analysis using methods given in GE Topical Report, Functional Capability Criteria for Essential Mark II Piping, NEDO-21985, September 1978, or an equivalent analysis.

Question 210.56N

The staff review of FSAR Section 3.9.3.3 finds that the design and installation details for mounting of pressure-relief devices require further clarification. Provide the following information for our review:

1. Clarify whether it is the intention of Section 3.9.3.3.2 to address BOP supplied components.

2. Clarify whether all the NSSS scope safety and relief valves transients are evaluated using detailed dynamic analysis techniques. Provide assurance that the most severe potential sequence of discharges, i.e., the maximum values of forces and moments are considered for multiple-valve discharges.

3. Provide a discussion of the basis for assuring that the valve end loads are acceptable. Specifically, address how the applicable design loads will be correctly reflected in the valve design specification.

Response

A. NSSS SCOPE

A description of the pressurizer safety and relief valve system is given in Section 3.9.3.3.1.1. This section also describes the analytical model of the system, the determination of forces, and method of analysis. The programs used in the dynamic analysis of the system are also provided in Section 3.9.3.3.1.1. All relevant valve discharge cases are evaluated using detailed dynamic analysis techniques. Discharge of the safety valves is the limiting design case for the downstream piping of all cases considered. The three safety valves are identical and have the same set pressure (± 1 percent). It was assumed that all three safety valves open simultaneously. The simultaneous opening of the safety valves results in peak loads in the common circular header. No appreciable impact in the tailpipe region, due to safety valve discharge, will occur if the valve sequencing is adjusted. The detailed design analyses performed for this discharge case illustrates a safety factor of 2 between the calculated stresses in the tailpipe and the allowable stresses.

The valve end loads are verified to be acceptable by ensuring that all calculated values are below conservative values specified in the piping design specification which has been approved by the valve engineer. Specific values are reconciled to the valve specification or vendor reports if any values exceed those specified in the piping design specification.

B. BOP Scope

1. Section 3.9.3.3.2 is intended to address the BOP supplied components. Section 3.9.3.3.2 has been revised to clarify applicability to BOP components.

Response (Continued)

2. BOP multiple valve discharge is applicable only to the main steam safety relief valves. The main steam safety relief discharge piping is designed so that the thrust force is transferred to the support structure, thus eliminating concern regarding force transfer to the piping system.

3. Consideration of active valve end loads is discussed in Sections 3.9.3.2.1.2 and 3.9.3.2.3. Calculated valve end loads are compared for compliance with the allowable loads identified in the valve specifications or in the vendor documentation.

Question 210.57N

The staff review of FSAR Section 3.9.3.4 finds that there is insufficient information regarding the design of ASME Class 1, 2, and 3 equipment and component supports. Per SRP Section 3.9.3, our review includes an assessment of design and structural integrity of the supports. The review addresses three types of supports: (1) plate and shell, (2) linear, and (3) component standard types. For each of the above three types of supports, excluding pipe supports, provide the following information (as applicable) for our review:

(a) Describe (for typical support details) which part of the support is designed and constructed as component supports and which part is designed and constructed as building steel (NF vs. AISC jurisdictional boundaries).

(b) Provide the complete basis used for the design and construction of both the component support and the building steel up to the building structure. Include the applicable codes and standards used in the design, procurement, installation, examination, and inspection.

(c) Provide the loads, load combinations, and stress limits used for the component support up to the building structure.

(d) Provide the deformation limits used for the component support.

(e) Describe the buckling criteria used for the design of component supports. Specifically, describe how the "A" term used in the response to NRC Question 110.19 was defined.

Response

A. NSSS SCOPE:

1. Class 2 and 3 component supports

(a) The supports are linear type or plate and shell type, and are part of the equipment. A typical support is welded to the equipment directly to the pressure boundary or wear plate, and is required to be rigidly attached to a foundation. The equipment designed to Code editions prior to the inclusion of Subsection NF into the ASME Code have the supports designed in accordance with the requirements of the AISC manual; equipment designed to the Code editions after the inclusion of Subsection NF are designed in accordance with ASME Code Subsection NF.

Response (Continued)

(b) The design, construction, examination, and inspection of the auxiliary equipment supports are in accordance with the requirements of ASME Subsection NF or AISC, depending on the procurement date of the equipment as discussed in the Part (a) response. In accordance with Westinghouse auxiliary equipment specifications, the equipment is required to be rigidly mounted.

(c) The loads and the loading combinations for the supports of the auxiliary equipment supplied by Westinghouse are the same as those of the supported component. These loads and combinations are given in Section 3.9.3.

The stress limits are in accordance with the ASME Code Subsection NF or AISC, depending on the procurement date of equipment as discussed in the response of Part (a).

(d) For passive auxiliary components, only the structural integrity of the pressure boundary and supports is required to be assured. Since passive components perform no safety function other than retaining structural integrity, there are no deformation limits specified for the supports or for the passive auxiliary components.

Deformation of supports for active pumps is limited so that certain critical clearances are maintained and the pump remains operable. These critical clearances are specified in the pump specifications.

(e) Buckling is prevented by limiting compressive stresses for linear-type auxiliary equipment supports under loadings from all service conditions to the limits of AISC Section 1.5 or ASME Appendix XVII-2210. These limits are based on the Column Research Council (CRC) buckling curve for centrally-loaded columns. Critical buckling loads are limited to two-thirds of the CRC curve.

Plate and shell type supports for Class 2 and 3 auxiliary equipment are evaluated for buckling and instability through selective use of the criteria of Appendix XVII, Subarticle XVII-200 and Subsection NC, Subparagraph NC-3133.6 of Section III of ASME Code. Subparagraph NC-3133.6 gives methods for calculating the maximum allowable compressive stress in cylindrical shells subjected to axial loadings that provide longitudinal compression stresses in the shell. Subarticle XVII-200 gives requirements for structural steel members including allowable

Response (Continued)

compressive loads based on slenderness ratios and interaction equations for combined stresses.

Uses of the above requirements in the design of linear or plate and shell type supports for Westinghouse-supplied auxiliary equipment ensures the dimensional stability of the support throughout the range of applied loadings.

2. Primary Equipment Supports

The following is a listing of support versus category for the RCS equipment supports.

Reactor Vessel Support Box	Plate and Shell
Steam Generator Columns	Linear
Steam Generator Lower Lateral Support	Linear
Steam Generator Upper Lateral Support	Linear
Reactor Coolant Pump Columns	Linear
Reactor Coolant Pump Tie Rods	Linear
Pressurizer Lateral Supports	Linear
Reactor Vessel Support Shoe/Pins	Linear

(a) Figures Q210.57N-1 and Q210.57N-2 show for a typical configuration the NF boundary between component support and building structure.

(b) All parts and components of the Class 1 primary equipment supports are designed and fabricated in accordance with Subsection NF of the ASME Code. The design and construction of the primary equipment support is based on a general design specification which is amended by a plant specific specification. The specifications address the design, procurement, installation, examination and inspection of the components which make up the primary equipment supports.

(c) Design loads, load combinations, and stress limits are contained in Tables 3.9-2.1 and 3.9-2.1A.

Final qualification of the RCS equipment supports is based upon loads and stresses resulting from a plant specific reactor coolant loop analysis. The results are summarized in a final as-built (P.E. stamped) design report.

(d) No deformation limits are used in the design and analysis of the primary equipment supports. The structural members are designed to the stress limits of the ASME Code, Section III, Subsection NF so that all members remain elastic. The elastic behavior of

Response (Continued)

the members is then considered in the reactor coolant system loop analysis.

(e) The buckling criteria used for the design of the primary equipment supports is based on the slenderness ratio. The allowable compressive stresses are limited to the requirements of the ASME Code, Section III, Articles XVII-2110b and XVII-2213. Critical buckling is based upon CRC curves where $kl/r < C_c$ (that is, for most RCS equipment support members) and the Euler curve where $kl/r > C_c$.

C_c is the slenderness ratio corresponding to the upper limit of elastic buckling failure.

The "A" term used in response to NRC Q110.19 is the cross sectional area of the member.

B. BOP SCOPE (excluding pipe supports):

1. The jurisdictional boundary between the pressure-retaining component and the component support is established in accordance with subsection NF of the ASME III Code.

   The jurisdictional boundary for ASME Section III, Division 1, Subsection NF component supports, is the baseplate or building structure to which the component support is attached.

   The typical support configurations shown Figures Q210.57N-3 and Q210.57N-4 are samples and are only intended to show NF jurisdictional boundaries.

2. Component supports and any supporting structure between the component and the building structure, are designed, constructed, and inspected in accordance with applicable ASME requirements. Baseplates which are supplied by the equipment vendor or owner in order to facilitate attachment to the building structure are designed and procure in accordance with AISC requirements. Welds between an NF item and non-NF item are designed, performed and inspected in accordance with the appropriate sections of ASME Section III, V, and IX. The baseplate is attached to the building structure by either welding or bolting. The welds to the building structure are considered to be AISC and as such are performed and inspected identically with the requirements delineated in the letter from M. Wisenburg to H. Thompson dated February 25, 1985 (ST-HL-AE-1185).

   Refer to the response to item Q210.62N for the design of anchor bolts for component supports.

Response (Continued)

3. The loads and load combinations for component supports are presented in Table 3.9-2.4.

   The allowable stress limits are presented in Tables 3.9-7b and 3.9-7c.

4. Deformation limits for component supports are specified by the suppliers for strain sensitive equipment. The limits insure that clearance and alignment requirements are met.

   There are no deformation limits specified for tanks, vessels, or exchanger component supports.

5. For component supports, the designs are in accordance with the buckling criteria given in ASME III Subsection NF.

Figures Q210.57N-1

Figures Q210.57N-2

Figures Q210.57N-3

Figures Q210.57N-4

Question 210.58N

Valve discs are considered part of the pressure boundary and as such should have allowable stress limits. Provide these limits for our review.

Response

1. NSSS Scope

The valve discs for Class 1 valves greater than 4-in. size are analyzed using the following allowables for acceptance criteria.

Primary Membrane, $P_m \leq 1.0\ S_m$

Primary Membrane + Bending, $P_m + P_b \leq 1.5\ S_m$

For Class 2 and 3 valves where analysis is required per the specification, the following acceptance criteria are used.

Primary Membrane, $P_m \leq 1.0\ S$

Primary Membrane + Bending, $P_m + P_b \leq 1.5\ S$

2. BOP Scope

A. ASME III, Class 1 Valves

No large bore (>4-inch-diameter) valves are in the BOP scope. For 4-in. and smaller valves structural integrity is demonstrated by a differential pressure test across the disc and not by analysis. NB-3530 contains requirements for hydrostatic tests for the shell and disc. The hydrostatic test report for the valve includes details to show that the requirements of NB-3530 are met.

B. ASME III, Class 2 and 3 Valves

For Code Class 2 and 3 valve discs no design requirements are described in NC or ND-3500. However, tests for structural and pressure integrity for valve disc or plugs are described in NC/ND-3514(b). A disc hydrostatic test is required with the disc or plug in the fully closed position with a test pressure across the disc or plug equal to the pressure rating of the valve at 100□F. The ASME III design specifications may be used to stipulate a higher or lower test pressure and do require specific limiting seat leakage.

Design requirements for valve discs and plugs are determined by the manufacturer, since items such as disc geometry, method of seating, materials, etc., are controlled by the manufacturer and subject only to review and acceptance by the owner, or his designee, as permitted in the ASME code.

Question 210.60N

Does the design criteria for component supports in systems categorize the stresses produced by seismic anchor point motion of piping and the thermal expansion of piping as primary or secondary? It is the staff's position that for the design of component supports, and stresses produced by seismic anchor point motion of piping and the thermal expansion of piping should be categorized as primary stresses. The application of this position is most critical for those supports which would be subjected to large deformations.

Response

The stresses produced by seismic anchor point motion of piping and thermal expansion of piping are considered as primary stresses in the design of component supports. Nuclear Steam Supply System (NSSS) component supports which have been designed in accordance with ASME III Subsection NF have been evaluated for compliance with this position and are acceptable.

Question 210.61N

Describe what actions have been taken to address the staff concerns regarding stiff pipe clamps as described in IE Information Notice 83-80.

Response

The applications of stiff pipe clamps on STPEGS have been reviewed based on IE Information Notice 83-80. Section III of the ASME B&PV Code does not provide rules for evaluating stresses due to loadings from nonintegral attachments such as clamps; however, clamp-induced stresses have been evaluated by methods consistent with the intent of the Section III of the ASME B&PV Code. The procedure includes the following:

1. Identification of the locations of "stiff" clamps installed on ASME Section III Nuclear Class 1 piping systems.

2. Identification of the types of clamps, the loads acting on the clamps, and the bolt pre-load values used in their installation. In piping, stresses due to all loading conditions at the locations of stiff clamps have also been identified and reviewed.

3. Addition of the primary membrane and primary bending stresses caused by the load being transmitted to the pipe through the clamp to the stresses caused by internal pressure and bending computed by equation 9 of NB-3652. Clamp-induced stresses caused by the constraint of the expansion of the pipe due to the internal pressure were added to other secondary stresses in evaluating equation 10. Clamp induced stresses due to differential-temperature and differential-thermal-expansion coefficients were calculated and added to other operating secondary and peak stresses. The fatigue usage factor at the clamp location was computed taking into consideration clamp induced stresses from pressure, temperature, and support loadings. The clamp induced stresses were added to the stresses in the pipe including secondary and peak stresses computed for each load set pair.

Although bolt preloads are not addressed under the ASME B&PV Code rules for piping, bolt preloads could result in damage to pipe if a clamp was improperly designed. Calculations were made to ensure that bolt preloads could not result in plastic deformation of the pipe walls.

A brief summary of the criteria used and the results of the analysis has been submitted under separate cover letter (see ST-HL-AE-1468, dated October 30, 1985).

Stiff clamps were not used on STPEGS to meet stiffness criteria. They were designed to meet the requirements for strength and load distribution using a minimum of space. The STPEGS position is to minimize the use of stiff clamps.

The clamp design utilizes a double nut arrangement to prevent the nuts from backing off. The low temperature (650°F) and stresses in the bolt from preloads will not cause a relaxation of the material. Consequently, no lift-off from the piping will occur.

Question 210.62N

The staff's review of your component support design finds the additional information is required regarding the design basis used for bolts.

(a) Describe the allowable stress limits used for bolts in equipment anchorage, component supports, and flanged connections.

(b) Provide discussion of the design methods used for expansion anchor bolts used in component supports.

Response

NSSS Scope

For primary equipment supports the bolt design, including anchor bolts, is in accordance with the Subsection NF (NF-3280). Allowable stresses are per Appendix XVII-2460 and/or those of Code Case 1644. The stress allowable may be increased according to the provisions of XVII-2110(a) and F-1370(a) for emergency and faulted conditions, respectively.

For tanks and heat exchangers supplied by Westinghouse, the only bolting for supports provided by Westinghouse is on the regenerative heat exchanger. These bolts meet the requirements of Subsection NF and Code Case 1644.

Bolting on supports for Westinghouse supplied Class 2 and 3 pumps meets the requirements of ASME B&PV Code Subsection NF and Code (i.e., Section III or Section VIII).

For flanged connections on tanks and heat exchangers the allowable stress limits are per the applicable section of the ASME Code (i.e., Section III or Section VIII).

For all bolts in the Westinghouse scope of design, an allowable stress equal to or less than the yield strength of the material at temperature is used for all loading conditions for component supports.

BOP Scope:

a. The bolts used in equipment anchorage and component supports including NSSS components, are classified as part of the building structures (i.e., non-ASME) and their embedment lengths are calculated using ACI-318. Allowable stresses for anchor bolts are in accordance with the AISC specification, except for safety-related NSSS component anchor bolts which are in accordance with the ASME Code.

   For bolts used in flanged connections on tanks and heat exchangers the allowable stress limits are per the applicable section of the ASME Code (i.e., Section III or Section VIII).

   For all bolts in the BOP scope, an allowable stress equal to or less than the yield strength of the material at temperature is used for all loading conditions for component supports.

Response (Continued)

b. In the STPEGS two types of expansion anchor bolts are used for permanent plant installations: the wedge-type (Hilti Kwik-bolt) and the ductile-type (Maxibolts) manufactured, respectively, by Hilti Fastening Systems, Inc. and by Drillco Devices Ltd.

For Hilti Kwik-bolts the allowable design loads in shear and tension are based on tested ultimate load capacities with an applied factor of safety of 4.0 or higher. These allowable loads are for all loading combinations, and specifically, are not increased for faulted or abnormal/extreme environmental loading combinations.

For Maxibolts the allowable design loads prescribed for tension are based on 0.33 times the specified ultimate tensile strength of the bolt steel material (F_u = 125 ksi), and for shear are based on 0.17 times F_u. Comprehensive tests performed on Maxibolts demonstrate that this type of expansion anchors, which is positively anchored into an undercut hole, develops the full ductility and tensile strength of the bolt material without any concrete failure. Therefore, the ultimate load capacity is governed by the steel bolt, and accordingly, the above provisions for allowable loads in accordance with the AISC Specification are appropriate and applicable. In the case of "Abnormal/Extreme Environmental" and "Faulted" loading conditions, the allowable loads are increased by a factor of 1.5.

For evaluation of simultaneous tension and shear loads, the design loads are combined by the following interaction formulas:

$$\left(\frac{t}{T}\right)+\left(\frac{s}{S}\right)\leq 1.0$$ (For Hilti Kwik-bolts)

$$\left(\frac{t}{T}\right)^{5/3}+\left(\frac{s}{S}\right)^{5/3}\leq 1.0$$ (For Maxibolts, whose load capacity is governed by steel material. Accordingly, this interaction formula with 5/3 exponents, which is enveloped by the AISC formula with 2.0 exponents, is used).

Where:

(t, s) = design tension and shear loads, respectively

(T, S) = specified allowable tension and shear loads, respectively

The design tension in expansion anchor bolts is calculated in the component support design process utilizing either a manual calculation or a computer analysis. The baseplate flexibility and prying action effects on the bolt tension are taken into account as described in the STPEGS responses to NRC Bulletin 79-02 (Ref. letter ST-HL-AE-1073 dated 07/30/84).

Question 032.3

We require that the environmental qualification program be provided for at least one item in each of the following groups of Class lE equipment (both NSSS supplied and B.0.P equipment).

1. Switchgear
2. Motor control centers
3. Valve operators (in-Containment)
4. Motors
5. Logic equipment
6. Cables
7. Diesel generator control equipment
8. Sensors
9. Limit switches
10. Heaters
11. Fans
12. Control boards
13. Instrument racks and panels
14. Connectors
15. Penetrations - Including design provisions for the overcurrent protection circuits
16. Splices
17. Terminal blocks and
18. Terminal cabinets

The qualification program should include:

1. Identification of equipment including,
    a. Manufacturer
    b. Manufacturer's type number
    c. Manufacturer's model number

Question 032.3 (Continued)

2. Equipment design specification requirements, including,

   a. The system function requirements

   b. An environmental envelope which includes all extreme parameters, both maximum and minimum values, expected to occur during plant shutdown, normal operation, abnormal operation and any design basis event

   c. Time required to fulfill its function when subjected to any of the extremes of the environmental envelope specified above

   d. The location of the equipment

3. Test plan

4. Test set-up

5. Test procedures

6. Acceptability goals and requirements

7. Test results

8. Identification of the documents which include and describe the above items

9. Justification must be provided when analyses is used to qualify equipment.

In accordance with the requirements of Appendix B of 10CFR50 the Staff requires a statement verifying: (1) that all remaining Class lE equipment will be qualified to the program described above and (2) that the qualification information will be available for an NRC audit.

Provide the information requested above.

Response

Most of the information requested concerning the environmental qualification program for the Class 1E equipment has been submitted to the NRC in Supplement l in WCAP-8587, Revision l (Reference 3.11-1).

The applicant believes further details of sample equipment qualification programs are not necessary for the FSAR. All results and test programs will be available for audit and all Class 1E equipment vendors have Quality Assurance programs in accordance with Appendix B of lOCFR50.

Question 040.8

Potential problem with containment electrical penetration assemblies: Recent operating experience at Millstone Unit No. 2 has shown that the deterioration of the epoxy insulation between splices has caused electrical shorts between conductors within a containment electrical penetration assembly. Indicate what tests and/or analysis that have been performed to demonstrate the acceptability of the design in this regard. Provide whatever information is required to perform an independent evaluation of this aspect of the electrical penetration design.

Response

1. The Millstone No. 2 Electrical Penetration Assemblies were manufactured and supplied by General Electric Company.

   The Electrical Penetrations used for the STPEGS Units 1 and 2 are of Westinghouse design and are not similar to G.E. Series 100 assemblies. A special epoxy compound, developed by Westinghouse, is used to seal the conductors and header. The epoxy compound consists of elastomer materials (1) silicone rubber for long life and high temperature performance, and (2) ethylene propylene rubber for long life and normal temperature performance. There are no internal bare contacts nor cable splices within the penetration assemblies. Additionally, the penetrations do not require any nitrogen gas pressure to function. Nitrogen pressurization is required only as a media for monitoring leakage from the assemblies.

   The electrical penetrations to be utilized at the STPEGS are Westinghouse modular type with a flange bolted bulkhead interface to the primary containment penetration nozzles. Feed-through modules are fully inserted and rest against the header plate. Three clamps keep the module in place by bearing against the shoulder of the module.

2. Westinghouse Creep Tests of the epoxy used in the Containment electrical penetration demonstrated the acceptability of the epoxy in that it did not soften after long-term exposure at 125□C temperatures.

   Westinghouse prototype tests have confirmed that electrical penetrations of the type to be utilized at the STPEGS meet the requirements of IEEE 317-1976 and IEEE 323-1974.

Question 321.4

Provide an analysis with respect to each position in the Regulatory Guide 1.140 (March 1978), "Design, Testing and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light Water-Cooled Nuclear Power Plants," for each atmosphere cleanup system designed to collect airborne radioactive materials during normal plant operation including anticipated operational occurrences. Only the items of noncompliance need be listed with the justification for noncompliance.

Response

The design of STPEGS Normal Ventilation Exhaust Systems' Air Filtration and Adsorption Units complies with Regulatory Guide 1.140 (March 1978) except as noted in Table Q321.4-1 and in Table 3.12-1, Note 80 and as described below.

There are two locations in each unit where HEPA filters were installed in non-nuclear applications: RCB Supplemental Purge Exhaust and Radioactive Vent Header. These installations were to limit migration of particulate to the unit vent and are not required for any safety related function; nor was the application required to credit dose calculations. RG 1.140 and N509/N510 do not apply.

TABLE Q321.4-1

REGULATORY GUIDE 1.140 (MARCH 1978)
NONCOMPLIANCE ITEMS -

Regulatory Position	RCB Containment Carbon Subsystem	MAB	TSC
C.1.a	Complies except radiation levels. The two components that could be jeopardized by radiation exposure are the filter unit's Fire Protection Control Panel and the fan motors. The Fire Protection Control Panel is located outside the Containment in a low radiation zone and the fan motor is capable of performing its function at the radiation level of its location.	Complies except radiation levels. Normal radiation levels are insignificant for the type of equipment involved.	Same as MAB.
C.2.c	Complies except flow rate is not monitored or alarmed. This system does not operate continuously during normal plant operation only for pre-containment access such as refueling. In addition, the system utilizes a 100 percent recirculation mode in lieu of an exhaust air system.	MAB Charcoal Filter Units are equipped with a high filter differential pressure switch. When the filter load increases, causing a subsequent reduction in air flow, an alarm is annunciated in the Main Control Room.	Complies.
C.3.f	Complies, except duct system air flows are less than (-)10 percent of design, for 1.25 times the design dirty filter condition (Ref. ANSI 509-1980 Section 5.10.9 and ANSI 510-1980 Section 8.3.1). A high filter differential pressure switch alarm for changing dirty filters will preclude operation at 1.25 times the design dirty filter condition. See item C.2.c above for further justification.	Complies, except duct system air flows are within ±15 percent of design, for different filter conditions (clean, 1.25 times dirty, and 0.5 times 1.25 dirty). The reduction in filter efficiency due to higher flows is negligible, and it does not effect plant operation and safety since no credit has been taken for these filters in determining the offsite dose release.	Complies.
C.5.d	Complies except allowable bypass leakage is 0.1 percent.	Same as RCB.	Same as RCB.

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Question 231.1

The fuel performance code (PAD 3.3) used for the South Texas safety analyses has recently been approved by us with some restrictions which are identified in a letter dated February 9, 1979, from J. Stolz, NRC to T. Anderson, Westinghouse. Provide an assessment as to whether those restrictions effect the results of the safety analyses presented in the FSAR. If so, revise the analyses accordingly and provide the results.

Response

The effects of the restrictions on the PAD Code given in the letter dated February 9, 1979, from J. Stolz, NRC to T. Anderson, Westinghouse was assessed. It was determined that the restrictions on the use of the code during normal operation had no effect on the safety analyses presented in the UFSAR. There was also a restriction on the use of the code to analyze transients. An analysis was conducted which conservatively bounded possible transient phenomena. Based on this analysis, it was also concluded that there is no effect on the results of the safety analyses discussed in Chapter 4.2.1.3 of the UFSAR.

Question 231.2

Predicted cladding collapse times for South Texas Units 1 and 2 have been calculated with the model as given in WCAP-8377. We have approved the use of this model, by letter to Westinghouse dated February 14, 1975, subject to provisions that no alternations were made to the specified curves used as input to the model. Provide assurance that these provisions have been satisfied.

Response

No alternations have been made to the specified curves used as input to the cladding collapse model described in WCAP-8377.

Question 231.3

Provide the basis for the internal fuel rod gas pressure criteria presented in the FSAR. We note that these criteria are the same as those approved in our review of WCAP-8963 (see letter from J. Stolz, NRC to T. Anderson, Westinghouse) in which an acceptable basis is provided. Therefore, a reference to WCAP-8963 will provide an acceptable response to this request. Due to the restrictions to the fuel performance code (PAD 3.3) imposed at high burnups, as discussed in Request No. 231.1, above, determine the effects of these restrictions on satisfying the rod pressure criteria.

Response

The basis for the internal fuel rod gas pressure criteria presented in the UFSAR is described in WCAP-8963. The restrictions on the fuel performance code (PAD 3.3) as discussed in Request No. 231.1 were reviewed. It was determined that these restrictions had no effects on satisfying the rod pressure criteria.

CN-2839

Question 231.6 Deleted

Question 231.7

Recent PWR experience has shown that fretting wear has occurred between control rods and thimble tubes at a location associated with the fully withdrawn "parked" rod position. Provide assurance, either through fuel assembly inspection results (see item 231.6 above) or prototypical hydraulic flow tests (see item 231.8 below), that fretting wear is not a concern in South Texas.

Response

Westinghouse has provided to the NRC the results of fuel assembly guide thimble tube examinations. This information was made generally available to the NRC in letter NS-TMA-2238, T.M. Anderson to H.R. Denton, dated April 29, 1980. These results show that the design of Westinghouse Reactor Internals, fuel assemblies, and control rod assemblies is such that fretting wear in thimble tubes is not a safety concern in Westinghouse facilities. A thimble wear post irradiation examination was conducted by Westinghouse at Salem Unit l, and there was no evidence of through-wear holes or other indications of excessive wear on the guide thimble tubes.

Question 231.08

WCAP-8278 is used to demonstrate that the design methods for predicting vibration amplitudes and fuel rod fretting wear are conservative, based upon a l000-hour flow loop test of a l2-foot l7xl7 fuel assembly. Similar verification tests for the l4-foot l7xl7 fuel have been previously discussed by Westinghouse and were to be completed in l978. Provide assurance that fuel rod fretting for the l4-foot fuel assembly is not a concern in South Texas.

Response

The hydraulic flow testing of the 17 x 17, 14-ft fuel assembly was completed with no anomalies being observed. The results have been summarized and were transmitted to the NRC in letter ST-HL-AE-1143 dated October 18, 1984.

Question 232.3

Comment on the division of the MTC into density and temperature effects as a function of core lifetime. Recent calculations (to be published) by BNL suggest that the spectral (temperature) component is positive and is a significant portion of the total MTC for cores with large (~10 GWd/t) burnups. Comment on the effect of the use of density only moderator coefficients in the affected transients in Chapter 15, particularly for reload cycles (Ref. letter, Eicheldinger to Ross, dated February 28, 1978, NS-CE-1706).

Response

The referenced letter to the NRC (D. F. Ross) still applies. Transient calculations have been made which include a correction for the deviation between actual moderator temperature to that which is inferred from the transient density at the referenced pressure at which the density coefficients were calculated [Ref. letter, C. E. Eicheldinger (Westinghouse) to D. F. Ross (NRC), dated February 28, 1978, NS-CE-1706].

Question 232.4

State whether the coolant temperature control action is passive (in that the coolant temperature automatically responds to power changes) or whether a deliberate action is undertaken. For example, in a rapid power rise performed as part of a load following procedure, state whether there is an anticipatory increase in moderator temperature in preparation for the power rise.

Response

All changes in reactor temperature are initiated by and follow only changes in turbine loading. No manual anticipatory changes are made in reactor temperature for any power transients.

Question 232.5

Discuss whether the burnable poison rod pattern shown in Figure 4.3-5 of the FSAR is consistent with the power distributions and reactivity coefficients given for the South Texas core.

Response

The burnable poison rod pattern shown in Figure 4.3-5 of the UFSAR is consistent with the power distributions and reactivity coefficients given for the STPEGS reference first core.

Question 232.6

Provide an estimate of the uncertainty in the calculation of the flux at the inner boundary of the pressure vessel. Discuss how the azimuthal peaking factor is obtained. State whether comparisons have been made between calculations and measurements for sample locations. If so, provide this information.

Response

Radial, axial, and azimuthal variations of fast neutron flux within the reactor vessel geometry are generated by means of the two-dimensional discrete ordinates method. Since the azimuthal flux distribution is obtained directly from an R, è computation, no explicit azimuthal peaking factor is applied.

The attached table presents a comparison of measured and calculated neutron flux monitor saturated activities for reactor vessel surveillance capsules removed from two-loop Westinghouse PWRs. Since the monitors listed respond to different portions of the neutron energy spectrum and, further, since the saturated activity is proportional to the neutron flux magnitude, agreement between calculation and measurement provides an indication of the analytical capability to predict both flux level and energy spectrum at the measurement location.

Based on the data included in the attached table, uncertainties in the neutron flux calculation method are estimated to be ±10 percent on a generic basis and ±20 percent on a single measurement, specific plant basis.

TABLE Q232.6-1

NEUTRON FLUX MONITOR SATURATED ACTIVITY AT THE DOSIMETER BLOCK LOCATION FOR SEVEN 2-LOOP PWR POWER PLANTS (NORMALIZED TO 1650 MWT)

SATURATED ACTIVITY (dps/gm)

Capsule	$Fe^{54}(n,p)Mn^{54}$	$Ni^{58}(n,p)Co^{58}$	$Np^{237}(n,f)Cs^{137}$	$U^{238}(n,f)Cs^{137}$
Plant 1	4.92×10^6	5.78×10^7	7.06×10^7	6.71×10^6
Plant 2	6.00×10^6	8.97×10^7	6.96×10^7	9.24×10^6
Plant 3	5.07×10^6	7.42×10^7	6.11×10^7	7.93×10^6
Plant 4	5.09×10^6	7.62×10^7	7.04×10^7	8.19×10^6
Plant 5	5.14×10^6	6.93×10^7	7.37×10^7	8.36×10^6
Plant 6	5.73×10^6	9.41×10^7		6.65×10^6
Plant 7	5.26×10^6	6.80×10^7	7.85×10^7	7.98×10^6
13° Avg	5.32×10^6	7.56×10^7	7.07×10^7	7.89×10^6
13° Calc	5.61×10^6	8.28×10^7	7.11×10^7	7.35×10^6

Question 232.9

Discuss the difference in operating strategy, cases calculated, core design, etc., which lead to a peaking factor of 2.50, as compared to the usual value of 2.32 obtained from the constant axial offset control strategy.

Response

HISTORICAL INFORMATION

STPEGS Units are designed for a peaking factor, F_Q, as presented in the Core Operating Limits Report (COLR). Constant axial offset control strategy with +3, -12 percent axial flux difference limits insure that the $F_Q(Z)$ upper bound times the normalized axial factor, K(Z), is not exceeded during normal operation. The usual value of 2.32 is associated with $\pm$5 percent axial flux difference limits.

The peaking factor, F_Q, and constant axial offset control strategy axial flux difference limits are presented in the COLR.

HISTORICAL INFORMATION

Question 491.1N

The configuration of control bank D and the discussion in Section 4.3.2.4.13 indicate that you intend to use an "improved load follow" system. For Westinghouse reactors with twelve foot cores this has meant a changed (increased) CAOC offset band and a changed (expanded) set of calculational cases to define the offset limits and F_Q. Furthermore, it has been found necessary to restrict the wider offset band width during the first part of the first cycle. This type of information has not been supplied for the fourteen foot core. If you are using an improved load follow system, provide a discussion of the expanded calculations, the offset band to be used and any necessary restrictions required in its use.

Response

HISTORICAL INFORMATION

The improved load follow Final Acceptance Criteria analysis with the increased Constant Axial Offset Control (CAOC) offset band and expanded set of calculational cases was made to define the offset limits and F_Q for the South Texas (17 x 17 standard), 14-ft core with the light D Bank design. A reduced CAOC offset band (±5%) was used up to 3000 mwd/mtu core average burnup in both units. Beyond 3000 mwd/mtu core average burnup, a +3, -12% band is used. The ±5% axial offset band was removed by Technical Specification Amendment 9 (Unit 1) and 1 (Unit 2).

The CAOC offset band is presented in the Core Operating Limits Repent (COLR).

HISTORICAL INFORMATION

Question 221.6

HISTORICAL INFORMATION

Figure 4.4-11 presents a comparison between a least squares fit through the" THINC-IV calculation and measured values of core ΔT under natural circulation" condition. Provide the calculated ΔT vs. assembly power for each assembly."

Response [HISTORICAL INFORMATION]

The THINC-IV model has been approved as a design tool in an NRC SER, dated April 19, 1978. The values used in Figure 4.4-11 were from a natural circulation THINC-IV generic verification test. This information is included in the STPEGS UFSAR only for background information on the types of testing used. No additional specific analysis was done with this experimental information for the STPEGS UFSAR.

HISTORICAL INFORMATION

Question 221.7

HISTORICAL INFORMATION

Equation 4.4-19 (Section 4.4.4.3) presents the design value of enthalpy rise factor:

$$F\frac{N}{\Delta H} = 1.52\left[1 + 0.3\,(1 - P)\right]$$

Both the full power value (1.52) and the assumed power dependence are different from previously approved Westinghouse designs. Provide a plot comparing the design enthalpy rise factor (Equation 4.4-19) and the maximum calculated values of the operating enthalpy rise factor as a function of power level. The calculated enthalpy factors should be based on the proposed rod insertion limits and the constant axial offset control strategy.

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

Increasing allowable $F^N_{\Delta H}$ with decreasing power is permitted by all previously approved Westinghouse designs. This increase is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limit as described in Section 4.4.4.3. Equation 4.4-19 (Section 4.4.4.3) presents the design limit of the nuclear enthalpy rise factor for the STPEGS plants:

$$\text{limit } F^N_{\Delta H} = 1.52\left[1 + 0.3\left(1 - P\right)\right]$$

where P is the fraction of full power.

The maximum calculated value of the operating nuclear enthalpy rise factor as a function of power level, including uncertainty, does not exceed the design limit at any power level for the STPEGS reference design:

$$\text{operating } F^N_{\Delta H}\left(\text{including uncertainty}\right) \le 1.52\left[1 + 0.3\left(1 - P\right)\right]$$

These calculated nuclear enthalpy rise factors for the reference South Texas Cycle l design are conservatively based on the Technical Specification's rod insertion limits.

As stated in Section 4.3.2.2.6, "Maintenance of constant axial offset control establishes rod positions which are above the allowed rod insertion limits, thus providing increased margin to the $F^N_{\Delta H}$ criterion."

Question 221.8

Provide a description of the instrumentation and procedures to be used in implementing the Technical Specification on Reactor Coolant System Flow. Provide a description of the associated uncertainties.

Response

The following is provided for monitoring Reactor Coolant System flow:

1. The STPEGS Technical Specifications will have a requirement to verify Reactor Coolant System (RCS) flow.

2. The operator has at his disposal several methods of detecting significant RCS flow reduction. These are:

   a. Flow meter on each RCS loop.

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

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

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

   e. Core exit thermocouple readings.

The Technical Specifications will require that the operator verify flow, perform calorimetric power checks, and incorporate flux maps.

Question 221.9

HISTORICAL INFORMATION

The THINC-IV code assumes a uniform radial pressure distribution at the core exit for all of the South Texas Units 1 and 2 thermal-hydraulic design calculations. The Westinghouse 1/7 scale hydraulic tests at the Forest Hill Facility indicate a significant radial pressure gradient. This gradient has also been observed in recent calculations by staff consultants.

The effects of the expected radial pressure gradient must be accounted for in the South Texas Units l and 2 thermal-hydraulic design. This can be accomplished by:

1. Providing the expected radial pressure gradient; and either

2. a. Providing a revised thermal-hydraulic design calculation which includes the effects of the radial pressure gradient, or

   b. Providing an analysis which demonstrates that the effect is small and that sufficient margin exists in the South Texas conservatism in this area.

Therefore, provide the above information.

Response [HISTORICAL INFORMATION]

As requested in (2), a cosine upper plenum radial pressure gradient with a maximum value of 5 psi at the core center and 0 psi at the core periphery was assumed for four-loop and three-loop operation. The results of this analysis showed that there was no effect on the minimum DNBR (to three significant figures) of this radial pressure gradient on four-loop or three-loop operation.

In performing this analysis, the hot assembly was assumed to be in the center of the core where the greatest flow reduction near the core outlet will occur due to the radial pressure gradient. In addition, an axial power distribution extremely peaked to the top of the core (~+30 percent axial offset) was assumed. This axial power distribution is more severe than would be expected during plant operations.

Thus, the use of a uniform upper plenum pressure distribution in thermal-hydraulic design is acceptable.

HISTORICAL INFORMATION

Question 492.1N

HISTORICAL INFORMATION

Operating experience on two pressurized water reactors, not of Westinghouse design, indicate that a significant reduction in the core flow rate can occur over a relatively short period as a result of crud deposition on the fuel rods. In establishing the Technical Specifications for South Texas Project, Units 1 & 2, we will require provisions to assure that the minimum design flow rates are achieved. Therefore, provide a description of the flow measurement capability for South Texas Units 1 and 2 as well as a description of the procedure to measure flow.

Response [HISTORICAL INFORMATION]

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

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

1. Flow meter on each RCS loop.

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

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

HISTORICAL INFORMATION

Question 492.2N

Regulatory Guides 1.133, Revision 1 and 1.70, Revision 3 require that FSAR Section 4.4.6 contain a description of the Loose Parts Monitoring System (LPMS) which will be installed at South Texas Units 1 and 2. The information that should be supplied is:

(1) a description of the monitoring equipment including sensor locations;

(2) a description of how alert levels will be determined, including sources of internal and external noise, diagnostic procedures used to confirm the presence of a loose part, and precautions to ensure acquisition of quality data;

(3) a description of the operation program, including signature analysis during startup, normal containment environment operation, the seismic design, and system sensitivity;

(4) a detailed discussion of the operator training program for operation of the LPMS, planned operating procedures, and record keeping procedures;

(5) a report from the applicant which contains an evaluation of the system for conformance to Regulatory Guide 1.133; and,

(6) a commitment from the applicant to supply a report describing operation of the system hardware and implementation of the loose part detection program.

Response

(1) A description of the monitoring equipment is provided in Section 4.4.6.4.

(2) A description of how alert levels will be determined is provided in Section 4.4.6.4.

(3) The LPMS will be used to generate baseline signatures for all channels at center frequencies of 25 HZ, 250 HZ, 2.5 KHZ, and 25 KHZ during initial startup testing, at reactor power levels of approximately 30 percent, 50 percent, 75 percent, and 100 percent. During reactor startups following breaching of the RCS or steam generators and in instances of automatic LPMS actuation additional signatures will be obtained for comparison with previous signatures to detect changes in amplitude or frequency.

Information concerning normal containment environment operation, seismic design, and system sensitivity is provided in Section 4.4.6.4.

(4) Licensed operators (including licensed supervisors) are presented a lecture (approximately 2 hours in length) on the Vibration and Loose Parts Monitoring System.

Response (Continued)

This lecture presents the following:

- Function and description of operation of the system,
- Function and description of major components of the system, and
- Controls and indication associated with the system.

Operators are provided with objectives which identify what knowledge they should gain from the lecture and are examined on these objectives with minimum passing grade of 70 percent.

Following the classrooms training, operators should have sufficient knowledge of the system, and its operation to be able to safely follow plant operating procedures or system operating instructions which address indications or alarms associated with the Vibration and Loose Parts Monitoring System. This training should allow operators to identify when the system has identified a vibration or loose parts problem, relate that indication to other plant indications, initiate actions (if necessary) to maintain the plant in a safe condition, and notify engineering for a detailed analysis of the vibration or loose part.

For practical experience with the operation of the system, current operators will be involved with the plant startup testing and operation during establishment of baseline data for the system. After commercial operation, operators will have practical factors associated with operation of the system during On-The-Job training as necessary to ensure that operators are able to conduct applicable procedures.

(5) The conformance of the Loose Parts Monitoring System (LPMS) to Regulatory Guide (RG) 1.133 has been provided in Section 4.4.6.4 and Table 3.12-1.

(6) The information provided or to be provided in items 1-5 includes sufficient details to satisfy the requirements of RG 1.70 and Standard Review Plan (SRP) 4.4 (Rev. 1 - July 1981). HL&P should not be required to provide an additional report. Note that HL&P will not have any operating experience to report until some time after the STPEGS units are in operation.

HISTORICAL INFORMATION

Question 492.3N

State your intentions with regard to N-1 loop operation.

Response [HISTORICAL INFORMATION]

At this time, HL&P does not intend to pursue licensing for N-1 loop operation of the STPEGS Units.

HISTORICAL INFORMAITON

HISTORICAL INFORMATION

Question 492.5N

Provide the documentation required by NUREG-0737 Item II.F.2. The responses to the documentation should be given item-by-item.

Response [HISTORICAL INFORMATION]
Instrumentation for the detection of inadequate core cooling is provided per NUREG-0737, Item II.F.2 and RG 1.97 (see Appendix 7A, Item II.F.2). The instrumentation includes reactor vessel water level indication, core exit thermocouples, and a subcooled margin monitor. This instrumentation provides unambiguous, easy-to-interpret indication of inadequate core cooling.

HISTORICAL INFORMAITON

HISTORICAL INFORMATION

Question 492.6N

Do you attribute the vibrational problems at the Paluel Station to the 14 foot core design?

Response [HISTORICAL INFORMATION]

Based on our review of the available information and the operational experience of other Westinghouse 14-ft core plants, we do not believe that the 14-ft core change is responsible for the problems at Paluel. The evidence to date indicates that the use of structurally more flexible thimble tubes in conjunction with the larger flow area around the tubes are the primary causes of the problems at that plant.

For 14-ft core plants the lower support plate has a larger number of smaller diameter flow holes than the plate for 12-ft core plants to allow flow up through the fuel. This results in a larger axial pressure gradient across the lower support plate. Thus the axial flow velocity in the annulus between the thimble and its guide structure increases. This may accentuate the potential for experiencing problems of this nature, particularly when the thimble size is reduced.

Westinghouse and STPEGS are closely monitoring the results of the test programs at EDF and Framatome in order to ensure that STPEGS is not adversely affected by similar problems. In addition, Westinghouse is also closely following the performance of the Westinghouse 14-ft core plants that are in operation.

HISTORICAL INFORMAITON

HISTORICAL INFORMATION

Question 492.7N

Do you feel the same vibrational problems are possible at STPEGS? If you do, then quantify the safety impact of such a problem. If you do not, then explain any design differences between STPEGS and Paluel that lead to this conclusion.

Response [HISTORICAL INFORMATION]

As was previously noted (letter ST-HL-AE-1334, dated 2/3/86) the vibrational problem experienced at Paluel is the vibration of the BMI thimble, not vibration of the reactor vessel lower internals. The STPEGS Units 1 and 2 use a flux thimble with a nominal outside diameter of .313 inches. The Paluel units (1, 2, 3, 4) are using a thimble with an outside diameter of .295 inches. The STPEGS thimbles also have a slightly thicker wall than the Paluel thimbles. The larger thimble also results in a smaller annular gap between the flux thimble and the inside of the BMI columns. (Unit 1 was modified such that the BMI column gap size is similar to Unit 2.) In conclusion, the stiffer STPEGS thimbles, with the smaller gaps, will perform satisfactorily based on the European plant experience to date.

With respect to the safety aspects of a thimble wear problem if it were to occur, we do not believe the issue to be a safety concern. Previous evaluations have been made by Westinghouse regarding the failure of flux thimble tubes. The evaluation concluded that up to three (3) BMI thimble tubes can fail simultaneously with a complete instantaneous guillotine break, and the coolant loss can be made-up by the output of the on-line charging pump. Since the coolant loss would not exceed the make-up capability of normal charging, no SI (safety injection) signal is generated. The occurrence of a thimble tube leak would be identified by the detectors in the seal table room.

It should be pointed-out that the assumption of three tubes rupturing at the same time is highly conservative. As noted above, even if the tubes ruptured, the plant would easily be able to complete a controlled shutdown so that the leaking thimble could be either isolated or replaced.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 492.8N

In light of the Paluel experience, do you still believe that the vessel model flow test which you submitted in your FSAR is still valid?

Response [HISTORICAL INFORMATION]

The purpose of the vessel model flow test is to demonstrate the structural integrity of the reactor vessel system and to provide data regarding the response of the reactor internals during operation. The BMI thimbles were not included in the vessel model flow test. Westinghouse has shown that these model tests are accurate and reliable predictors of plant performance and that these objectives were met. The vibratory levels of the reactor internals have been shown to be negligible and the response of the internals is well behaved. As has been previously discussed in letter ST-HL-AE-1339, dated February 3, 1986, the issue here is vibration of the removable thimble tubes, not vibration of the reactor internals. Hence, the vessel model flow test is still valid. Please note that this issue was discussed by Westinghouse at the MEB review on STPEGS and Westinghouse has provided a vibration assessment report, WCAP-10865, which demonstrates the acceptability of the vibration levels of the STPEGS units.

HISTORICAL INFORMAITON

Question 122.1

Provide a list of all ASME Class 2 and Class 3 components of ferritic steel for each system in South Texas l and 2. Provide the fracture toughness data obtained for the components, and indicate the fracture toughness requirements, specifications, testing procedures, and acceptance standards that were followed to obtain the data.

Response

Fracture toughness testing is required only for the Main Steam and Feedwater Systems; other systems in Safety Classes 2 and 3 are exempted.

The following list is an example of ASME Class 2 and 3 components with ferritic pressure boundary material at STPEGS 1 and 2.

Reactor Containment Fan Coolers
Main Feedwater Isolation Valves
Main Steam Isolation Valves
Main Steam Safety Valves
Main Steam PORVs
Standby Diesel Generator
Standby Diesel Generator Fuel Oil Storage Tank
Auxiliary Feedwater Pumps
CCW Pumps
CCW Surge Tanks
CCW Heat Exchangers
ECW Self Cleaning Strainers
Feedwater Isolation Bypass Valves
Steam Generator Preheater Bypass Valves
Auxiliary Feedwater Pump Discharge Valves
Steam Generator Feedwater Bypass Valves
Auxiliary Feedwater Turbine Steam Isolation Valves
Main Steam Isolation Bypass Valves
Main Steam Vents & Drains Isolation Valves
Auxiliary Feedwater Pump Recirculation Valves
Steam Dump Valves
Feedwater Control Valves
Feedwater Bypass Control Valves

The responses to NRC Questions 122.17 and 122.22 provide the requirements, specifications, testing procedures, and acceptance standards for the fracture toughness.

Question 122.3

State whether any of the following materials that have a yield strength greater than 90,000 psi are being used in the control rod drive mechanisms or in the reactor internals: cold-worked austenitic stainless steels or hardenable martensitic stainless steels. If such materials are employed, identify their usage and provide evidence that stress corrosion cracking will not occur during service life in components fabricated from the materials.

Response

Hardenable martensitic stainless steel Type 403 with a minimum yield strength of 90,000 psi is used for the reactor internals holddown spring. Martensitic stainless steel ASTM A276 Type 410 Condition H with a minimum yield strength of 90,000 psi is used in the following control rod drive mechanism applications: drive rod breech housing, external breech, disconnect rod, positioning nut, and loading bolt.

Stress corrosion cracking in these materials is not anticipated in a Westinghouse PWR with properly controlled reactor coolant chemistry; RCS chemistry specifications and control are discussed in Section 5.2.3.2.1.

Question 122.4

Provide the tempering temperatures of the hardenable martensitic steels and the processing and treatment of other special materials, such as cobalt-base alloys and Inconels, used to fabricate the control rod drive mechanisms and the reactor internals. Provide information regarding the mechanical properties of all of the special materials.

Response

Reactor Internals

The hardenable martensitic stainless steel Type 403 (with minimum yield strength of 90,000 psi) used for the reactor internals holddown spring, identified in the response to Question 122.3, is tempered at 1125^{0}F.

Inconel (Type 600 for clevise and Type 750 for some bolting) with 115,000 psi yield strength is solution treated at 1800^{0}F and double aged at 1350^{0}F and 1150^{0}F.

Stellite is used as a hard surface clad for wear resistance in some areas of the reactor internals (such as the core barrel/vessel keys).

Control Rod Drive Mechanisms

Martensitic stainless steel ASTM A276 Type 410 Condition H (with minimum yield strength of 90,000 psi), which is used in the CRDM applications identified in the response to Question 122.3, is tempered at a minimum temperature of 1050^{0}F.

Inconel X750 Class A with minimum tensile strength of 190,000 psi is used for the latch assembly return springs. This material is temper cold drawn and age hardened at 1350^{0}F.

Inconel X750 Class D with minimum tensile strength of 220,000 psi is used for the drive rod locking spring. This material is temper cold drawn and age hardened at 1200^{0}F.

Inconel 718 with minimum Rockwell hardness of 41 is used for the springs on the heavy drive rod. The material is processed by an 18-25 percent cold reduction; it is aged at 1400^{0}F, cooled to 1200^{0}F and held, and cooled to room temperature.

Haynes 25 with minimum yield strength of 120,000 psi and Rockwell hardness of 35-45 is used for the locking button. This material is solution heat treated at 2250^{0}F, quenched or rapidly air cooled, reduced, and aged at 1000^0 to 1050^{0}F. Heat treated and cold worked Haynes 25 with Rockwell hardness of 34-40 is used for the latch pins.

Stellite 6 is used on the latch tips.

Question 122.6

Provide the specific welding materials used for fabricating the ferritic steel components of the reactor coolant pressure boundary (i.e., reactor vessel, pressurizer, steam generator) and give the ASME specifications for the welding materials. Discuss or tabulate separately the specific welding materials used to join parts fabricated from SA 533 Grade A, B, or C, Class 2 and SA 508 Class 2a materials.

Response

Acceptable welding materials for pressure-retaining weldments in the reactor vessel are ASME Specifications SFA 5.5, SFA 5.11, and SFA 5.14, as well as Military Specification MIL-E-18193A.

The welding material used for pressure-retaining weldments in the pressurizer is ASME Specification SFA 5.5. ASME Specification SFA 5.5 welding material is used to join parts fabricated from SA 533 Grade A Class 2 and SA 508 Class 2a materials.

Acceptable welding materials for pressure-retaining weldments in the steam generator (primary side) are ASME Specifications SFA 5.5 and SFA 5.17. ASME Specifications SFA 5.5 and SFA 5.17 welding materials are used to join parts fabricated from SA 533 Grade A, B, or C Class 2 and SA 508 Class 2a materials.

Acceptable welding materials for pressure-retaining weldments in the Model Delta 94 steam generator (primary side) are ASME Specifications SFA 5.5, SFA 5.11 Class ERNiCrFe-7, SFA 5.14 Class ERNiCrFe-7, SFA 5.23. ASME SA 533 Grade A, B, or C Class 2 and SA 508 Class 2a materials are not used in the construction of the Model Delta 94 steam generators.

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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

Response (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.

Response (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. Plate No.	B8120-2 R1606-1	B8120-1 R1606-2	C4326-2 R1606-3	B9566-2 R1622-1	B9575-2 R1622-2	B9575-1 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. Plate No.	NR62067-1 R2507-1	NR62230-1 R2507-2	NR62248-1 R2507-3	NR64647-1 R3022-1	NR64627-1 R3022-2	NR64445-1 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.

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

T_{NDT} = -40°F
RT_{NDT} = 10°F

T_{NDT} = -20°F
RT_{NDT} = 0°F

T_{NDT} = -20°F
RT_{NDT} = 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

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				
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

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				T_{NDT} = -10°F				T_{NDT} = -40°F			
RT_{NDT} = -10°F				RT_{NDT} = -10°F				RT_{NDT} = -40°F			

TABLE Q251.3N-6

SOUTH TEXAS UNIT 2 REACTOR VESSEL BELTLINE REGION TOUGHNESS PROPERTIES

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.

Question 211.14

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?

Response

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		4.0×10^{-10} ft/(Loop gal/min)^2
Total RC Loop	24.0×10^{-10}	18.0×10^{-10} ft/(Loop gal/min)^2
Steam Generator	114.5×10^{-10}	132.1×10^{-10} ft/(Loop gal/min)^2
Total	303.6×10^{-10}	327.1×10^{-10} ft/(Loop gal/min)^2
Flow Ratio Per Loop	$\frac{\text{STPEGS}}{\text{Diablo Canyon}} = \sim$	$\frac{303.6}{327.1} - 1/2 = 0.963$

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.

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Question 122.17

Provide the fracture toughness data for the ferritic steel components of the engineered safety features and the Steam and Feedwater System, and indicate the fracture toughness requirements, specifications, testing procedures, and acceptance standards that were followed to obtain the data.

Response

See UFSAR section 10.3.6.

Question 122.18

Regarding the ferritic steel components of the engineered safety features and the Steam and Feedwater System, give the degree of conformance with all of the recommendations of Regulatory Guide 1.50, "Control of Preheat Temperature for Welding Low-Alloy Steel."

Response

Field Erection Welds:

The welding procedures used specify the minimum preheat temperature and maximum allowable interpass temperature.

During production welding, the temperatures are monitored to verify that the specified limits are not violated. Preheat is maintained throughout welding until the PWHT cycle begins. Alternatively, the weld is wrapped with insulation and allowed to cool slowly until ambient temperature is reached or until the minimum preheat temperature is reestablished.

The completed welds are examined in accordance with the Code requirements.

Question 281.2N

Indicate the total amount of paint or protective coatings (area and film thickness) used inside containment that do not meet the requirements of ANSI N101.2 (1972) and Regulatory Guide 1.54. We will use the above information to estimate the rate of combustible gas generation vs. time and the amount (volume) of solid debris that can be formed from these unqualified organic materials under DBA conditions that can potentially reach the containment sump. A G value of 5 will be used unless a lower G value is justified technically.

Response

Estimates of the various categories of surface areas that are protected with paints that do not comply with the quality standards of ANSI N101.2 (1972) or that were applied in ways not providing the level of quality assurance outlined in Regulatory Guide 1.54 are listed in Table 6.1-4, with their respective dry-film thickness range. The total estimated surface area of such organic paints is 20,865 ft^2. The quantities of zinc-rich silicate paints are included in Table 6.1-4. Additionally, there is some 4050 ft^2 of epoxy surfacer applied to concrete surfaces in the reactor cavity of Unit 1 where the total integrated radiation does rate may exceed the radiation resistance of the coating material.

UFSAR Table 6.1-4 provides the qualification information for coating materials used inside containment. As shown by the table, only a very small fraction of these coatings are not qualified to the requirements of Regulatory Guide 1.54. The total weight of these unqualified organic coatings is less than 3000 pounds.

With the assumption that the organic materials mentioned above be considered as unsaturated hydrocarbons, Reference 1 indicates they would have a G value for hydrogen of 1 molecule per 100 ev of energy absorbed. The integrated dose that the materials could be subjected to would be less than 1.4×10^8 rads over one 6-month period following a design basis accident. Under these conservative assumptions, approximately 0.725 lb-moles of hydrogen could be released over the 6-month period. This quantity of hydrogen is not considered to be a significant contribution compared to that identified in Section 6.2.5.

References

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

Question 022.2 (Deleted)

Question 022.8

In Section 6.2.1.2.3.1, it is stated that the pressure transients were determined with the RELAP-3 computer code. However, it is our understanding that this version of the RELAP code models only single component two-phase flow, thereby neglecting the effects of air. Therefore, provide a discussion as to how this assumption in the model (i.e., neglecting air) will affect net results of each subcompartment analysis.

Response

In the present subcompartment analysis, COPDA-an NRC approved code for evaluating short term peak pressures has been used. This code models air, water, and steam mixture to be present in any subcompartment and they are considered to be in thermodynamic equilibrium with all phases and components at the same temperature and to be homogeneously mixed. Other assumptions made in the development of the code are given in BN-TOP-4 (Ref. 6.2.1.2-2).

HISTORICAL INFORMATION

Question 022.9

The response to Request No. 022.5 regarding containment purging is incomplete since you plan to use the supplementary containment purge subsystem (Section 9.4.5.2.6) more than 90 hours per year. Therefore, address the following sections of BTP CSB 6-4 (which was provided during the Acceptance Review): B.l.a, B.l.c, B.l.g and B.5.h.

Response

The additional information requested concerning the design of the Supplementary Containment Purge Subsystems is provided in the following paragraphs:

The supplementary purge isolation valves are designed to perform their required isolation function in the postulated accident environment. The isolation valves and actuators are designed as active components and are designed and tested as described in Sections 3.9.3.2.3 and 3.10. Additionally, the valves are designed to close during the transient pressure buildup in the containment resulting from the design basis LOCA described in Section 6.2.1.1.

The supplementary purge supply and exhaust lines have 18-in. diameters. The Supplementary Containment Purge Subsystem is designed to reduce airborne radioactivity in the RCB atmosphere prior to and during personnel access during normal plant operation in accordance with the principle of maintaining personnel exposures as low as reasonably achievable (ALARA). System capacities and hence line sizes are based on ALARA and plant availability considerations. The design adequacy of the Supplementary Purge Subsystem during postulated accidents has been demonstrated via analysis. These analyses (i.e., consideration of a postulated LOCA during purging) have shown that the radiological consequences are well within the guidelines of 10CFR100, the effects on ECCS backpressure are minimal and the requirements of 10CFR50.46 are met.

The supplementary purge supply takes air from outside the containment through the isolation valves and directs it, via piping, into the Reactor Containment Fan Cooler (RCFC) ring duct (fan suction plenum). The supplementary purge exhaust takes suction from the containment and directs the air via piping out the isolation valves. This piping is shown in Figures 9.4.5-3 and 6.2.2-4. Because of the arrangement of the supplementary purge piping in relation to the isolation valves, there is no credible means for any postulated debris to impair isolation valve closure.

Because the Supplementary Purge Subsystem equipment (fans, filters, and dampers) located outside the containment (beyond the outer isolation valve) is non-safety class (NNS), there is no need to protect the equipment from the environment created by the escaping air and steam resulting from the postulated accident.

Question 022.11

The response to Request No. 022.5 assumes a maximum closure time for the supplementary containment purge subsystem (18-inch) isolation valves of 25 seconds. It is our position that the closure time for the valves should not exceed 5 seconds (see BTP CSB 6-4, Item B.1.f). Revise your FSAR accordingly.

Response

Two analyses were performed in order to demonstrate the adequacy of the Supplementary Containment Purge Subsystem. These analyses were calculations of the radiological consequences of a postulated Loss-of-Coolant-Accident (LOCA) concurrent with operation of the Supplementary Purge Subsystem and analysis of the reduction in Containment pressure resulting from the partial loss of containment atmosphere during the accident for ECCS backpressure determination. For both of these analyses, a total isolation time of 23 seconds was assumed. This assumed isolation time conservatively bounds the time required for valve closure, instrument delay, and diesel generator start (assuming loss of offsite power).

The Supplementary Containment Purge Subsystem motor-operated isolation valve closure time is 10 seconds or less, while the pneumatic valves have a closure time of 5 seconds or less. The results of the analyses have demonstrated the adequacy of the present Supplementary Containment Purge Subsystem isolation valve design.

Question 022.l9

The response to Request No. 022.7 is not complete. Therefore, provide the following information:

(1) The response to Item 5 of 022.7 does not address the issue. If a system is not vented and drained for the Type A test, it is presumed that the system will not constitute a containment atmosphere leak path following a LOCA. For this situation to exist, there must be a sufficient water inventory at a sufficiently high pressure to preclude containment leakage or to assure that only liquid leakage will occur. Therefore, justify that a sufficient water inventory will exist assuming a single failure of any active component. Discuss how hydrostatic testing of the system, including the containment isolation valves, will be done to quantify the liquid leakage and to demonstrate inventory.

(2) The response to Item 6 of 022.7 does not address the issue. Certain systems may be needed to facilitate the performance of the containment integrated leakage rate test and, therefore, are not vented and drained. However, under accident conditions these systems may become containment atmosphere leak paths. It is these systems which should be addressed. It is our position that the containment isolation valves in these systems be locally (Type C) leak tested and the measured leakage added to the Type A test results. Identify the systems involved and discuss your plans for complying with the above position.

(3) Provide the basis for concluding that the reverse leakage testing of containment isolation valve XFC050 (see Table 6.2.2-3) is at least equivalent to testing the valve in the forward direction.

(4) Table 6.2.6-2 indicates that containment isolation valves associated with the secondary side will not be locally (Type C) leak tested. However, if containment atmosphere leakage is postulated to occur through the steam generator tube bundle, the secondary system isolation valves would become containment atmosphere leak paths. In this regard, a water seal may be shown to exist that will preclude containment atmosphere leakage. If this approach is taken, discuss how a water seal can be established and maintained using safety grade pipes and components. Provide system drawings showing the routing and elevation of piping to show the existence of a water seal.

(5) It is our position that the containment isolation valves for the fol- lowing piping penetrations be included in the local (Type C) leak testing program: M-4l, M-42, M-43, M-44, M-54, M-7l, and M-87. Discuss your plans for complying with this position.

Response

(1) Revised FSAR Table 6.2.6-l lists the fluid-filled systems that will not be vented and drained during Type A tests and will therefore not be exposed to the containment atmosphere during such tests. The systems that are not Type C tested are identified, with justification, on Figure 6.2.4-1.

(2) The Chemical and Volume Control System (CVCS) maintains the plant in a safe condition during testing and is required to be operating when the plant is in shutdown. The containment isolation valves associated with these penetrations (M-46, M-48, and M-53) will be locally leak tested (Type C) as indicated in Figure 6.2.4-l.

(3) Containment isolation valve XFC050 has been deleted from Table 6.2.6-3 since it will not be tested in the opposite direction. The revised Table 6.2.6-3 lists the containment isolation valves (butterfly, globe, and ball) to be tested in the direction opposite to that in which the pressure exists when the valve is required to perform its safety function. Globe valves are tested in the opposite direction. This will provide more conservative leak rates since globe valves tend to unseat when pressure is applied in the reverse direction. Butterfly and ball valves produce the same leakage rates independent of the direction of pressure.

(4) Refer to Figure 6.2.4-1, Sheet 1a, Note 1.

(5) Containment isolation valves located on lines penetrating M-41, M-42, M-43, and M-44 will be Type C tested. Penetrations M-7l and M-87 will be Type B tested. M-54 originally assigned to Emergency Boration System (EBS) is reassigned to Containment Pressure Monitoring and RCS Pressure Monitoring. Hence this will be Type A tested.

Question 222.3 (Deleted)

HISTORICAL INFORMATION

Question 222.4

Mass and energy release rates from postulated breaks in the secondary system piping for use in subcompartment analysis were calculated using the RELAP-3 code. This code uses the Moody slip flow model to calculate critical flow from the break. Comparisons to experimental data indicate that the Moody model is not conservative for predicting critical flow for subcooled stagnation conditions. One such comparison may be found in TREE-NUREG-1006, "A Study of Critical Flow Prediction for Semiscale Mod-1 Loss-of-Coolant Accident Experiments," Idaho National Engineering Laboratory, December 1976. Provide subcompartment analyses using mass and energy release rates for postulated feedwater and letdown line breaks calculated using a critical flow model that is conservative when the fluid is subcooled.

Response

The new analysis for postulated breaks in the secondary system piping uses the widely used RELAP5/MOD1 code (Ref. 6.2.1.2-6). RELAP/MOD1 bases the development of the code on conservation equations of mass, energy, and momentum and are solved in one dimension for steam and/or water flow. The equations assume a nonhomogeneous mixture of steam and liquid and nonequilibrium between phases has been modelled. Choking flow model developed by Ransom and Trapp ("The RELAP5 Closed Flow Model and Application to a Large Scale Flow Test", Proceedings of the ANS/ASME/NRC International Topical Meeting on Nuclear Reactor Thermal-Hydraulics, Saratoga Springs, New York, October 5-8, 1980 pp. 799-819) is included in RELAP5 for calculation of the mass discharge from this system at a pipe break. The code has been verified to yield conservative blowdown against experimental results.

HISTORICAL INFORMATION

Question 222.7

Describe any difference between the steam line break analysis methods and resulted reports in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases," with those reported in the South Texas Project Electric Generating Station Units l & 2 FSAR.

Response

The single safety injection train failure has been verified to be the limiting single failure for the South Texas Project Electric Generating Station's steam line break as concluded in WCAP-9226. The trends of the sensitivity studies presented in WCAP-9226 are expected to apply to the STPEGS, considering the differences in Safety Injection Systems, with identification of the full double-ended rupture from hot shutdown with offsite power available as the limiting case. The WCAP-9226 sensitivity studies of non-zero power levels are directly applicable.

Question 222.8

Describe any difference between the feedline break analysis methods and results reported in WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture," with those reported in the present FSAR.

Response

The only differences between the methods of analysis and results reported in WCAP-9230 and those utilized in the STPEGS UFSAR are as follows:

1. Credit was taken for charging pumps (shutoff head approximately 2700 psia) in the results of the feedline rupture in WCAP-9230. Since the high head safety injection (HHSI) pumps on STPEGS have a shutoff head of approximately 1600 psia, no credit is taken for safety injection flow in the feedline rupture analysis.

2. The sensitivity study presented in WCAP-9230 showed that the transient behavior following a feedline rupture was more severe if the pressurizer power-operated relief valves (PORVs) were not assumed to be operable. However, since STPEGS does not have high head charging pumps (shutoff head approximately 2700 psia), a sensitivity study was conducted for the STPEGS UFSAR that showed that the results of the feedline rupture were more severe with PORVs operable.

   Thus, the STPEGS UFSAR feedline rupture was presented with the PORVs in automatic control.

3. All other sensitivity results presented in WCAP-9230 were found to be applicable to the STPEGS UFSAR feedline rupture analysis.

Question 222.9

Describe in detail the method used to analyze the consequences of the steam generator tube rupture accident including the following information:

1. Details of the code used to calculate the primary and secondary pressures. Include the nodalization diagram and major assumptions used in the calculations.

2. Describe the details of how primary to secondary tube leakage is calculated.

3. Range of failed tubes that can be considered in this calculation.

Response

The assumptions and analysis process leading to the conservative-valued mass transfer results (UFSAR Section 15.6) of a steam generator tube rupture included utilizing the LOFTRAN computer code (WCAP-7907 and UFSAR Section 15.0.10.2). Assumptions related to the approach are discussed in UFSAR Section 15.6.3. The LOFTRAN-related assumptions are discussed in the WCAP and in the UFSAR section cited above.

Mass release results were calculated using the orifice equation, full power steady-state operating primary and secondary pressures and a conservative treatment of the tube area; i.e., a complete severance of the steam generator tube. The LOFTRAN noding scheme used in the pressure transient calculation is provided below:

Item	Number of Nodes
Reactor Vessel Outlet	1
Reactor Core	3
Reactor Vessel Inlet	1
Hot Leg	1
Cold Leg	1
Steam Generator Inlet	1
Steam Generator Tubes	16
Steam Generator Outlet	1
Dead End Volume (eq Upper Head)	1

Question 480.1N (Deleted)

Question 480.10N (Deleted)

Question 480.14N

The FSAR states in Section 6.2.2.2.1 that the RCFC performance is not affected by flooding following a LOCA, as the discharge points of supply duct are located above the flood level. However, as shown in FSAR Figure 6.2.2-5, portions of the supply duct from the RCFCs lie below the containment flood level. Justify that water would not accumulate in the supply duct as a result of a LOCA or MSLB and thereby cause an unacceptable increase in the discharge head of the RCFCs and consequent decrease in RCFC flow. Also verify that the supply duct is leak-tight and able to withstand the maximum postulated differential pressure resulting from submergence following the design basis LOCA or main steam line break.

Response

Each RCFC discharges downward, penetrates the secondary shield wall and turns upward into the steam generator compartments. The connecting branch supply duct serves the annular spaces for normal cooling and represents 8.0 percent of the total RCFC fan capacity. This 16-inch-diameter branch is furnished with a 90□ elbow which turns upward inside the main trunk duct and terminates 2.0 ft above the flood level. Although the branch duct could be flooded to a 6-in. depth, the trunk duct is precluded from flooding due to the internal elbow. Although branch flow would be reduced due to a partially flooded condition, adequate flow for containment atmosphere mixing is maintained since less than 50 percent of the duct cross-sectional area is blocked.

The main trunk duct terminates above the flood level within the secondary shield wall. A portion of the concrete floor slab and secondary shield wall comprise the fourth side of the main trunk duct as it penetrates the secondary shield wall below the flood level. At the ductwork/concrete interface, a grouted concrete curb has been provided to inhibit the inleakage of water. The boundaries of the main trunk duct have been analytically checked to assure that the submerged ductwork is able to withstand the differential pressure resulting from the submergence.

Question 480.15N (Deleted)

Question 480.19N

Valves FV9647, FV9696, are listed as containment isolation valves for the normal containment purge subsystem in Table 3.6-1 of FSAR Chapter 16 but are not listed in Figure 6.2.4-1 and are not shown on Figure 9.4.5-2. Provide a piping and instrumentation diagram showing the location of these valves relative to the normal containment purge subsystem penetrations (M-41 and

M-42) and the previously identified containment isolation barriers associated with these penetrations. Also, provide the design information prescribed by Section 6.2.4.2 of Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," for these valves.

Response

Chapter 16 was deleted in its entirety by Amendment 27. The current project Technical Specifications were submitted in January 1986.

The normal purge isolation valves are identified by tag numbers HC0007, HC0008, HC0009, and HC0010. These valves can be found on Figures 6.2.4-1 (sheets 43 and 44) and 9.4.5-2.

Question 480.28N

To provide additional assurance that long term cooling of the reactor core can be achieved and maintained following a postulated LOCA:

A. Establish a procedure to perform an inspection of the containment, and the containment sump area in particular, to identify any materials which have the potential for becoming debris capable of blocking the containment sump when required for recirculation of coolant water. Typically, these materials consist of: plastic bags, step-off pads, health physics instrumentation, welding equipment, scaffolding, metal chips and screws, portable inspection lights, unsecured wood, construction materials and tools as well as other miscellaneous loose equipment. Containment cleanliness should be periodically assured; at a minimum this inspection should be performed at the end of each refueling outage.

B. Describe any changes deemed necessary to reduce vertical flow in the neighborhood of the sump. Ideally, flow should approach uniformly from all directions. Pipe breaks, drain flow and channeling of spray flow released below or impinging on the containment water surface in the area of the sump can cause a variety of problems; for example, air entrainment cavitation and vortex formation.

C. Compare the size of opening in the fine screens with the minimum dimensions in the pumps which take suction from the sump, the minimum dimension in any spray nozzle and the fuel assemblies in the reactor core or any other line in the recirculation flow patch whose size is comparable to or smaller than the sump screen mesh size, in order to show that no flow blockage will occur at any point past the screen. Estimate what effect debris particles, capable of passing through the fine screen, would have on the operability and performance of all pumps used for recirculation cooling. Address effects on pump seals and bearings.

Response

A. Procedures were established to implement the requirements of Technical Specification 4.5.2 which address these concerns.

B. As identified in the response to Q480.25N, an analysis to evaluate the overall containment emergency sump performance was performed and determined that vortex formation is a potential. Following the guidelines in proposed Rev. 1 to RG 1.82, the containment sumps did not meet all of the criteria for zero air ingestion thus avoiding pump cavitation. Additionally, the sumps did not meet all the criteria for a less than 2 percent air ingestion, thus avoiding degradation of pumping capability. Accordingly, a vortex breaker per the guidelines in RG 1.82 has been included in the design of the sumps to reduce air ingestion and vertical flow.

Response (Continued)

Following this modification, the sump design is adequate to ensure uniform flow thus avoiding the subject problems. In the vicinity of the emergency sumps there are no high energy piping, drains or spray flow paths which would adversely impact the effectiveness of the sumps.

C. The containment spray, high-head and low-head pumps all take suction from the containment sump. The RHR pump is used for recirculation cooling following a small break LOCA.

RHR Pumps

The RHR pumps were specified for satisfactory operation following a LOCA with water in the containment sump containing solid particles of concrete, insulation and paint flakes which could pass through the strainer screens and into the suction of the RHR pump (via the safety injection system). Particular attention was given to the design of these pumps to handle this debris.

Containment Spray Nozzles

The containment spray nozzles will not be subject to clogging following a design basis large LOCA. The containment spray nozzles are SPRACO type 1713A. These nozzles have a swirl chamber design (referred to as ramp bottom by SPRACO) and thus have no internal parts, such as swirl vanes which would be subject to clogging. In addition, the nozzle discharge orifice diameter is 3/8 in. which is sufficiently large to preclude clogging by any particles which would pass through the nominal 0.095 inch diameter openings of the strainer screens.

High-Head Safety Injection, Low-Head Safety Injection, and Containment Spray Pumps

These pumps were specified for a satisfactory operation following a LOCA with water in the containment sump containing particles of concrete, insulation, and paint flakes which could pass through the strainer screens into the suction of the high-head, low-head and containment spray pumps. Particular attention was given to the design of these pumps to handle this debris.

Long-Term Core Cooling

For certain hypothetical LOCAs, the ECCS will be aligned to draw suction from the containment sump following depletion of the RWST. Upon this alignment, it is possible to ingest debris carried into the sump by primary coolant that has flowed through the break. The strainer screens in the sump limit the size of this debris to a dimension of no more than 0.095 inch (nominal). This debris could then pass through a recirculating pump and into the RCS.

Initially, the ECCS is aligned to deliver flow to the RCS cold legs. The recirculating flow proceeds downward into reactor vessel lower plenum, turns, and flows upward into the reactor core. It is expected that the low recirculating flow rate and large flow area in

Response (Continued)

the lower plenum region will result in small local fluid velocities. These local fluid velocities are sufficiently small such that larger debris will settle out of solution in the reactor vessel lower plenum. Smaller debris is expected to be carried upward by the recirculating flow into the core. Thus, the formation of flow blockages in the core by debris following a hypothetical LOCA is not a concern for long-term core cooling.

Section 6.3

Question 211.5

The single active failure mode and effects analysis (FMEA) presented for the RHR (Table 5.4-17) and ECC (Table 6.3-5) systems are incomplete. The FMEA should include or justification be provided for exclusion of the following:

1. FMEA for the electrical actuation and instrumentation systems employed for each subsystem

2. FMEA for the electrical power supplies

3. exclusion of check valves for analysis

4. spurious movement of a powered component

5. operator error

6. leakage resulting from passive failures during the long term after a LOCA

Response

ECCS system reliability, including compliance with the single failure criterion, is fully discussed in Section 6.3.2.5. RHRS system reliability is fully discussed in Section 5.4.7.2.6. The applicant does not believe additional FMEAs are required for the reasons discussed below:

1. The ECCS is described with independent and fully redundant subsystems. The Engineered Safety Features Actuation System is designed to be compatible with the ECCS and also consists of independent and redundant subsystems. Therefore, no single failure in the Engineered Safety Features Actuation System can effect more than one subsystem of the ECCS. The Engineered Safety Features Actuation System is discussed in Section 7.3.

2. The ECCS is designed with independent and fully redundant subsystems. The onsite emergency power system is designed to be compatible with the ECCS and also consists of independent and redundant subsystems. Therefore, no single failure in the onsite emergency power system can effect more than one subsystem of the ECCS. The RHRS is also designed with separate and independent subsystems. The electrical power supplies to components in the RHRS are consistent with this concept except for the power supplies to the RHR suction isolation valves. This results in the possibility that the failure of one power supply can effect two of the three RHR trains, leaving the third train available to perform the RHR function. For a more complete discussion of this arrangement, see Section 5.4.7.2.6. The onsite emergency power system is discussed in Section 8.3.

Response (Continued)

3. Because of the simple nature of their design and the fact that they are self-actuated, Westinghouse does not consider "active" failure of check valves to be credible events. This conclusion is supported by the following information:

   A. The Ralph M. Parsons Co., under contract to Westinghouse, conducted a study to determine generic failure rates of ECCS components applicable to PWR nuclear power plants. Non-nuclear data for check valves were:

      1) For 270 check valves exposed to 240,430 cycles (3.5 cycles per day), no failures to open or close were reported.

      2) For 648 check valves operating for a total of 12.5 million hours, there were:

         - Five cases of leakage
         - Four cases of internal failure, chaffed or binding with valve in open position
         - Zero cases of valves sticking closed

   B. The NPRDS (Nuclear Plant Reliability Data System) at the end of 18.1 million hours indicates:

      - Twenty-one cases of reverse leakage
      - Four cases of external leakage
      - Two cases of valves sticking

      The information regarding the two sticking cases is not explicit as to whether the valve is sticking open or closed. However, from the brief information provided, it appears that the two cases are actually two reports for the same event--once on initial discovery and again when the valve was replaced after a short period of operation. Also, based on the system in which the valve was located (feedwater pump lube oil pump discharge check valve) and on the fact that operation continued until a replacement check valve had been delivered, it seems likely that the valve was stuck open rather than closed.

   The data from A.1 indicates zero failures to open in 240,000 cycles or less than 4×10^{-6} per demand. Combining the data from A.2 and B indicates zero to two failures to open in 30 million operating hours or about 6.7×10^{-8} failures per hour. Assuming yearly testing, this hourly rate corresponds to an unavailability of 3×10^{-4} per demand. Correspondingly, lower unavailabilities result from more frequent testing. "Component Failure Rate Data for the Emergency Core Cooling

Response (Continued)

Systems of the Rochester Gas and Electric and Indian Point Plant No. 2 Nuclear Power Plants," Ralph M. Parsons Co. report to Westinghouse, June, 1969. (Westinghouse Proprietary).

4. As stated in Section 6.3.2.2, "Motor-Operated Valves and Controls": "Inadvertant mispositioning of a MOV due to a malfunction in the control circuitry in conjunction with an accident has been analyzed and found not to be a credible event for use in design".

5. Other than to eliminate the operator and fully automate the plant (which is undesirable), it is not possible to design against "operator error". Simple operator errors such as failure to open a valve or start a pump are addressed in the same manner as a single failure of the valve or the pump. However, more complex operator errors, such as failure to follow the emergency procedures, cannot be addressed. System design depends on well-trained operators following correct procedures. As such, "operator error" is more properly addressed by ensuring adequate training programs and well-written and correct Procedures.

6. Because the ECCS is designed with separate and independent subsystems, Passive failure in one subsystem is acceptable since it can be isolated and removed from service without affecting the remaining subsystems. Passive failure is discussed more fully in Section 6.3.2.5.

Question 211.19

Operator error or spurious movement of valves XS1008A, XS1008B, or XS1008C would apparently result in hot leg injection following safety injection initiation. Provide means to assure that these valves will remain closed during the injection phase of ECCS operation. Administrative controls and alarms alone will not be sufficient for this purpose.

Response

Valves XS1008A, XSI008B, and XSI008C will have power lockout to the valves to prevent spurious actuation.

Question 211.20

Identify any lengths of ECCS and RCS piping which have normally closed valves, that do not have pressure relief in the piping section between the valves.

Response

The following piping sections are between normally closed valves with no pressure relief provided:

Reactor Coolant System

a) 2-in. loop drain connections

RC-1121-BBl	19 in. long
RC-1220-BBI	9 in.
RC-1321-BBl	12 in.
RC-1418-BBI	15 in.

b) 1-in. Nitrogen to pressurizer relief tank

RC-1032-UB2	22 ft long

Safety Injection System

a) 3/4-in. accumulator test lines

SI-1112-BD7	140 ft long
SI- 1212-BD7	123 ft
SI-1309-BD7	166 ft

b) 3/4-in. penetration for the test above

SI-1321-BB2	14 ft long

c) 3-in. line in piping from RWST to refueling water purification pump

SI-1117-UB2	13 in. long

d) 12-in. PHR pump suction lines

RH-1101-BBl	82 ft long
RH-1202-BB1	95 ft
RH-1301-BBl	39 ft

In all cases, the identified piping sections have design pressure/temperature conditions compatible with the process piping to which they connect. Thus, valve leakage will not function to overpressurize the identified piping sections and pressure relief provisions to accommodate valve leakage are not required.

Question 211.23

Provide a discussion of procedures and administrative controls for manually resetting SIS following a LOCA. Specifically address the minimum time after actuation that the SI signal can be reset, and procedures to be followed by a loss of offsite power.

Response

Although specific plant procedures have not been written as of this date, it is anticipated that the Westinghouse Reference Operating Instructions will be used as guidelines in the preparation of the Emergency Operation Procedures.

When the cause of safety injection has been identified and the unit has been stabilized, the Unit Supervisor will evaluate specific plant parameters which must be satisfied prior to resetting safety injection. The plant parameters and values to be included in the Emergency Operating Procedure on safety injection have not yet been specified. These parameters may include, but are not limited to a minimum time interval after initiation, reactor coolant system pressure, pressurizer level, reactor coolant temperature (sub-cooling) and steam generator water level. The minimum time at which the plant operator may reset the safety injection signal is dependent on the timer interlock which can be set from 30 seconds to 2 minutes.

Following a loss of offsite power the plant operators will perform the immediate actions and refer to the Emergency Operation Procedure on station blackout for subsequent steps. During this time the plant operators will stabilize the unit using safeguards powered equipment and maintain the unit in safe condition.

Question 211.25

For some plant designs, an early manual reset of the safety injection signal followed by a loss of offsite power during the injection phase requires operator action in order to reposition ECCS valves and to restart some pumps. Discuss whether the reset of all or a portion of the ECCS during the injection phase would necessitate operator action to restart equipment.

Response

The consequence of a loss of offsite power occurring subsequently to a system level safety injection (SI) reset may be that certain safety injection pumps would not be automatically restarted after start-up of the diesel generator even though the pumps needed for shutdown under blackout conditions would be automatically restarted. The design provides for a block of manual systems level SI reset until a 2-minute timer times out and the reactor is tripped because the design basis is that a blackout is postulated as occurring at the same time as the start of the accident. The procedure for emergency operations would address the transfer of the cold leg recirculation following a loss of reactor coolant and the resetting of SI to restart pumps that would not automatically restart in the event of a subsequent blackout. Generic evaluation of such a postulated sequence of events has shown that consequences are acceptable by thus taking credit for procedures and appropriate operator action.

Question 211.27

The single active failure analysis for ECCS components is provided in Table 6.3-5. Modify the table to include the following additional failures:

(1) Spurious movement of a powered component.

(2) Operator error.

(3) Leakage resulting from passive failures and

(4) Failure of components connected to the ECCS, but not necessarily a part of the ECCS, such as air-operated valve.

Include or reference the information identified or provide the rationale for its exclusion.

Response

The FMEA postulates failure of various mechanical components; e.g., valves failing in the wrong position. The cause of the component failure is not germane to the FMEA. A spurious movement, an operator error, failure of some ancillary device could all potentially cause a component failure. For the purposes of a FMEA, it matters only that the component be postulated to fail.

Question 211.30

Because of freezing weather conditions, blocking of the vent line on the RWST has occurred on at least one operating plant. Describe design basis and features that preclude this condition from occurring.

Response

The RWST is located in the MAB where the minimum ambient temperature (37˚F) is above freezing.

Question 211.31

Recent plant experience has identified a potential problem regarding the long-term reliability of some pumps used for long-term core cooling following a LOCA. For all pumps that are required to operate to provide long-term core cooling, provide justification that the pumps are capable of operating for the required period of time. This justification could be based on previous testing or on previous operational experience of identical pumps. Differences between expected post LOCA conditions and the conditions during previous testing or operational experience cited should be justified (e.g., water temperature, debris, water chemistry).

Response

The pumps used for long term core cooling are the high-head safety injection (HHSI) pumps and the low-head safety injection (LHSI) pumps. In the STPEGS Safety Injection System there are three motor-driven vertical HHSI pumps and three motor-driven vertical LHSI pumps. In order to determine the ability of the pump to sustain a transient and remain operable following a postulated LOCA, a series of tests were performed on the pumps.

For the thermal transient, critical part dimensions were measured and recorded. The pump was operated at design speed and data was recorded at minimum flow, design flow, and runout flow. The pump was then subjected to a thermal transient at runout flow and injected with particulate matter. After the pump was stabilized, data was recorded at minimum design and runout flow. The measurements taken during the test included vibration, hydraulic performance, water temperature, electric power, and seal leakage. Upon completion of the test, the pump was dismantled and critical part dimensions were again recorded. Post transient performance was within 2 percent of pre-test data and no unusual or excessive wear occurred.

The pump was also subject to an endurance test to determine that it would operate within required performance characteristics. Four critical parts dimensions were measured and recorded before the test. The pump was then operated for 100 hours at design speed with data being recorded at minimum, design, and runout flow distributed equally throughout the operating time. A minimum of four start-stop cycles were scheduled during the run. Upon completion of the test, the pump was dismantled and critical dimensions were again recorded. The pump experienced no performance degradation and no unusual or excessive wear.

The testing described above along with the analyses and testing performed on these pumps as part of the Westinghouse operability program (see UFSAR Section 3.9.3.2) demonstrates the ability of the high and low head safety injection pumps to perform their intended functions.

Question 211.32

Certain automatic safety injection signals are blocked to preclude unwanted actuation of these systems during normal shutdown and startup operations. Describe the alarms available to alert the operator to a failure in the primary or secondary system during this phase of operation and the time frame available to mitigate the consequences of such an accident. Justify the time frame available.

Response

During the shutdown the following operator actions pertain to the isolation of Emergency Core Cooling System (ECCS) equipment and would effect a Loss-of-Coolant Accident (LOCA). (Startup is not addressed since shutdown is more limiting due to the high core decay heat generation.)

i. Below the P-11 setpoint, the operator is instructed to manually block the automatic safety injection (SI) actuation circuit. This action disarms the SI signals from the pressurizer pressure transmitters and the low compensated steam line pressure transmitters. The containment high pressure signal remains armed and will actuate SI if the setpoint is exceeded. Manual SI actuation is also available. The circuit will automatically unblock if the Reactor Coolant System (RCS) pressure should increase above the P-11 setpoint.

ii. At l000 psig or below, the operator closes and locks out the SI accumulator discharge isolation valves.

iii. At approximately 350 psig and 350°F, the operator aligns the Residual Heat Removal System (RHRS) for cooldown.

The significance of these actions on the mitigation of a LOCA are:

(i) Below the P-11 setpoint SI will be initiated by the HI-1 containment pressure signal. For small LOCAs (<2-in. diameter break) manual SI initiation may be required. The results for this event are analyzed in the safety significance portion of this question.

(ii) Between 1000 psig and 350 psig, a portion of the ECCS may be actuated automatically on containment high pressure signal or manually by the operator. The equipment that can be energized are the low-head and high-head SI pumps. Three trains of SI are required to be operational in Modes 1, 2, and 3. In Mode 4 one train of SI plus one additional LHSI pump are required to be operational. The other HHSI pumps are locked out per Technical Specification requirements. However, at least one of the locked out HHSI pumps can be restored to operable status within 30 minutes. The operator would reinstitute power in the main control room to the accumulator isolation valves.

(iii) Below 350 psig, the system is in the RHRS cooling mode. The operator would manually initiate SI and isolate the RHR system from the RCS.

Subsequently the operator would restore power in the main control room to the accumulator isolation valves.

Response (Continued)

Safety Significance During Shutdown

Comparing plant cooldown and heatup, the limiting case for a LOCA would be during a plant cooldown rather than a plant heat-up because the core decay heat generation would be higher. The ECCS analysis presented in Chapter 15 conforms to the Acceptance Criteria of l0CFR50.46 so that initiation of the LOCA is at 102 percent of full licensed power rating and corresponding RCS conditions. Some of the reasons why the analysis presented in Chapter 15 would be more limiting than LOCA during shutdown are:

(1) A LOCA initiated during shutdown would have reduced decay heat generation since the reactor, in general, would have been at zero power for an extended period of time,

(2) The core stored energy during shutdown would be reduced due to the RCS uniform temperature condition at a reduced temperature, and;

(3) The energy content of the RCS would be lower.

Furthermore, the probability of the occurrence of a LOCA during this period along with the critical flaw size needed to rupture the RCS piping at reduced pressure clearly indicates that a LOCA is considered to be incredible. These arguments are provided in the following sections.

i. Between 1000 psig and 350 psig: For the purpose of calculating the probability of a LOCA, a conservative time of seven hours is assumed to cool the plant from 500°F to 350°F. The annual probabilities of small and large LOCAs were estimated at 10^{-3} and 10^{-4} per year in WASH-1400.* Assuming this same failure rate holds at reduced pressure (this assumption is not realistic since normal operation serves as a proof test for lower pressure operating modes as discussed later), the probability of a LOCA during heatup/cooldown periods (assuming two heatup/cooldown cycles per year) would be:

Small LOCA	3.2×10^{-6}/yr.
Large LOCA	3.2×10^{-7}/yr.

These can be compared to the total meltdown probabilities for small LOCA and large LOCA initiating event analyzed in WASH-l400:

Small LOCA	2×10^{-5}/yr.
Large LOCA	3×10^{-6}/yr.

Therefore, even if there were no pipe rupture protection for these heatup/cooldown periods, it is concluded that such events add only a small increase to the meltdown risk due to the short time periods involved.

* WASH-1400, "Reactor Safety Study", U. S. NRC, October, 1975.

Response (Continued)

ii. Rupture of RCS piping at reduced pressure: Below 1000 psig, RCS piping rupture is considered incredible since normal operation serves as a proof test against rupture. Calculations of critical flaw size for the reactor coolant piping show that at 1000 psi internal pressure:

1 Rupture cannot occur for a part through-wall flaw regardless of orientation.

2 For a circumferential through-wall flaw, a catastrophic rupture is not possible.

3 For a through-wall longitudinal flaw, the critical flaw size is in excess of 70 inches.

Therefore, postulated RCS piping flaws of critical size for internal pressure below l000 psig cannot exist since they would have previously failed at the normal operating pressure (2235 psig).

iii. Below 350 psig: After several hours into the cooldown procedure (a minimum time is approximately 4 hours) when the RCS pressure and temperature have decreased to 350 psig and 350°F, the RHRS is placed in operation. This system has a 600 psig design pressure and rupture of this system is also considered highly unlikely. However, the proof test argument given above for RCS piping does not apply to the piping in this system.

The provisions to isolate these lines and the ECCS capability for core cooling should a leak or rupture develop during this mode of operation are as follows. Any leakage of the RHRS piping would be expected to occur when the system is initially pressurized at 350 psig. The RCS is at this time under manual control by the reactor operator. The reactor operator is monitoring the pressurizer level and the RCS loop pressure so that any significant leakage from the RHRS would be immediately detected. When leakage is detected, then the operator would isolate the RHRS and identify the location and cause. Since the decay heat generation 4 hours after shutdown is about 1.2 percent of full power, the RCS fluid temperature is at about 350°F and the core stored energy is essentially removed, the operator would have ample time to isolate the RHRS loop.

Therefore, in spite of the low probability of occurrence and the fact that certain failure modes for pipe rupture do not exist during cooldown at the RCS pressure of 1000 psig, the plant operation procedures are as follows:

1. At 1000 psig, the operator will maintain pressure and proceed to cool down the RCS to 425°F.

2. At 1000 psig and 425°F, the operator will close and lock out the accumulator isolation valves.

Response (Continued)

The above plant operating procedures will ensure that the accumulator isolation valves will not be locked out prior to about 3-1/2 hours after reactor shutdown for a cooldown rate of 50°F/hr.

A conservative analysis has determined that the peak clad temperature resulting from a large break LOCA would be significantly less than the 2200°F Acceptance Criteria limit using the ECCS equipment available 3-1/2 hours after reactor shutdown.

The following assumptions were used in the large break analysis:

1. The RCS fluid is isothermal at a temperature of 425°F and a pressure of 1000 psig.

2. The core and metal sensible heat above 425°F has been removed.

3. The hot spot occurs at the core midplane.

4. The peak fuel heat generation during full power operation of 13.257 kW/ft will be used to calculate adiabatic heatup.

5. At 3 hours, using decay heat in conformance with Appendix K of 10CFR50, the peak heat generation rate is 0.1667 kW/ft.

6. The SI pumps are available for automatic actuation by the containment HI-1 signal. The SI flows used in the analysis correspond to one train of SI delivering flow to the core.

7. SI flow starts at the end of blowdown.

8. No liquid water is present in the reactor vessel at the end of blowdown.

9. A large cold leg break is considered.

For a postulated LOCA at the cooldown condition of 1000 psig, previous calculations show that the clad does not heat up above its initial temperature during blowdown. Proceeding from the end of blowdown and assuming adiabatic heatup of the fuel and clad at the hot spot, an increase of 418.7°F was calculated during the lower plenum refill transient of 87.2 seconds. During reflood, the core and downcomer water levels rise together until steam generation in the core becomes sufficient to inhibit the reflooding rate. At that time, heat transfer from the clad at the hot spot to the steam boiloff and entrained water will commence. This heat removal process will continue as the water level in the core rises while the downcomer is being filled with SI water. The reflood transient was evaluated by considering two bounding cases:

1. Downcomer and core levels rise at the same rate. No cooling due to steam boiloff is considered at the hot spot. Quenching of the hot spot occurs when the core water level reaches the core midplane.

Response (Continued)

2. Core reflooding is delayed until the SI pumps have completely filled the downcomer. No cooling due to steam boiloff is considered at the hot spot until the downcomer is filled. The full downcomer situation may then be compared with the results of the ECCS analysis for South Texas to obtain a bounding clad temperature rise thereafter.

For Case 1 described above, the water level reaches the core midplane 84.28 seconds after the bottom of the core recovery. The temperature rise during reflood at the hot spot from adiabatic heatup is 404.5°F, which results in a peak clad temperature of approximately 1248.3°F.

For Case 2, the delay due to downcomer filling is 69.4 sec. The corresponding temperature rise at the hot spot from adiabatic heatup is 333.25°F, which gives a hot spot clad temperature of 1177°F.

The above analysis is not affected by the changes in Chapter 15 large break LOCA analysis which uses the BART code. The above analysis is conservative for both the previous and current BART methodology. The Case 2 calculated Peak Clad Temperature (PCT) at the time the downcomer is full is bounded by Chapter 15 analysis results using BART.

The clad temperatures at the time when the downcomer has filled for the DECLG, $C_D = 0.6$ submitted to satisfy 10CFR50.46 requirements are 1494°F and 1444°F at the 7.0 and 8.0 foot (peak node) elevations, respectively.

Core reflooding in the shutdown case under consideration will be more rapid from this point on due to less steam generation at the lower core power level in effect; decay heat input at any given elevation is less in the shutdown case. The combination of more rapid reflooding and lower power in the fuel ensures that the clad temperature rise during reflood will be less for the shutdown case than for the design basis case.

The standard l4 foot core reference plant (RESAR 4l4) was used to demonstrate the safety of this plant design under shutdown conditions for small LOCAs. Note that the SI flows for South Texas would be much higher than the flow used in the RESAR 414 analyses because the HHSI pumps are not locked out at 1000 psig. The analysis results discussed below are therefore conservative for South Texas.

For the small break LOCA the following assumptions were used in the RESAR 414 analysis:

1. Initially the RCS fluid is at a temperature of 400°F and a pressure of 1000 psig.

2. The infinite decay heat standard was used in conformance with Appendix K of 10CFR50.

3. The HHSI pumps and the acumulators are locked out when the break occurs. However, operator action can be taken to unlock one of the HHSI pumps. (This is a conservative asumption for South Texas because three trains of HHSI and LHSI pumps are required operable in Mode 3.)

Response (Continued)

4. One LHSI pump is available (a second pump is assumed to fail) from either manual SI actuation or automatic actuation by the containment HI-1 signal.

For breaks of 6 and 8 in. the calculations show that one low head SI pump turned on manually by the operator 10 minutes following the break gives sufficient flow to prevent the top of the core from being uncovered. For the 8-in. break SI flow was initiated at 10 minutes plus 25 seconds (delay time between operator manually actuating safety injection and the beginning of flow). For the 6-in. break, although the SI signal was generated by the operator at 10 minutes, SI flow did not start until approximately 18 minutes following the break when the RCS pressure dropped below the LHSI pump shutoff head of 700 ft.

The RCS pressure transient for a 4-in. break is so slow that the operator, in addition to manually activating the LHSI pump at 10 minutes, is conservatively assumed to unlock one of the HHSI pumps at 30 minutes following the break. With one LHSI pump and one HHSI pump available at these times, the core remains covered.

Another facet which must be considered is the availability of alarms which would alert the operator to manually initiate SI for very small LOCAs (1-2 inch diameter) that do not pressurize the containment to containment HI-1 set pressure (5.5 psig) (which would automatically initiate safety injection).

The Class 1E indication available to the operator includes the narrow range water level sensors. In addition, the alarms available would include the Reactor Coolant Pressure Boundary (RCPB) leak detection system alarms. Break flow from a 1-in. break is on the order of 500 gal/min and a 2-in. break would have a flow of approximately 2000 gal/min. Thus, these breaks would be expected to set off the RCPB leak detection alarms much sooner than an hour after the break occurs. Based on the Inadequate Core Cooling Study (WCAP-9753) for full operation, a 1-in. break would exhibit an extremely long transient prior to core uncovery from the initiation of break flow (approximately 2.5 hrs for a 4-loop plant). Other small break analyses with SI for similar 4-loop plants were reviewed and similar results were found. An even longer transient would be expected for a small break during shutdown. Thus, the operator would have ample time to diagnose the situation, initiate SI and prevent core uncovery. For a 2-in. break, the RCPB leak detection alarms would sound within 30 minutes of initiation of the break. From McGuire low power test analyses (5 percent power), for a 2-in. break no core uncovery occurs prior to 1.67 hours. Thus, the operator again has ample time to initiate safety injection manually.

When RCS pressure is below the P-11 setpoint and SI is blocked on low pressurizer pressure and low compensated steam line pressure, a steam line rupture would be less severe from a core integrity standpoint than the steamline ruptures at hot zero power presented in Chapter 15. Technical Specification require shutdown margins such that the return-to-power transient would be less severe than the cases presented in Chapter 15.

Response (Continued)

The engineered safeguards functions desired during a steam line rupture are actuation of SI and steamline isolation. When the low pressurizer pressure signals and the low compensated steamline pressure signals are blocked, SI and steamline isolation may be automatically initiated by the following signals:

1. HI-1 Negative Steamline Pressure Rate Signal

This signal is unblocked automatically when the low compensated steam line pressure signals are blocked.

(Actuates steamline isolation.)

2. Containment Pressure Signal

(Actuates SI [HI-1] & steam line isolation [HI-2].)

SI and steam line isolation may also be actuated manually by the operator. During a steam line break, steam line pressure, pressurizer pressure, pressurizer level, and steam generator water level will tend to decrease and steam flow will increase. These parameters are all displayed in the control room. The operator's attention may be drawn to them by the following alarms;

a. Low pressurizer level deviation alarm

b. Low pressurizer level alarm

c. Steam flow/feedwater flow mismatch alarm

d. Low steam generator level deviation alarm

e. Low steam generator level alarm

Question 211.33

The containments sumps do not conform to the closed system criteria. Justify the use of only one containment isolation valve on a system that is in contact with the containment atmosphere and is subjected to the loss-of-coolant accident environment or modify your design to conform with GDC 56.

Response

Westinghouse Containment isolation philosophy for fluid systems complies with the guidance provided by ANSI N271-1976 and/or Regulatory Guide 1.141 with the following exceptions.

Section 3.6.4 of the ANSI standard states that a single isolation valve and closed system outside Containment is an acceptable isolation arrangement if the closed system is treated as an extension of the Containment. Further, the standard requires that the valve and the piping between the valve and the Containment be enclosed in a protective leak tight or controlled leakage compartment. The closed system is also required to be leak tested (in accordance with lOCFR50 Appendix J) unless it can be shown by inspection that system integrity is being maintained for those systems operating during normal plant operation at a pressure equal to or above the Containment design pressure.

Westinghouse employs this design arrangement on the ECCS sump isolation valves and is in basic agreement with the provisions of the standard. However, Westinghouse perceives no basis for the requirement to leak test the closed system. The recirculation system (closed system), regardless of the sump isolation configuration will be circulating radioactive fluid during LOCA conditions. Should a leak develop in a recirculation loop, that loop can be isolated by remote closure of the sump isolation valve to prevent further loss of sump water. Should a leak develop in the isolation valve body or piping between the sump and the valve, then the sump fluid will be contained by the leaktight compartment and guardpipe arrangement (Westinghouse design does have provisions for compartment/guardpipe leak testing). With these provisions no single active or passive failure will prevent the recirculation of core cooling water or adversely affect the integrity of the Containment.

It should be noted that the staff provides in Standard Review Plan 6.2.4 Section II.6.d and e for deletion of sump valve encapsulation as a Containment isolation barrier if certain additional criteria are satisfied. These include conservative piping design, conformance with Standard Review Plan 3.6.2, leakage detection, and isolation provisions.

Question 211.35

Provide justification for the statement in Section 6.3.1, that spurious movement of a motor operated valve coincident with a LOCA has been found not to be credible.

Response

Spurious movement of motor-operated valves in the emergency core cooling system coincident with a LOCA was analyzed and reported in WCAP-8966 (Proprietary) and WCAP-9207 (Nonproprietary) entitled "Evaluation of Mispositioned ECCS Valves". These documents were used as the basis of the statement.

References

Hill, R. A., et al, "Evaluation of Mispositioned ECCS Valves", WCAP-8966 (Proprietary), WCAP-9207 (Nonproprietary), September 1977.

Question 211.37

Provide a discussion of NPSH requirements for the safety injection pumps. Include in this discussion NPSH as required by pump warranty, estimated variability between pumps, and testing inaccuracies. Also provide the assumptions and calculations used to establish available NPSH.

Response

Discussion of the NPSH requirements is given in Section 6.3.2.2, with the values of both required and available NPSH stated in Table 6.3-1.

Emergency Core Cooling System (ECCS) pump specifications include a specified maximum required NPSH which the pump is required to meet. Pump vendors have verified that the required NPSH for the STPEGS pumps was less than the maximum required NPSH through testing in accordance with the criteria established by the Hydraulic Institute Standards. Further, from the pump head/flow and NPSH required characteristic curves that are derived from the testing, Westinghouse subsequently confirmed that adequate NPSH is available based on the actual system piping layouts, and conservatively calculated maximum pump runout that will be verified by preoperational testing.

The ECCS is designed so that adequate net positive suction head is provided to system pumps. In addition to considering the static head and suction line pressure drop, the calculation of available net positive suction head in the recirculation mode assumes that the vapor pressure of the liquid in the sump is equal to the Containment ambient pressure. This assures that the actual available net positive suction head is greater than the calculated net positive suction head.

The calculation of available net positive suction head is as follows:

$$(\text{Net positive suction head})_{\text{actual}} = (h)_{\text{ambient pressure}} - (h)_{\text{vapor pressure}} + (h)_{\text{static head}} - (h)_{\text{loss}}$$

Conservatism is introduced into the net positive suction head calculation for the recirculation mode by calculating the static head from the elevation of the bottom of the sump instead of the available water level in the sump. Other conservative assumptions which have been included to minimize the NPSH available are (1) no credit is taken for water above the sump lowest level, (2) no credit is taken for containment pressure, and (3) no credit is taken for subcooling of the sump liquid.

Question 211.38

Provide the information concerning accumulator water volume and pressure values used in LOCA analysis. What are the volumes assumed in the LOCA analysis and the criterion for determining them.

Response

Accumulator Nominal Water Volume = 1200 ft^3/accumulator

Pressure = 600 psia

Accumulator pressure is set by Technical Specifications to be the minimum expected accumulator pressure.

The accumulator water volume is set by the Techncial Specifications to ensure that the downcomer will be full at the time when the accumulator empties.

Question 211.40

The response to Question 211.5 is not acceptable. If operator error is to be addressed in the same manner as a single failure of a valve or pump, spurious movement of powered components must be considered. As the FMEA is currently presented, spurious movement and thus operator error is not addressed. The FMEA should be expanded to include inadvertent mispositioning of valves due to spurious movement or operator error.

Response

Westinghouse Topical Report WCAP-8966, Evaluation of Mispositioned ECCS Valves, is presently under review by the NRC. The above concerns are addressed completely in the report.

Question 440.11N

a. Clarify what automatic and manual actions are required for ECCS switchover to the recirculation mode. FSAR page 6.3-14 indicates that the sump isolation valves are automatically opened and the SI pump miniflow valves are automatically closed when low-low RWST level is reached, but that manual action is required to secure the RWST. Later you state that "failure of the operator to act will cause no adverse effect since switchover is essentially automatic". In Table 6.3-7 you state that no manual actions are required for cold leg recirculation initiation, but that the operator is instructed to close the RWST valves. Your response to Question 211.34 indicates that interlocks prevent the sump isolation vlaves from opening until the RWST discharge isolation valve and miniflow line isolation valves in the same train are closed.

b. If the operator action is required during switchover, demonstrate that sufficient time is available for the operator to take the proper action to mitigate the consequences of the accident.

c. The above interlocks and automatic valve actions should be indicated in the ECCS P&IDs.

Response

a. The switchover from the injection mode to recirculation mode is completed automatically with manual operator action from the main control room required only to secure the refueling water storage tank (RWST) to prevent backflow leakage across the check valve into the RWST. Section 6.3.2.8 has been modified to clarify this point. With respect to the response to Question 211.34, it states that the interlock prevents the sump isolation valves from being opened by operator action from the main control room unless the corresponding RWST isolation valves are closed and either of the redundant isolation valves in both the high-head safety injection (HHSI) and low-head safety injection (LHSI) miniflow lines are closed. The interlock with the RWST isolation valves does not prevent the automatic opening of the sump isolation valves.

b. Operator action is not required during switchover from injection mode to recirculation mode.

c. See revised Figures 6.3-1, 6.3-2, and 6.3-3.

Question 440.12N

Clarify the statement on page 6.3-5 regarding RHR heat exchangers: "During ECCS operation no credit is taken for core cooling from the RHR HX inasmuch as recirculated water is assumed to be returned to the vessel in a saturated condition . . . without benefit of subcooling". How is decay heat removal accomplished during long-term recirculation? Is this assumption utilized in the LOCA analyses?

Response

The Residual Heat Removal (RHR) heat exchangers do provide heat removal capability during long-term recirculation (see clarification on Q440.38N). Component cooling water to the heat exchangers is automatically initiated by the safety injection signal.

As the Chapter 15 Loss-of-Coolant-Accident (LOCA) analyses address the initial 10 to 15 minutes following the accident, the analyses correctly assume no credit for core cooling from the heat exchangers. The heat exchangers are modeled, however, in the long-term analyses in UFSAR Section 6.2.1 to determine containment pressure response and sump water temperature (see Table 6.2.1.1-5).

Question 440.13N (Deleted)

Question 440.38N

a. Demonstrate that the STPEGS ECCS meets 10 CFR Part 50.46 criteria for long term decay heat removal in the event of a small break LOCA of a size such that recirculation would be required but the RCS pressure either remains above the low-head safety injection (LHSI) pump shutoff head or recovers after loss of the secondary heat sink. An examination of Figures 6.3-1 through 6.3-5 does not indicate that the STPEGS ECCS is designed for high-head recirculation combined with decay heat removal by the RHR heat exchangers, i.e., there are no apparent provisions for routing recirculation flow from the RHR heat exchangers to the HHSI pumps. Also, as described in Appendix 5.4.A "Cold Shutdown Capability", the steam generators have a limited supply of safety grade secondary water supply, since there is not a safety grade backup to the auxiliary feedwater storage tank (AFST). Therefore, provide long term analyses for a spectrum of small break LOCAs that demonstrate that decay heat can be adequately removed and the RCS depressurized using only safety grade equipment and water sources, assuming loss of offsite power and the most severe single failure. If credit is taken for operator actions, the STPEGS emergency response guideline (ERG) sequence of operator actions should be followed. Justify the timing of operator actions if they are less conservative than those recommended in ANSI N-660 for a condition IV event.

b. In a conference call held on March 8, 1985, the applicant indicated to NRC that for small break LOCAs the combined heat sink capacity of the RWST and the steam generators would provide core cooling for approximately 18 hours, after which the reactor containment fan coolers (RCFCs) would provide an adequate heat sink for decay heat removal. No credit is taken for heat removal by the RHR heat exchangers. Provide a detailed explanation of the mechanism of energy removal from the RCS after loss of the secondary heat sink and supporting analyses that demonstrate that energy can be adequately removed to meet the acceptance criteria of 10 CFR Part 50.46. We are concerned that for very small break LOCAs (e.g., 1 inch) energy would not be adequately removed from the RCS for a considerable period of time after the accident. Thus, WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System" June 1979, indicates that for 1 inch breaks the break can remove all the decay heat only after about 24 hours, and that prior to that time, auxiliary feedwater is required to maintain the heat sink.

Response

Large Break LOCA

For large break LOCA (breaks greater than 1 ft^2) the break will cause a significant Reactor Coolant System (RCS) depressurization. Breaks of this size are not isolable so the sump is used for long term cooling and makeup. Breaks considered large breaks will have sufficient energy removal through the break to sump flow path to remove decay heat energy. Sufficient make-up capability to keep the core adequately cooled and to meet 10CFR Part 50.46 (b)(5) requirements is provided. Containment heat removal will be provided in the

Response (Continued)

STPEGS design by both containment fan coolers and low-head safety injection (LHSI) recirculation flow which is cooled by the RHR heat exchangers. Equipment relied upon is fully qualified for the environmental conditions that prevail during the accident.

Small Break LOCA

As a result of the accident at Three Mile Island Unit 2, Westinghouse performed extensive analyses that focused on the behavior of small break loss of coolant accidents (SBLOCA) for the Westinghouse NSSS. The purpose of the analyses was to demonstrate adequacy of the Westinghouse NSSS design in mitigation and long term recovery from a range of breaks classified as small breaks (less than 1-ft^2 area).

The results of the analyses were reported in WCAP-9600, "Report on Small Break Accident for Westinghouse NSSS System", dated June 1979. The "Small Break Evaluation Model" at that time consisted of the WFLASH thermal-hydraulic code and the LOCTA fuel rod model. The analyses were performed for generic application using a standard 4-loop Westinghouse design, a standard 3-loop and standard 2-loop depending on the nature of the study and which plant type was expected to be bounding. The conclusions are applicable for all Westinghouse designs, including STPEGS with exceptions as described in the following.

STPEGS SBLOCA Design Features

STPEGS has a three train low pressure SI system consisting of three high-head SI (HHSI) pumps, three LHSI pumps, and three accumulators. Each train is aligned to a separate RCS loop. The pressure ranges for the SI pumps follow:

HHSI: 0 - 1445 psig

LHSI: 0 - 283 psig

For recirculation, the LHSI and HHSI pumps take suction directly from the sump. The LHSI pump flow passes through the RHR heat exchanger and is cooled before entering the RCS.

The plant has three motor driven auxiliary feedwater (AFW) pumps and one turbine-driven auxiliary feedwater pump. The normal system alignment connects each AFW pump directly to one steam generator. The steam does not have a common header, but cross connections exist in the AFW lines. The valves in the cross connections are normally closed and fail closed. Two motor-driven AFW pumps and the turbine driven AFW pump are required operable by the Technical Specifications.

The Auxiliary Feedwater Storage Tank (AFST) is required by Technical Specifications to maintain a minimum volume of 485,000 gallons.

Non-safety grade sources of condensate grade make-up to the AFST are:

- Demineralized Water Storage Tank-One 1,000,000 gallon storage tank shared between units.

Response (Continued)

- Secondary Make-up Tank-One 300,000 gallon storage tank per unit
- Condenser Hotwell-about 100,000 gallons per unit

While the non-safety grade tank volumes are not covered by Technical Specifications or other administrative controls, it would be very improbable to have less than 500,000 gallons of condensate grade water available for each unit.

The limiting single failure for the STPEGS design will result in the loss of one train of safety injection (one LHSI and HHSI pump) and one AFW pump. Since one AFW pump is allowed out-of-service for maintenance, this will result in the ability to feed two steam generators.

The STPEGS design provides means to remove energy through the steam generators (AFW and atmospheric relief valves), through Containment steam condensation (fan coolers), and through the RHR heat exchangers (LHSI pumps and RHR heat exchangers). In this way energy is removed from containment sump water (RHR heat exchangers) so that relatively cool water will be continued to be supplied as make-up and for decay heat removal.

For all break sizes, heat is removed from the core by the break and steam generators. AFW is required for secondary inventory and heat removal until the break is able to remove all the decay heat or the RHR System is placed in operation. The break removes energy from the RCS because the makeup water from the RWST is relatively cold and can absorb energy before exiting the RCS. The WCAP-9600 analyses with consideration of STPEGS design features and STPEGS analyses of long term cooling discussed in the report titled "Long Term Cooling Analysis for South Texas Project" demonstrate decay heat removal capability for SBLOCA. The Long Term Cooling Report was transmitted in HL&P letter ST-HL-AE-1767 dated September 30, 1986.

SBLOCA Response

The initiating event is the break. If the break is 3/8 in. or less equivalent diameter and the charging system and feedwater system are available, the event is classified as a leak since normal charging flow would be sufficient to keep up with leak flow without a significant RCS depressurization. There would not be an automatic reactor trip or safety injection signal.

For breaks larger than 3/8 in., automatic reactor trip and safety injection will occur due to RCS depressurization caused by the loss of primary inventory. After reactor trip and safety injection initiation, safety injection pump flow provides makeup to the RCS and maximum peak clad temperature will remain below 10CFR50.46 Appendix K criteria.

For breaks greater than 3/8 in. and less than 1.5 in., SI flow can match break flow so no significant RCS depressurization or core uncovery will occur. At the point where SI flow matches break flow, the mitigation phase of the accident ends and a long term decay heat removal phase begins. The operator will cool down and depressurize to below the shutoff head pressure of the LHSI pumps (283 psig). This will be accomplished using the steam generator PORVs for cooldown and pressurizer PORVs in combination with HHSI flow termination

Response (Continued)

for depressurization. The detailed actions will be provided in the STPEGS Emergency Procedures which are based on the WOG Emergency Response Guidelines. The RHRS will be available to provide heat removal at RCS pressures below 350 psig and temperatures below 350ºF. Adequate long term decay heat removal will be provided by LHSI pump flow through an RHR heat exchanger in addition to RHRS operation.

For breaks from 1.5 in. to 4 in., the operator will cool down and depressurize the RCS to a pressure below the shutoff head pressure of the LHSI. The combined heat sink capacity of the Refueling Water Storage Tank and the steam generators would provide core cooling until the containment fan coolers and the RHR heat exchangers via LHSI pumps provide an adequate heat sink for decay removal.

For breaks greater than 4 in., the decay heat will be removed by the break and the containment fan coolers and the RHR heat exchangers via LHSI pumps. No operator action is required.

For isolable breaks, the operator will cool down and depressurize the RCS via a sufficient quantity of auxiliary feedwater to RHRS cut-in conditions of 350 psig and 350ºF. Adequate long term decay heat removal will then be provided via the Residual Heat Removal System.

Question 440.43N

Figure 9.3.4-3 indicates that normally closed valves MOV-0113B and -0112C, which can route RWST water to the charging pumps, are respectively actuated by ESF-B and ESF-C. Clarify whether this is a signal to open or close the valves. If these valves are actuated open on an SI signal, explain whether the charging pumps are utilized for safety injection.

Response

As shown in Table 7.3-5, the safety injection (SI) signals close the volume control tank (VCT) outlet isolation valves (XCV0112B and XCV0113A) and open the refueling water storage tank (RWST) to charging pump valves (XCV0112C and XCVO113B). The logic diagrams for these valves are shown on Figures 7.6-12 and 7.6-13.

The purpose of these actuations following an SI signal is to align an assured source of water to the centrifugal charging pumps and allow seal injection for the reactor coolant pumps (RCPs).

If a loss of offsite power (LOOP) occurs concurrent with the SI signal, this actuation has aligned the charging pumps to the RWST. After the sequenced loading of the standby diesel generators (SBDG), the operator may manually load the charging pumps and reinitiate seal injection.

Should a LOOP not occur concurrent with the SI signal, the charging pump(s) which were operating are not tripped and continue to operate, providing seal injection using RWST water.

The centrifugal charging pumps are not utilized for SI, and are not actuated by the SI signal.

Question 440.44N

Figure 6.3-1 through 6.3-4 indicate a number of low pressure nonsafety-grade lines that are separated from the ECCS safety grade lines by only one valve, e.g., the SI jockey pump return line is separated from the LHSI pump discharge line by one safety grade check valve, the test lines are separated from the SI pump discharge lines by only one fail closed air-operated valve, and the drain lines are only separated from the safety grade ECCS piping by single manual valves, most but not all of which are locked closed. We are concerned that valve failure or erroneous operator action could cause ECCS flow to be diverted to these lines. Provide a list of all nonsafety-grade lines that are connected to the ECCS, including the portions of the RHRs that are utilized for ECCS purposes, and describe the adequacy of their design regarding separation. In particular, SRP Section 6.3 states that long term decay heat removal should be provided assuming a single passive failure. Show that a failure of the single check valve off of the SI jockey pump discharge line or active failures of other valves will not result in a violation of the long term cooling requirement.

Response

The requested list of all nonsafety-grade lines connected to the Emergency Core Cooling System (ECCS) is provided herein under Tables Q440.44N-1 and Q440.44N-2.

The safety injection (SI) jockey pumps have been deleted from the design. Section 6.3.2.2, Figures 6.3-1 through 6.3-4, and Figure 5.4-6 have been revised to reflect this change.

Table Q440.44N-1 lists the nonsafety-grade lines inside the Containment connected to the ECCS. Safety Injection System (SIS) test lines and accumulator nitrogen supply lines are the only two lines where single valves are provided with operators. The SIS test lines are designed for full Reactor Coolant System (RCS) pressure up to and including the Containment isolation valves. Leakage through one of the valves in the test line or nitrogen supply line would be very small and would be stopped by the Containment isolation valves if the nonsafety-grade portion of the line remained intact, or would leak into the Containment if the nonsafety-grade pipe had failed. Neither case would affect the long term cooling capability of the system or water inventory. The vent and drain valves are manual, normally closed valves which would not be opened in a post Loss-of-Coolant-Accident (LOCA) environment. A passive failure in any of the connections listed under Table Q440.44N-1 would cause a very small leakage directly into the Containment and would not affect the water inventory or long term cooling capability of the system.

The nonsafety lines outside the Containment, connected to the ECCS, are listed in Table Q440.44N-2. As listed in the table, the vent, drain, and test connections are provided with manual, normally closed valves plus a threaded pipe cap. If a passive failure is assumed in one of the connections listed in Table Q440.44N-2 it would cause a small amount of leakage into the Engineered Safety Feature (ESF) pump cubicle sumps. The safety-related instrumentation provided in the Fuel-Handling Building (FHB)

Response (Continued)

ESF pump cubicle sump will alarm and appropriate operator action can be taken to isolate any leakage. Failure of locked closed manual valves is not postulated, thus the quantity of ECCS fluid lost outside the Containment will not be substantial enough to affect the ECCS performance.

It should be noted that the SI and Containment spray systems are provided with three independent trains. The three trains consist of an accumulator, high head safety injection (HHSI), low head safety injection (LHSI), and Containment spray pump. Any two trains provide adequate capacity and will be available in the case of a single failure in the third train.

TABLE Q440.44N-1

NON-SAFETY GRADE LINES CONNECTED
TO THE ECCS INSIDE CONTAINMENT

Number Per Train	Service Description	Size	Isolation Provided
7	SIS Test Lines	3/4"	Air operated valve, fail close
1	Accumulator PSV	1"	Code safety valve
1	SI header PSV	3/4"	Code safety valve
1	Standpipe connection	3/4"	Two check valves
1	Accumulator drain	2"	Closed manual valve plus blind lange
1	Accumulator N_2 Supply	1"	Solenoid valve, fail close
1	RHR heat exchanger	1"	Closed manual valve channel drain
Various	Local vents, drains and test connections	1"	Closed manual valve plus threaded pipe cap

TABLE Q440.44N-2

NONSAFETY GRADE LINES CONNECTED
TO THE ECCS OUTSIDE CONTAINMENT

Number Per Train	Service Description	Size	Isolation Provided
2	SI pumps miniflow	2"	Two MOVs
1	CSS test line	6"	Locked closed manual valve
4	Containment penetration test connections	1"	Locked closed manual valve plus threaded pipe cap
Various	Local vents, drains, and test connections	1-3/4"	Closed manual valve plus threaded pipe cap
1 (Total)	RWST drain	2"	Locked closed manual valve
1 (Total)	RWST local sample	3/4"	Closed manual valve, sample tubing valve and threaded tubing cap
1	SIS pump suction header pressure relief	3/4"	Code safety relief valves
4	Lines piped to CS and	2"	Locked closed manual valve
1	SI sample	3/4"	Closed manual valve

Question 440.46N (Deleted)

Question 312.24

In reference to Figure 9.4.1-2, sheet 3 of 4, provide an estimate of the return air flow rate attributable to the zones within the control room habitability envelope (i.e., the zones defined in Section 6.4.2.1 of the FSAR). In making the estimate, assume that the HVAC system is operating in the radiological emergency ventilation mode. Describe briefly the basis for your estimate.

Response

The following is an estimate of return air flow during a radiological emergency from rooms identified in Section 6.4.2.1 of the UFSAR as belonging to the control room habitability envelope.

Room Name & No.	Return Air Rate
Control Room (#203)	12,120 ft^3/min
Computer Room (#215)	0 ft^3/min
*Men's Toilet (#204)	0 ft^3/min
*Kitchen (#205C)	0 ft^3/min
Shift Engineer's Office (#208)	740 ft^3/min
Shift Supervisor's Office (#209)	580 ft^3/min
Women's Bunk & Toilet* (#210)	360 ft^3/min
Men's Bunk (#211)	340 ft^3/min
Relay Room (#202)	13,250 ft^3/min
Lobby (#205)	3,700 ft^3/min

Results Engineer Office (#203B)	360 ft^3/min	
HVAC Rooms (#013, 206, 307)	1,350 ft^3/min	
	32,800 ft^3/min	(2,000 ft^3/min Exfiltration)

The basis for this estimate is the following:

1. Outside design environmental conditions - 95F DB/81°F WB Summer

Response (Continued)

2. Inside design conditions -

   78°F DB, for control room envelope except HVAC Rooms, Relay Room and Computer Room

   80°F DB for Relay Room

   104°F DB for HVAC Rooms

   75 ±2°F DB, 40% RH for Computer Room

3. Minimum ventilation (exhaust air) rate of 2 ft^3/min per ft^2 for rooms marked with * above.

4. Heat dissipated from electrical equipment, lighting, and people in the rooms.

Question 312.25

Since the control room habitability envelope and the rest of the Electrical Auxiliary Building (EAB) are interconnected via the common air return duct, potential inleakage of airborne radioactivity into the EAB also would affect the control room area. This is not a recommended configuration (e.g., see Standard Review Plan Section 6.4, item III.1). Describe all points of entry into the EAB (i.e., windows, doors) in terms of control room operators knowing their status (i.e., open or closed) and having the ability to close them in the event of a design basis accident.

Response

The heating, ventilating, and air conditioning (HVAC) system has been revised to completely separate the control room envelope from the remaining Electrical Auxiliary Building (EAB). The control room envelope is now serviced by a separate HVAC system with supply and return air ducts located in the control room envelope and physically separated from the remaining EAB. There are a total of 23 doors at the control room envelope boundary, of which the three commonly used doors are provided with air locks. These three commonly used doors are in rooms 202A, 205B, and 205D. The major points of entry from outside the EAB will be one door on the east wall opening to the outside environment, and one door on the south wall opening to the Mechanical Auxiliary Building (MAB). They are both provided with air locks. In the event of a Design Basis Accident (DBA), the operator will have a visual inspection to check the status of the doors.

Question 450.3N

Identify those portions, if any, of the control room envelope HVAC system's duct work which are exposed to negative pressure relative to unfiltered surroundings during emergency conditions; e.g., duct with charging fan located outside the control room envelope. Assess the contribution to control room personnel doses from this additional source of infiltration.

Response

The control room make-up filter units (3VIIVXV004, 005, 006) and their associated fans and ductwork (Figure 9.4.1-2, Sh. 1) are located outside of the control room envelope. Thus, the ductwork upstream of the make-up unit fans will be at a negative pressure relative to the unfiltered surroundings. Since all infiltration to this section of the ductwork subsequently passes through the filter units, this is not a source of unfiltered air for the control room envelope.

The remainder of the system is maintained within the control room envelope (Figure 6.4-1) and will not be exposed to unfiltered air. Thus, there will be no impact on the control room doses from the infiltration of unfiltered air into the control room HVAC system.

Question 450.4N Deleted

Question 250.1N

The Applicant's response to FSAR Question 121.1 dated October 9, 1978 and Question 121.5 dated May 4, 1979, regarding the staff's request for submittal of the PSI program, states that "Upon completion of it's development, the preservice plan will be submitted to the NRC six months prior to commercial operation".

The Applicant's response is not acceptable. In order to complete the input to SER Sections 5.2.4, 5.4.2.2, and 6.6, the staff requires that the PSI program be submitted for review prior to starting examinations. The PSI program should include reference to the ASME Code Section XI Edition and Addenda that will be used for the selection of components for examinations, lists of the components subject to examination, a description of the components exempt from examination by the Code exclusion criteria in IWB-1220 and IWC-1220, the examination isometric drawings for ASME Code Class 1 and 2 components, and a detailed description of the inspection plan for component supports.

Paragraph 50.55a(b) (2)(iv) requires that ASME Code 2 piping welds in the Residual Heat Removal Systems, Emergency Core Cooling Systems, and Containment Heat Removal Systems shall be examined. These systems should not be completely exempted from preservice volumetric examination based on Section XI exclusion criteria contained in IWC-1220. To satisfy the inspection requirements of General Design Criteria 36, 39, 42, and 45, the PSI program must include volumetric examination of a representative sample of welds in the RHR, ECCS, and Containment Heat Removal Systems.

Response

A preservice inspection program will be conducted on Class 1, 2, and 3 components (and their supports) of South Texas Project Unit 1 in accordance with Article 55a of 10CFR50 and ASME Section XI. Preservice examination plans for weld examination were submitted to the NRC in HL&P letter ST-HL-AE-1343, dated September 6, 1985. Weld examinations began during October 1985. Preservice examination plans for eddy current testing were submitted in HL&P letter ST-HL-AE-1362 dated September 30, 1985. Eddy current testing began during September 1985. The preservice examination plans will describe the preservice inspection (PSI) program for STPEGS Unit 1 in terms of Code and regulatory bases for the program, scope of systems and components subject to PSI, and technical positions and approaches to be incorporated in the program. The preservice examination plans will contain a detailed listing of the specific systems, welds, and examination areas to be examined, the examination methods and procedures applicable to each examination, and isometric drawings denoting the locations of welds and examination areas in Class 1, 2, and 3 systems subject to examination and testing.

The PSI of STPEGS Unit 1 will be conducted in accordance with the 1980 Edition of ASME Section XI with addenda through the Winter 1981 Addenda (80W981). In accordance with Article 55a of 10CFR50, the examination requirements of Subsection IWE of Section XI will not be included in the PSI program. The Class 1 components of STPEGS Unit 1 will be examined during PSI in accordance with Subsection IWB of Section XI. Eddy current PSI examinations of steam generator tubing will be conducted at the site in accordance with the STPEGS Technical Specifications and Section XI.

Response (Continued)

The Class 2 components of STPEGS Unit 1 will be examined during the PSI in accordance with Subsection IWC of the 80W81 Section XI Code except that the extent of examinations of piping welds in the Residual Heat Removal System (RHRS), Emergency Core Cooling (i.e., Safety Injection System (SIS)), and Containment Heat Removal (i.e., Containment Spray System (CSS)) systems will be determined in accordance with portions of the 74S75 Section XI Code as required by paragraph (b) (2) (iv) of 10CFR50.55a. However, only the Class 2 exemption criteria of IWC-1220 (a) and (d) of the 74S75 Section XI will be applied to exempt RHRS, SIS, and CSS piping welds from examination. Additionally, a representative sample (approximately 7.5 percent of the non-exempt welds in each system, as a minimum) of piping welds in the RHRS, SIS, and CSS will be examined volumetrically based on the selection and examination requirements of Categories C-F-1 and C-F-2 of the Winter 1983 Addenda of Section XI. Class 3 components of STPEGS Unit 1 will be examined during the PSI in accordance with Subsection IWD of Section XI.

Component supports for Class 1, 2, and 3 components of STPEGS Unit 1 will be examined and tested during the PSI in accordance with Subsection IWF of Section XI. Visual examinations (VT-3 and VT-4) will be performed on the supports of nonexempt Class 1, 2, and 3 components in accordance with IWF-2510(a) and (b). Preservice testing of snubbers as required by IWF-5000 of Section XI will be conducted in the snubber manufacturer's shop. The additional preservice examination and pre-operational testing requirements for snubbers specified in NRC's October 17, 1980, letter to HL&P (ST-AE-HL-608) will be accomplished at the STPEGS site. The examinations and tests specified in this NRC letter will be performed in conjunction with either the PSI of component supports or during the pre-operational test program.

Question 250.2N

Inservice inspection and maintenance access considerations may not have been given adequate attention during the design and analysis of pipe whip restraints. During the PSI, the Applicant should document all ASME Code, Section XI examination requirements that are impractical to perform, should identify limitations to examination of specific welds, and should provide the staff with a technical justification.

Response

During the preservice inspection (PSI) of STPEGS Unit 1, HL&P will document all Section XI examination requirements which are impractical to perform, identify the limitations to examination of specific welds, and provide a technical justification for noncompliance with Section XI caused by lack of adequate access due to pipe whip restraints on/or adjacent to welds subject to examination. In such cases, HL&P may propose to employ alternate examination methods to those specified by Section XI in lieu of providing a technical justification for nonperformance of Code-required examinations.

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Question 032.27

With regard to remote shutdown panels, describe the criteria for the installation and routing of instrumentation and control circuitries between these panels and the main control room control boards.

Response

The main control panels are located at El. 35 ft in the Electrical Auxiliary Building (EAB). The auxiliary shutdown panel (ASP) is located at El. 10 ft in the same building. Control circuits for equipment required for safe shutdown are isolated by transfer switches, located in each of the Train A, B, and C Engineered Safety Feature (ESF) switchgear rooms. These transfer switches select between control room and auxiliary shutdown panel (ASP) control. Instrumentation circuits required for safe shutdown are routed from signal processing cabinets (located in five separate areas adjacent to the ASP) to the control room and the ASP. Isolation is provided to protect control room instrumentation from possible faults in the ASP instrumentation and to protect ASP instrumentation from possible faults in the control room instrumentation. Safe shutdown equipment cables are routed through separate fire areas to the control room and ASP; in addition train-to-train separation is maintained.

Cables of different trains are separated in accordance with Regulatory Guide 1.75 and IEEE 384-1974. Except where they converge at control panel locations, the cables are routed through different floor levels and different fire areas to provide maximum separation possible.

Where minimum separation distance between train and non-Class 1E raceways cannot be maintained, cable tray covers or conduit are utilized as barriers in accordance with the criteria referenced.

Question 032.9

The discussion of the solid state logic testing does not address several problems which have been experienced with the testing of the solid state protection system in operating nuclear power plants. For each of the following problems, describe how the implementation of the solid state equipment in the STPEGS has been modified to prevent the stated problem:

1. Integrated circuit ZlC (a NAND gate in the scram breaker undervoltage card) is not tested by the automatic test equipment.

2. An isolation problem was identified in the general warning circuit.

3. BFD-31 (sic) relays were not qualified for the equalizing voltage.

4. Previously qualified components were modified during production by their vendors and the modified components could not satisfy their original functional requirements.

5. Diodes with insufficient voltage ratings have been used in some circuits.

Response

Items 1, 2, and 5 are related to the same problem. This problem was an undetectable failure which occurred in the General Warning Alarm Circuit during testing of the Solid-State Protection System (SSPS). The consequence of this failure was reported by an operating plant. Westinghouse assessed the incident, reported the generic impact to the NRC, and submitted for approval modifications necessary to resolve the deficiency. After NRC acceptance was received (Letter June 21, 1976, R. Heineman to C. Eicheldinger) NRC Inspection and Enforcement witnessed verification tests which Westinghouse conducted. The modifications have been implemented in the SSPS for the South Texas Project Units 1 and 2, and are confirmed and documented in accordance with established Westinghouse PWR Quality Assurance procedures.

Item 3

BFD relays are not used in the instrumentation and control systems for STPEGS Units 1 & 2.

Item 4

Modifications to Westinghouse-supplied AR relays with latch assembly used in the protection system equipment for STPEGS Units 1 and 2 were completed prior to shipment of the equipment to the site. Confirmation and documentation are in accordance with established Westinghouse PWR Quality Assurance procedures. These changes resolve a tolerance problem discovered and reported to the NRC by Westinghouse.

HISTORICAL INFORMATION

Question 032.10

According to Regulatory Guide 1.70 "Standard format and content" Sections 7.2 and 7.3 the applicant should provide in the FSAR electrical schematic diagrams for all RTS and ESF circuits and supporting systems, and final logic diagrams, P&I diagrams, and location layout drawings.

Provide this information in your FSAR and describe any significant differences there may be between the logic diagrams and schematics which you previously submitted in the PSAR and the effects on safety-related systems.

Response

Electrical schematic diagrams and logic diagrams are provided in reference in Section 1.7. The piping and instrument diagrams (P&IDs) are provided in the appropriate sections of the UFSAR, with the system discussion. Tables 7.3-5 through 7.3-12, and Table 7.3-14 and 7.3-15 give the equipment actuated by the various Engineered Safety Features Actuation System (ESFAS) signals, and the P&ID number and UFSAR figure number on which each component may be found. Differences between logic diagrams and schematics previously submitted in the PSAR and those in the UFSAR is a result of the deletion of the Emergency Boration System (EBS), incorporation of new regulatory requirements (TMI), and continued system design.

Question 032.31
Describe the design basis, and separation and isolation for:

(a) Reactor Trip on Turbine Trip circuitry. Also, provide detailed cable routing diagrams for this trip circuitry from the sensor in the turbine building to the final actuation located in the Reactor Trip System.

(b) The circuitries from Reactor Trip System to the BOP devices in the Turbine/Auxiliary Building.

Response

Part (a)

The reactor trip on turbine trip is an "anticipatory trip".

The reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public.

The signal is derived from redundant limit switches on each turbine steam stop valve and from redundant controls on three pressure switches that monitor the turbine emergency trip fluid pressure. Figure 7.2-17 shows the functional diagram and Section 7.2.1.1.3, item 6, describes the design basis for this reactor trip. The limit switches and pressure switches identified above are purchased as Class lE qualified equipment.

These limit switches and pressure switches are located in the nonseismically qualified Turbine Generator Building (TGB). Seismic qualification is limited to the mounting of the components at their respective localities, the mounting supports for the rigid steel conduits, and to the components themselves.

Wiring from these devices, located in the TGB, to the Solid-State Protection System (SSPS) cabinets, located in the Mechanical Electrical Auxiliary Building is routed in accordance with the same separation criteria applicable to Protection Channels, I, II, III and IV (as discussed in Sections 7.1.2.2 and 8.3.1.4), and is in rigid steel conduit dedicated exclusively for these signals within the TGB. Detailed cable routing diagrams for this trip circuitry was sent under separate cover, by letter ST-HL-AE-1486, dated October 29, 1985.

Part (b)

The circuitry from the Reactor Trip System to balance-of-plant (BOP) devices in the TGB is limited to the turbine trip on reactor trip.

The turbine trip on reactor trip circuitry is implemented in accordance with IEEE 279 with the following exceptions:

1. The circuitry is routed through a nonseismic structure.

Response (Continued)

2. The turbine trip equipment supplied by the turbine manufacturer, although of appropriate high quality, is not seismically or environmentally qualified to nuclear qualification standards.

3. The turbine solenoids are non-Class 1E and are powered by highly reliable non-Class 1E power sources.

The circuit design, up to and including the turbine trip solenoids, conforms to those sections of IEEE 279 concerning single failure (Section 4.2), quality (Section 4.3), channel integrity (Section 4.5, excluding seismic), channel independence (Section 4.6), and testability (Section 4.10), so as to assure adequate reliability.

The turbine trip solenoids are implemented so that the turbine is tripped on loss of control power. Wiring from the SSPS cabinet (located in the Mechanical-Electrical Auxiliary Building (MEAB)) to the turbine trip solenoids (located in the TGB) is routed in accordance with the same separation criteria applicable to Class lE circuits (Sections 7.1.2.2 and 8.3.1.4) and are in rigid steel conduit dedicated exclusively for these signals to maintain the integrity of the individual redundant trains.

Question 032.41

We deduce from Figures 7.2-3 and 7.2-4 that a single failure of the P-6 signal generation circuitry so that P-6 is energized at a power level lower than the P-6 setpoint places the reactor system in jeopardy. The operator can block out the source range trip at power levels at which it was intended for protection. In addition, the trip circuitry will not reset as the power level decreases below the P-6 setpoint during a power reduction. This appears to violate the single failure criterion. Bring your system in compliance with the single failure criterion or justify not so doing.

Response

The Chapter 15 analysis does not currently take credit for the source range reactor trip, which is provided as a backup trip.

Question 032.43

Engineering Safety Features (ESF) Reset Controls (IE Bulletin 80-06)

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

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

The NRC staff has determined that all construction permit holders, as part of the OL review process, are to be requested to address this issue. Accordingly, you are requested to take the actions called for in Bulletin 80-06 Actions 1 thru 4 under "Actions to be taken by Licensees". Complete the review verification and descriptions of corrective actions taken or planned as stated in Action 1 thru 3 and submit the report called for in Action Item 4.

Response

The STPEGS Engineered Safety Features (ESF) systems were reviewed against requirements in IE Bulletin 80-06, as requested by Action 1. The STPEGS position including exceptions is stated in Sections 7.3.1.2.4, 7.3.2.1.1(3), and 7.3.3.1.1(3).

Actions 2 through 4 of IE Bulletin 80-06 were completed prior to fuel load. The testing required by Action 2 is included in the interlocks and controls testing for the various systems, as discussed in Section 14.2.12.

Question 032.42

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

You are requested to address these issues by taking IE Bulletin 79-27 Actions 1 through 3 under "Actions to be Taken by Licensees". Within the response time called for in the attached transmittal letter, complete the review and evaluation required by Actions 1 thru 3 and provide a written response describing your reviews and actions.

Response

The responses to each action item of IE Bulletin 79-27 are given below by action item number.

1. A review of the instrumentation and control systems which could affect the ability to achieve a hot standby condition (see Section 7.4) and a cold shutdown condition (Appendix 5.4.A) has been performed. Each of these systems is supplied power from one of the redundant Class 1E 120 vac or 125 vdc busses. Refer to Figure 8.3-3 (sheet 1).

   The Class 1E 120 vac power is provided from one of the six 120 V vital AC channel distribution panels. Each panel is supplied power either through manual transfer circuit breakers or a static transfer switch from an individual inverter. There are two panels each for Channels I and IV and one panel each for Channels II and III. See also Section 8.3.1.1.4.5.

   The Class IE 125 vdc power is provided from one of the four 125 vdc distribution switchboards. Each switchboard is connected to a separate battery and two battery chargers. See also Section 8.3.2.1.1.

   Turbine, nonsafety-related reactor and other nonsafety-related instrumentation and control systems are provided power from non-Class 1E panels and switchboards. Refer to Figure 8.3-3 (sheet 1). The non-Class 1E 120 vac power for the Electrical Auxiliary Building (EAB) is provided from one of two 120 V vital AC distribution panels, each connected to an automatic transfer switch and an individual inverter. Another 120 V vital AC distribution panel is provided in the Turbine Generator Building (TGB); this panel is connected to an inverter package with an internal static transfer switch. Two 120 vac regulated power distribution panels are also provided for non-Class 1E instrumentation and control systems.

Response (Continued)

The non-Class 1E 125 vdc power is provided from two 125 vdc distribution switchboards, each connected to one battery and two battery chargers. A 48 vdc distribution switchboard supplying power only to the plant annunciator system is connected to one battery and two battery chargers. A non-Class 1E 250 vdc distribution switchboard is provided in the TGB, serving motors and the main generator control panels; it is connected to one battery and two battery chargers.

A separate non-Class 1E uninterruptible power supply system (120 vac) is provided for the plant computer. The Emergency Response Facilities (ERF) computer is powered from non-Class 1E 480 vac and has an uninterruptible power supply system to support its functions during a loss of power. Refer to Figure 8.3-3 (sheet 2).

The Radiation Monitoring System (RMS) computer is powered from non-Class 1E 480 vac and has uninterruptible power supply systems to supports its functions during a loss of power.

Non-Class 1E power is not required to support the ability to achieve hot standby or cold shutdown conditions. However, the non-Class 1E power supports indications to the operator (such as computer alarms and annunciation) of abnormal conditions and control systems normally used during plant operating modes.

1a. Loss of power to each of the six Class 1E 120V vital AC distribution panel busses is alarmed individually in the control room on a window of the Engineered Safety Features (ESF) status monitoring system. A ground fault on any of these panel busses is alarmed individually on a window of the plant annunciator as Panel Trouble. The ERF computer also indicates that a loss of power or a ground fault has occurred. Alarms are provided for each inverter through the ERF computer and the ESF status monitoring system.

Loss of power to each of the four Class 1E 125 vdc distribution switchboard busses is alarmed individually in the control room on a reflash window of the plant annunciator, along with other bus and battery charger alarms, as System Trouble. The ERF computer indicates whether bus or charger trouble has occurred. The ESF status monitoring system provides other battery and charger alarms.

Loss of power or a ground fault to the two EAB non-Class 1E 120V vital AC distribution panel busses is alarmed individually in the control room through the plant computer. Alarms are provided for each inverter through the annunciator and the plant computer.

Loss of power or a ground fault to the TGB non-Class 1E 120V vital AC distribution panel bus is alarmed in the control room through the plant computer. Inverter/rectifier alarms are provided through the plant computer and the annunciator.

Response (Continued)

Loss of power or a ground fault to either of the two non-Class 1E 120 vac regulated power distribution panel busses is alarmed in the control room through the plant computer.

Loss of power to either of the two non-Class 1E 125 vdc switchboard busses is alarmed individually in the control room on a reflash window of the plant annunciator, along with other bus and battery charger alarms, as System Trouble. The plant computer indicates whether bus or charger trouble has occurred.

Loss of power to the non-Class 1E 48 vdc switchboard bus, along with other bus alarms, is alarmed in the control room via the plant computer. Other bus and battery charger alarms are provided on a reflash window of the plant annunciator as System Trouble. The plant computer indicated whether bus or charger trouble has occurred.

Loss of power to the non-Class 1E 250 vdc switchboard bus is alarmed in the control room on a reflash window of the plant annunciator, along with other bus and battery charger alarms, as System Trouble. The plant computer indicated whether bus or charger trouble has occurred.

Loss of power or a ground fault to the non-Class 1E 120 vac distribution panel bus for the plant computer is alarmed in the control room. Various battery, charger, and inverter alarms for the computer uninterruptible power supply (UPS) are given in the control room on two reflash windows of the plant annunciator, one for Battery/Charger Trouble and one for Inverter Failure. The ERF computer indicated which signal caused the annunciator alarm.

Power to the ERF data acquisition, computer and display equipment is provided by an uninterruptible power supply (UPS) through two distribution panels, as shown on Figure 8.3-3 (sheet 2). Loss of power to these distribution panels is not alarmed specifically to the control room operator. However, should power to either panel be lost, the six monitors (CRTs) in the control room would not be updated, providing unambiguous indication of the power loss.

Various alarms are available to the operator through the ERF computer concerning the functioning of the UPS. These alarms include improper breaker positions (of power supply to the rectifier/charger, battery output, inverter input, inverter output, bypass power main supply and bypass power to static switch breakers), inverter problems (out of sync, low DC volts, fan failure), static switch not in normal position, and manual bypass switch not in normal position.

Responses (Continued)

Power to the Radiation Monitoring System computer (RM-11) is also supplied by UPS systems, as shown on Figure 8.3-3 (sheet 2). Since alarm output contacts are held in the non-alarm condition by energized relays, should power be lost to either computer, all annunciator windows associated with that computer would be lit and an audible alarm sounded. Three annunciator windows are associated with the Radiation Monitoring System computer. Also the associated CRT screen in the control room would be blank.

The RM-21A Dose Assessment computer has been replaced with a new Dose Assessment and Report Generation computer system with new software application. The new computer system runs in an ORACLE database environment with current technology servers and workstations. It can be accessible anywhere on site through the plant Local Area Network (LAN); it has been designed to be highly reliable utilizing hardware redundancy and backup power sources using uninterruptible power supply (UPS) and diesel generator.

1b. The review and evaluation of the Class 1E and non-Class 1E busses described above indicate that loss of power to any one instrumentation and control bus will not inhibit the ability to achieve a cold shutdown condition.

1c. The review and evaluation indicate that design modifications are not required.

2. The operating procedures used by control room operators will be reviewed with respect to loss of power to each Class 1E and non-Class 1E bus supplying power to instrumentation and control systems.

2a. The procedures will define symptoms and specify actions to be taken by the operators upon loss of power to Class 1E or non-Class 1E instrumentation and control systems.

2b. Where necessary, the procedures will specify alternate instrumentation and control circuits for use by operators.

2c. The procedures will include methods and precautions for restoring power to each Class 1E and non-Class 1E bus supplying power to instrumentation and control systems.

Should any design modifications or administrative controls be required as a result of the development of these procedures, descriptions of these will be provided.

3. 1E Circular No. 79-02 has been reviewed in relation to the safety-related power supply inverters. All safety-related power supply inverters are Class 1E. For these inverters, relative to the Circular requirements:

3a. Class 1E inverters do not use time delay circuitry.

3b. The AC input to each Class 1E inverter is to a transformer/rectifier section. The

Response (Continued)

transformer has taps that will be set according to the recommendations of the manufacturer. A relay trips the transformer/rectifier supply circuit breaker if overvoltage occurs.

3c. The alternate 120 V source is supplied either by manual operation of interlocked circuit breakers or through a static transfer switch. Manual operation of interlocked bypass switches will be used during testing or if the static transfer switch fails.

3d. Administrative controls will confirm the position of transformer taps and manual bypass circuit breakers when maintenance or testing have been completed.

No design modifications or additional administrative controls are required.

Question 032.22

General design criteria 20 and 25 require that the protection system be designed to assure that specified fuel design limits are not exceeded from an accidental withdrawal of a single rod control cluster assembly (not ejection). In the accident analysis, presented in Section 15.4 of the FSAR, it is assumed that no electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single rod control system could cause the accidental withdrawal of a single rod control cluster assembly. However, FSAR Chapter 7.7.1 does not describe how the design prevents such an occurrence. Provide a detailed description of the control circuitry and discuss how the design meets the requirements of criteria 20 and 25. Also, demonstrate conformance with Branch Technical Position 14 as stated in Appendix 7A of the standard review plant or identify and justify the alternative designs. In particular, demonstrate that no single failure in the rod control system can result in a violation of the specified fuel design limits while retrieving a rod which is out of alignment.

Response

For the discussion of design features that prevent an inadvertent single rod withdrawal, see Section 7.7.2.2. The capability of withdrawing a single rod cluster control assembly (RCCA) in a control bank is necessary in order to allow the reactor operator to retrieve an RCCA should one be accidentally dropped or misaligned.

In order to retrieve the RCCA, the Rod Control System is manually aligned to permit withdrawal of the dropped RCCA. The operator then manually withdraws the affected RCCA, with appropriate manual turbine load or boron concentration control to maintain the programmed value of Reactor Coolant System average temperature. Withdrawal is terminated when the RCCA reaches its recorded group step counter position. The Technical Specifications define the time period in which the dropped RCCA must be restored to operable status, within specified alignment requirements in order to continue power operation.

After the Rod Control System is manually aligned to permit withdrawal of the single RCCA, a single RCCA withdrawal accident could occur only with a subsequent single failure of the Rod Control System or an operator error during the recovery procedure. If the withdrawal is to be caused by a single failure, the failure would have to occur within the Technical Specification time limit for recovery from the failure which caused the RCCA to drop. In order for the single RCCA withdrawal event to occur due to operator error, the operator would have to:

1. Withdraw the RCCA all the way out of the core, ignoring the recorded step counter position of the remainder of the group. The group position is recorded by the operator before the retrieval process proceeds.

Response (Continued)

2. Ignore operating instructions which specify that the programmed Reactor Coolant System average temperature be maintained by manually controlling turbine load or born concentration.

3. Disregard most or all of the following event indications:

   a. Rod position indicators

   b. Rod deviation alarm

   c. T_{avg} deviation alarm

   d. High neutron flux alarm and rod stop

   e. High Delta T rod stop

   f. Control bank D Rod withdrawal limit alarm

   g. Continuous recorder indication of increasing nuclear power and T_{avg}

   h. T_{avg} - T_{ref} deviation alarm

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Even if the operator were to withdraw the RCCA completely out of the core, there is no DNB problem unless the operator also ignores items b and c, above. The case of a fully withdrawn single bank D rod at full power is covered by the static rod misalignment analysis presented in Section 15.4.3.

A dropped or misaligned RCCA is itself an American Nuclear Society (ANS) Condition II event caused by some single failure in the Rod Control System. There no "planned adjustments" affecting a single RCCA which are otherwise required for Westinghouse plants.

Retrieval of the RCCA is therefore not a normal operational occurrence, and is under strict administrative control. The operator is expected to be fully cognizant of all actions and plant indications associated with the retrieval process. The combined probability of dropping or misaligning a single RCCA and either (1) a single failure which causes undesired RCCA withdrawal or (2) a series of operator errors as outlined above, plus failure or operator disregard of event indication, is so low that classification of the single RCCA withdrawal event as a Condition III fault is justified. For example, from experience the expected frequency of any RCCA drop while operating in the power range is expected to be about 0.6 per year. This probability should be multiplied by 0.17 to give the total probability per year of a Bank D RCCA drop, since full withdrawal of a single RCCA leads to an adverse power distribution only if the RCCA is a member of a partially inserted bank, and only control bank D is inserted in the core above about 50 percent power.

Response (Continued)

The probability of either a single failure or a series of operator errors during the recovery period which could lead to subsequent withdrawal of the RCCA is estimated to be no worse that 0.01 based on WASH-1400 Appendix III. This gives a combined probability of 0.001 per year which is well within the expected frequency of ANS Condition III events. A survey of data obtained from Westinghouse reactors operating between 1972 and 1974 supports this probability assessment, and also shows that for all single dropped RCCA events reported in the approximately 30 reactor years of operation between 1972 and 1974, the dropped RCCA was in all cases retrieved without incident.

Since the single RCCA withdrawal accident can only occur as a result of multiple faults or failures, and the probability of occurrence of these failures is within the expected frequency of Condition III events, it is concluded that the single RCCA withdrawal accident should continue to be classified as a Condition III event. As a Condition III event, the consequences presented in Section 15.4.3 are acceptable, not in violation of general design criterion 20 or 25 and, therefore, are in conformance with Branch Technical Position (BTP) Instrumentation and Controls System Branch (ICSB) 14.

Question 032.44

Operating reactor licensees were informed by IE Information Notice 79-22, issued September 19, 1979, that certain nonsafety-grade or control equipment, if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. Enclose is a copy of IE Information Notice 79-22, and reprinted copies of an August 20, 1979, Westinghouse letter and a September 10, 1979, Public Service Electric and Gas Company letter which address this matter. Operating Reactor licensees conducted reviews to determine whether such problems could exist at operating facilities.

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

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

Response

IE Information Notice 79-22 specifically identified four potential interaction scenarios between nonsafety-grade and safety-grade equipment which could occur because of the effect of an adverse environment following a high energy line break. The four systems identified are:

- Steam Generator Power-Operated Relief Valve (PORV) Control System
- Pressurizer PORV Control System
- Main Feedwater Control System
- Automatic Rod Control System

A discussion of each scenario and affected system and its applicability to STPEGS follows.

Response (Continued)

It has been postulated that a failure of the steam generator (SG) PORV control system, due to adverse environment following a feedline rupture, could cause a depressurization of the unaffected SGs. The STPEGS SG PORV system is a Class 1E system. In addition, all portions of the SG PORV system that could be exposed to an adverse environment are isolated in the Isolation Valve Cubicle (IVC) structure on a loop-by-loop basis. Only one PORV could be affected by adverse conditions and that PORV would be in the affected SG loop. For these reasons, the scenario concerning the SG PORV control system is not applicable to STPEGS.

The second scenario assumes that the pressurizer PORVs fail in the open position, due to an adverse environment following a feedline rupture. This would cause a depressurization of the Reactor Coolant System (RCS), which may result in a voiding of the RCS and potentially uncovering the core. However, all portions of the pressurizer PORV control system located inside Containment have been environmentally qualified for the adverse environment. For this reason, the scenario involving the pressurizer PORV control system is not applicable to STPEGS.

The third scenario assumes a failure of the main feedwater control system, due to adverse environment following a small feedline rupture which occurs between the main feedline check valve and the Containment penetration. Such a failure could cause the liquid mass in the intact SGs at the time of reactor trip to be less than was assumed in the UFSAR analysis. The STPEGS SG water level transmitters are located within the Containment and are environmentally qualified for the adverse environment. The steam flow transmitters are also located in containment but are not environmentally qualified because the special treatment exemption has been applied. The feedwater flow transmitters are located inside the Turbine Generator Building (TGB) and the feedwater process controls are located in the Mechanical and Electrical Auxiliary Building (MEAB). Because of their respective locations, the transmitters and the feedwater controls would not be exposed to an adverse environment following a feedline rupture between the main feedline check valve and the Containment penetration. In addition, the feedwater isolation valves and associated instrumentation are compartmentalized by loop within the IVC, thus restricting exposure to the harsh environment to the loop with the break. For these reasons, the scenario involving a failure of the main feedwater control system is not applicable to STPEGS.

The fourth scenario assumes that the automatic rod control system fails, due to adverse environment following a small steamline rupture, in such a way that the control rods begin stepping out prior to receipt of a reactor trip signal on overpower ΔT. This could result in a departure from nucleate boiling ratio (DNBR) less than the limiting value. For a steam line rupture, the excore detectors which supply input to the rod control system could be exposed to the adverse environment and initiate rod withdrawal. In STPEGS, these excore detectors (and associated safety-related equipment) are part of the reactor trip system and have been environmentally qualified for a limited period of time (5 minutes) after a main steam line break (MSLB). Analysis has shown that steam line breaks which are too small to cause a reactor trip in less than five minutes will result in adequate DNB margin for the duration of the event. Control rod withdrawal will eventually bring the reactor into a condition from which an overpower ΔT reactor trip signal will be generated. For this reason, the scenario involving the automatic rod control system for a steam line rupture is not applicable to STPEGS.

Question 620.2N

Provide the following information and clarification regarding your summary report for the Detailed Control Room Design Review (DCRDR) submitted April 12, 1984:

a. Your systems function and task analysis (SFTA) was performed through document reviews, briefings, and walk-throughs on the mock-up and updated using the revised mock-up as reported in the SFTA Validation Report. Because the SFTA was not based on upgraded emergency operating procedures (EOPs) required by Supplement 1 to NUREG-0737, and because EOPs are not typically available at early stages of design and construction, but should be available prior to licensing, please confirm, after EOPs are finalized, that information and control function needs have been adequately identified and are satisfied by available instrumentation and controls.

b. Verify that an objective comparison of independently determined display and control requirements, as determined by function and task analyses has been made with the control room inventory to identify missing controls and displays as required in Supplement 1 to NUREG-0737, and summarize the results of this comparison.

c. Substantiate that an objective, independent determination of the operator information and control needs for each operator task has been made before instrument and control specifications are developed.

d. Describe the specific process for using generic guidelines and background documentation to identify the characteristics of needed instrumentation and controls. For the information of this type that is not available from the Emergency Response Guidelines and background documentation, described the process used to generate this information to derive required instrumentation and control characteristics.

e. Verify an auditable record is maintained regarding how the needed characteristics of required instruments and controls were determined for each instrument and control used to implement the emergency operating procedures.

f. Discuss the present status of the design of the sit-down control stations.

g. Provide a summary discussion and conclusions regarding the supplementary assessment to accommodate smaller (i.e., 5th-20th percentile) female operators and to use extended functional reach criteria for lower percentile subjects.

Question 620.2N (Continued)

h. Discuss the resolution of the three category "A" human engineering deficiencies regarding:

(1) The green Rotobellite indicator lights which cannot be distinguished when illuminated;

(2) The bypass and inoperable status light legend which are unreadable due to narrow stroke width and inadequate character separation and line spacing; and

(3) The legend messages containing more than three lines of text.

i. Discuss the results of the resolution of all unresolved human engineering deficiencies in categories "B", "C", "D", and "E".

j. Provide justification and rationale for using random checks rather than 100 percent checks of items which cannot be completed until the control room and/or simulator is operational.

k. Your present schedule is stated in general terms for completion of all planned DCRDR work. Provide a more specific schedule for implementation of corrective actions for human engineering deficiencies.

Response

STPEGS performed the Control Room Design Review (CRDR) as part of an overall integrated effort to address the requirements and guidance of Supplement 1 to NUREG-0737. CRDR activities were and continue to be integrated with the following STPEGS activities:

- Development of the Safety Parameter Display System (SPDS) which is implemented via the Emergency Response Facilities Data Acquisition and Display System (ERFDADS).
- Determination of instrumentation requirement for post-accident monitoring to address Regulatory Guide (RG) 1.97.
- Development of STPEGS Emergency Operating Procedures (EOPs) that are human factored, function oriented, and well integrated with the plant design.

The CRDR System Function and Task Analysis (SFTA) was independently performed by Torrey Pines Technology to comply with NUREG-0700 as defined in the STPEGS CRDR Program Plan submitted to the NRC by letter ST-HL-AE-899, Mr. J. H. Goldberg of Houston Lighting and Power to Mr. Thomas M. Novak, U.S. Nuclear Regulatory Commission dated October 20, 1982, and resubmitted with the CRDR Executive Summary Report by letter ST-HL-AE-1080, Mr. J. H. Goldberg of Houston Lighting and Power to Mr. Darrell G. Eisenhut, U.S. Nuclear Regulatory

Response (Continued)

Commission, dated April 12, 1984. A flow chart of the STPEGS CRDR SFTA process is shown in Figure Q620.2N-1. This SFTA was based on the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs) as well as the STPEGS Plant design. The STPEGS design was integrated with the WOG ERGs utilizing STPEGS design documentation and input from STPEGS plant operators to develop functional flow diagrams specific to STPEGS. These diagrams formed the basis for the SFTA tabulation of the operator tasks and required equipment (i.e., instrumentation or controls) associated with each task. This process for performing the STPEGS CRDR SFTA and the SFTA results are documented in the STPEGS CRDR System Function and Task Analysis Report submitted to the NRC with the CRDR Executive Summary. Following the revision to the STPEGS main control panel layout, the SFTA tabulations of operator tasks and required equipment were revised to reflect the new panel equipment and locations. This update formed the basis of the SFTA validation of the panel design. A procedure walk-through/talk-through was also conducted using draft plant specific procedures in the control room mock-up. These draft plant specific procedures were based on the WOG ERGs, STPEGS process design, and the STPEGS SFTA functional flow diagrams. This SFTA validation process and the results are documented in the STPEGS CRDR System Function and Task Analysis Validation Report submitted to the NRC with the CRDR Executive Summary.

In parallel with the STPEGS CRDR SFTA efforts, STPEGS performed an analysis to address post-accident monitoring requirements to respond to Regulatory Guide 1.97. A flow chart of the STPEGS RG 1.97 implementation process is shown in Figure Q620.2N-2. This was accomplished by performing a task analysis based on the WOG ERGs to identify variables necessary for implementation of the guidelines. This analysis was applied to the STPEGS specific design through a plant survey of the STPEGS design documents. The STPEGS specific analysis is summarized in STPEGS UFSAR, Appendix 7B. The analysis itself identified, in addition to the variables necessary for implementation of the ERGs, variable display requirements including range, accuracy, qualification, redundancy, recording needs, and operator task utilization. These requirements were compared to existing STPEGS instrumentation to determine required design changes. These changes were incorporated in the revised main control panel mock-up and were utilized in the CRDR SFTA validation. This instrumentation is summarized in UFSAR Table 7.5-1.

Also in parallel with the STPEGS CRDR SFTA and with the STPEGS RG 1.97 implementation, STPEGS began development of the EOPs based on the WOG ERGs, the identified RG 1.97 variables, and the revised panel layouts.

The RG 1.97 variable list developed during the RG 1.97 implementation process was then utilized to determine the ERFDADS/SPDS data base. This system is described in UFSAR Section 7.5.7. A subset of this data base, those Category I Type A and Type B variables determined from the Optimal Recovery Guidelines (ORGs) and the Critical Safety Function (CSF) Status Trees/Functional Recovery Guidelines (FRGs), respectively, is the data base for the Qualified Display Processing System (QDPS) described in UFSAR Section 7.5.6. The ERFDADS/SPDS display development process is shown in Figure Q620.2N-3.

Response (Continued)

a. The development of the South Texas Project Electric Generating Station (STPEGS) EOPs is based on Revision 1 of the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs). During the conversion process the instrumentation and control requirements of the ERGs are compared with the RG 1.97 equipment to develop both the normal and alternate indications available to the operators. Prior to final approval of the STPEGS EOPs, they were placed through a verification and validation program as specified by Supplement 1 to NUREG-0737. This program was described in detail in the Procedure Generation Package in letter ST-HL-AE-1266, dated June 14, 1985, from Mr. J.G. Dewease of Houston Lighting and Power Company to Mr. Hugh L. Thompson, Jr. of NRC. This program confirmed that the instrumentation and control function needs have been adequately identified and are satisfied. The validation of the STPEGS Emergency Operating Procedures was conducted during May 1986. This validation process was performed in the STPEGS simulator, using scenarios chosen to test the principal safety actions and branching into the steps of as many procedures as possible. This EDP validation process and the results are discussed in the Emergency Operating Procedures Validation Report, which was provided to the NRC by letter ST-HL-AE-1860, Mr. M.R. Wisenburg of Houston Lighting and Power Company to Mr. Vincent S. Noonan, U.S. Nuclear Regulatory Commission, dated December 23, 1986.

b. The CRDR SFTA process included a comparison of the display or control requirement, as defined by a task objective, to the main control panel equipment. The task objectives are stated in specific terms relating to plant equipment, for status or control requirements. This comparison was performed by Torrey Pines Technology personnel during the SFTA. The task objectives defining a display or control requirement were developed from functional flow diagrams. These functional flow diagrams were developed by Torrey Pines Technology utilizing the WOG ERGs, plant process design documentation, and input from plant design and operations personnel relative to plant system function.

The RG 1.97 implementation process included a comparison of the display or monitoring requirements, as defined by the STPEGS design basis to respond to RG 1.97, to the main control panel equipment. The monitoring requirements are stated in terms of range, accuracy, and RG 1.97 category which in turn defines instrumentation qualification, redundancy, and display and/or recording requirements. This comparison was performed and documented in an STPEGS RG 1.97 plant survey.

As a result of the CRDR SFTA, it was determined that the existing panel layout contained the required instrumentation and control equipment with the exception of essential cooling water (ECW) flow indication. This was documented as HED S-875 in the CRDR Executive Summary. The adequacy of the existing equipment was not specifically addressed as part of the SFTA. This was addressed as

Response (Continued)

part of the control room survey and as part of the RG 1.97 review. The CRDR SFTA identified significant concerns relative to panel layout and functional grouping of panel equipment. These results were a primary input to the decision to perform extensive panel redesign.

The RG 1.97 task analysis identified numerous changes required to panel display instrumentation (including ECW flow monitoring). The changes were in the form of additional or revised ranges, instrument qualification, or new display or recording devices. Approximately 100 changes were identified and were summarized in the STPEGS CRDR Implementation Plan Report initially submitted to the NRC by letter ST-HL-AE-946, from Mr. J. H. Goldberg to Mr. Thomas M. Novak, April 7, 1983.

The RG 1.97 results are also documented in Table 7.5-1.

c. The CRDR SFTA functional flow diagrams and task objectives were developed by Torrey Pines Technology utilizing the WOG ERGs, plant process design documentation, and input from plant design and operations personnel relative to plant system function. The task objectives defining a display or control requirement are stated in specific terms relating to plant equipment for status information or control needs, or plant process variable, for monitoring information or control needs. These task objectives determining operator information and control needs were developed prior to the comparison to the main control panel equipment as documented on the SFTA operator task identification and analysis forms.

The RG 1.97 variable requirements were defined based on the Westinghouse generic design basis to respond to RG 1.97. These generic design bases were applied to the STPEGS specific process designs through reviews utilizing plant process flow diagrams and single lines, and the plant accident analyses. These variable requirements were developed prior to the comparison to the existing plant instrumentation.

Numerous control and instrumentation specifications existed prior to the inception of the STPEGS CRDR or the STPEGS RG 1.97 implementation. As a result of both of these efforts, the majority of these specifications were revised to replace, upgrade, or enhance the existing controls and instrumentation. In addition many new specifications were developed after the needs were determined through either the CRDR or the RG 1.97 review.

d. The CRDR SFTA and the RG 1.97 review utilized the WOG ERGs and numerous plant specific documents. From these Torrey Pines Technology, as part of the CRDR SFTA, developed an extensive STPEGS "systems" background employing where necessary interviews with plant design and operations personnel. This "systems" knowledge is documented in the CRDR SFTA report and formed the basis for the SFTA.

Response (Continued)

The RG 1.97 reviews also employed the WOG ERGs and plant specific documents including the plant accident analyses for plant specific design data required to derive operator informational needs. As the STPEGS EOPs are developed, a continuing dialogue exists between the HL&P Operations staff and the system designers to ensure that operational information needed is identified and addressed by the control room instrumentation. The design basis for the operational information needs is documented in Appendix 7B and the instrument requirements are documented in Table 7.5-1.

e. An auditable record is maintained documenting the design basis for determining the instrumentation requirements (operator informational needs) based on the WOG ERGs and STPEGS plant specific documentation. This design basis, provided in Appendix 7B, and the detailed instrumentation listing provided in Table 7.5-1, are maintained through the development and validation of the EOPs.

f. There are six consoles within the control room: ZCC-025, ZCC-026, ZCC-027, ZCC-028, ZCC-029 and ZCC-030. The design has been completed on the consoles and the design has been reviewed for compliance to the STPEGS CRDR Criteria. The consoles have been fabricated and installed.

g. Houston Lighting and Power (HL&P) has developed a functional reach test to be administered to all Reactor Operator candidates. The development of the test included the identification of all controls that are critical in emergency situations. Two types of critical controls that are located at the greatest height on the vertical panels were identified. A mock-up test panel has been constructed to simulate the locations of the critical controls. Simultaneous with the functional reach test, a job-relevant preliminary visual acuity screen is conducted using control and annunciator labels identical to those used on the main control board. Procedures for the administration of the tests are detailed and provide clear pass/fail criteria. Personnel not passing the tests are not allowed to perform in the Reactor Operator position.

h. Dispositions of the Category "A" human engineering discrepancies (HEDs) have been updated and are included in the CRDR Human Engineering Discrepancy Resolution Report (see HL&P letter ST-HL-AE-1228, April 15, 1985). The three Category "A" HEDs questioned here are addressed on pages A-4 and A-5 of Appendix A.

i. Dispositions of the Category "B", "C", and "D" human engineering deficiencies (HEDs) have been updated and are included in the CRDR Human Engineering Discrepancy Resolution Report. Category "E" criteria are those checklist items that could not be reviewed prior to the control room completion. These include items such as lighting, sound, and communications. The schedule for completion

Response (Continued)

of review of Category "E" criteria is provided in response to item k below. HEDs resulting from review of Category "E" criteria are addressed in the Executive Summary Addenda and in the Human Engineering Discrepancy Resolution Report Addenda.

j. All of the following items have been or are in the process of being implemented through engineering drawings, data sheets, and specifications.

- Labels
- Annunciator tiles
- Demarcation painting
- Meter scales
- Legend light engravings and "closed corner" markings
- Recorder charts
- Vertical meter pointed color

Each of these are designed and controlled using documents which undergo 100 percent review for compliance to the STPEGS CRDR Criteria prior to issue for purchase, fabrication, and/or installation. This is a controlled design process and the purchase, fabrication, and/or installation of these items are governed by the STPEGS Quality Assurance Program. Sample checks are performed as identified in the CRDR Executive Summary Report as an additional assurance measure.

k. The STPEGS schedule for ongoing CRDR activities is located in the addenda to the CRDR Executive Summary Report, Section 5.0, schedule. The latest addendum provides a schedule for implementation of corrective actions and resolution of HEDs, which was subsequently modified in letter ST-HL-AE-3074, dated May 11, 1989, from Mr. M.A. McBurnett of the Houston Lighting & Power Company to the NRC.

Section 7A.S.5 provides a detailed list of all STPEGS CRDR reports, including addenda, which have been provided to NRC.

Figure Q620.02N-1

Figure Q620.02N-2

Figure Q620.2N-3

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Question 430.3N

In Section 8.1.4.2 you state that automatic inoperability of a bypassed status indication for the safety-related systems is provided in the main control room. IEEE 279-1971 and Regulatory Guide 1.47 require that this bypass and inoperability indication be at the system level. Verify your compliance with this requirement and amend your FSAR accordingly.

Response

Bypass and inoperable status indication is provided at the system level in accordance with Regulatory Guide (RG) 1.47. The 480 vac 30 ESF, 4160 vac 30 ESF, 125 vac Class 1E, and 125 vdc Class 1E busses are monitored for their inoperability via the specific Engineered Safety Feature(s) (ESF) components and the ESF systems that these busses power.

Question 430.73N

Incidents have occurred at nuclear power stations that indicate a deficiency in the electrical control circuitry design. These incidents included the inadvertent disabling of a component by racking out the circuit breakers for a different component.

As a result of these occurrences, we request that you perform a review of the electrical control circuits of all safety-related equipment at the plant, so as to assure that disabling of one component does not, through incorporation in other interlocking or sequencing controls, render other components inoperable. All modes of test, operation and failure should be considered. Verify and state the results of your review.

Also your procedures should be reviewed to ensure they provide that, whenever a part of a redundant system is removed from service, the portion remaining in service is functionally tested immediately after the disabling of the affected portion. Verify that your procedures include the above cited provisions.

Response

A review of control circuits has not indicated any deficiency in the electrical circuit design such that when a circuit breaker is racked out, it disables another component that is interlocked with it. The subject review is performed continuously as part of the design process to avoid such deficiencies.

Question 430.108N

Staff's review of the FSAR is guided by the current revision of the applicable regulatory guides and the referenced standards. Tables 3.12-1 and 8.1-2 list old revisions of guides and standards for STPEGS compliance. Clearly identify the differences between STPEGS design and the requirements of the current revisions of the regulatory guides and the referenced standards listed below. Justify the differences.

Guide (Standard)	Current Revision	Revision Listed in the Tables
RG 1.9	Rev. 2 (12/79)	Rev. 0 (3/71)
RG 1.63	Rev. 2 (7/78)	Rev. 0 (10/73)
RG 1.75	Rev. 2 (9/78)	Rev. 1 (1/75)
IEEE Std 338	1975 - (incorp. by RG 1.118)	1971
IEEE Std 387	1977 - (incorp.by RG 1.9)	1972

Response

Table 8.1-2 has been revised as shown:

RG 1.118 (IEEE 338-1977)
RG 1.9 (IEEE 387-1977)

Table 3.12-1 has been revised as shown:

RG 1.9, Rev. 2 (12/79), UFSAR Ref. Section 8.3.1.1.4.7, Status C
RG 1.118, Rev. 2 (6/78), UFSAR Ref. Table 8.1-2, Section 7.1.2.11, Status A

The only substantive difference between Rev. 1 and Rev. 2 of RG 1.75 is the addition of the following paragraph in Rev. 2:

> This guide addresses only some aspects of defense against the effects of fires. Additional criteria for protection against the effects of fires are provided in Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants".

STPEGS uses an alternate approach for RG 1.120 (fire protection); the criteria used is specified in BTP APCSB 9.5-1 Appendix A.

Compliance with RG 1.75, Rev. 2 is as stated in Section 8.3.1.4, with exceptions as stated in Sections 7.1.2.2.1 and 8.3.1.4.4.14, items No. 6 and 8.

Response (Continued)

The vendors have confirmed that the STPEGS electric penetration prototype tests were made in accordance with RG 1.63, Rev. 2. Also, all other aspects of the STPEGS electric penetrations meet the requirements of RG 1.63, Rev. 2.

Regarding RG 1.9, the diesel generator (DG) protective trips are tagged by the Emergency Response Facilities (ERF) computer with a time, but time resolution provided may not be sufficient to identify the first trip as depicted by Rev. 2 of RG 1.9.

Question 430.110N

Table 3.12-1 indicates the status of the following regulatory guides to be not applicable to STP design due to their implementation dates. Clearly identify where and how the STP design is not in accordance with the positions of these regulatory guides and justify the deviations.

Regulatory Guide 1.118, Rev. 1, dated 11/77
Regulatory Guide 1.108, Rev. 1, dated 8/77
Regulatory Guide 1.128, Rev. 0, dated 4/77
Regulatory Guide 1.131, Rev. 0, dated 8/77

Response

Note 69 to Table 3.12-1 indicates STPEGS conformance to Regulatory Guide (RG) 1.118.

Note 40 to Table 3.12-1 explains that STPEGS will comply with RG 1.108 with the interpretations and exceptions presented in Section 8.3.1.2.10.

The "Status on STPEGS" of RG 1.128 as shown in Table 3.12-1 was revised to "A" (conform to guide). See also revised response to Q430.14N.

Note 24 to Table 3.12-1 and Section 3.11.2.2 have been revised as described in the response to Q430.109, regarding RG 1.131.

Question 430.9N

In Section 8.2.2.1 you state that the grid will remain stable for loss of any two generators. The diagrams you provide for load flow results (Figures 8.2-6 through 8.2-9) do not show results for loss of both STPEGS generators. Update FSAR to include figure for loss of both STPEGS generators and discuss this effect on grid.

Response

Figure 8.2-12 has been added to the FSAR to show the effects of the loss of both STP Units 1 & 2 to the system grid.

Question 430.10N

Define the facility's operating limits (real and reactive power, voltage frequency and other) which have been established and provide a brief description as to how these limits were established. Also, describe the operating procedures or other provisions (presently planned) for assuring that the facility will be operated within these limits.

Response

The operating limits of the facility are governed by the rating and operating mode of the limiting major component for power generation namely the reactor, the steam generator, the main turbine generator, or the generator step-up transformers.

Refer to Section 8.2.1.5 of the UFSAR for the ratings of the generator and the main step-up transformers. The main step-up transformer bank is sized to deliver, to the 345 kV utility grid system, the maximum generator power at design power factor, less the transformer bank losses and less the auxiliary power operating load.

The operating limits are established on the basis of recommendations of Westinghouse Electric Corporation and STPNOC operating practices.

The real power limit of the turbine generator unit is 1,329 MW. This limit is the maximum guaranteed net rating of the turbine when operating within the cycle defined by design steam conditions of 1,060 psia; 551.7°F; 0.050 percent moisture at the throttle, reheating to 521.7°F; 3.5 in. Hg abs at the exhaust, 0 percent makeup, with all six stages of feedwater heating in service, and extracting steam for steam generator feed pump turbines.

The reactive power limits are shown on the reactive capability curves (MVAr vs MW). A copy of the Westinghouse Reactive Capability Curve is shown on Figure Q430.10N-1. It depicts the reactive power limits at rated voltage under different real power conditions at various power factors.
The MVAr limits at 1,329 MW in the overexcited and underexcited conditions are given below:

MW	MVAr Limits	MVA
1,329	(Lagging P.F.) 680.0 Overexcited	1,493
	(Leading P.F.) 560.0 Underexcited	1,442

The generator is capable of operation at its rated capacity with rated frequency, power factor, and gas pressure at any voltage not more than 5 percent above or below rated voltage (25 kV).

HISTORICAL INFORMATION CN-2951

Response (Continued)

During normal operation, the automatic voltage regulator and excitation system will maintain the voltage at its set value within the above limits.

The frequency limits are determined by the turbine. Westinghouse recommended limits are 59.5 Hz and 60.5 Hz. The automatic analog electro-hydraulic control system of the turbine with its load and speed control features maintains the frequency within the above limits under normal operation.

These limits will be included in the general operating procedures for power operation from 0 to 100 percent power. Applicable operating curves will be maintained in a plant curve book.

HISTORICAL INFORMATION CN-2951

Figure Q430.10N-1

Question 430.106N

Section 8.2.III.4 of the SRP requires determination that all component/ equipment from and including the switchyard to the onsite Class 1E system are included in the quality assurance program. Confirm STPEGS design for compliance.

Response

The switchyard and cable from the switchyard to the various transformers; e.g., main, standby, and emergency, were installed, inspected, and tested according to standard HL&P practices. The component/equipment from the aforementioned transformers to the onsite Class 1E system were installed, inspected, and tested according to STPEGS Quality Assurance (QA) requirements for non-Class 1E components/equipment. Since the components/equipment discussed above are not safety-related or "important to safety", the above complies with GDC 1. NUREG-0800, Section 8.2.III.4 was not applied for all of the offsite power system, but installed, inspected, and tested in accordance with standard utility high quality.

Question 430.112N

The use of a generator breaker to provide immediate access offsite power to a Class 1E bus requires the design to follow the guidelines provided in Appendix A to the SRP Section 8.2. STPEGS design utilizes generator breaker to provide immediate access offsite power to one of the redundant Class 1E onsite distribution systems. Confirm that the STPEGS design follows the guidelines for the performance and capability tests specified in section B of the reference SRP. Describe the test program with results which demonstrate the breaker's ability to perform its intended function during various modes of operation as specified in the SRP guidelines.

Response

In regard to specific guidelines of Appendix A, (Rev. 0, 7/83) to Standard Review Plan (SRP), Section 8.2 (Rev. 3, 7/83):

Item 1. The device is a circuit breaker capable of interrupting the maximum available fault current.

Item 2. STPEGS has purchased Cogenel type PKG2C breakers. Unless noted otherwise test documents listed in a) through i) below have been performed on type PKG breakers with various voltage and current ratings. The Cogenel test meets the requirements of Appendix A. The breaker will be tested every 18 months or less.

a) Dielectric withstand strength is documented by Cogenel Type Test Report No. 1738A. The test documents comply with ANSI C37.09, but were completed prior to the issue of the 1979 version of the ANSI standard. The test report is dated 1/20/76.

b) Load current switching capability is documented by Cogenel Type Test Report No. 2090A.

c) Fault current interrupting capability is documented by Cogenel Report of Performance Test No. 291-81A.

d) The rate of rise of recovery voltage (RRRV) is specified by Cogenel to be greater than 6 kV/microsecond. Justification that the system RRRV is less than circuit breaker RRRV will be provided.

e) Short term current carrying capability is documented by Cogenel Report of Performance Test No. 2283-74A. The test report is dated 4/29/74.

f) Momentary current carrying cability is documented by Cogenel Report of Performance Test No. 2945-78. The test report is dated 11/3/78.

g) The ability to interrupt magnetizing current of an unloaded station main and/or auxiliary transformer is documented by Cogenel Type Test Report No. 1720A. The test report is dated 11/24/75.

Response (Continued)

h) Thermal capability is documented by Cogenel Test Report No. HM51-02-806. The test was performed 3/15/78 to 3/17/78.

i) Mechanical operation test endurance is documented by Cogenel Type Test Report No. 1784A, dated May 1976 and Cogenel Endurance Test Report No. 314. The endurance test was performed 1/27/78 to 6/30/78.

Item 3. Offsite power is available independently of the generator breaker; manual realignment is required. (See response to Q430.111N.)

Selectivity in tripping between the generator breaker and the two associate switchyard breakers is maintained in that a separate set of relays is used for each function. Only unit differentials and ground fault detection are common. The unit differential protection zone, includes the generator breaker and a short section of plant side isophase bus. Ground fault detection is provided by relaying on the generator neutral (trips generator breaker) and on the isophase bus section on the switchyard side of the generator breaker (trips switchyard). The ground fault detectors are coordinated so that the generator neutral detector operates first. The remaining relays used for switchyard relaying are directional and do not operate for a fault on the plant side of the generator breaker.

Item 4. This addresses load break switches and is not applicable to generator breakers.

Question 430.113N

Figure 8.2-3 indicates that the standby transformers No. 1 and No. 2 are supplied from the switchyard north and south busses, respectively, through disconnect switches which do not have fault interrupting capability. In order to isolate a fault in the standby transformers 1 or 2 or their associated cable, all the six breakers on the respective 345 kV switchyard bus will have to be automatically opened. Analyze this condition and certify that the relay coordination is so designed as not to cause, directly or indirectly, tripping of the other 345 kV bus breakers and the generator bay middle breakers which may cause loss of power to the other standby transformer and unit auxiliary transformer through the main transformer.

Response

The subject condition has been analyzed and it has been certified that the relay coordination will not trip, directly or indirectly, the south bus breakers for a fault on standby transformer no. 1 or other north bus faults. South bus protection is identical and likewise only the south bus breakers will trip. Generator bay middle breakers are not directly tripped for faults on the standby transformers or other bus faults, but upon failure of the generator bus breakers to properly clear the fault, the middle breaker will trip to isolate the fault. Even upon loss of the unit, however, the standby transformer is tied to the opposite bus and remains energized. By using primary and back-up systems on the bus differential control schemes, each with respective DC station battery power supplies and separately wired trip coils, a high level of reliability can be attained. Attached are relay wiring diagrams illustrating this point and various examples of potential faults with associated sequence of events summaries.

Question 040.5

Diesel generator alarms in the control room: A review of malfunction reports of diesel generators at operating nuclear plants has uncovered that in some cases the information available to the control room operator to indicate the operational status of the diesel generator may be imprecise and could lead to misinterpretation. This can be caused by the sharing of a single annunciator station to alarm conditions that render a diesel generator unable to respond to an automatic emergency start signal and to also alarm abnormal, but not disabling, conditions. Another cause can be the use of wording of an annunciator window that does not specifically say that a diesel generator is inoperable (i.e., unable at the time to respond to an automatic emergency start signal) when in fact it is inoperable for that purpose.

Provide the alarm and control circuitry logic for the diesel generators at your facility to determine how each condition that renders a diesel generator unable to respond to an automatic emergency start signal is alarmed in the control room. These conditions include not only the trips that lock out the diesel-generator start and require manual reset, but also control switch or mode switch positions that block automatic start, loss of control voltage, insufficient starting air pressure or battery voltage, etc. This review should consider all aspects of possible diesel generator operational condition for example text conditions and operation from local control stations. One area of particular concern is the unreset conditions following a manual stop at the location station which terminates a diesel generator test and prior to resetting the diesel generator controls for enabling subsequent automatic operation.

Provide the details of your evaluation, the results and conclusions, and a tabulation of the following information:

1. All conditions that render the diesel generator incapable of responding to an automatic emergency start signal for each operating mode as discussed above;

2. The wording on the annunciator window in the control room that is alarmed for each of the conditions identified in (1);

3. Any other alarm signals not included in (1), above, that also cause the same annunciator to alarm;

4. Any condition that renders the diesel generator incapable of responding to an automatic emergency start signal which is not alarmed in the control room; and

5. Any proposed modifications resulting from this evaluation.

Response

Figure 8.3-4 (sheet 1) shows the standby diesel generator (SBDG) logic, including alarm circuitry and local operation capability, and includes all operating modes for the SBDG. The Engineered Safety Feature (ESF) Status Monitoring System provides the operator with diesel generator (DG) bypass or inoperable status information in the control room. The ESF Status Monitoring System is described in Section 7.5.4. Other systems also provide status information to the operator; e.g. indicators, annunciators, and computer alarms. However, the ESF Status Monitoring System is the specifically identified system for provision of bypass or inoperable status. This separation of functions eliminates one source of misinterpretation by the operators.

The specific information requested is provided as follows:

1. The following conditions render the DG incapable of responding to an automatic emergency start signal for all operating modes:

    a. Engine overspeed lockout not reset

    b. Generator differential lockout not reset

    c. Loss of control power

    d. Mode selector switch not in "remote" position

    e. Emergency stop push button not reset

    f. Loss of starting air pressure or starting system malfunction

    g. Start circuit inoperable

2. Each of the conditions identified in (1) is alarmed through the ESF Status Monitoring System. The wording on the windows in the control room is:

    a. OVER SP LCKOUT

    b. GEN DIFF LCKOUT

    c. LOSS DG CONT PWR

    d. MODE SEL SW NOT RMT POS

    e. EMERG STOP NOT RESET

    f. LOSS STRT AIR

    g. STRT CKT INOP

3. No other signals cause the SBDG-related ESF Status Monitoring System windows to light.

Response (Continued)

4. No other SBDG conditions (anticipated more than once per year) could render the DG incapable of responding to an emergency start signal. Manual bypass or operable status indication may be initiated for conditions occurring infrequently (less than once per year). Electrical power distribution bypass or inoperable conditions, support systems (cooling water and heating, ventilating, and air conditioning [HVAC]) bypass or inoperable status conditions and ESF load sequencer bypass or inoperable conditions are alarmed using ESF Status Monitoring windows in the same group of windows. (As indicated in Section 7.5.4, lighting of a component-level bypass/inop window also results in lighting of the system-level bypass/inop window.)

5. No modifications are required.

Question 430.16N

In Section 8.3.1 you discuss the onsite distribution system. Your discussion provides insufficient detail for evaluation. Specifically address breaker coordination and the interrupting capacities of switchgear, load centers, motor control centers, and distribution panels under maximum short circuit conditions. Provide this information including supporting drawings and amend your FSAR accordingly.

Response

Interrupting capacities of 13.8 kV and 4.l6 kV switchgear are provided in Sections 8.3.1.1.1 and 8.3.1.1.4.1, respectively. Interrupting capacities of 480 V switchgear are selected appropriately based on the fault current contribution from loads and the source at a bus. Criteria for breaker coordination for onsite power system is discussed in Section 8.3.l.l.4.6.

Maximum short circuit conditions have been calculated conservatively, by assuming the ultimate system contribution of 30 gva (the system contribution with the two STPEGS units on line, and the eight transmission circuits will be 19.41 gva) and maximum load fault current contribution (motors≥ 50 HP and with standby diesel generator during testing). The calculations will be updated with final data.

The present calculations indicate that the interrupting capacities of the equipment identified below is not exceeded under worst-case circuit conditions, with the exception of two out of four 13.8 kV switchgear which yield a negligible, yet negative interrupting capacity margin of 0.2 percent. The present calculations are acceptable considering the conservatism in the present calculations as discussed above.

		Rated Interrupting Capacity (amp,rms symm)
1.	13.8 kV Switchgear	28,000 (@ 15 kV)
2.	4.16 kV Switchgear	30,300 (@ 4.76 kV)
3.	480 V Loadcenter	30,000
4.	480V MCC	25,000
5.	120/208 V dist. Pnl	8,500

The drawings with breaker coordination curves were submitted by separate cover letter (see ST-HL-AE-1487, dated October 29, 1985).

Question 430.19N

In section 8.3.1.2.7 you state that the design and basic layout of the electrical system is structure in accordance with the basic objectives of Regulatory Guide 1.75. Your FSAR does not address the following areas in sufficient detail for evaluation.

(a) Isolation and separation of non-Class 1E and associated circuits from Class 1E circuits as covered in IEEE 384-1974 section 4.5 and 4.6.

(b) Cable splices in raceway. IEEE 384-1974 section 5.1.1.3.

(c) Physical identification by color coding of cables. IEEE 384-1974 section 5.1.2.

    (l) Were cables labeled prior to installation or were cables jackets color coded during manufacturing.

    (2) If cables were field labeled does labeling meet IEEE 384-1974 requirements.

(d) Limiting the non-Class 1E load connected to Class 1E power supplies to only those required to maintain the plant in a safe orderly condition and insuring that their connection does not degrade the capacity, capability and reliability of the Class 1E system.

(e) Sufficient slack provided in cables at building interfaces to allow building motion under DBE conditions.

(f) Separation of cable trays and conduit of redundant trains.

Provide this additional information and amend your FSAR accordingly.

<u>Response</u>

(a) Isolation and separation of non-Class 1E and associated circuits as required per IEEE 384-1974 is covered in UFSAR Section 8.3.1.4.4.4.

(b) Splicing of cables is not allowed in cable tray or rigid conduit. Splicing is performed within enclosures (totally enclosed locations including manholes, equipment, boxes, conduit fittings, etc.) that are accessible. All splices are performed with qualified material and in accordance with applicable plant procedures and specifications.

(c) Physical identification by color coding of cable for separation groups is covered in UFSAR Section 8.3.1.3. The cables either have jackets color coded during manufacture or are color coded in field in a manner of sufficient durability for the life of the plant and in accordance with IEEE 384-1974.

(d) A limited number of non-Class 1E devices are connected to Class 1E power supplies. These non-Class 1E devices are either connected through an isolation device, or are fed through breakers which are tripped by a safety injection (SI) signal. Depending upon the loading of

Response (Continued)

the Class 1E system these tripped non-Class 1E loads can be reconnected manually by the operator after all the required Class 1E loads have been connected and the SI signal reset. Also see response to Question 430.33N for more details.

(e) Sufficient slack is provided during installation in the cables at building interfaces to allow building motion under Design Basis Earthquake (DBE) conditions.

(f) Identification and separation of redundant trains is covered in UFSAR Sections 8.3.1.3 and 8.3.1.4.

Question 430.20N

Your response to question 040.9 is not acceptable. We have recently revised this position to include an added feature to the second level undervoltage protection and further clarification. Our preference is compliance with the revised position. Your response to Part 4 concerning acceptable verification testing will be required regardless of which position you opt to meet, i.e., the original criteria presented in question 040.9 or the revised version. Supplement the description of your design in the FSAR to show
conformance with the positions or provide detailed analysis to justify nonconformance.

1. In addition to the undervoltage scheme provided to detect loss of offsite power at the Class 1E busses, a second level of undervoltage protection with time delay should also be provided to protect the Class 1E equipment; this second level of undervoltage protection shall satisfy the following criteria:

    a. The selection of undervoltage and time delay setpoints shall be determined from an analysis of the voltage requirements of the Class 1E loads at all onsite system distribution levels;

    b. Two separate time delays shall be selected for the second level of undervoltage protection based on the following conditions:

        (1) The first time delay should be of a duration that establishes the existence of a sustained degraded voltage condition; i.e., something longer than a motor starting transient. Following this delay, an alarm in the control room should alert the operator to the degraded condition. The subsequent occurrence of a safety injection actuation signal (SIAS) should immediately separate the Class 1E distribution system from the offsite power system.

        (2) The second time delay should be of a limited duration such that the permanently connected Class 1E loads will not be damaged. Following this delay, if the operator has failed to restore adequate voltages, the Class 1E distribution system should be automatically separated from the offsite power system. Bases and justification must be provided in support of the actual delay chosen.

    c. The voltage sensors shall be designed to satisfy the following applicable requirements derived from IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations":

        (1) Class 1E equipment shall be utilized and shall be physically located at and electrically connected to the Class 1E switchgear.

        (2) An independent scheme shall be provided for each division of the Class 1E power system.

Question 430.20N (Continued)

(3) The undervoltage protection shall include coincidence logic on a per bus basis to preclude spurious trips of the offsite power source.

(4) The voltage sensors shall automatically initiate the disconnection of offsite power sources whenever the voltage set point and time delay limits (cited in item l.b.2, above) have been exceeded.

(5) Capability for test and calibration during power operation shall be provided.

(6) Annunciation must be provided in the control room for any bypasses incorporated in the design.

d. The Technical Specification shall include limiting conditions for operations, surveillance requirements, trip setpoints with minimum and maximum limits, and allowable values for the second-level voltage protection sensors and associated time delay devices.

2. The Class 1E bus load shedding scheme should automatically prevent shedding during sequencing of the emergency loads to the bus. The load shedding feature should, however, be reinstated upon completion of the load sequencing action. The Technical Specifications must include a test requirement to demonstrate the operability of the automatic bypass and reinstatement features at least once per l8 months during shutdown.

   In the event an adequate basis can be provided for retaining the load shed feature during the above transient conditions, the setpoint value in the Technical Specifications for the first level of undervoltage protection (loss of offsite power) must specify a value having maximum and minimum limits. The basis for the setpoints and limits selected must be documented.

3. The voltage levels at the safety-related busses should be optimized for the maximum and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power sources by appropriate adjustment of the voltage tap settings of the intervening transformers. The tap settings selected should be based on an analysis of the voltage at the terminals of the Class 1E loads. The analyses performed to determine minimum operating voltages should typically consider maximum unit steady state and transient loads for events such as a unit trip, loss of coolant accident, startup or shutdown; with the offsite power supply (grid) at minimum anticipated voltage and only the offsite source being considered available. Maximum voltages should be analyzed with the offsite power supply (grid) at maximum expected voltage concurrent with minimum unit loads; e.g. cold shutdown, refueling. A separate set of the above analyses should be performed for each available connection to the offsite power supply.

Question 430.20N (Continued)

4. The analytical techniques and assumptions used in the voltage analysis cited in item 3 above must be verified by actual measurement. The verification and test should be performed prior to initial full power reactor operation on all sources of offsite power by:

   a. Loading the station distribution busses, including all Class 1E busses down to the 120/208 volt level, to at least 30 percent

   b. Recording the existing grid and Class 1E bus voltages and bus loading down to the l20/208 volt level at steady state conditions and during starting of both a large Class 1E and non-Class 1E motor (not concurrently)

      Note: To minimize the number of instrumented locations, (recorders) during the motor starting transient tests, the bus voltages and loading need only be recorded on that string of busses which previously showed the lowest analyzed voltages from item 3, above.

   c. Using the analytical techniques and assumptions of the previous voltage analysis cited in item 3 above, and the measured existing grid voltage and bus loading conditions recorded during conduct of the test, calculate a new set of voltages for all Class 1E busses down to the l20/208 volt level

   d. Compare the analytically derived voltage values against the test results

   With good correlation between the analytical results and the test results, the test verification requirement will be met. That is, the validity of the mathematical model used in performance of the analyses of item 3 will have been established; therefore, the validity of the results of the analysis is also established. In general the test results should not be more than 3 percent lower than the analytical results; however, the differences between the two when subtracted from the voltage levels determined in the original analyses should never be less than the Class 1E equipment rated voltages.

Response

1. Two undervoltage sensing schemes are employed for each Class 1E 4.16 kV bus to provide two levels of undervoltage protection. The first scheme detects loss of voltage and the second scheme detects degraded voltage conditions on the bus. Voltage signals to each scheme are provided through four potential transformers connected to each bus. Four solid state type instantaneous undervoltage relays and four time delay relays are used for the first scheme (loss of voltage). The devices used for the second scheme (degraded voltage) include four solid state type instantaneous undervoltage relays and two sets of four time delay relays.

Response (Continued)

The first set provides for an alarm only, and the second set initiates a logic signal as shown on Figure 8.3-4.

a. The devices for the first (loss of voltage) scheme are set to operate after a time delay setpoint of 1.75 seconds at 74.7 percent of nominal voltage, which is below the minimum expected voltage during diesel generator sequencing. A 1.75 second time delay is provided to prevent spurious initiation of the logic signal due to a transient dip in voltage. The 74.7 percent voltage setpoint results in a relay operating range, including tolerance, of 71.6 percent to 77.6 percent of nominal voltage.

   The degraded voltage relays are set to operate at 92.2 percent of 4.16 kV, which corresponds to 90 percent of 480 volts at the bus of the worst case motor control center (MCC). The worst case MCC is determined based on the maximum voltage drop from the 4.16 kV switchgear bus to the MCC bus with the lowest offsite system voltage and maximum in plant load conditions.

b. (1) The first set of time delay relays used in the degraded voltage scheme are set to operate after 35 seconds and provide an alarm in the control room to alert the operator. The setpoint is longer than the worst case motor accelerating time of approximately 30.6 seconds at 80 percent rated voltage for the Essential Cooling Water Pump drive motor. The logic is set up to trip the offsite source feeder breaker in the event of a subsequent occurrence of safety injection actuation signal (SIAS) in order to separate the Class 1E distribution system from the degraded offsite source.

   (2) The second set of time delay relays used in the degraded voltage are set to operate at 50 seconds to initiate separation of the system from the degraded source. Analysis of motor thermal damage curves indicates that the loads are capable of withstanding 70 percent of nominal voltage, for a duration of more than 50 seconds without damage.

c. The undervoltage sensors are designed to satisfy the following applicable requirements derived for IEEE 279-1971 "Criteria for Protection Systems for Nuclear Power Generating Stations".

   (1) Class 1E equipment is utilized, physically located in and electrically connected to the Class 1E switchgear.

   (2) An independent scheme is provided for each division of the Class 1E power system.

   (3) The undervoltage protection uses coincident logic on a per bus basis to preclude spurious trips of the offsite power source. This is shown in Figure 8.3-4, sheets 2 and 5.

Response (Continued)

(4) The undervoltage relays automatically initiate disconnection of the offsite power source in the event the voltage setpoint and time delay limits (cited in item 1.b.2, above) are exceeded.

(5) The undervoltage relays can be tested and calibrated during power operation.

(6) Annunciation is provided in the control room in the event any of the undervoltage relays operate. The relay test procedures require that some alarms be activated during testing of an undervoltage relay by applying a shorting link to the test switch used to isolate the relay. The shorting link energizes the timer that is used to provide the alarm.

d. The Technical Specifications includes setpoints, with minimum or maximum limits, as applicable, for the loss of voltage and degraded voltage relays, and associated time delay relays.

2. The design of the bus loading scheme does not permit sequencing and shedding of emergency loads at the same time. See Figure 8.3-4 and Section 8.3.1.1.4.4 for a description of the load shedding scheme. In the event a mode I or mode II recognition signal is received, while load sequencing is in progress, the logic is such that further sequencing of loads stops immediately. The emergency loads already connected to the bus by the sequencer are shed and the sequencer is restarted from step 1. Westinghouse indicates that, based on sensitivity studies (WCAP-8471), the time delay due to stopping and restarting of sequencer under the worst condition is within the acceptable limit of LOCA analysis.

   Upon completion of sequencing, load shedding reinstatement is accomplished by manually resetting the reset button in the Main Control Room or at the sequencer panel. Note that manual resetting prevents inadvertent excessive starting of motors. The Technical Specifications include testing of the automatically bypassed load shed and manual operation of load shed reinstatement.

   Since simultaneous occurrence of sequencing and shedding of emergency loads is precluded per logic design, it is not necessary to include the first level undervoltage relay setpoint limits in the Technical Specifications.

3. A voltage analysis was performed in accordance with BTP PSB-1, Position 3. Optimum transformer tap settings have been selected to maintain terminal voltage levels within 90-110 percent of rated voltage during steady state operation, and at 80 percent or above during motor starting (75 percent or above for starting the Reactor Containment Fan Cooler motors). The tap settings selected are based on the results of the analysis which calculates bus and terminal voltage levels for various worst case plant operating modes and loading conditions (normal, startup, LOCA, and shutdown). In the analysis, particular emphasis is placed on analyzing the voltage levels at those loads which are supplied

Response (Continued)

through the standby transformer. The basis for this is that these loads will be susceptible to voltage violations in the offsite system (0.96-1.02 p.u.), as opposed to loads supplied through the unit auxiliary transformer, which has an automatic tap changer.

Minimum steady state voltage levels were determined by considering the following:

- Maximum loading of the standby transformers assuming that Unit 1 unit auxiliary transformer is not available
- Operation of Class 1E loads required during a LOCA
- Minimum system voltage (e.g., 0.96 p.u.)

Minimum transient voltage levels were determined by considering the above scenario and emulating the Class 1E load starting profile of the ESF load sequencer, which includes the simultaneous starting of Class 1E 4.16 kV and 480 V motors.

Maximum bus voltage levels were determined by considering maximum anticipated grid voltage (1.02 p.u.) concurrent with each standby transformer winding exclusively supplying a safety-related train under light load conditions; e.g., less than 25 percent of LOCA loads.

The various interconnections to the offsite power system are documented and discussed in the analysis. Only those arrangements that are representative of the worst case conditions (e.g., max-min loading and system voltage levels), as discussed above, were analyzed in detail.

4. Field verification of the analytical techniques and assumptions used in the voltage analysis were accomplished and documented.

Question 430.21N

In FSAR Section 8.3.l you state that protection of the electrical penetrations is provided by source and feeder breakers with a backup means of sizing the penetration conductors larger than the cable, thus taking advantage of the self-fusing concept. This concept is unacceptable to the staff because of the inherent fire hazards in such an approach. Additionally in your response to question 040.07 on this subject you discuss overcurrent protection of the electrical penetrations, including the primary and backup protection; however, the coordination curves shown on sheets 1 and 6 show only a single curve of overcurrent protection. You also state in section 4.d of the response that fuses are used for backup protection; the coordination curves for 14 A.W.G penetration on sheet 10 do not show a curve for this fuse. The time current curves do not show the instantaneous and time delay curves for all circuit breakers used and does not relate those breakers to a single line diagram for the circuit application. Modify your time current coordination curves for each size penetration to include penetration rating, curves for instantaneous, long and short time overcurrent trips provided by primary and backup protective devices. Additionally provide a single line diagram and a drawing that shows circuit configuration and breaker coordination.

Response

Power and control field cables to the electric penetrations are capable of carrying the load circuit based on the penetration conductor ampacity, as calculated for the electric penetration protection. Credit for self-fusing concept of field conductors has not been taken. See Section 8.3.l.l.5.

Coordination curves with single line diagram showing circuit configuration of each type of penetration conductor was submitted in letter ST-HL-AE-1687 dated June 11, 1986.

The types of circuits that go through penetration assemblies are as follows:

1. Power feeders for medium voltage 13.2 kV motors

2. 480 vac load center power feeders

3. 480 vac motor control center power feeders

4. 120 vac miscellaneous power feeders

5. 120 vac vital circuits

6. 120 vac control circuits

7. 125 vdc power circuits

8. 125 vdc control circuits

9. Control rod drive mechanism (CRDM) circuits

Response (Continued)

10. Instrument circuits

11. Communication circuits

The following system features are provided to ensure compliance with the Regulatory Guide (RG) 1.63 position in regard to single random failures of circuit overcurrent protective devices:

1. Medium voltage penetration assemblies: The only medium voltage circuits routed through the penetration are for the 13.2 kV, non-Class 1E reactor coolant pump motors. Two 1000 kcmil conductors per phase have been used in each of four penetration assemblies for these circuits. Primary and backup protection for the penetration conductors are provided by the switchgear source and feeder breaker overcurrent relays. Curve no. 1 shown that the time-current capability of the 1000 kcmil penetration conductors is greater than any maximum short circuit current vs. time condition that could possibly occur even if one relay fails. Thus, the penetration conductors are protected against any overcurrent in the event of a single random failure of a protective device.

2. 480 vac load center power feeders: 3-300 hp Residual Heat Removal (RHR) Pumps and 6-150 hp Reactor Containment Fan Cooler (RCFC) Supply Fans are supplied from 480 V load centers. All other 480 V loads inside the containment are fed from 480 V Motor Control Centers (MCCs). The RHR and RCFC circuit penetration conductors are protected by the load center solid state overcurrent trip devices. The primary and backup protection is provided by the load center feeder and source breaker trip devices respectively, as shown on curve nos. 2 and 3.

3. 480 vac MCC power feeders: The circuits for motor loads fed from MCCs are provided with an additional thermal-magnetic (TM) circuit breaker in series with the magnetic-only circuit breaker used in the combination starter for each motor. The TM breakers are generally located in separate cubicles of the MCCs and they provide backup protection for the associated penetration conductors. The magnetic-only breakers together with the starter thermal overload relays provide the primary protection. Curves nos. 4 through 10 show that the protective devices provide satisfactory primary and backup protection for the penetration conductors used for the continuous duty motor load circuits.

   For Class 1E motor operated valves (MOVs), the thermal overload relay contacts are bypassed to comply with RG 1.106. The contacts are wired to provide alarm only. Therefore, primary protection for the Class 1E MOV circuits, provided by the magnetic-only breaker, is for short circuit only. For these Class 1E MOVs, the backup breakers are selected to allow for sustained locked rotor current, and the penetration conductors are selected large enough to ensure that the thermal limits of the penetrations are not exceeded. The selected penetration conductors are capable of carrying motor locked rotor current continuously. Curves nos. 11 through 19 show the thermal damage curves for penetration conductors for Class 1E MOVs and the associated time-current curves for primary and backup protective devices. Curves

Response (Continued)

nos. 20 through 22 show similar coordination curves for the non-Class 1E MOV circuits. Non-Class 1E 480 V MCCs supply power to miscellaneous in-Containment loads such as lighting transformers, reactor coolant pump motor space heaters, incore detector drive units, fuel handling control panel, etc. Each of these power feeders is furnished with two TM breakers in series to provide primary and backup protection for the associated penetration conductors. These breakers have generally the same rating and are located in separate cubicles of the MCC. The ratings of both series connected breakers are selected that in the event of an overcurrent, the breakers trip before the thermal limits of penetration conductors are reached. Curves nos. 23 through 29 demonstrate the operation of the breakers under such overcurrent conditions.

4. 120 vac miscellaneous power feeders: 120/208 V distribution panels provide 120 vac power to motor space heaters, instrument enclosure space heaters, and other small miscellaneous loads. These circuits are furnished with TM breakers and fuses in series to provide primary and backup protection for the associated penetration conductors. The TM breakers are located in the 120/208 V distribution panels, and the fuses are located separately from the distribution panels. Curves nos. 30 through 32 show that the protective devices used provide adequate protection for the penetration conductors.

5. 120 vac vital circuits: There are only two 120 vac vital circuits routed through penetrations. These circuits originate from the uninterrupted power supply (UPS) distribution panel and they provide power to digital rod position indication (DRPI) data cabinets A&B located inside the Containment. Two TM circuit breakers in series are used in each circuit to provide primary and backup protection for the associated penetration conductors. The breakers have same rating and they are housed in separate enclosures. Curve no. 33 shows that the breaker time-current characteristics curves are well under the thermal damage curve of the penetration conductors, thus the breakers provide satisfactory protection for the penetration conductors.

6. 120 vac control circuits: 120 vac control circuits originating from MCCs are powered by 480/120 vac control power transformers (CPT) located in the MCC cubicles. Each of the circuits are provided with two fuses in series except for those cases where available maximum short circuit current is demonstrated to be less than the ampacity of the minimum size (10 AWG) penetration conductors used for control circuits. The short circuit study shows that for 100 and 150 VA CPT circuits the maximum available fault current is less than the ampacity (32A) of the associated 10 AWG penetration conductors. These circuits are not furnished with an additional fuse as backup because the integrity of the penetration will not be jeopardized even in the event of a sustained fault. Curve no. 34 shows that two fuses, 3A and 6A, connected in series provide satisfactory primary and backup protection for the 10 AWG penetration conductors.

Response (Continued)

Curve no. 35 shows protection coordination for other 120 vac control circuits that originate from the auxiliary relay panels, isolation relay panels, or miscellaneous control panels (ZLP panels). The primary protection is provided by a fuse, 15A or less, used for each circuit. The backup protection is provided by the 20A TM main breaker used for each panel.

7. 125 vdc power circuits: There are only two 125 vdc power feeders that go through Containment penetrations. These feeders provide power to the solenoid operated reactor coolant pressurizer power relief valves. Two TM breakers, connected in series, are used in each circuit to provide the primary and backup protection for the associated penetration conductors. The breakers are located in the 125 vdc distribution switchboard. Curve no. 36 illustrates that the penetration conductors are satisfactorily protected.

8. 125 vdc control circuits: The 125 vdc control circuits routed through penetration assembly are generally powered from the auxiliary relay panels or isolation relay panels. Each circuit is furnished with a 15A, or less, fuse which provides the primary protection for the associated penetration conductors. The 20A TM main breakers, used for each relay panel, provides the backup protection as in the case of 120 vac control circuits. See Curve no. 35. The curves show that the fuse with TM breakers provide satisfactory primary and backup protection for the 10 AWG penetration conductors.

   There are a few 125 vdc control circuits which are not powered from relay panels. These circuits are for RCFC fans and they are powered from the load center 125 vdc control bus. Each of these circuits is provided with two fuses in series in each lead, one located in the load center and the other in the transfer panel. These fuses provide primary and backup protection for the 10 AWG penetration conductors as shown on curve no. 38.

9. Control rod drive mechanism (CRDM) circuits: DC power to the CRDM circuits is provided by motor-generator sets through a series of rectifiers located in the CRDM power cabinets. The maximum fault current available for a fault inside the Containment is limited by the inherent current limiting feature of the rectifier. The CRDM lift power circuits are protected by two 50A fuses, one in the positive lead and other in the negative lead. The CRDM stationary, or moving gripper, power circuits are protected by two fuses, one in each lead. The two fuses in each circuit provide both primary and backup protection because the DC distribution system for the CRDM is ungrounded. Curve no. 37 demonstrates that the penetration conductors are well protected against circuit overcurrent.

10. Instrument circuits: Instrument circuits are all low energy circuits carrying only a few milliamperes. Also these circuits are routed in separate raceways from power and control cables to preclude the possibility of a short between the instrument and other circuits.

Response (Continued)

Therefore, fault current exceeding the ampacity of 16 AWG (minimum size used) penetration conductors under any faulted condition is not credible. Hence, backup protection for the instrument circuit penetration conductors is not required. Primary protection is, however, provided by the devices which are integral with the power supply to the circuits.

11. Communication circuits: There are three types of communication circuits, telephone, paging, and maintenance jack, that are routed through penetration assemblies. All of these circuits are low energy circuits and routed in separate raceways from power and control circuits. These circuits cannot have significant short circuit current to pose a threat to the penetration assembly. Therefore backup protection for the associated penetration conductors (19 AWG) is not provided.

Question 430.23N

Provide a listing of all Class 1E and l3.8 kV non-Class 1E switchgear (by bus nomenclature) within the design and specifically address the source of control power to each. This is needed to facilitate an independent review of how your emergency power system design meets the single failure criterion and to determine the extent of loss due to postulated failures.

Response

Refer to Table Q430.23N-1.

TABLE Q430.23N-1

CONTROL POWER SOURCES

Bus Description	Control Power Source
13.8 kV Non-Class 1E Bus lF Except RCP 1A Circuit Bkr	125 vdc Dist. PNL PL125E (125 V Non-Class 1E Battery)
13.8 kV Non-Class 1E Bus lG Except RCP 1B Circuit Bkr.	125 vdc Dist. PNL PL125B (125 V Non-Class 1E Battery)
13.8 kV Non-Class 1E Bus lH Except RCP 1C Circuit Bkr.	125 vdc Dist. PNL PL125E (125 V Non-Class 1E Battery)
13.8 kV Non-Class 1E Bus 1J Except RCP lD Circuit Bkr.	125 vdc Dist. PNL PL125B (125 V Non-Class 1E Battery)
RCP Feeder Bkrs. 1A, B, C, and D	125 vdc Dist. PNL PL125K (125 V Non-Class 1E Battery)
4.16 kV Non-Class 1E Bus 1D1	125 vdc Dist. PNL PL125A
4.16 kV Non-Class 1E Bus 1D2	125 vdc Dist. PNL PL125A
4.16 kV Class 1E Bus E1A	125 vdc Class 1E Dist. SWBD E1A11 (125 V Class 1E Battery)
4.16 kV Class 1E Bus E1B	125 vdc Class 1E Dist. SWBD E1B11 (125 V Class 1E Battey)
4.16 kV Class 1E Bus E1C	125 vdc Class 1E Dist. SWBD E1C11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1Al	125 vdc Class 1E Dist. SWBD E1A11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1A2	125 vdc Class 1E Dist. SWBD E1A11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1Bl	125 vdc Class 1E Dist. SWBD E1B11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1B2	125 vdc Class 1E Dist. SWBD E1B11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1Cl	125 vdc Class 1E Dist. SWBD E1C11 (125 V Class 1E Battery)
480 V Class 1E 4L Bus E1C2	125 vdc Class 1E Dist. SWBD E1C11 (125 V Class 1E Battery)

TABLE Q430.23N-1 (Continued)

CONTROL POWER SOURCES

Bus Description	Control Power Source
Reactor Trip SWGR 'R'	125 vdc Class 1E Dist. SWBD E1A11 (125 V Class 1E Battery)
Reactor Trip SWGR 'S'	125 vdc Class 1E Dist. SWBD E1B11 (125 V Class 1E Battery)

Question 430.24N

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

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

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

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

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

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

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

Response

See Section 9.5.5.6 for a description of the loading of the diesel generators (DGs) for testing and troubleshooting.

The Preventive Maintenance (PM) program includes directions to review PM documentation for information pertaining to equipment failure trends, frequency, and the root causes of failures. This program will identify and track equipment failure and determine the root causes of failures.

The Maintenance Work Request (MWR) program includes directions to review the MWR package for information pertaining to equipment failure trends, frequency, and the root causes of failures. This program will identify and track equipment failures and determine root causes of failure which require corrective maintenance.

The procedure for returning the DG to an operable status following maintenance will incorporate a final equipment check to assure that electrical circuits are functional.

STPEGS has procedural commitments to perform reviews of equipment failures. Based on these reviews, design changes are considered which would improve reliability.

Maintenance is performed in accordance with written procedures, which require verification or testing to ensure that equipment meets its design requirements prior to being declared operable. Refer to Section 13.5.1.3.

For STPEGS's position on Regulatory Guide (RG) 1.108, see the response to Q430.11N.

Question 430.25N

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

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

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

Response

The engine and generator control and instrumentation panels are physically located approximately 12 ft from the diesel generator (DG) at an elevation of 10 ft above the bottom of the generator. The natural frequency of the DG and foundation system is lower than the machine speed. Also, the ratio of foundation weight to the DG weight is approximately eight. Transmission of vibratory motion from the DG to the engine and generator panel is considered insignificant.

In addition the control panels were seismically tested and the Test Response Spectra curves envelope the Required Response Spectra curves by a margin of more than 10 percent. The panels were also tested to the equivalent of 5 Operating Basis Earthquakes (OBEs).

The location and mounting arrangement of the DG control panel has been reviewed with the manufacturer and they have indicated that the configuration is acceptable from a vibration standpoint.

Question 430.26N

It has been noted during past reviews that pressure switches or other devices were incorporated into the final actuation control circuitry for large horsepower safety-related motors which are used to drive pumps. These switches or devices preclude automatic (safety signal) and manual operation of the motor/pump combination unless permissive conditions such as lube oil pressure are satisfied. Accordingly, identify any safety-related motor/pump combinations which are used in the STPEGS design that operate as noted above. Also, describe the redundancy and diversity which is provided for the pressure switches or permissive devices that are used in this manner.

Response

There are not any large horsepower safety-related motor/pump combinations where process devices (used as start permissives in the final actuation control circuit) would preclude the automatic (safety signal) and manual operation of the equipment on STPEGS.

Question 430.27N

Identify all electrical equipment, both safety and non-safety, that may become submerged as a result of a LOCA. For all such equipment that is not qualified for service in such an environment provide an analysis to determine the following:

1. The safety significance of the failure of this electrical equipment (e.g., spurious actuation or loss of actuation function) as a result of flooding.

2. The effects on Class 1E electrical power sources serving this equipment as a result of such submergence.

3. Any proposed design changes resulting from this analysis.

Response

All electrical equipment subject to submergence during the maximum postulated LOCA are identified in Table Q430.27N-1 along with the anticipated result of such submergence. For additional listing of instrumentation and control items see response to Question Q32.35. For protection of penetration integrity see response to Question 430.2lN.

TABLE Q430.27N-1

EQUIPMENT BELOW RCB MAXIMUM FLOOD ELEVATION
FAILURE EFFECT FOR EQUIPMENT

Equipment No.	Service Description	Open Circuit	Short Circuit	Safety Related	Effect on Class 1E Power Source
9Q061NPA101A	Normal Sump Pump 1A	Pump Inoperative	Motor Destroyed	No	None
9Q061NPA101B	Normal Sump Pump 1B	Pump Inoperative	Motor Destroyed	No	None
9E171ECS7561	Normal Sump Pump Test P.B. Station	None	Pump May Get Started	No	None
9Q061NPA102A	Sec. Containment Normal Sump Pump 1A	Pump Inoperative	Motor Destroyed	No	None
9E171ECS7563	Test P.B. Station For Sec. Cont. Normal Sump Pump	None	Pump May Get Started	No	None
8V141VFN023	Reactor Cavity Vent Fan No. 11A	Fan Inoperative	Motor Destroyed	No	None
8V141VFN024	Reactor Cavity Vent Fan No. 11B	Fan Inoperative	Motor Destroyed	No	None
7R301NPA107A	Reactor Coolant Drain Tank Pump 1A	Pump Inoperative	Motor Destroyed	No	None
7R301NPA107B	Reactor Coolant Drain Tank Pump 1B	Pump Inoperative	Motor Destroyed	No	None
9E591ERP0002	Welding Receptacle	Inoperative	Receptacle Destroyed	No	None

Question 430.28N

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

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

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

Response

The training program for supervisors, operators, and maintenance personnel described in Chapter 13 includes training on the standby diesel generators (SBDGs).

The Nuclear Training group wil initially provide training to appropriate Nuclear Plant Operations Department (NPOD) and Nuclear Training Department personnel. This training will be equivalent or similar to the vendor or manufacaturer's training program. Depending on the discipline, this training is expected to last from two to five days involving a combination of classroom, demonstrations/tours, and walk throughs, as appropriate. This training will be completed prior to NPOD assuming operational and maintenance responsibility for the SBDGs from Startup. Retraining will be factored in to appropriate requalification or retraining programs as well as integrated into appropriate apprentice training programs. The goal of the initial and retraining programs is to identify specific job responsibilities and train personnel accordingly thus assuring optimum availability of the SBDG.

Specific personnel are not exclusively dedicated to the SBDGs. The level of education, experience, numbers, and type of personnel assigned to supervision, operation and maintenance is described in Chapter 13. The criteria stated in Chapter 13 apply to DGs as well as other plant systems and components.

The training, education, experience, and staffing of QA personnel is described in Chapter 17.

Question 430.29N

Recent experience with Nuclear Power Plant Class 1E electrical system equipment protective relay applications has established that relay trip setpoints drifts with conventional type relays have resulted in premature trips of redundant safety-related system pump motors when the safety system was required to be operative. While the basic need for proper protection for feeders/equipment against permanent faults is recognized, it is the staff's position that total non-availability of redundant safety systems due to spurious trips in protective relays is not acceptable.

Provide a description of your circuit protection criteria for safety systems/equipment to avoid incorrect initial setpoint selection and the above cited protective relay trip setpoint drift problems.

Response

Primary relays and direct acting trip devices at STPEGS are solid state type and thus subject to minimal setpoint drift. The short circuit protection system is analyzed to determine correct setpoints for the protective devices. During preoperation testing the protective devices are tested to verify operability at the correct setpoints.

Questions 430.32N

Provide the results of a review of your operating, maintenance, and testing procedures to determine the extent of usage of jumpers or other temporary forms of bypassing functions for operating, testing, or maintaining of safety related systems. Identify and justify any cases where the use of the above methods cannot be avoided. Provide the criteria for any use of jumpers for testing.

Response

The problems associated with use of jumpers are recognized and administrative controls have been developed to control their use. In general, jumpers and temporary bypasses will only be used in safety-related systems when no other practical means is available to accomplish a necessary operating, maintenance, or testing function. If it becomes necessary to use a jumper or temporary bypass in a safety system, such use will be controlled by approved procedures. Incorporation of the safeguards test features described in UFSAR Section 7.3.1.2.2.5.4 should minimize such occurrences.

Question 430.35N

In FSAR section 8.3.2.1.3 you indicate that each battery charger is equipped with a DC voltmeter, ammeter, AC failure relay, DC output circuit breaker and DC low voltage alarm relay with the position status of the battery circuit breakers, the DC output circuit breaker of the charger, and the main breakers feeding the charger indicated in the control room and alarmed when off normal. As an optimum we require that the following indications and alarms of the Class 1E DC power system status be provided in the control room:

a) battery charger output current (ammeter)

b) battery current (ammeter-charge/discharge)

c) DC bus voltage voltmeter

d) battery charger output voltage (voltmeter)

e) battery high discharge rate ALARM

f) DC bus ground alarm (for ungrounded systems)

g) battery breaker(s) or fuse(s) open alarm

h) battery charger output breaker(s) or fuse(s) open alarm

i) battery charger trouble alarm (one alarm for a number of abnormal conditions which are usually indicated locally).

Confirm compliance with the above requirements or provide adequate justification for any deviations.

Response

See revised Sections 8.3.2.1.1, 8.3.2.1.2, and 8.3.2.1.3. Battery high discharge rate is not alarmed in the control room because the discharge rate of the battery varies with time, so an overcurrent setting on the sensing device cannot be provided without generating nuisance alarms. The proposed DC bus voltage indicator in the control room, supplemented by DC bus undervoltage alarm, provides adequate information to the operator regarding the battery status.

Question 430.37N

Provide a description of the capability of emergency power system battery chargers to properly function and remain stable upon the disconnection of the battery. Include in the description any foreseen modes of operation that would require battery disconnection such as when applying an equalizing charge. State if the stability of the battery charger output is load dependent and if so describe. Additionally discuss the capability of the battery charger to operate all required accident loads assuming the battery is not available. Amend your FSAR accordingly.

Response

The Class 1E power system battery chargers are qualified to STP specifications with or without a battery connected. Basis is similarity to the battery charger that was tested to document the equipment environmental qualification report.

Powering the switchboard with a battery charger with no battery connected during operation is not a design basis, and using the active charger in this manner requires entry into an LCO condition.

Examples of conditions under which a charger might be operated without a battery connected are: 1) disconnecting the battery to remove or replace a defective cell, 2) service, capacity or discharge testing, or 3) the battery charger (standby charger) load test. Disconnecting the battery is not required for application of an equalization charge.

No stabilization problems have been encountered on the battery chargers from no load to full load.

Amendments #73 and #62 to the facility operating licenses were issued on the basis of demonstrated ability of a single battery charger to maintain operability of the affected channel at design loading.

The battery chargers were designed to comply with NEMA Standard PV-5-1976.

Question 430.38N

In section 8.3.2.1.6 and 8.3.2.3 you state "The bus supply breakers of the 13.8 kV auxiliary busses provide the 125 vdc control power from the independent 125 vdc system". Clarify this statement. Also provide discussion on the capability to transfer from offsite to onsite power or onsite to offsite in sufficient time to prevent fuel damage should 125 vdc control power be lost. Amend your FSAR accordingly.

Response

All 13.8 kV breakers are supplied control power from the non-Class 1E 125 vdc bus. The main generator breaker is supplied control power from the non-Class 1E 250 vdc bus. On loss of control power these breakers neither trip nor close but remain in position. The loss of power to the 125 vdc or 250 vdc bus or loss of control power to these breakers is indicated in the control room.

The aforementioned breakers are capable of being manually operated. The 13.8 kV breakers are the stored energy type using charged springs to provide a minimum of one closing and opening operation upon loss of 125 vdc. The main generator breaker is the stored energy type using compressed air to provide a minimum of one closing and opening operation; the compressor motor is 460 VAC. These stored energy systems can be manually released to open or close the breakers upon loss of 125 vdc.

In the event of loss of offsite power due to the inability to electrically operate (i.e., loss of the non-Class 1E DC systems) the 13.8 kV and generator circuit breakers, the respective ESF bus would be manually isolated and supplied power from its DG. After manually operating the necessary 13.8 kV and/or generator circuit breakers, the offsite power source can be paralleled to the DG and then the breaker to the DG tripped.

Note, this question is no longer applicable to the referenced sections.

Question 430.39N

Concerning the emergency load sequencers which are associated with the offsite and onsite power sources we require that you either provide a separate sequencer for offsite and onsite power (per electrical division) or a detailed analysis to demonstrate that there are no credible sneak circuits or common failures modes in sequencer design that could render both onsite and offsite power sources unavailable. In addition provide information concerning the reliability of your sequencer and reference design detailed drawings.

Response

Section 8.3.1.1.4.4 has been revised (in response to NRC Question 430.33N) to provide reliability data for the Engineered Safety Feature(s) (ESF) load sequencers. The following discussion is provided to support the existing system design which utilizes one ESF load sequencer for each redundant Engineered Safety Features Actuation System (ESFAS) channel.

On receipt of an safety injection (SI) signal (Mode I), the ESF load sequencer will sequence the equipment required in programmed steps to the preferred (offsite) power source.

On loss of offsite power (LOOP) (Mode II) the ESF load sequencer will initiate the following:

(a) Shed all loads on the 4.16 kV ESF bus (except the load center primary breakers).

(b) Start the standby diesel generator (DG) and enter it into isochronous mode and the voltage regulator into the automatic mode. Under these conditions, all non-critical protective devices are bypassed as described in Section 8.3.1.1.4.6.

(c) Trip the ESF 4.16 kV preferred source (offsite) power supply breaker.

(d) Energize the equipment required in programmed steps.

Tripping the offsite power supply breaker will isolate the Class 1E onsite power system. There is, therefore, no possibility of subsequent interaction between the load shed and the offsite power system. After load shed, tripping of the 4.16 kV ESF bus offsite supply breaker and subsequent closing of the DG breaker to the 4.16 kV ESF bus, the undervoltage relays now monitor the standby (onsite) power supply for an undervoltage occurrence.

No bypass of the undervoltage relays to prevent interaction of offsite power with the shed feature is required because the relays are transferred with the 4.16 kV ESF bus from offsite power (preferred) to onsite power (standby) on LOOP.

Response (Continued)

If a separate sequencer were provided so that one could be used to sequence the safety-related loads on offsite power and the other could be used to sequence safety-related loads on onsite power, it would be incorporated as an integral part of the same redundant load group of the existing sequencer. As a result, the power supplies for the separate sequencing systems would be derived from the same load group power source, and the sequencers would be electrically interconnected. As such, no independence or significant increase in reliability would be achieved by the addition of another sequencer.

The existing design implements the applicable criteria with sufficient assurance of proper operation independence.

Question 430.74N

Operating experience at two nuclear power plants has shown that during periodic surveillance testing of a standby diesel generator, initiation of an emergency start signal (LOCA or LOOP) resulted in the diesel failing to start and perform its function due to depletion of the starting air supply from repeated activation of the starting relay. This event occurred as the result of inadequate procedures and from a hang-up in engine starting and control circuit logic failing to address a built-in time delay relay to assure the engine comes to a complete stop before attempting a restart. During the period that the relay was timing out, fuel to the engine was blocked while the starting air was uninhibited. This condition with repeated start attempts depleted starting air and rendered the diesel generator unavailable until the air system could be repressurized.

Review procedures and control system logic to assure this event will not occur at your plant. Provide a detailed discussion of how your system design, supplemented by procedures, precludes an occurrence of this event. Should the diesel generator starting and control circuit logic and procedures require changes, provide a description of the proposed modifications. (Refer to Request 430.96 for control air requirements) (SRP 8.3.1, Part II and III)

Response

HL&P has reviewed the standby diesel control system logics and has determined that the diesel does not have the built-in time delay feature which requires the engine to come to a complete stop before attempting to restart.

Question 430.116N

Section 6.4.2 of IEEE Standard 387-1977 requires, in part, that the load acceptance test consider the potential effects on load acceptance after prolonged no load or light load operation of the diesel generator. Provide the results of load acceptance tests or analysis that demonstrates the capability of the diesel generator to accept the design accident load sequence after prolonged no load operation. This capability should be demonstrated over the full range of ambient air temperatures that may exist at the diesel engine air intake. If this capability cannot be demonstrated for minimum ambient air temperature conditions, describe design provision that will assure an acceptable engine air intake temperature during no load operation.

Response

The diesel generator (DG) specification requires that the DG be capable of running at no load for one hour without deterioration of the engine, generator or auxiliaries. In order to enhance the DG availability, the manufacturer recommends that for each 6 hours of cumulative no load operation, the DG should be run at least 15 minutes at 75 percent or greater load. This is accomplished by manually synchronizing the DG with the offsite power supply and loading to the desired point.

Station operating procedures will be provided to assure that after a 6-hour accumulation of no load and/or light load (less than 50 percent rating) operation, a DG will be operated at a minimum of 75 percent of full load for 15-30 minutes per the manufacturer's recommendations.

A one time field test will be performed on a DG during which load up to 100 percent of continuous rating will be applied immediately following 6 hours of no load operation.

Response to Q430.102N describes effect of ambient air temperature variations on the DG's capability to carry full load.

Question 430.117N

Loads connected to the DC bus may be subject to voltage variations from 105 to 140 volts due to battery discharge and equalizing charge as stated in section 8.3.2.1 of the FSAR. It is the staff position that DC loads be designed and qualified to operate when subject to these voltage variations. Describe compliance of STPEGS design to this position for both minimum and maximum voltages.

Response

The Class 1E 125 V DC systems are designed such that the loads will operate within the battery and charger voltage range of 105 volts to 140 volts except as stated by note 4 and note 5, below. The following DC system circuit voltage drop criteria are used for the Class 1E distribution system:

Class 1E system	vdc
Battery to switchboard	1.0
Switchboard to panel	2.5
Switchboard to 100 V load	4.0 (1)
Switchboard to 90 V load	14.0 (1)(5)
Switchboard to inverter	0.5
Panel to 100 V load	1.5 (1)
Panel to 90 V load	11.5 (1)
DC control circuits for specific 4.16 kV breakers	10.0 (2)
DC control circuits for specific 480 V breakers	(3)
All other DC control circuit	20.0 (4)

Notes:

1. The loads are defined as motors, solenoids, power supply units, switchgear control power busses, and other equipment control panel control power busses, etc.

2. ESF diesel generator (DGs) breakers and the bus supply breakers to the 4.16 kV switchgear busses E1A, E1B, and E1C.

3. The allowable voltage drop from the bus to the switchgear shall be the difference between the minimum battery voltage at 2-hour duty cycle (106 vdc) minus the actual voltage drop from the battery to the bus and the actual minimum voltage required by the control equipment (100 vdc) for the bus supply breakers to the 480 V switchgear busses E1A1, E1A2, E1B1, E1B2, E1C1, E1C2.

4. All DC control circuits, except those listed in notes 2 and 3, which are required to operate only when the battery charger is energized. The battery nominal float voltage is 130 vdc.

5. The voltage drop for safety-related DC powered AFW regulator valve, FV 7526, is calculated to be 19.3 VDC.

STPEGS will verify that all the 125 vdc Class 1E loads will be capable of operating at the maximum and minimum voltages. In addition all the Class 1E DC equipment will be qualified for operation over the required voltage range.

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Question 430.119N

From the statement on battery capacity in Section 8.3.2.1.2 of the FSAR it is implied that power will be available to DC system loads for at least two hours in the event of loss of all AC power. After two hours you have assumed that AC power is either restored or that the emergency generators are available to energize the battery chargers. Based on the staff's review of recent applications, this period for restoration of AC power appears to be too short. Provide the basis and operational experience data for the assumption that AC power can be restored within two hours.

Emergency procedures and training requirements for station blackout events are described in generic letter 81-04. Provide a statement of compliance with these generic requirements.

Response

It was not the intent in Section 8.3.2.1.2 to refer to a blackout. This Section has been revised to delete the word "all" to read: "The batteries are sized to carry their connected Engineered Safety Feature (ESF) loads for two hours without power flow from the chargers in the event of loss of AC power".

An emergency operating procedure for the loss of all AC power was developed from the Westinghouse Owners Group (WOG) Emergency Response Guideline ECA-0.0, "Loss of All AC Power." Reenergization of specific equipment, as required, is covered in other emergency operating plant procedures. Operations training for all emergency procedures at STPNOC is an intricate part of the plant operations training program. STPNOC is in compliance with Generic Letter 81.04.

Question 430.120N

Recent experience with nuclear power plant Class 1E motor-operated valve motors has shown that in some instances the motor winding on the valve operator could fail when the valve is subjected to frequent cycling. This is primarily due to the limited duty cycle of the motor. Provide the required duty cycle of the following valves as it relates to system mode of operation in various events:

1. Steam supply valve to AFW pump turbine (if they are MOVS)

2. Auxiliary feedwater flow control valves

3. RHR heat exchanger valves

4. SI injection valves

5. SI discharge valves

6. Atmospheric dump valves (if they are MOVS)

Demonstrate that the availability of the safety systems in the South Texas Project Electric Generating Station design will not be compromised due to the limited duty cycle of the valve operator motors.

Response

The following responses correspond to the above valve applications:

1. Steam Supply valve to AFW Pump Turbine

   The steam supply valve, MS0143 (shown on Figure 10.4.9-1), to the auxiliary feedwater pump turbine is a DC motor-operated valve. This valve is normally closed and receives an AFW initiation signal (see Section 7.3) to open. Except for periodic testing, the valve remains closed. In the event of an incident requiring AFW initiation, the valve would be opened and remain open until operator action to close it; e.g., to effect isolation in the event of a steam generator tube rupture. It is qualified for 5000 cycles (open-close-open) over the 40-year life of the plant.

   Valve XMS0514 is the turbine trip and throttle valve for the AFW pump turbine, and is also shown on Figure 10.4.9-1. It is a DC motor-operated valve, and is normally open, receiving a confirmatory AFW initiation signal to open during an incident requiring AFW initiation. Except for periodic testing, the valve remains open and is closed only to provide redundant isolation to valve MS0143 discussed above. The valve is qualified for 1460 cycles over the 40-year life of the plant.

Response (Continued)

2. AFW Flow Control Valves

The AFW regulator valves, FV-7523, FV-7524, and FV-7525, are AC motor-operated valves. The AFW regulator valve in the steam-driven train, FV-7526, is a DC motor-operated valve. These valves are shown on Figure 10.4.9-1.

Except for periodic testing, these valves are controlled by the Qualified Display Processing System (described in Section 7.5.6) based upon the flowrate in the AFW train. Considering the pressure in the steam generator during the most limiting incident, the AFW regulator valves are jogged 10 full or partial strokes within the first 10 minutes after AFW initiation. The valves will be qualified for this conservative duty cycle. Since this is the most stringent duty requirement, these valves will be modulated less frequently than the cycling rate for which they are qualified.

3. RHR Heat Exchanger Valves

The RHR heat exchanger valves are air-operated valves. Therefore, this question does not apply.

4,5. SI Injection Valves/SI Discharge Valves

The safety injection system valves referenced are AC motor-operated gate valves and are not required to be repetitively stroked during normal or emergency modes of operation. These valves are qualified for 2000 cycles over the 40-year plant life.

6. Atmospheric Steam Dump Valves

The steam generator power-operated relief valves are electro-hydraulically actuated valves. The turbine bypass valves are air-operated valves. Therefore, this question does not apply to these valves.

The above indicated numbers of cycles are the number of cycles the valve is qualified for over the 40-year life of the plant. If the valve's qualified life is shorter than 40 years, it is qualified for the number of cycles needed during its qualified life. Thus, a valve qualified for 2000 cycles over 40 years, but having a qualified life of 5 years, is qualified for 1/8 of 2000 cycles, or 250 cycles.

Based upon the above information, the duty cycles of these motor-operated valves are adequate for normal operation, required periodic surveillance testing and emergency operation. The availability of safety systems in the South Texas design will not be compromised due to limited duty cycles of valve operator motors.

Question 430.123N

Table 8.3-3 of the FSAR shows step 1 load to be 0 kW as this step only energizes the load center transformers. However, the total running load of step 2 as shown on page 8.3-43 is significantly less than the total step 2 loads shown on page 8.3-42. Explain the difference and confirm that the diesel generator is sized for the correct values of loads applied automatically in various loading steps and also all the manually applied loads to the diesel generator.

Response

There is no conflict in loading steps as deliminated in note "e" of Table 8.3-3 as stated: "The high pressure (HP) valve shown represents a summation of all the motor-operated valves (MOVs) connected to the diesel generator (DG) and this load is assumed to be intermittent. Therefore, it is not being added in the next step." The MOV loads on page 8.3-42 (step 2) are not included on page 8.3-43 (step 3), since the valves do not require continued power after their appropriate action is completed.

The DG is sized for the correct values of loads which are applied automatically in various loading steps and also for all of the manually applied loads.

This fact is verified by a transient voltage response analysis of the DG units (by Generator Manufacturer) to step loads indicated in Table 8.3-3.

Question 430.128N

ESF load sequencer drawing (5Z-10-9-Z-42117) indicates incoming breakers to 480 volt bus E1A1 and E1A2 are stripped in Mode II and also in Mode III for an emergency trip of the diesel generator and are resequenced for both modes. The logic does not show individual 480 volt and 120 volt loads stripped and sequenced. For this design, when the incoming breakers to 480 volt busses E1A1 and E1A2 close when sequenced, all their loads will be energized simultaneously. Confirm that this transient will not cause starting problems to Class 1E loads and all equipment will be energized without being overstressed. Substantiate your answer with the analysis results.

Response

The Engineered Safety Feature (ESF) Load Sequencer Actuations Train A Logic Diagram Figure 8.3-4 Sheet 2 (9-Z-42117) indicates that in the event that a Loss of Offsite Power (LOOP) condition is recognized, the 460 V Residual Heat Removal (RHR) pump, 460 V Reactor Containment fan cooler (RCFC) fans the 460 V Electrical Auxiliary Building (EAB) heating, ventilating, and air conditioning (HVAC) supply air to 480 V Pressurizer Heater Group, and 460 V Essential Chiller are stripped from the Load Center Busses E1A1 and E1A2 and the Load Center 480 V incoming breakers are opened. Upon closing of the Load Center incoming breakers in Load Sequence Step 2, approximately 920 Load kVA (3375 Starting kVA) is energized on the 480 V and 120 V distribution systems. The diesel generator (DG) transient voltage response analysis shows that the calculated 4.16 kV voltage dip is less than 11 percent for less than a third of a second at the generator terminals. It should be noted that if required, the generator voltage regulator can be set to provide a generator output voltage as high as 4160 V and 10 percent. The results of the DG transient voltage response analysis will be expanded to verify that voltages at the Class 1E loads are above the minimum voltage rating for satisfactory operation.

Question 430.129N

STPEGS drawing no. 5Z-10-9-Z-42117 indicates five seconds, four seconds and one second time delays in bus strip signal for various conditions. Explain the basic reason for each of these time delays. If the five seconds time delay for Mode III is interlocked as permissive with diesel generator breakers closure logic (reference drawing 5Z-10-9-Z-42121 and STPEGS letter to NRC dated June 25, 1984), then explain why the load stripping is also delayed for five seconds. From the STPEGSs referenced letter, we understood that the five second time delay in the diesel generator breaker closure was after the load stripping had taken place and was not to delay the load stripping also for five seconds.

Response

The load stripping is not delayed. Figure 8.3-4 Sheet 2 (STPEGS drawing 5Z-10-9-Z-42117) shows that the bus strip signals are pulse signals maintained for a duration of 5 seconds or 1 second (not delayed). The Mode II (or Mode III) signal is initially not present, satisfying only one-half of the "AND" gate. When the Mode II (or Mode III) signal is generated the "AND" gate is satisfied and the bus strip signal(s) generated. When the time delay drop out (TDDO) times out, the "AND" gate is no longer satisfied, thus removing the bus strip signal and allowing reclosure of the indicated breakers. Thus the bus strip signals are pulsed, rather than delayed, for the times shown.

The bus strip signal pulse for 5 seconds (after a Mode III condition) and the bus strip signal pulse for 1 second (after a Mode II condition) provide positive strip signals to ensure that breakers are tripped before a closure signal is sent.

The second bus strip signal pulse for 1 second (after a coincident LOOP and DG emergency trip following closure of the DG breaker) provides a positive strip signal to ensure that breakers are tripped following a DG emergency trip after its breaker was closed following a Loss-of-Offsite Power (LOOP). Followup actions after a DG emergency trip must be made by the operator; this strip signal ensures that loads have been stripped from the bus. The 4-second TDDO is provided to give positive input to the bus strip signal just described.

Section 8.3.1.1.4.4.3 has been revised to provide a description of the various entries to Mode III and the automatic features provided for each entry.

Question 430.131N

FSAR Section 8.3.2.1.3 includes various alarms, indications, and meters for the status of various components in the 125 vdc, Class 1E battery system. This section, however, does not include "Battery High Discharge Rate" alarm. In the absence of this alarm, the control room operator will only know of a discharging battery when he periodically checks the battery current indicator or when the battery has sufficiently been discharged to trip the undervoltage alarm. It is, therefore, a good engineering practice to provide a battery high discharge rate alarm and not take the risk of a partial discharge of the battery before the operator is alerted of this condition. We believe that STPEGS design should include this alarm or justify its omission.

Response

Under normal operating conditions the battery is on float charge and the battery chargers supply all required power to the DC distribution switchboard. Any current flow from the battery to the DC distribution switchboard discharges the battery. This current flow is indicated on a meter in the control room. In addition it is alarmed in the control room at a preset level via the Emergency Response Facility Data Acquisition Display System (ERFDADS) computer. This alarm alerts the operator to the battery discharging condition.

Question 430.133N

Response to NRC question 430.30N refers to Section 8.3.1.1.4.1.1 and Table 8.3-3 of the FSAR. However, these two references include only the AC non-Class 1E loads being supplied from Class 1E buses. The question also requested similar information for DC non-Class 1E loads being supplied from Class 1E buses and should be tripped on receipt of an accident signal. The AC loads included in Table 8.3-3 do not include 120 V AC vital instrument bus loads and any non-Class 1E loads fed from the 120 V AC vital instrument buses that are being shed by an accident signal. Explicitly list all such AC and DC loads.

Response

Table 8.3-3 has been revised. The following non-Class 1E loads are tripped in the event of an Safety Injection (SI) signal.

480 V	LC EIA Press HTR Group A	431 kW
480 V	LC EIC Press HTR Group B	431 kW
480 V	MCC 1A5* (as listed)	156 kW
	DGB OIL TK RM EXH FAN	1 HP
	REACTOR CAVITY VENT FAN 11B	40 HP
	REACTOP SUPPORT EXH FAN	20 HP
	CRDM VENT FAN	40 HP
	RHRP 1A MINIFLOW MOV	1.9 HP
	STBY DG11 AIR COMPR 12	15 HP
	STBY DG11 AIR COMPR 11	15 HP
	N1E 125vdc BAT CHRG #2	75 kVA
480 V	MCC 1B5* (as listed)	80 kW
	RHRP 1B MINIFLOW MOV	1.9 HP
	CRDM VENT FAN	40 HP
	REACTOR SUPPORT EXH FAN	20 HP
	DGB OIL TK RM EXH FAN	1 HP
	STBY DG #12 AIR COMPR 14	15 HP
	STBY DG #12 AIR COMPR 13	15 HP
480 V	MCC 1C5* (as listed)	11O kW
	RHPP IC MINIFLOW MOV	1.9 HP
	REACTOR CAVITY VENT FAN 11A	40 HP
	CRDM VENT FAN	40 HP
	STBY DG 13 AIR COMPR 16	15 HP
	STBY DG 13 AIR COMPR 15	15 HP
	DGB OIL TK RM EXH FAN	1 HP

* MCC SUPPLY BREAKER TRIPPED

Response (Continued)

Distribution Panels (DP)

208/120 V	DP A435		9.518 kW
	Circuits for DG, motors and switchgear (Train A) space heaters		
208/120 V	DP B435		9.858 kW
	Circuits for DG, motors and switchgear (Train B) space heaters		
208/120 V	DP C435		9.858 kW
	Circuits for DG, Motors and switchgear (Train C) space heaters		
120 V	DP A335	Branch CKT 1	0.15 kW
	For ECWIS Equipment space heaters (Train A)		
120 V	DP B335	Branch CKT 1	0.15 kW
	For ECWIS Equipment space heaters (Train B)		
120 V	DP C335	Branch CKT 1	0.15 kW
	For ECWIS Equipment space heaters (Train C)		

Note: The EAB and the control room essential lighting (non-Class 1E) loads are connected to MCC E1A2 and MCC E1C2, through 30 kVA isolation/ distribution transformers which are not stripped from the buses in the event of an SI signal.

Also, electrical heat tracing (non-Class 1E) will be supplied from Class 1E buses through redundant Class 1E thermal magnetic trip devices in series which are not tripped in the event of an SI signal.

There are no non-Class 1E 125 vdc, nor non-Class 1E 120 V vital AC loads connected to the Class 1E channel buses.

Question 430.136N

IE Information Notices 83-11 and 84-83 addressed to holders of operating license (OL) and construction permit (CP) reported failure and/or degradation of batteries at various power plants. This has been attributed to swollen positive plates and/or cracked cases of the battery cells. A seismic event might accelerate the degration of the battery and could cause a common mode failure of the plant DC systems. Confirm that the IE Notices and the concerns therein were evaluated for their impact on the STPEGS design of Class 1E batteries and the seismic capability of its racks.

Response

Information Notice 83-11 expresses a concern that old lead-acid storage batteries may fail during a seismic event and cause a common mode failure of plant DC systems.

The STPEGS specification for Class 1E lead storage batteries requires the batteries to be qualified in accordance with IEEE 535-1979. This document requires that the increased seismic vulnerability of old batteries be reflected in a battery's qualified life.

Therefore, this concern has been evaluated and should have no impact on the STPEGS.

Information Notice 84-83 expresses concerns of overloading DC busses and solvent induced battery case cracking. STPEGS is continuing the review of the loading to ensure that adequate capacity is maintained.

All STPEGS batteries are sized and designed to carry all loads connected to the associated DC bus. The design complies with the recommendation of IEEE 450-1975, having the batteries' capacity at least 125 percent of the load expected at the end of their service life. The Class 1E battery manufacturer's (GNB) instruction manual includes a "CAUTION" against the use of solvent as a cleaning agent for plastic battery cells, jars, and battery covers. This manual also includes procedures for cleaning the battery posts.

The concerns contained in Information Notices 83-11 and 84-83 were evaluated and are not applicable to STPEGS.

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Question 010.19

In Section 9.1.2 you state that the spent fuel pool is lined on the inside surfaces with stainless steel plates and that leak tightness is assured by means of a leak detection system. You do not, however, state that the plates are designed to seismic Category I requirements. Verify that they are designed to seismic Category I requirements, or show that a failure of the liner plate as a result of an SSE will not result in any of the following:

1. Significant release of radioactive material due to mechanical damage to the spent fuel.

2. Significant loss of water from the pool which could uncover the fuel and lead to release of radioactivity due to heatup.

3. Loss of ability to cool the fuel due to flow blockage caused by a portion or one complete section of the liner plate falling on top of the fuel racks.

4. Damage to safety-related equipment as a result of the pool leakage.

5. Uncontrolled release of significant quantities of radioactive fluids to the environs.

Response

The stainless steel liner plates are designed according to the seismic Category I requirements. The plates will therefore not fail as a result of an SSE.

Question 010.22

Table 9.l-lA indicates that the spent fuel pool maximum heat load with complete full core unloading in the pool is 62.7 x $l0^6$ Btu/hr. The spent fuel cooling water temperature can be maintained below l50□F with two cooling trains and the supplemental cooling system in operation. However, Table 9.l-2 indicates that the total design heat load of the three heat exchangers in the cooling system is 32.2 x $l0^6$ Btu/hr. Explain how the above pool water temperature will be maintained with your present design.

Response

Initially, the Spent Fuel Pool Cooling and Cleanup System (SFPCCS) heat exchangers were each designed to remove 9.l x $l0^6$ Btu/hr with the Condition A parameters indicated in Table Q0l0.22-l.

These same heat exchangers will remove the heat generated by the abnormal maximum heat load shown in Table 9.1-1. As in the SFPCCS pool temperature increases to the peak temperature shown in Table 9.1-1, the log mean temperature difference increases by a factor of about three, resulting in a similar increase of the heat exchanger heat transfer capacity. As an example of the effect on the heat transfer capacity, an increase in pool temperature is shown in Table Q010.22-1. It should be noted that the temperature of the component cooling water entering the shell side of the SFPCCS heat exchangers remains the same for both Condition A and B because of the large heat sink provided by the Essential Cooling Pond.

Analysis of the spent fuel pool decay heat load demonstrates the ability of the SFPCCS to handle the normal maximum and abnormal maximum heat loads, utilizing the criteria of Standard Review Plan 9.l.3. The results of the analyses are summarized in revised Table 9.l-l.

Since the total design heat load is within the capacity of two SFPCCS heat exchangers, the supplemental cooling system has been deleted in revised Section 9.l.3.l.l, Table 9.l-2, and Figure 9.l.3-l. Table 9.4-1A has also been deleted since it pertained to the supplemental cooling capacity.

TABLE Q010.22-1

HEAT TRANSFER CALCULATION PARAMETERS

	Condition A	Condition B
Design Flow (10^6 lb/hr)		
Tube	1.41	1.41
Shell	1.5	1.5
Temperature, Inlet/Outlet (°F)		
Tube	120/113.6	158/136.2
Shell	105/111.1	105/125.5
Log Mean Temperature Difference	7.95	26.8
Calculated Heat Transfer (10^6 Btu/hr)	18.2	61.4
Coefficient of Heat Transfer (Btu/hr-°F-ft²)	343.15	343.15

Question 281.3N

Describe the samples and instrument readings and their frequency of measurement that will be performed to monitor the Spent Fuel Pool (SFP) water purity and need for SFP cleanup system demineralizer resin and filter replacement. State the chemical and radiochemical limits to be used in monitoring the SFP water and initiating corrective action. Provide the basis for establishing these limits. Your response should consider variables such as: boron concentration, gross gamma and iodine activity, demineralizer and/or filter different pressure, demineralizer decontamination factor, pH, and crud level.

Response

The sample and their frequency of measurement for monitoring the spent fuel pool (SFP) water purity are detailed in Table 9.3-4. Using these samples and the differential pressure instrumentation described in Section 9.1.3.4.2 will allow for a timely replacement of the demineralizer resin and filters as well as indicating a need for purification of the SFP water.

Table 9.1.4 provides the proposed monitoring limits for the STPEGS water purity and the bases for establishing these limits.

Suspended matter (crud) may be introduced into the SFP via the initial fill water, boric acid used to borate the water, corrosion products from the pool lining and fuel storage racks, and from deposited matter on the spent fuel elements which may slough off into the water.

Crud levels are maintained sufficiently low, through removal of suspended matter by filtration in the SFP demineralizer and filters, to ensure proper water clarity for spent fuel and fuel handling operations.

Radiochemistry sampling and analyses (gross beta-gamma activity determination) on the inlet and outlet of the SFP demineralizers is used to monitor the performance (i.e., decontamination factor) of these demineralizers. Gamma Spectrum analyses may be performed for fission products arising from fuel cladding defects to monitor for increasing activity levels (including iodine activity) in order to determine possible health hazards to personnel during refueling operations, depending on the fuel cladding conditions as determined by reactor coolant activities during normal operation.

Question 410.9N

Verify that the fuel pool is not located in the vicinity of any high energy lines or rotating machinery to ensure physical protection for the spent fuel from internally generated missiles and the effects of high energy line breaks.

Response

There are no high energy lines in the Fuel Handling Building (FHB), Postulated breaks in auxiliary steam piping outside the FHB were found not to cause pipe whip or jet impingement with sufficient energy to damage the spent fuel pool to the extent that its safety function would be impaired. Motors, pumps, or fans within the Fuel Handling Building are not capable of generating a missile that could impact the spent fuel pool. The sump pumps, safety injection and spray pumps, and cubicle fans coolers are located in the FHB below the spent fuel pool and rotate in a horizontal plane so potential missiles would not impact the walls or floor of the spent fuel pool. The other pumps and coolers in the FHB are separated from the spent fuel pool by the refueling canal which has sufficient structural strength to stop potential missiles.

Question 010.26

In Section 9.4.l you indicate that centrifugal exhaust air fans are provided to exhaust air from the battery rooms. These exhaust air fans are not shown in Table 9.4-2.l, which lists all safety-related components of the control room and the electrical auxiliary building HVAC system. Also, these exhaust air fans are not shown in your P&IDs. Provide sufficient information to demonstrate that the battery room exhaust system is designed to maintain the hydrogen concentration below two percent by volume assuming a single failure. Confirm that you have provided an alarm in the control room in case the battery exhaust fan should fail.

Response

The EAB HVAC design has been revised to provide safety-related exhaust fans for battery rooms, which will operate continuously during normal and emergency conditions to maintain the Battery Room hydrogen concentration below 2 percent.

These exhaust fans are shown in Figure 9.4.l-l (sheet 2 of 4) and included in Table 9.4-2.l.

Alarm is provided in the Control Room to indicate a Battery Room exhaust fan failure.

Question 410.15N

Describe measures provided for detecting and correcting dust accumulation on safety-related equipment in order to assure their availability when needed. List any outside air intake for safety-related equipment which is less than 20 ft from grade elevation.

Response

With the exception of the ECW intake structure which is approximately 16 ft above grade, all HVAC outside air intakes for Category I structures are located at least 20 ft above plant grade elevation. The HVAC systems for Category I structures are equipped with air filters to remove atmospheric dust particles from the incoming airstream with the exception of the Diesel Generator Building during operation of the diesel generator, the Essential Cooling Water Intake Structure, and the Main Steam Isolation Valve Cubicles.

Question 040.17

Figure 1.2-10 [general arrangement drawing 6D01-9-M-00020-8] shows the location of the fuel oil storage tank vent line with flame arrestor. What provision has been made to protect the vent lines from tornado missiles? The arrangement indicates that the three fuel oil storage tank vent lines could be damaged by a single tornado missile.

Response

An impact by a tornado missile causing a complete loss of function of the flame arrestors is not considered to be credible. This is based on the amount of crimping that would be required (99.3 percent) to cause a vacuum to be formed in the tank. It is more likely that the pipe would shear. In addition, the physical location of the arrestors will reduce the probability of a missile impact.

Question 040.18

Assume an unlikely event has occurred requiring operation of a diesel generator for a prolonged period that would require replenishment of fuel oil without interrupting operation of the diesel generator. What provision will be made in the design of the fuel oil storage fill system to minimize the creation of turbulence of the sediment in the bottom of the storage tank? Stirring of this sediment during addition of new fuel has the potential of causing the overall quality of the fuel to become unacceptable and could potentially lead to the degradation or failure of the diesel generator.

Response

See Figure 9.5.4-1 which shows a perforated pipe extending the height of the tank with a closed end. The multiple perforations will diffuse the flow of the fuel oil into many flow paths rather than a single, large impingement on the tank bottom. The perforations will also serve as siphon breakers.

Question 040.19

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

Response

The internal walls of the Diesel Generator Building (DGB) are designed to withstand the effects of internally generated missiles (see Section 3.5.1.1.2, Item 4, and Table 3.5-1). Missiles created from a crankcase explosion are not considered to be credible due to adequately sized explosion doors which would relieve the pressure from the primary crankcase explosions and prevent the entry of air to eliminate the possibility of a secondary explosion. The walls, including doors and piping penetrations, of the building are also designed to contain flooding in one compartment. Additionally, there are no cross connections in floor drains or process flow lines which could result in propagation of flooding from one compartment to another.

There are no high energy lines in the DGB. The systems which contain moderate energy lines are discussed in Section 3.6.

Question 040.20

Discuss the precautionary measures that will be taken to assure the quality and reliability of the fuel oil supply for emergency diesel generator operation. Include the type of fuel oil, impurity and quality limitations as well as diesel index number or its equivalent, clould point, entrained moisture, sulfur, particulates and other deleterious insoluble substances; procedure for testing newly delivered fuel, periodic sampling and testing of onsite fuel oil (including interval between tests), interval of time between periodic removal of condensate from fuel tanks and periodic system inspection. In your discussion include reference to industry. (or other) standards which will be followed to assure a reliable fuel oil supply to the emergency generators. (SRP 9.5.4, Part III, items 3 and 4).

Response

1. STPEGS intends to use the McGuire Technical Specifications with the following exception:

   ASTM D4294-83, Sulfur in Petroleum Products by Non-Dispersive X-Ray Fluorescence Spectrometry, will be included in the STPEGS Technical Specifications in addition to ASTM D2622-82, Sulfur in Petroleum Products X-Ray Spectrographic Method. These two analytical procedures are similar in measurement methodology.

   Both methods utilize x-rays to excite the sample. The fundamental difference lies in the method of detection. ASTM D2622-82 describes a general purpose wavelength to dispersive X-ray spectrograph. It uses detector positioning to quantify the sulfur K-alpha radiation (a specific wavelength of radiation which is manifested due to the presence of sulfur). K-alpha radiation is dispersed from an analyzing crystal at a specific angle. ASTM D4294-83 describes a dedicated non-wavelength dispersive sulfur X-ray analyzer. It uses a filter to allow only a narrow band pass of X-rays, which includes the sulfur K-alpha radiation, to reach the detector.

   The wavelength dispersive spectrograph is designed to detect low levels in general, and can detect as low as 10 ppm sulfur. The non-wavelength dispersive analyzer's sensitivity is 100 ppm, but is well suited for the 1000 ppm or greater level of sulfur normally found in no. 2 diesel fuel oil.

   Dedicated sulfur analyzers employing the non-wavelength dispersive technique drastically reduce the cost of sulfur analyses, when compared to the general purpose wavelength dispersive spectrograph required by ASTM D2622-82.

   It should be noted that the consultant used by SNUPPS to revise their Technical Specifications, was contacted on this matter and his professional recommendation was requested. He concurred that the proposed test method satisfies the intent of ASTM 2622-82 and could be

Response (Continued)

used as an alternate test method for sulfur. This recommendation has been documented and transmitted to the NRC via letter from M. R. Wisenburg (HL&P) to George W. Knighton (NRC), ST-HL-AE-1364, dated September 19, 1985.

2. The quality of the fuel oil supply will be verified in accordance with applicable industry standards as discussed in Section 9.5.4.4.

Question 280.2N

Substantiate the fire resistance capability of the barriers used to separate safety-related areas or high hazard areas by verifying that their construction is in accordance with a particular design that has been fire tested. Describe the design, the test method used and the acceptance criteria. Provide information for the following components:

(a) Rated fire barriers, including floor and ceiling construction and the support structure for barriers that are not floors or ceilings;

(b) Fire dampers and fire doors, including a description of how they are installed in the ventilation ducts that penetrate rated fire barriers of safety-related areas; and

(c) Fire barrier penetration seals around ducts, pipes, cables, cable trays, and in other openings (e.g., concrete joints seals and fillers) including verification that all seals are of the thickness specified in the tests, and that cables and cable trays are supported in a manner similar to supporting arrangements used in any tests.

Response

(a) Floors and ceilings in high hazard areas are cast-in-place reinforced concrete. Walls in high hazard areas are cast-in-place reinforced concrete or fire rated concrete unit masonry construction. Steel columns, steel beams, and the under-side of floor decks where required, will be protected with fireproofing material to the required fire rating which will be based on testing and approval by a nationally recognized laboratory.

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(b) With the exception of special purpose doors, doors and frames contained in fire barriers are constructed and installed in accordance with UL requirements for a labeled door with a rating of the fire barrier. Special purpose (airtight and watertight) doors are constructed in accordance with requirements of comparitable 3-hour rated fire door but are not tested and labeled.

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Fabrication and construction of three hour rated Class A, curtain type fire dampers, suitable for horizontal and vertical installation, are in accordance with the applicable requirements of National Fire Protection Association (NFPA) and UL. Fire dampers are installed in accordance with the manufacturers' instructions, with the exception of three dampers located in Fire Area 7. See Section 3.0 of the FHAR for further detail.

(c) Fire barrier penetration seal assemblies in vertical and horizontal concrete fire barriers are designed to resist a fire for the rated duration of the barrier unless otherwise noted in the FHAR. Prototype assemblies including the immediate support for cable trays are tested in accordance with IEEE 634 for cable penetrations and ASTM E-ll9 for all other penetrating objects. Results are compared by ANI to NELPIA/MAERP standards.

Question 280.4N

Verify that primary and secondary power for the alarm system can be maintained by using normal offsite power as the primary supply, with a 4-hour battery supply as the secondary source and having the capability for manual connection to Class 1E emergency power bus within 4 hours of loss of offsite power.

Response

The plant alarm system consisting of tone-generators and controls provided with the paging system, is fed from the normal station auxiliary power. On loss of offsite power (LOOP), a non-Class 1E diesel generator (DG) automatically provides emergency power supply to the plant alarm system.

The capability for manual connection to a Class 1E power bus is not provided since a non-Class 1E DG is automatically connected on a LOOP to feed the alarm system.

Question 280.12N

Provide a list of all interior finish insulation, sound proofing, etc., that are other than noncombustible. Indicate the flame spread and smoke contributed ratings of each material where available. Indicate where their materials are used (by fire area) and in what quantities.

Response

The following finish materials are other than noncombustible:

Suspended acoustical ceiling tiles have a flame spread of 0-25 with a Underwriter Laboratories (UL) label of 25 or under when tested in accordance with ASTM E-84, and will meet the requirements of Federal Specification SS-S-118A. The smoke contributed rating is not available.

Drywall partitions have a flame spread rating of l5 or less and a smoke contributed rating of 0 in accordance with fire test number USG-l7-FT-G&H and/or GA-WP-45-1HR, and are therefore not considered combustible.

Vinyl asbestos floor tiles have a flame spread rating of 75 or less when tested in accordance with ASTM E-84, a NBS Smoke Chamber 450 or less (Specific Optical Smoke Density), and an UL 992 Flame Propagation Index 4.0 or less.

Epoxy floor topping at 15 or 20 dry mil film thickness has been tested in accordance with ASTM E-84 and exhibits a flame spread of 10, smoke density of 40, and a fuel contribution of 0.

The floor of Unit 1 & 2 Control Room and EAB Room 209 (Elev. 35') are covered with carpeting that has been tested in accordance with ASTM E648 to have an average Critical Radiant Flux (CRF) of not less than 0.45 watts/square cm. and in accordance with ASTM E662 to have an average corrected maximum specific optical density DM (corr.) $\leq$450.

Thin-film paints on walls and ceiling in other Category I areas have been tested in accordance with ASTM E-84 and exhibit a flame spread rating of less than 25 with zero fuel contribution and smoke density and are therefore not considered combustible.

There are no combustible finishes in the Diesel Generator Building and the Isolation Valve cubicles.

Thin-film paints applied to non-combustible substrates are not considered combustible.

The epoxy surfaces applied to concrete floors and walls in the Reactor Containment Building has a flame spread rating of 10, a smoke density factor of 15, and a fuel contribution factor of 0, and is therefore not considered combustible.

The above materials are used in building areas normally occupied by the power plant operating personnel, and in nonoccupied areas such as corridors, equipment rooms, etc. The approximate quantities are given in square feet and are listed by fire areas in Table Q280.12N-1.

TABLE Q280.12N-1

APPROXIMATE QUANTITIES OF COMBUSTIBLES (ft^2)

Building	Fire Area	Epoxy	V-A Tile	Carpeting	Ceiling
EAB	2	1,940			
	1		1,020	2,630	250
	3	17,440	6,530	243	5,910
	31		0		0
	4	0	820		820
	67		4,180	0	4,560
MAB	21	550			
	27	11,220			
	24	11,950			
	22	4,190			
	29	1,940			
	23	40,560			
	28	570			
	32	23,840			
	75	19,270			
	30	800			
	25	460			
	26	310			

*(From UFSAR Table 6.1-4)

Question 280.19N

It is our position that an automatic water extinguishing system be provided for the RAB Drumming Storage Area and the RAB Decontamination Room.

Response

An automatic water extinguishing system is provided for the waste baler area and the truck bay area of the drum storage area of the MAB El. 41 ft. The drumming system utilizes concrete and therefore does not intrinsically contain combustibles. These systems are provided for property protection, and the loss of this area to a postulated fire does not affect the ability of the plant to achieve safe shutdown.

The Decontamination Room does not contain flammable liquids and does not present a significant fire hazard. An automatic water extinguishing system is not provided in the Decontamination Room. The FHAR shows that a fire in the Fire Area containing the Decontamination Room (Fire Area 32) would not prevent achieving and maintaining the plant in a safe shutdown condition.

Question 280.23N

Throughout your evaluation you have identified areas which contain redundant HVAC system ductwork and have stated that a fire would not damage the ductwork. Revise your analysis to include the effects on safe cold shutdown if these systems were rendered inoperable by a fire in these areas through collapse of the ductwork and/or closing of fire dampers at area/zone boundaries.

Response

The common risers for the redundant, safety-related HVAC units are separate fire areas. The riser fire areas are bounded by 3-hour fire barriers which are provided with 3-hour rated fire dampers where ventilation ducts enter the risers. (See the response to question 280.24N and the revised STPEGS FHAR.) There is one exception which is the common ductwork to and from the Auxiliary Shutdown Room and the train A, B, and C QDPS Rooms. (See FHAR Zone Figure 7-1 and Fire Area 7, deviation 2.)

Question 280.24N

Fire Areas 005, 036, 039, and 049. In these areas you indicate that ductwork common to trains A, B and C is enclosed in a fire rated casing. Identify the fire rated casing by providing a description of the construction and fire rating of the casing.

Response

The ductwork headers common to equipment trains A, B, and C are encased within 3-hour fire rated concrete chases. Three-hour rated fire dampers are provided at each of the ductwork penetrations through the walls of the concrete chase. The Fire Areas in question are shown in the revised FHAR as Area 2/zone 005, Area 3/zone 036, Area 3/zone 039, and Area 4/zone 049.

Question 280.25N

In Fire Areas 007, 008, 011, 012, 020, 021, 022, 023, 027, 109, 111, and 112 you have not indicated the presence of any access openings to these cable chases. Indicate how access to these areas is obtained for manual firefighting.

Response

The following fire areas have access openings as shown:

- Fire Areas 007 and 008 Train "B" and "C" have access on El. 10 ft-0 in. Rm. 001, 008 Train "C" also has access on El. 35 ft-0 in. Rm. 201. (Fire Areas 71 and 69 in revised FHAR)

- Fire Areas 011 and 012 Train "B" and "C" have access on El. 10 ft-0 in. Rm. 002, El. 35 ft-0 in. Rm. 202 and El. 60 ft-0 in. Rm. 302. (Fire Areas 68 and 74 in revised FHAR)

- Fire Areas 020, 021, 022 and 023 Train "A", "B" and "C" have access on El. 18 ft-3 in., El. 35 ft-0 in. and El. 60 ft-0 in. from rooms 015, 208, 209, 210, 211, 309, 310, 311 and 312. (Fire Areas 18, 73 and 70 in revised FHAR)

- Fire Areas 109 and 111 Electrical chases have access on El. 26 ft-0 in. Rm.106. (Fire Area 27, zone 109 and Fire Area 3, zone 111 in revised FHAR)

- Fire Area 027 Electrical chase has access on El. 21 ft-0 in. Rm. 102. (Fire Area 2, zone 027 in revised FHAR)

- Fire Area 112 Electrical chase has access on El. 29 ft-0 in. Rm. 108B El 41 ft-0in. Rm. 217 and El. 60 ft-0in. Rm. 324A. (Fire Area 75 in revised FHAR)

These chases are dedicated to a single safety related train. Penetration seals and fire rated barrier walls are provided to separate each chase into smaller fire areas. Fire detection devices are installed in each chase. The barriers are rated for 3-hour fire duration.

The revised Fire Hazard Analysis Report discusses access to these cable chases.

Question 280.28N

Verify that hydrogen and other gas lines are not routed through safety-related areas.

Response

There is a 1 in. hydrogen line running through the radioactive pipe chase in the MEAB Area 28 at El. 35 ft-3 inches. Analysis has shown that sufficient ventilation is provided to preclude hydrogen buildup in this area. There are no other explosive gas lines running through safety-related areas.

High pressure nitrogen lines are routed in the following areas:

1. MEAB

    a. Penetration area near refueling water purification pump 1A.
    b. Area near the refueling water storage tank.
    c. Area near the reactor makeup water storage tank and the reactor makeup water pump.

2. RCB

    a. Lines running through RCB to the safety injection accumulator tanks.

    These lines are included in the analysis of potential sources of internally generated missiles close to pressurized sources.

    Low pressure nitrogen lines are routed in the following areas:

    (1) MEAB

        (a) Area near the refueling water storage tank.

    (2) RCB

        (b) Outside the secondary shield wall to the pressurizer relief tank and the Reactor Coolant System (RCS) pressurizer.

Question 280.29N

State the location of all transformers in the plant and describe the fire protection features provided. If a transformer is one that contains a fire resistant fluid, then describe how its failure/rupture will not impair safety-related cables/equipment.

Response

Figure 8.2-1 indicates the location of all outdoor oil-filled transformers except the 345 kV switchyard service and 500 kVA load center transformers, which are located near the switchyard and the 1200 kVA load center transformer located south of the Fuel Handling Building in the yard. Fire protection provisions for the transformers are discussed in Section 9.5.1.2.13 and Table 9.5-3. The 138 kV emergency transformer and the 345 kV switchyard service transformers are not provided with water spray deluge systems because their isolated locations prevent fires in those transformers from being hazardous to plant safety systems.

In addition to the outdoor oil-filled transformers, there are load center, distribution, and lighting transformers located indoors throughout the plant (refer to general arrangement drawings in Section 1.2). These are air-ventilated dry-type transformers.

There are no transformers in the plant that contain fire resistant fluid.

Question 430.41N

Your response to Question 040.14 is unacceptable. You have not justified the omitting of the day tank in your EDEFSS design, nor have you provided a discussion comparing the system availability and reliability of your present design to system which would have included a day tank. Provide this information. Your discussion should also take into consideration a pipe break in the portion of the fuel oil line in the D/G room from the fuel oil storage tank to the diesel engines and its effect or D/G availability, effect on plant operational safety, means of detection and controlling fuel spill from a pipe break, and provisions made in the plant design to prevent fuel flow into other D/G room and areas of plant containing safe shutdown system and expose these areas to a potential fire hazard.

Response

The response to Question 430.40N provides the technical justification for providing a large fuel oil storage tank internal to the diesel generator (DG) building in lieu of day tanks served by remote storage tanks. Fuel oil is supplied from the tank at El. 55 ft to the engine at El. 25 ft via a 1-in. gravity flow line. A pipe break in the portion of the fuel oil line in the DG room from the fuel oil storage tank (FOST) to the diesel engines is not considered credible; however:

1. If a leak renders a DG inoperable there are two more DGs capable of performing the safety function. Each of the DG trains is physically separated by a 3-hr fire-rated wall from the other trains and no impact results from the above event in the other two trains; if a leak occurs in a DG room fuel oil cannot penetrate the other rooms.

2. Means are provided for detecting and controlling a fuel spill. Each DG room is equipped with an instrumented drain sump. A high level alarm located in the main control room will indicate a leak (whether fuel oil, lube oil, cooling water, etc.) in the DG room. Once a leak has been detected it can be isolated external to the DG room. Once a leak has been detected it can be isolated external to the DG room by a shut off valve in the FOST room thus preventing further leakage.

3. The postulated leakage in a fuel oil line crack is minimal and does not add appreciably to the existing DG room severity.

Question 430.46N

Your response to Question 040.22 with regards to the sources of quality diesel fuel oil is incomplete. Provide the sources where quality diesel fuel oil will be available and the distance required to be travelled from the sources to the plant, as well as discuss how fuel oil will be delivered onsite under extremely unfavorable environmental conditions such as during a flood.

Response

Each standby diesel generator (DG) is provided with a fuel oil storage tank to permit a minimum of seven days continuous operations.

Fuel oil for continued operation beyond the seven-day time interval may be obtained for the onsite fuel oil storage tank. If this supply is unavailable, there are several major suppliers of acceptable quality fuel oil in the area surrounding STPEGS, any one of which can be utilized to provide the additional supply of fuel oil. The following lists several suppliers, their location, and approximate distance required to travel to the plant:

Gulf Oil	Victoria	65 miles
Tesoro Oil	Port Lavaca	55 miles
Mobil Oil	Wadsworth	10 miles
Superior Oil	El Campo	50 miles
Mobil Oil	Houston	110 miles

It is highly unlikely that extremely unfavorable weather conditions will be of such duration as to exhaust all onsite supplies and require fuel delivery while the weather conditions persists. However, HL&P (historical context) has extensive experience in handling and mitigating weather related problems (e.g, hurricanes, tornados, floods). This experience, coupled with the fact that numerous water transportation vehicles are available in the South Texas area, provide assurance that STPNOC will be able to deliver any necessary fuel oil during unfavorable environment conditions. Note that numerous roads to the general site area are available for the transportation of fuel oil to the site area.

See also the response to Q430.86N, item b.

Question 430.47N

The FSAR text, Figure 9.5.4-1 through 9.5.8-1, and Table 3.2-1 states that the components and piping systems for the diesel generator auxiliaries (fuel oil system, cooling water, lubrication, air starting, and intake and combustion system) that are mounted on the auxiliary skids are designed seismic Category I and are ASME Section III Class 3 quality. The engine mounted components and piping are designed and manufactured to DEMA standards, and are seismic Category I. This is not in accordance with Regulatory Guide 1.26 which requires the entire diesel generator auxiliary systems be designed to ASME Section III Class 3 or Quality Group C. Provide the industry standards that were used in the design, manufacture, and inspection of the engine mounted piping and components. Also show on the appropriate P&ID's where the Quality Group Classification changes from ASME Section III Class 3 (Quality Group C).

Response

Regulatory Guide (RG) 1.26, Revision 3, states:

> "Other systems not covered by this guide, such as instrument and service air, diesel engine and its generators and auxiliary support systems, diesel fuel, emergency and normal ventilation, fuel handling, and radioactive waste management systems, should be designed, fabricated erected, and tested to quality standards commensurate with the safety function to be performed."

The engine mounted components and piping from the engine block to the engine interface are considered part of the engine assembly and are seismically qualified to Category I requirements. This piping and associated components such as valves, manufactured headers, fittings, etc. are designed, manufactured and tested in accordance with the guidelines and requirements of DEMA, ANSI B31.1, ANSI N45.2 and 10CFR50 Appendix B QA. (See Table 9.5.4-1). The DEMA standards provide assurance that these auxiliaries are designed, fabricated, erected, and tested to quality standards commensurate with the safety function to be performed. In addition to DEMA tests, the engine is qualified by a reliability test. Generally, diesels are subject to low working stresses for the application which results in a high operational reliability.

Amended Figures 9.5.4-1, 9.5.5-1, 9.5.6-1, 9.5.7-1, and 9.5.8-1 show quality group changes.

Question 430.58N

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

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

Response

Dust accumulation from exterior sources:

The diesel generator building (DGB) heating and ventilating system utilizes three 100-percent capacity supply fans, providing air flow of approximately 16,600 ft^3/min to each DG train which function only when the diesel is not operating. During diesel operation, a larger fan providing air flow of approximately 123,000 ft^3/min to each DG train is operated. The inlet to the smaller supply fan is equipped with a filter having a 40 percent atmospheric dust spot efficiency. Use of the filter will prevent entrance and accumulation of all types of dust (including concrete dust) and other deleterious material on electrical equipment associated with starting of the diesel. See Section 9.4.6, for details. The diesel is operated infrequently for either (1) periodic system testing or (2) subsequent to loss of offsite power or a design basis accident. Operation of the diesel in Unit 1 is scheduled when very little concrete work or other abnormal dust-generating activities remain to be done in Unit 2.

Combustion air is filtered via an oil bath air filter as reflected in Figure 9.5.8-1. Filters are provided to filter the supply air in the DGB HVAC Systems. For details see Section 9.4.6.

Dust accumulation from interior sources:

The diesel and generator control panels are housed in a dust-tight enclosure. All concrete surfaces internal to the DGB except the fuel oil tank compartments and the non-labeled fume-tight fire doors will be coated as follows:

1) fluorosilicate concrete hardener on floor.

2) epoxy - polyamide concrete sealer on walls and ceilings.

Response (Continued)

Procedures governing housekeeping that implement the recommendations of Regulatory Guide (RG) 1.39 will be available on site for NRC review prior to fuel load.

The preventive maintenance program developed will require periodic inspection for dust and other deleterious materials and require cleaning, as necessary, of the electrical equipment associated with starting the diesel generator.

Question 430.77N

Section 9.5.2 of the FSAR describes the intraplant communication system at South Texas which is composed of five subsystems. They are the Public Address (PA), Telephone, Fuel Loading Communications, Maintenance Communication, and Two-Way Radio Systems. A number of areas in the plant are served by one or more of these systems. All these systems are classified non-Class 1E. The PA and telephone systems are powered from Class 1E AC power system and the power sources for the other systems are undefined. Assuming a failure, non-availability, due to loss of power, or inability to use a system due to its interference with control instrumentation or equipment such as the radio system, of any or all of these systems following a seismic event, it is possible that portions of the plant may be without adequate communications for an extended period of time during the design basis event. This is unacceptable. It is a requirement that adequate communications be provided at all vital, hazardous, and safety-related areas needed for the safe shutdown of the reactor and the evacuation of personnel in the event of a design basis event. Confirm this service is provided or modify your design to provide the necessary communication for postulated conditions above or justify the present design. (SRP 9.5.2, Parts I and II)

Response

Table 1 below has been prepared to show the power sources for the various communications systems.

TABLE 1

System	Primary Power	Back-Up
Telephone Switch	Normal Plant 120 vac	8 Hr Battery
Public Address	Normal Plant 120 vac	TSC non-Class 1E Diesel
Maintenance Jack and Refueling Communication	a. Normal Plant 120 vac b. Sound Power	Sound Power
2-Way Radio a. Base/Repeater Stations	Normal Plant 120 vac	TSC non-Class 1E Diesel
b. Hand-held Transceivers	Battery Packs	Spare Batteries
Distributed Command Consoles	Normal Plant 120 vac	TSC non-Class 1E Diesel

Response (Continued)

The ability to provide back-up power sources and the proven reliability of the standard telecommunications products being supplied coupled with the diversity of systems furnished makes complete failure of the communications system necessary for safe shutdown unlikely.

Further, all locations needed for safe shutdown have radio, telephone and maintenance jack stations available. If power should be lost or a major equipment failure should occur to the telephone and radio systems, the maintenance jack stations are equipped with a sound powered telephone circuit in addition to two DC powered electrosound loops.

The sound powered loops throughout the plant are interconnected at a sectionalizing panel in the Electrical Auxiliary Building (EAB). The simplicity of the sound powered system and the ability to isolate defective loops at the sectionalizing panel make it a highly reliable emergency communication system.

Question 430.78N

Expand the lighting section of the FSAR to include a discussion of how lighting will be provided for these areas listed in requests Q40.10 and Q40.11 and illuminated by the DC emergency lighting system only, in the event of a sustained loss of offsite AC power (in excess of 8 hours and up to 7 days), or provide the rationale why lighting is not required in these areas. Include in your discussion what, if any, other areas would require lighting during a sustained loss of AC power, and how it would be provided. (SRP 9.5.3, Parts I and II)

Response

The Emergency DC Lighting System described in Section 9.5.3.2.3 is part of an integrated lighting system, backed up by the Essential AC Lighting System (described in Section 9.5.3.2.2 item 1), which is powered by onsite diesel generators (DGs) in case of loss of offsite power (LOOP), and is capable of providing illumination up to seven days.

Areas that must be manned for cold shutdown, including all of the containment, are not required to have emergency lighting provided by sealed beam units with eight hour minimum battery power supplies. The justification for this is that:

- Access to these areas is normally required at a time beyond the eight hour battery life.
- Fire brigade and operations personnel required to achieve cold shutdown will be provided with battery-powered portable hand lights.
- Essential AC lighting is provided in these areas.

Question 430.80N

Provide a discussion on the protective measures taken to assure a functionally operable lighting system, including considerations given to component failures, loss of AC power, and the severing of lighting cables as a result of an accident or fire. (SRP 9.5.3, Parts I and II)

Response

As described in Section 9.5.3, the Lighting System is comprised of three entities: the Normal AC Lighting, the Essential AC Lighting, and the Emergency DC Lighting System. The diversity of power sources fed from normal lighting and diesel generators (DGs) together with the eight hour battery packs will assure that lighting from one or more sources is available due to any single malfunction or failure due to fire in a particular fire zone. Upon loss of normal lighting or offsite power the Essential AC Lighting System will provide lighting in the safe shutdown areas. In the event of fire or severing of lighting cables, lighting is provided in the safe shutdown areas, including access/egress, by the eight hour Holophane battery packs supported to withstand a Safe Shutdown Earthquake (SSE).

Question 430.81N

Section 9.5.3 of the FSAR describes the Emergency Lighting System which is composed of four subsystems. They are the 125 vdc, essential AC, 90 minute battery lighting, and 8 hour battery lighting systems. A number of areas in the plant are served by one or more of these systems. All these systems are classified non-Class 1E and receive power from the following sources: non- Class 1E station batteries for the DC lighting, the Class 1E emergency diesel generator for a few select areas of the plant and the non-Class 1E emergency diesel generator for the balance of the AC lighting. Assuming a failure or nonavailability of any or all of these systems following a seismic event, it is possible that portions of the plant particularly the control room may be without sufficient lighting or without lighting for an extended period of time during this design basis event. This is unacceptable. It is a requirement that adequate lighting be provided to all vital, hazardous, and safety-related areas needed for the safe shutdown of the reactor and the evacuation of personnel in the event of any design bases accident. Confirm this service is provided or modify your design to provide this necessary lighting. (SRP 9.5.3, Parts I and II)

Response

8-hour battery packs, supported to withstand a Safe Shutdown Earthquake (SSE), integrated with the Essential AC Lighting System will provide lighting to vital, hazardous, and safety-related areas needed for the safe shutdown of the reactor and evacuation of personnel. See Section 9.5.3. Note: The control room 125 vdc 2-hour station battery has been deleted.

Question 430.82N

You state in Sections 9.5.3.1 and 9.5.3.3 of the FSAR that illumination levels provided in the various areas of the plant either conform to or exceed that required in the Illumination Engineering Society (IES) Handbook. This statement is too general particularly for emergency lighting. Based on the guidelines in the IES Handbook (pages 2-11 and 2-45), the staff has determined that the plant emergency lighting for access and egress should be considered safety lighting for high hazards requiring visual detection and that a minimum of 10 foot-candles at the work station is required to adequately control, monitor and/or maintain safety-related equipment during accident and transient conditions and a minimum of 2 to 5 foot-candles in the corridors which provide access to and egress from these areas. For those safety-related areas listed in requests Q40.10 and Q40.11 and illuminated by the DC lighting systems only verify that the minimum of 10 foot-candles at the work station is being met. Also verify that the 10 foot-candle minimum at the work station is being met in those safety-related areas illuminated by the ac emergency system. Verify that the access and egress corridors are illuminated by a minimum of 2 to 5 foot-candles. Confirm that the design provides the above or modify your design as necessary. (SRP 9.5.3, Parts I and II)

Response

Section 9.5.3.2.2. has been revised. There are no safety-related areas which are illuminated by the DC lighting systems only.

The Essential AC Lighting System provides a minimum of 10 ft-candles at the work stations and illuminates the access/egress routes by a minimum of 2 to 5 ft-candles as described in Section 9.5.3.2.2.

Power for the Essential AC Lighting System is supplied from two Class 1E and one non-Class 1E system. Upon loss of the normal power supply, the Essential AC Lighting System is automatically connected to the power sources. The sources for the safe shutdown areas and access/egress routes are provided in Table 9.5.3-1.

The Emergency DC Lighting System consists of lighting supplied from batteries upon the loss of both the normal and Essential AC Lighting Systems. Although the Emergency DC Lighting System provides illumination at safe shutdown areas including access/egress routes between them, primary emergency lighting is provided by the Essential AC Lighting System. Therefore, the illumination levels provided by the Emergency DC Lighting System do not necessarily meet IES guidelines.

Question 430.83N

Section 9.5.3 of the FSAR does not describe the inservice inspection tests, preventive maintenance, and operability checks that will be performed periodically to prove the availability of the emergency lighting systems. Provide this information. (SRP 9.5.2 Part II and III)

Response

See UFSAR Sections 9.5.3.4 and 14.2.12.2.

Question 430.86N

In Section 9.5.4.3 of the FSAR you state that the emergency flood protected fill connection for the fuel oil storage tanks is located on the DG building roof. It is also stated that "a hose could then be routed to the roof via an existing hose reel for tank filling when the flood level has receded". Provide the following:

a. State whether the "existing hose reel" is located inside or outside the DG building. Describe any other uses (fire protection, etc.) associated with this hose and hose reel.

b. Assuming the emergency fill connection must be used to refill the fuel oil storage tanks, describe how fuel oil will be delivered to the site during flood conditions and the procedures that will be used in refilling and storage tanks during flood conditions and non-flood conditions. The procedures should include fuel hose routing and fire watches. (SRP 9.5.4, Parts I, II, and III).

Response

a. Present plans are not to provide a permanent existing hose reel in the Diesel Generator Building (DGB), but to utilize a hose from the fuel delivery service; i.e., truck.

b. Plant procedures will detail the method for refilling the storage tanks using the emergency fill connection. The procedure will include provisions for routing the hose up to the roof from outside the building. The truck pump can supply sufficient head to transfer the fuel oil from the truck to the storage tank.

The method for delivery of fuel oil to the site will be via standard fuel-oil tank truck, even in the event of flood conditions. Local fuel oil distributors utilize Roper rotary pumps on their fuel oil trucks. The pump vendor has verified that the pumps have sufficient discharge head to transfer the fuel oil from the truck to the storage tank using the emergency fill connection. A procedure for emergency filling of the fuel oil storage tanks will be in place prior to fuel load. The duration of impassable flood water levels around the site is such that the on-site seven day fuel oil capacity is adequate to endure the maximum flood event.

Hydrology studies for STPEGS show that the limiting flood event, the breech of upstream dams (see Section 2.4, event 7), results in flood levels that increase gradually to approximately 4 ft above grade and decrease gradually afterwards. However, the total duration of flood water levels which exceed the local grade elevation is only 2.5 days. For further discussion of external flooding see Section 2.4.

Question 430.88N

Section 9.5.5 indicates that the function of the diesel generator cooling water system is to dissipate the heat transferred through the: 1) engine water jacket, 2) lube oil cooler; 3) engine air water coolers, 4) fuel oil cooler, and 5) governor lube oil cooler. Provide the design margin (excess heat removal capacity) included in the design of major components and subsystems. (SRP 9.5.5, Parts II and III)

Response

The Diesel Generator Cooling Water System (DGCWS) is designed to handle a maximum heat load of 13.99 x 10^6 Btu/hr, per engine, from the engine water jacket, lube oil cooler, engine air water coolers, and governor lube oil cooler. All the coolers are designed to dissipate the actual predicted heat losses. Various fouling factors are used which require the predicted heat loss still be dissipated given a fouled (or dirty) heat exchanger (HX). In addition, the worst cases of coolant flow and temperature are used to maximize HX sizing and therefore capability. The HXs are designed for a maximum essential cooling water (ECW) temperature of 115 F, however, the design basis ECW temperature is 105.7 F.

Question 430.91N

Recent licensee event reports have shown that tube leaks are being experienced in the heat exchangers of diesel engine jacket cooling water systems with resultant engine failure to start on demand. Provide a discussion of the means used to detect tube leakage and to corrective measures that will be taken. Include jacket water leakage into the lube oil system (standby mode), lube oil leakage into the jacket water (operating mode), jacket water leakage into the engine air intake and governor systems (operating or standby mode). Provide the permissible inleakage or outleakage in each of the above conditions which can be tolerated without degraded engine performance or causing engine failure. This discussion should also include the effects of jacket water/service water systems leakage. (SRP 9.5.5, Parts II and III)

Response

The jacket water system is completely separate from and does not interface (provide cooling) with the lube oil system. The ECW system provides cooling water to the lube oil system cooler.

It is noted that a major cause of the reported tube leaks (see IE Information Notice 79-23) was attributed to inadequate tubesheet thicknesses and poor tube to tube sheet attachments. The STPEGS lube oil and jacket water cooler tubesheets are greater than 1-inch in thickness (versus 1/8 in. reported in IE Information Notice 79-23) and the tubes are rolled (versus soldered and epoxy reported in IE Information Notice 79-23). Another potential cause of tube leaks is the quality of water used for cooling. The essential cooling water (ECW) quality has been evaluated in Section 9.2.1.2.3. The STPEGS diesel engine manufacturer is not aware of any tube leaks in these coolers on diesel engines they have supplied. They have supplied 36 diesel engines to the nuclear industry. Ten of these engines have been operated over ten years and there have been no reports of tube leaks. Based upon the construction of these coolers, tube leakage is considered improbable.

In the unlikely event of tube leaks; e.g., lube oil into the ECW, unusual amounts of makeup required are an indication that the system should be checked for leakage. The lube oil sump tank level gauge can be used to check lube oil level for abnormal changes. For a jacket water/ECW leak, ECW would leak into the jacket water resulting in raising the jacket water standpipe level. This would alarm in the control room. Corrective measures could then be initiated. Additionally, the cooling water, lube oil and air intake systems will be inspected as described in Sections 9.5.5.4, 9.5.7.4, and 9.5.8.4, respectively.

Question 430.92N

Operating experience indicates that diesel engines have failed to start on demand due to water spraying on locally mounted electronic/electrical components in the diesel engine starting system. Describe what measures have been incorporated in the diesel engine electrical starting system to protect such electronic/electrical components from such potential environment. (SRP 9.5.5, Parts II and III)

Response

Except for solenoids and various instrument switches, there are no locally mounted electronic/electrical components in the starting system. The starting components are mounted inside the engine control panel (similar to NEMA 3R) which is located in excess of 40 ft from the subject water sources. The starting air valves are pneumatic as such the water spray from a leak is not considered a potential problem. Solenoids and various instrument switches (pressure, temperature, limit, etc.) are gasketed, redundant and determined not to impact the starting system as a result of potential water source.

Question 430.94N

Diesel generators in many cases utilize air pressure or air flow devices to control diesel generator operation and/or emergency trip functions such as air operated overspeed trips. The air for these controls is normally supplied from the emergency diesel generator air starting system. Provide the following:

a) Expand your FSAR to discuss any diesel engine control functions supplied by the air starting system or any air system. The discussion should include the mode of operation for the control function (air pressure and/or flow), a failure modes and effects analysis, and the necessary P&ID's to evaluate the system.

b) Since air systems are not completely air tight, there is a potential for slight leakage from the system. The air starting system uses a nonseismic air compressor to maintain air pressure in the seismic Category I air receivers during the standby condition. In case of an accident, a seismic event, and/or loop, the air in the air receivers is used to start the diesel engine. After the engine is started, the air starting system becomes nonessential to diesel generator operation unless the air system supplies air to the engine controls. In this case the controls must rely on the air stored in the air receivers, since the air compressor may not be available to maintain system pressure and/or flow. If your air starting system is used to control engine operation, with the compressor not available, show that a sufficient quantity of air will remain in the air receivers, following a diesel engine start, to control engine operations for a minimum of seven days assuming a reasonable leakage rate. If the air starting system is not used for engine control describe the air control system provided and provide assurance that it can perform for a period of seven days or longer. (SRP 9.5.6, Part III)

<u>Response</u>

1. Air is needed to start the engine and once the engine is operating in the emergency mode, air pressure is no longer required for control function including the maintenance barring device. It should be noted that there are only three protection trips when operating in the emergency mode: 1) generator differential, 2) overspeeding, and 3) low lube oil pressure. If a generator differential or low lube oil pressure exists, the generator is stripped from the bus mechanically. However, the engine is stopped using air to isolate the fuel supply. In the event air is lost, a manual operated control is provided. Although air is needed to stop the engine, it is not needed to satisfy the system protection since the bus is stripped mechanically. In the event an overspeed condition exists the engine is stopped when combustion air is blocked to the turbocharger via mechanical operation of a butterfly valve. The fuel supply is stopped in the same manner as for the generator differential or low lube oil pressure with the use of the air controlled valve.

2. Not Applicable, See 1, above.

Question 430.97N

You state in Section 9.5.7 of the FSAR that the lube oil to lubricate the engine is stored in the engine lube oil sump tank. During diesel engine operation a certain amount of lube oil is consumed as part of the combustion process. Since the diesel generator may be required to operate for a minimum seven days during a loss of offsite power or accident condition, sufficient lube oil should be stored in the sump and/or site to preclude diesel generator unavailability due to lack of lube oil. Provide the following:

a) Provide the normal lube oil usage rate for each diesel engine under full load conditions, the lube oil usage rates which would be considered excessive, and the sump capacity.

b) Show with the lube oil in the sump at the minimum recommended level (low level alarm setting) that the diesel engine can operate without refilling the lube oil sump for a minimum of seven days at full rated load. If the sump tank capacity is insufficient for this condition, show that adequate lube oil will be stored onsite for each engine to assure seven days of operation at rated load.

c) If the lube oil consumption rate becomes excessive, discuss the provisions for determining when to overhaul the engine. The discussion should include the procedures used and the quality of operator training provided to enable determination of excessive L.0. consumption rate. (Refer to requests 430.28 and 430.100 for additional requirements on procedures and training). (SRP 9.5.7, Parts II and III)

<u>Response</u>

a) Normal lube oil usage: approximately 12 gallons per 24 hrs at rated load

Excessive lube oil usage: See item (c) below

Sump capacity: 1260 gallons

b) The oil sump capacity between low oil level alarm and minimum operating oil level is 549 gallons. Thus, assurance of seven days of operation at rated load would be possible at a lube oil consumption rate of as much as 78 gallons per day before reaching minimum operating level.

c) Logs of engine characteristics such as temperature, pressure, run time, as well as lube oil consumption rate, will be maintained. This information may be used to determine whether or not the lube oil consumption rate is excessive and to identify the need for an engine overhaul.

Licensed and non-licensed operators are presented a classroom lecture on Engineered Safety Feature (ESF) Diesel Generators (DGs) followed by written examination and a system checkout. This training includes how

Response (Continued)

to monitor the oil level in the engine sump and the alarms and setpoints associated with engine sump oil level. Operator training also alerts them to monitor for trends in operational parameters as good engineering practice.

Question 430.98N

In Section 9.5.4 you state that diesel fuel oil is available from local distribution sources, but you have not discussed the availability of the lube oil. Identify the sources where diesel quality lube oil will be available and the distances required to be travelled from the source(s) to the plant. Also discuss how the lube oil will be delivered onsite under extremely unfavorable environmental conditions. (SRP 9.5.7, Parts II & III)

Response

Quality lube oil for the diesel may be obtained from the onsite lube oil storage facility. If this supply is unavailable, there are several local distribution sources of acceptable quality lube oil. The following lists the suppliers, locations, and approximate distance to the plant:

Gulf Oil	Bay City	20 miles
Gulf Oil	El Campo	50 miles
Gulf Oil	Victoria	65 miles
Gulf Oil	Houston	110 miles

The method for delivery of lube oil to the site will be via standard lube delivery service (i.e., truck), even in the event of extremely unfavorable environmental conditions, including flood conditions. The duration of impassable flood water levels around the site is such that the on-site lube oil capacity is adequate to endure the maximum flood event.

Hydrology studies for STPEGS show that the limiting flood event, the breech of upstream dams (see Section 2.4, event 7), results in flood levels that increase gradually to approximately 4 ft above grade and decrease gradually afterwards. However, the total duration of flood water levels which exceed the local grade elevation is only 2.5 days. For further discussion of external flooding see Section 2.4.

Question 430.99N

Assume an unlikely event has occurred requiring operation of a diesel generator for a prolonged period that would require replenishment of lube oil without interrupting operation of the diesel generator. Provide the following:

a) What provisions will be made in the design of the lube oil system to add lube oil to the sump. These provisions shall include procedures or instructions available to the operator on the proper addition of lube oil to the diesel generator as follows:

   1. How and where lube oil can be added while the equipment is in operation,

   2. Particular assurance that the wrong kind of oil is not inadvertently added to the lubricating oil system, and

   3. That the expected rise in level occurs and is verified for each unit of the lube oil added.

b) Verification that these operating procedures or instructions will be posted locally in the diesel generator rooms.

c) Verification that personnel responsible for the operation and maintenance of the diesel are trained in the use of these procedures. Verification of the ability of the personnel on the use of the procedures shall be demonstrated during preoperational tests and during operator requalification.

d) Verification that the color coded, or otherwise marked, lines associated with the diesel-generator are correctly identified and that the line or point for adding lube oil (when the engine is on standby or in operation) has been clearly identified. (SRP 9.5.7, Parts II & III)

<u>Response</u>

a) A plant procedure will be written for the addition of lube oil to an operating diesel generator. This procedure will address how to add lube oil and the type of lube oil to be used and will require the operator to verify the expected rise in oil level.

b) The plant procedure for adding lube oil will be available for use at the operator's work station.

c) Training on the Engineered Safety Feature (ESF) Diesel Generators (DGs) will provide operators with sufficient knowledge of the Diesel Engine Oil System such that they can safely follow the procedure for oil addition during engine operation.

d) The plant procedure for adding lube oil will contain adequate instructions such that special markings will not be required.

Question 430.101N

In Figure 9.5.8-1 of the FSAR a crankcase breather system is shown. Provide a more detailed description of the system including operating modes, and power sources. If this system is necessary during normal operation of the diesel engine (prevention of crankcase explosion) we require that the mechanical portions of this system be designed to seismic Category I ASME Section III Class 3 (Quality Group C) requirements and the electrical systems (if any) to Class 1E requirements. The portion of the system extending outside the diesel generator building shall be tornado missile protected. Describe any other systems or devices used to preclude or mitigate the consequences of a crankcase explosion. (SRP 9.5.7, Part II)

Response

The crankcase breather system is a static piping system that allows the evacuation of crankcase gases. This system does not need to be functional during any operation of the diesel engine. Since there is no fan required to evacuate these gases from the crankcase, there are no electrical power requirements. In addition to the crankcase vent system, rapid pressure relief valves (non ASME; Diesel meets DEMA standards) are provided on some of the crankcase doors to relieve overpressure in the event such would occur inside the engine crankcase.

Question 430.102N

Diesel generators for nuclear power plants should be capable of operating at maximum rated output under various service conditions. No load and light load operations, the diesel generator may not be capable of operating for extended periods of time under extreme service conditions or weather disturbances without serious degradation of the engine performance. This could result in the inability of the diesel engine to accept full load or fail to perform on demand. Provide the following:

a) The environmental service conditions for which your diesel generator is designed to deliver rated load including the following:

Service Conditions

(a) ambient air intake temperature range,˚F

(b) humidity, max-%

b) Assurance that the diesel generator can provide full rated load under the following weather disturbances:

(1) A tornado pressure transient causing an atmospheric pressure reduction of 3 psi in 1.5 seconds followed by a rise to normal pressure in 1.5 seconds.

(2) A low pressure storm such as a hurricane resulting in ambient pressure of not less than 26 inches Hg for a minimum duration of 2 hours followed by a pressure of no less than 26 to 27 inches Hg for an extended period of time (approximately 12 hours).

c) In light of recent weather conditions (subzero temperatures), discuss the effects low ambient temperature will have on engine standby and operation and effect on its output particularly at no load and light load operation. Will air preheating be required to maintain engine performance? Provide curve or table which shows, performance verses ambient temperature for your diesel generator at normal rated load, light load, and no load conditions. Also provide assurance that the engine jacket water and lube oil preheat systems have the capacity to maintain the diesel engine at manufacturer's recommended standby temperatures with minimum expected ambient conditions. If the engine jacket water and lube oil preheat systems' capacity is not sufficient to do the above, discuss how this equipment will be maintained at ready standby status with minimum ambient temperature.

d) Provide the manufacturer's design data for ambient pressure vs engine derating.

e) Discuss the effects of any other service and weather conditions will have on engine operation and output, i.e., dust storm, air restriction, etc. (SRP 8.3.1, Parts II and III; SRP 9.5.5, Part III, SRP 9.5.7, Parts II and III; and SRP 9.5.8, Parts II and III)

Response (Continued)

a) The diesel generators (DGs) are designed to deliver rated load at:

Ambient air intake temperature: 29 - 95°F
81°F Wet Bulb

b) The engines will continue to maintain 100 percent rated load given the pressure depression at 3 psi in 1.5 seconds followed by a rise to normal pressure in 1.5 seconds. The postulated hurricane resulting in 25 in. Hg ambient pressure for a time period of 2 hours minimum duration followed by a rise to a pressure of no less than 26 in. to 27 in. Hg for a minimum time of 12 hours will not prevent the diesel engine from maintaining 100 percent rated load.

c) It is not anticipated that the temperature at the STPEGS location will be subzero. The lower recorded temperature is 5°F (Houston area), 8°F (Bay City area), and in the last 40 years, 11□F (Bay City). The diesel generator building (DGB) is provided with 5 heaters per room to maintain a minimum room temperature of 50°F, based on an outside temperature of 29□F. Although the outside temperature has gone below 29°F, this temperature represents the 99 percent design value. Per ASHRAE, therefore, only at 1 percent of the winter month hours would the temperature be below 29°F. This corresponds to 22 hours per year. The diesel engine manufacturer has identified that their engines can start and operate with an outside temperature of 8°F.

The outdoor service condition of 29°F to 95°F are based on the environmental conditions stated in ASHRAE Handbook of Fundamentals. These conditions are used in the design of the ventilation systems serving the DGB. Provision for air preheating is included in the engine design. Whenever the turbocharger blower discharge temperature is less than 105°F, heated jacket water will be circulated through the fore section of the intercoolers and will therefore preheat the combustion air either for startup or light load operation. Therefore during winter months, jacket water will be heating the combustion air as needed. It is noted that air for startup comes predominantly from the air receivers which are located inside the DGB. Total outside air is used after the engine has reached 280 rpm.

The power to both the jacket water heater and circulation pump motor is Class 1E. The heater and pump are seismically supported and the heater meets the requirements of IEEE 323-1974. The above is also true for the lube oil circulation pump and heater. The engine jacket water and lube oil coolers are sized to a room ambient temperature down to 50°F minimum. The engine manufacturer assures that the jacket water and lube oil systems will maintain their proper warm standby temperature conditions.

The diesel engine is capable of operating with an outside air ambient temperature between 8°F to 105°F. Humidity has no adverse effect on DG performance. Although low temperature is not alarmed, DG room temperature is available in the control room.

In the event of sustained cold weather at the plant site, less than 29°F, administrative procedures will require that DG room temperature is monitored at a

Response (Continued)

frequency of once per shift to allow for appropriate and immediate remedial action. If the minimum ambient room conditions fall below 50□F, the key parameters which affect the operability of the diesel will be monitored and maintained within the required limits.

Class 1E temperature indication is provided in the DGB to alarm on high temperature. This is necessary for determining if the HVAC system is operating to avoid violating environmental qualifications of equipment. A low temperature alarm is not considered necessary since DG generator room temperature is available in the control room.

d) The ability of the diesel engines to deliver rated load at various altitudes is affected by the ability of the turbocharger to develop the required manifold pressures. The turbochargers on these engines are rated for a 3:1 pressure ratio. Based upon this rating, the turbocharger can develop sufficient manifold pressure with a minimum ambient pressure of 25 in. Hg. Consequently, no engine derating applies with respect to the expected ambient pressure.

e) In order to reduce the potential impact of the external environment, the engine combustion air intake system, including the intake filter, is installed indoors. The air intake filter is installed in a separate room located on the second level of the DGB. Air is drawn from the outside through a louvered/screened opening into the air filter room. The intake air filter is an oil bath type with a screened intake opening. As a result of abnormal climatic conditions, i.e., dust storms, or air restriction (due to foreign objects), the air filter will of course require maintenance sooner than the scheduled maintenance. The air filter is provided with differential pressure indications to ensure that the intake pressure losses do not exceed manufacturer's recommendations. (See Q430.103N.)

Question 430.103N

Recent events have shown that not all aspects in the design of the DG combustion air intake and exhaust system have been taken into account resulting in the pressure losses through the system exceeding manufacturer's limitations. Verify that the pressure losses through your system do not exceed manufacturer`s recommendations taking into consideration pipe losses, and pressure drops associated with the filters, silencers, and intake and exhaust structure openings. (SRP 9.5.8, Part III)

Response

The engine manufacturer's maximum allowable total inlet and exhaust system pressure drop is 25 in. H_2O (20 exhaust; 5 intake). A calculation has been performed to determine the actual values and they do not exceed the manufacturer's recommended pressure losses.

This calculation considers pipe losses, and pressure drops associated with filters, silencers, and intake and exhaust openings.

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	010.30	Q&R 10.4-2
	040.38	Q&R 10.4-3
	410.18N	Q&R 10.4-4

Question 121.6

The response to Request No. 121.3 cited the following references:

3.5-1 Shaffer, D. H., S. C. Chay, D. K. McClain, and B. A. Powell, "Analysis of the Probability of the Generation and Strike of Missiles From a Nuclear Turbine," Mathematics Department, Westinghouse Research Laboratories, March 1974 for Steam Turbine Division Engineering, Westinghouse Electric Corporation (also Appendix 3.5-A, STPEGS PSAR, Docket Nos. 50-498 and 50-499, Amendment 27, July 18, 1975).

3.5-2 Westinghouse Electric Corporation, "Missile Report for Turbines with 40 Inch Last Row Blades at Design, Intermediate and Destructive Overspeeds," (also Appendix 3.5-B, STPEGS PSAR, Docket Nos. 50-498 and 50-499, Amendment 27, July 18, 1975).

3.5-3 Westinghouse Electric Corporation, "The Containment of Disc Burst Fragments by Cylindrical Shells," (also Appendix 3.5-C, STPEGS PSAR, Docket Nos. 50-498 and 50-499, Amendment 27, July 18, 1975); also published as ASME Paper No. 73-WA-Pwr-2 by A. C. Hagg and G. O. Sankey and as Scientific Paper 73-1E7-STGRO-P2, Mechanics Department, Westinghouse Research Laboratories, June 25, 1973, done for Steam Turbine Division Engineering, Westinghouse Electric Corporation by the same authors.

3.5-4 "The Westinghouse Preservice Inspection and Test Programs for Nuclear Turbine Rotors and Discs," Westinghouse Electric Corporation (also Appendix 3.5-D, STPEGS PSAR, Docket Nos. 50-498 and 50-499, Amendment 27, July 18, 1975).

3.5-9 Westinghouse Electric Corporation, "Turbine Disc and Rotor Integrity," Steam Turbine Information Section 17, CT-23989, Revision 1 (May 1977).

The contents in References 3.5-1, 3.5-2, 3.5-3, and 3.5-4 do not contain the specific information needed to evaluate the degree of conformance of the STPEGS turbines with SRP 10.2.3, "Turbine Disk Integrity." Reference 3.5-9 is not on file with the NRC. Provide the information necessary to show the degree of compliance with paragraph II, "Acceptance Criteria," of SRP 10.2.3.

Response

It is Westinghouse Steam Turbine Division's position that all of the guidelines of SRP 10.2.3 have been addressed in the documents submitted. In addition, however, report CT-23989 has previously been submitted to the NRC requesting comment.

Question 032.34

Provide the results of analyses to show that your design of the initiation, actuation and control portions of the Main Steam Isolation Systems will perform their functions assuming any single failure in the instrumentation and control system following a steam line break accident. In this plant, redundant Main Steam Isolation Valves (MSIVs) for each steam line are not provided. Therefore, these analyses must include the initiation, control and actuation system for the Turbine Stop valves and any other valve in the main system downstream of the MSIVs, since they perform the redundant isolation function in each steam line. These analyses shall demonstrate that the initiation control and actuation circuits for both the MSIVs and the Turbine Stop Valve and the valves downstream of the MSIV will meet the Single Failure criterion with respect to isolation of the broken main steam line.

Response

The STPEGS design meets the requirements of Standard Review Plan 10.3, paragraph III.5.d, which states that the design will preclude the blowdown of more than one steam generator assuming a concurrent single component failure and considering that the main turbine stop and control valves are functional. The design is also consistent with the NRC Staff position documented in NUREG-0138, Issue No. 1, "Treatment of Non-Safety Grade Equipment in Evaluations of Postulated Steam Line Break Accidents".

The main turbine stop and control valves are closed within 150 milliseconds after the turbine Emergency Trip System is actuated by the Solid State Protection System (SSPS). As shown on Figure 7.2-17, the turbine is tripped by redundant actuation signals from the SSPS when at least one of the four normally energized solenoid valves in the hydraulic fluid lines is de-energized and causes the hydraulic fluid, which holds the valves open, to be dumped to drain. This arrangement provides redundancy in the initiation, actuation and control of the turbine stop and control valves.

The actuation of the turbine bypass valves is shown in Figure 7.2-11. The turbine bypass system is described in Section 10.4.4. The turbine bypass valves are actuated to close by the SSPS which blocks the steam dump to the condenser. This is accomplished by redundant actuation signals from the SSPS which cause redundant solenoid valves on each bypass valve to de-energize and close the associated bypass valve. Therefore, the required redundancy is provided for the turbine bypass valves.

The MSIVs are discussed in Section 10.3.2.5 which provides the analysis to demonstrate that the initiation, actuation, and control portions meet the single failure criterion.

Question 010.13

It is our position that the power sources for all controls, valve operators, and other supporting systems (e.g., pump lube oil cooling system) associated with the turbine driven auxiliary feedwater pump be independent from AC power. This is to comply with the diversity requirement in attached Branch Technical Position APCSB 10-1. Modify the system design to comply with this position and confirm that the turbine-driven pump lube oil cooler will receive cooling water from the pump recirculation line.

Response

The design of the controls, valve operators, and other supporting systems associated with the turbine driven auxiliary feedwater pump are such that they do not depend on AC power to perform their safety-related function. The turbine-driven pump lube oil cooler will take cooling water from a pump interstage bleed-off connection. The Auxiliary Feedwater System flow sheet is shown on Figure 10.4.9-1.

Question 010.30

Your response to our request 010.13 is not complete. Identify on Figure 10.4.9-1 whether the motor-operated valves are AC or DC operated. If there are any AC-operated valves in the turbine-driven auxiliary feedwater pump discharge or steam supply lines, discuss how they will meet the power diver- sity requirements of Branch Technical Position ASB 10-1.

Response

The motor-operated valves (MOVs) on the turbine-driven Auxiliary Feedwater System (AFW) pump discharge and steam supply lines are as follows:

MOV	Power Supply	Engineered Safety System Train Assignment
MSO143	DC	A, Channel II
XMSO514	DC	A, Channel II
FV-7526	DC	A, Channel II
AF0019	DC	A, Channel II
FV-0143	DC	A, Channel II

Question 040.38

Provide additional description (with the aid of drawings) of the turbine bypass valves and associated controls. In your discussion include the principle of operation, construction and set points, and the malfunctions and/or modes or failure considered in the design of the turbine bypass system. (SRP 10.4.4, Part III, Item 1).

Response

The turbine bypass valves are ASME Section III Class 7 Class 900, size 8 x 6 body and design temperature 6000F. The required air pressure to initiate travel is 19 psig with a l300 psi ÄP across the valve set. The valve is to be mounted in horizontal piping run, with the stem in a vertical position and the operator above valve centerline. Principals of operation are discussed in Sections 7.7.1.1, 7.7.1.4, 7.7.1.8, 7.7.1.8.1, 7.7.1.8.2, 7.7.1.8.3, 7.7.2.1, 7.7.2.3, 7.7.2.5, and 7.7.2.6. The failure modes are discussed in revised Section l0.4.4

A description of the interlocks can be found in Table 7.7-1.

Question 410.18N

Provide a response to the staff's March 10, 1980 letter to near-term operating license applicants concerning your AFW system design (TMI-2 Task Action Plan, NUREG-0737, item II.E.1.1). This response should include the following:

(a) A review of the AFW system design against Standard Review Plan Section 10.4.9, and Branch Technical Position ASB 10-1.

(b) A review of the AFW system design, Technical Specifications and operating procedures against the generic short-term and long-term requirements discussed in the March 10, 1980, letter.

(c) The design basis for the AFW flow requirements and verification that the AFW system will meet these requirements (refer to Enclosure 2 of the March 10, 1980, letter).

Response

(a) Tables Q410.18N-1 and Q410.18N-2 summarize the STPEGS conformance to SRP 10.4.9 and BTP ASB 10-1.

(b) The draft STPEGS Technical Specifications were submitted on June 17, 1985 (reference letter ST-HL-AE-1271 to Mr. Hugh L. Thompson from J. H. Goldberg). Technical Specifications for the AFWS have been prepared and were provided by letter ST-HL-AE-1548 dated January 15, 1986.

(c) The response is provided in Section 7A, item II.E.1.1.

Table 410.18N-1

STANDARD REVIEW PLAN, SECTION 10.4.9

Item	Acceptance Criteria	Related to	STPEGS Position	Reference UFSAR Section
1.	II.2	GDC 2	Conforms	10.4.9.2 & 10.4.9.3
2.	II.2	GDC 4	Conforms	3.5, Table 3.5-1, 3.6 & 10.4.9.2
3.	II.3	GDC 5		Conforms 10.4.9.2[1]
4.	II.4	GDC 19	Conforms	7.4.1, 7.4.1.1 & 10.4.9
5.	II.5 (a)	GDC 34 & 44	Conforms	
	II.5 (b)	GDC 34 & 44	Conforms	10.4.9.1 10.4.9.1, 10.4.9.2, 10.4.9.3 & Table 10.4-3
	II.5 (c)	GDC 34 & 44	Conforms	10.4.9.2 (paragraph 7 & 11), 6.2.4, 10.4.9.3 and Appendix 10A
6.	II.6	GDC 45	Conforms	6.6
7.	II.7	GDC 46	Conforms	10.4.9.4, 14.2 & STPEGS Tech Specs

1. Each unit has an entirely independent Auxiliary Feedwater System.

Table 410.18N-2

BRANCH TECHNICAL POSITION ASB 10-1

Item	ASB 10-1 Position	Related to	STPEGS Position	Reference UFSAR Sections
1.	B.1	Independency & Diversity	Conforms(1)	10.4.9.2
2.	B.2	Diverse & Separate Motive Power	Conforms	10.4.9.2, 7.4.1.1, Table 10.1-1
3.	B.3	Train Separation & Cross-connect	Meets the intent(2)	10.4.9.2, Fig. 10.4.9-1, 10.4.9.1.4, 10.4.9.3
4.	B.4	Redundancy	Conforms	10.4.9.1.4, 10.4.9.3
5.	B.5	AFW Flow Following HELB	Conforms(1)	10.4.9.1.4

1. Operator action is required to open the safety grade steam generator power-operated relief valves for specific events.

2. The STPEGS AFW system with its four independent trains is designed to function (provide the required AFW flow) following a postulated piping failure with or without offsite power available considering, at the same time, any single failure.

   Additionally, the AFW trains are provided with a cross-connect for use during nonsafety-actuated AFW system operation. This allows one, two, three, or four operating pumps to feed any or all four SGs. In addition, the cross-connect valves are provided with manual (locally operated) actuators which would allow any operable AFW pump to be aligned with any effective SG during an extreme accident and failure combination.

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Question 331.6

With regard to the review of the design process, and changes made as a result, to assure that occupational radiation exposures are as low as is reasonably achievable (ALARA):

1. Identify by title the individuals who have been responsible for the radiation protection aspects of the design review, and describe their relationship to the individual responsible for the overall plant design.

2. Provide a breakdown by title of radiation protection personnel who have been participating in such reviews, tabulating the health physics education and experience required of each.

3. Describe formal arrangements and procedures for assuring that adequate radiation protection reviews are performed throughout the design and construction processes and that adequate records are kept to document the completion of each such review.

4. Describe specific examples of actual dose-reducing changes in design that have resulted from these radiation protection design reviews.

Response

The response as applicable to the design and construction phase of the South Texas Project is found in the Final Safety Analysis Report, Amendment 62.

For information concerning the current program for reviewing designs for as low as is reasonably achievable considerations, see Chapter 12 of the Updated Final Safety Analysis Report, Section 12.1.

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	640.8N	Q&R 14.2-18
	640.11N	Q&R 14.2-23
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	640.26N	Q&R 14.2-33
	640.27N	Q&R 14.2-34
	640.30N	Q&R 14.2-35

Question 423.22

Our review of your test program description disclosed that the operability of several of the systems and components listed in Regulatory Guide 1.68 (Revision 2) Appendix A may not be demonstrated by your initial test program. Expand your test description to address the following listed items:

1. Preoperational Testing

1.a(2) (a)	-	Pressurizer
1.a(2) (b)	-	Pumps, motors, and associated power sources
1.a(2) (c)	-	Steam generators
1.a(2) (d)	-	Pressurizer relief valves and supports and restraints
1.a(2) (e)	-	Main steam isolation valves
1.a(2) (g)	-	Instrumentation used for monitoring system performance or performing permissive or prohibit interlock functions
1.a(2) (h)	-	Reactor vessel and internals
1.a(2) (i)	-	Safety valves
1.a(3)	-	Vibration test
1.a(4)	-	Pressure boundary integrity test
1.d(1)	-	Turbine bypass valves
1.d(2)	-	Steam line atmospheric dump valves
1.d(3)	-	Relief valves
1.d(4)	-	Safety valves
1.d(9)	-	Condensate storage system
1.e(1)	-	Steam generators
1.e(5)	-	Steam extraction system
1.e(10)	-	Feedwater heater and drain systems
1.h(1) (c)	-	ECCS demonstration
1.h(1) (d)	-	ECCS interlocks and isolation valves
1.h(4)	-	Containment combustible gas control
1.h(8)	-	Tanks and other sources of water for ECCS
1.h(10)	-	Ultimate heat sink
1.j(1)	-	Pressurizer pressure and level control
1.j(6)	-	Loose parts monitoring
1.j(7)	-	ECCS leak detection systems
1.j(8)	-	Automatic reactor power control system, T_{avg} control system
1.j(9)	-	Seismic instrumentation
1.j(17)	-	FW heater temperature, level, and bypass control
1.j(20)	-	Flooding detection
1.j(22)	-	PAMS
1.j(25)	-	Process computers
1.k(2)	-	Personnel monitors and radiation survey instruments
1.k(3)	-	HEPA filter and charcoal absorber in place tests
1.k(5)	-	Isolation of condenser offgas
1.k(7)	-	Isolation of liquid radwaste effluent
1.n(10)	-	Purification and cleanup of RCS
1.n(14)	-	HVAC systems (specifically Containment Subsystems other than RCFC, Purge, and Isolation Valve Cubicle HVAC, Fuel Handling Building HVAC, and Supplementary Fuel Pool Cooling)

Question 423.22 (Continued)

1.n(18)	-	Heat tracing and freeze protection
1.o(1)	-	Crane load tests
1.o(2)	-	Component handling interlocks
1.o(3)	-	Safety devices on fuel handling equipment

4. Low Power Testing

4.h	-	Chemical and radiochemical tests to demonstrate chemical control and analysis systems
4.i	-	Rod withdrawal inhibit and interlock
4.k	-	Operability of steam driven equipment
4.l	-	Operability of MSIVs and branch steam line valves at rated temperature and pressure
4.n	-	Control room computer
4.p	-	Demonstration of pressurizer and main steam relief valves at rated temperature
4.t	-	Performance of natural circulation test
	-	

5. Power Ascension Tests

5.l	-	ECCS demonstration
5.m	-	RCS demonstration
5.n	-	Loose parts monitoring baseline data
5.o	-	RCS leak detection
5.q	-	Verification of computer inputs and calculations
5.u	-	MSIV and branch line isolation valves
5.v	-	Main steam and feedwater verification
5.aa	-	Chemical and radiochemical control demonstration
5.bb	-	Neutron and gamma surveys
5.cc	-	Radwaste demonstrations
5.ii	-	Reactor coolant pump trip tests
5.kk	-	Loss of feedwater heater tests
5.mm	-	MSIV closure test
5.nn	-	Load rejection test
5.oo	-	Piping movement, vibration, and expansion

Response

The operability of the systems and components will be demonstrated either as a prerequisite to or during the tests as described by the test summaries as noted below.

1. Preoperational Testing

Item No.	Test Description No.
1.a(2)(a)	98
1.a(2)(b)	Applicable systems
1.a(2)(c)	98
1.a(2)(d)	98
1.a(2)(e)	84
1.a(2)(g)	All applicable tests

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1.e(5)	98
1.e(10)	98
1.h(1)(c)	76
1.h(1)(d)	78
1.h(4)	103
1.h(8)	All applicable tests
1.h(10)	88
1.j(1)	98
1.j(6)	Startup Test 30
1.j(7)	94
1.j(8)	Startup Test 21
1.j(9)	102
1.j(17)	65
1.j(20)	94
1.j(22)	41, 50
1.j(25)	105
1.k(2)	Personnel Monitoring and Survey Instrumentation will be tested, operated and maintained by the Nuclear Plant Operations Department
1.k(3)	Applicable HVAC System Tests
1.k(5)	50
1.k(0)	50
1.k(7)	50
1.n(10)	809
1.n(14)	98
1.n(18)	18
1.o(1)	86
1.o(2)	86
1.o(3)	86

4. Low Power Testing

4.h	See Section 14.2.12.2 Test Summaries 48, 54, 62, 66, and 80.
4.i	Demonstration of the operability of the control rods will be accomplished during the performance of Test 3 in Section 14.2.12.3 and Test 47 in Section 14.2.12.2.
4.k	See Section 14.2.12.2 Test Summary 65 and 98. Main turbine and steam-driven feed pumps will be demonstrated to be operable during the power ascension testing. See Section 14.2.12.3 Test Summary 20.

Response (Continued)

4.l	See revised Section 14.2.12.2 Test Summary 98.
4.n	See revised Section 14.2.12.2 Test Summary 105.
4.p	See revised Section 14.2.12.2 Test Summary 98.
4.t	See revised Section 14.2.12.3 Test Summary 13.

5. Power Ascension Test

5.l	Test to demonstrate design capability of all systems and components provided to remove residual or decay heat from the Reactor Coolant System (RCS), including Turbine Bypass System, atmospheric steam dump valves, Residual Heat Removal System (RHRS) and Auxiliary Feedwater System (AFWS) will be performed during the preoperational hot functional test.
5.m	These tests are described in Section 14.2.12.3 Test Summary 6.
5.n	See Section 14.2.12.3 Test Summary 30.
5.o	A leak integrity test will be performed as a standard operating procedure every time the reactor vessel head is installed.
5.q	Various systems that will be acceptance tested.
5.u	See the response to NRC Question 640.08N, 5.mm.
5.v	See revised Section 14.2.12.3 Test Summary 20.
5.aa	See revised Section 14.2.12.3 Test Summary 29.
5.bb	See revised Section 14.2.12.3 Test Summary 14.
5.cc	These tests are described in Section 14.2.12.2 test summary 91, 96, and 97.
5.ii	This test appears to be a requirement for BWR facilities and does not apply to STPEGS.
5.kk	See revised Section 14.2.12.3 test description 32.
5.mm	See the response to NRC Question 640.08N, 5.mm.
5.nn	See revised Section 14.2.12.3 Test Description 23.
5.oo	These test are performed earlier in the test program (see Section 14.2.12.2 Test Descriptions 99 and 101) and need not be repeated.

Question 423.25

Our review of recent licensee event reports disclosed that a significant number of reported events concerned the operability of hydraulic and mechanical snubbers. Provide a description of the inspections or tests that will be performed following system operation to assure yourself that the snubbers are operable.These inspections or tests should be performed preoperationally if system operation can be accomplished prior to generation of nuclear heat.

Response

Following preoperational testing and prior to initial criticality, safety-related and designated high-energy snubbers will be inspected in accordance with the manufacturer's recommendations to assure that there are no visible signs of damage to the snubbers or loosening of secured attachments as a result of system operation.

Question 423.26

Provide test descriptions or modify existing test descriptions to assure that tests will be performed to demonstrate (1) that the plant's ventilation systems are adequate to maintain all ESF equipment within its design temperature range during normal operations and (2) that the emergency ventilation systems are capable of maintaining all ESF equipment within its design temperature range with the equipment operating in a manner that will produce the maximum heat load in the compartment. If it is not possible to operate equipment to produce maximum heat loads, describe how the tests performed satisfy the objectives listed above. Also include testing in accordance with Regulatory Guide 1.52 or 1.140, as applicable.

Response

1. To the extent practical, it is intended that HVAC systems will be operated during hot functional testing. Doing this will produce the maximum heat load attainable to verify design requirements. In those cases where certain equipment cannot be subject to an adequate heat load, data will be collected to confirm design calculations.

2. Emergency ventilation systems testing has been included as part of the integrated testing during diesel generator testing.

Question 423.27

1. Provide descriptions of the electrical lineups of both units during preoperational testing of Unit 1 in accordance with Regulatory Guide 1.41. Include an evaluation of how this lineup precludes inadvertently powering Unit 1 buses from Unit 2 sources. Address both normal and emergency power distribution systems.

2. Provide descriptions of the electrical lineups of both units during preoperational testing of Unit 2 in accordance with Regulatory Guide 1.41 subsequent to initial criticality of Unit 1. Provide assurance that crossties between the units that could result in loss of power to any Unit 1 emergency power distribution systems.

3. Provide a test description for integrated electrical system testing to accomplish these objectives.

Response

1. Initially, power for Unit 1 preoperational testing will be derived from Standby 1 and 2 transformers. Prior to major load accumulation, Unit 1 auxiliary transformer will replace the need for Standby 2 transformers except for the testing of Engineered Safety Features (ESF) preferred and alternate power sources. (Reference Test Description 2, Section 14.2.12.2.)

2. Standby 1 transformer will not be required in support of Unit 2 preoperational testing. Standby 2 transformer loading will be administratively restricted to its normal Unit 2 plant loads. In the event this backup alternate ESF power source is required for Unit 1 an adequate pretested power source for Unit 1 ESF loads will be available.

3. Test Descriptions 2, 3, and 14, Section 14.2.12.2, provide the test coverage to demonstrate the capability of these alternate ESF power sources for Unit 1 and 2.

Question 423.29

Describe the testing to be conducted to verify that the capacity of pressurizer and steam generator power-operated reliefs and steam dump and turbine bypass valves are within the minimum and maximum values assumed in the accident analysis.

Response

Testing of each pressurizer and steam generator power-operated relief valve (PORV) and each steam dump and turbine bypass valve, to demonstrate that the capacity of each valve is within the minimum and maximum values assumed in the accident analysis, is neither practical nor justified for the following reasons.

1. There is no practical method of measuring steam flow rate from any of these valves after they are installed.

2. Assuming that a method of measuring flow rate could be developed, testing of each valve would put the unit through numerous undesirable transients, because there are 2 pressurizer PORVs, 4 steam generator PORVs, 20 steam safety valves, and 12 condenser steam dump valves. A relatively lengthy blowdown period would be required for each test in order to measure either (a) steam flow rate or (b) cooldown rate, which could be extrapolated to flow rate. Imposing a modified Condition II event on the unit is not justified.

3. Testing of the unit's full load rejection capability adequately demonstrates that the capacities of the PORVs and steam dump valves are consistent with design.

4. The safety valves are ASME Section III components and as such have been tested by the manufacturer in accordance with the code requirements. The other relief/dump valve capacities have been verified by the respective manufacturers to be in accordance with design flow rates. These verifications are based on standard industry practices, which include obtaining flow characteristics by testing and/or calculating flow capacities based on specified conditions. The present test program verifies the valve stroke length to be in accordance with the manufacturers' specifications for each valve, thus ensuring that the specified valve opening is not exceeded.

Question 640.3N

List any tests, or portions of tests, described in Subsection 14.2.12 which you do not intent to perform on Unit No. 2 and provide technical justification for the deletion of each.

Response

Test 18. Axial Xenon Oscillation Test

The Axial Xenon Oscillation Test performed on STPEGS Unit 1 verified that axial xenon oscillations are controllable and need not be repeated on STPEGS Unit 2 in accordance with the provisions of Regulatory Guide 1.68, Rev. 2, Appendix A.5.d.

Test 28. Pseudo Rod Ejection Test

The Pseudo Rod Ejection Test performed on STPEGS Unit 1 validated the rod ejection analysis and need not be repeated on STPEGS Unit 2 in accordance with the provisions of Regulatory Guide 1.68, Rev. 2, Appendix A.5.e.

Question 640.4N

Your response to item 423.17, part 3, and item 423.22, part nn is not acceptable. It is the staff position that the preoperational testing of diesel generator units conform to positions C.2.a and C.2.b of Regulatory Guide 1.108. Modify Section 3.12 and Phase II test number 81, Standby Diesel Generator Test, accordingly.

Response

Preoperational testing will be conducted on the diesel generator units to conform to Regulatory Guide 1.108, Rev. 1 - positions C.2.a and C.2.b.

Question 640.7N

Certain terminology used in the individual test descriptions does not clearly indicate the source of the acceptance criteria to be used in determining test adequacy. An acceptable format for providing acceptance criteria for test results includes any of the following:

- Referencing technical specifications (Chapter 16)
- Referencing accident analysis (Chapter 15)
- Referencing other specific sections of the FSAR (ex. 7.4.1.2)
- Referencing vendor technical manuals
- Providing specific quantitative bounds (only if the information cannot be provided in any of the above ways).

Modify the individual test description abstracts presented below to provide adequate acceptance criteria for all items in the respective test summaries or, if applicable, add a paragraph to Subsection 14.2.12 that provides an acceptable description to each of the following unclear terms.

(1) Phase II Tests

(a) required, required, tolerance, as required, within required limits

5.b.2	33.b.3
6.b.1	35.b.1
11.b.1	40.b.1
11.b.2	47.b.3
12.b.2	48.b.3
13.b.1	49.b.1
14.b.1	67.b.1
16.b.1	69.b.1
20.b.3	70.b.1
21.b.1	72.b.1
26.b.2	79.b.3
26.b.3	92.b.3
27.b.1	
29.b.2	

(b) as designed, appropriate design documents, design minimum, within design limits, below design maximum, in accordance with system design, per design, design requirements, in accordance with design, within the limits prescribed by system design, design, design function

2.b.3	30.b.1	43.b.5
5.b.1	30.b.2	44.b
7.b.1	31.b.1	45.b.1
8.b.2	31.b.2	46.b.1
9.b.2	32.b.1	47.b.1
10.b.1	32.b.21	47.b.2
12.b.1 (twice)	32.b.3	48.b.1
14.b.1	32.b.4	49.b.1

Question 640.7N (Continued)

15.b.1	32.b.5	50.b.1
15.b.2	33.b.1	50.b.3
16.b.3	33.b.2	51.b.3
17.b.1	33.b.3	51.b.4
18.b.2	33.b.4	52.b.1
19.b.1	33.b.5	52.b.2
20.b.1	34.b.1	52.b.3
22.b.2	34.b.2	53.b.1
23.b.2	35.b.1	53.b.2
24.b.2	35.b.2	54.b.1
25.b.1	35.b.3	54.b.2
25.b.4	36.b.1	55.b.1
26.b.1	36.b.2	55.b.2
27.b.1	37.b.1	56.b.1
27.b.2	38.b.2	57.b.1
28.b.1	38.b.3	57.b.2
28.b.2	39.b.1	58.b.2
28.b.3	41.b.2	59.b.1
29.b.1	42.b.1	59.b.2
29.b.2	43.b.1	60.b.1
29.b.3	43.b.1	60.b.2
61.b.3	76.b.6	87.b.3
62.b.1	78.b.1	88.b.1
62.b.2	78.b.2	88.b.3
63.b.1	78.b.3	89.b.1
64.b.1	79.b.1	89.b.2
64.b.2	79.b.4	90.b.1
65.b.1	80.b.1	90.b.2
66.b.1	80.b.2	91.b.1
66.b.2	80.b.3	91.b.2
66.b.3	80.b.4	94.b.1
67.b.1	80.b.5	94.b.2
68.b.2	80.b.6	95.b.1
69.b.1	81.b.1	95.b.2
69.b.2	81.b.3	96.b.1
70.b.1	81.b.4	96.b.2
70.b.2	82.b.1	97.b.1
71.b.1	82.b.2	97.b.2
71.b.2	82.b.3	97.b.3
72.b.1	82.b.4	98.b.2
72. b.2	84.b.1	101.b.1
75.b.1	84.b.2	102.b
76.b.1	85.b.1 (twice)	103.b.1
76.b.2	85.b.2	103.b.2
76.b.3	86.b.3	104.b.1
76.b.4	86.b.4	105.b.1
76.b.5	87.b.1	105.b.1

Question 640.7N (Continued)

(c) within the rating, rated, near rated, within their ratings

2.b.1
3.b.4
7.b.1
8.b.1
10.b.5
14.b.2

(d) undue

9.b.1
17.b.2
22.b.1
23.b.1
24.b.1
100.b.3

(e) as specified, specified, within specified tolerances, equipment specifications, specified

5.b.3
10.b.3
12.b.3
25.b.3
42.b.1
96.b.3
99.b.2
99.b.3

(f) peturbance

10.b.2
25.b.2

(g) sufficient

4.b.1
4.b.2
4.b.3

(h) minimum, above minimum, acceptable minimum

10.b.5
18.b.1
41.b.3

Question 640.7N (Continued)

(i) within acceptable limits, within limits, within prescribed limits, allowed limits

2.b.1
2.b.3
5.b.4
12.b.4
15.b.1
16.b.2
39.b.2
48.b.2
61.b.2
81.b.2
87.b.2

(j) as necessary, as prescribed

15.b.1
43.b.4
50.b.4
58.b.1

(k) adequate

15.b.1
50.b.1
61.b.1
68.b.1

(l) recommended

21.b.4

(m) correct

40.b.1
42.b.2
102.b

(n) function properly, responds properly, properly calibrated to reference standard sources, proper

56.b.2
65.b.3
65.b.4
92.b.1
104.b.1

(o) approximate

77.b.2
100.b.4

Question 640.7N (Continued)

(p) consistent

77.b.1
74.b.2

(q) applicable, applicable regulatory guides

49.b.1
77.b.3
93.b.1

(r) allowable, within the allowed

40.b.2
93.b.2
93.b.3

(s) within the required tolerances, tolerances

41.b.1
50.b.2
100.b.1

(t) satisfactorily verifies, satisfactory

73.b.1
98.b.1

(u) misalignments

77.b.1
100.b.3

(v) change in status, evidence, excessive

37.b.2
38.b.1
77.b.1

(w) function to protect both equipment and personnel, acceptable, discrepancy

1.b.1
2.b.2
46.b.2
99.b.1
99.b.4

Question 640.7N (Continued)

(x) in accordance with approved procedures, established criteria, code requirements

99.b.1
99.b.4
101.b.1

(y) anticipated transients, nominal output

1.b.2
5.b.2

(z) degradation, capabilities

2.b.4
10.b.4

(2) Phase III Tests

(a) design

3.b.2
4.b
6.b.1
16.b.1
16.b.2
17.b
18.b
21.b
22.b.1
27.b.1
31.b.2
31.b.3

(b) in accordance with those specified, within the limits specified

3.b.1
12.b.1

(c) satisfactory

2.b

(d) no major deviation

8.b.1

(e) consistent

15.b.3

Question 640.7N (Continued)

(f) confirmed by laboratory or other analysis

16.b.1

(g) compatible

19.b.2

(h) responsive

22.b.2

(i) significant

22.b.3

Response

As stated in Section 14.2.12.2, the test summaries contain the general objectives and acceptance criteria. Specific details, objectives, acceptance criteria, and prerequisites will be in the individual preoperational test procedures. Acceptance criteria for preoperational procedures are obtained from a variety of project design controlled documents. These documents are subject to change as the project progresses, therefore, preoperational procedures will be revised accordingly. For this reason, test summaries containing general information are provided in Section 14.2.

Preoperational Test Procedures are prepared in the format described in Section 14.2.3.3 which includes a "References" section. Source documents utilized in the procedure preparation will be listed. The responsible design organization, via the Joint Test Group, will perform a technical review of the procedure preparation will be listed. The responsible design organization, via the Joint Test Group, will perform a technical review of the procedure prior to its being accepted by the Startup Manager per Section 14.2.3.1. In addition, a draft of the procedure will be submitted to the NRC at least 60 days prior to the conduct of the test.

HL&P does not agree that the terms identified by the NRC as "unclear" in this question are unclear. These are common terms whose usage is straight-forward and easily understood when taken in context with the test summary.

Initial Startup test abstracts (Section 14.2.12.3) have been revised to use terminology which more clearly indicates the source of the acceptance criteria. See revised Sections 14.2.12.3; Test Summaries 2, 3, 4, 6, 8, 9, 12, 15, 16, 17, 18, 19, 21, and 27.

Question 640.8N

Our review of your test program description and your response to item 423.22 disclosed that the operability of several of the systems and components listed in Regulatory Guide 1.68 (Revision 1) Appendix A may not be demonstrated by your initial test program. Expand your test description to address the following items:

1. <u>Preoperational Testing</u>

1.a (2) (i)	-	Expand the preoperational test phase such that the safety valves of the reactor coolant systems are tested at temperature.
1.e (5) (10)	-	Expand that preoperational test phase such that the steam extraction system and feedwater heater and drain systems are tested.
1.h (10)	-	Verify that containment recirculation fan motor current is within its design valve at conditions representative of accident conditions. Address such issues as air density, temperature, humidity, fan speed, and blade angle.
1.j (17)	-	Expand Phase II test number 65, Main Feedwater System, to include testing of feedwater heater temperature and level control systems.
1.j (22)	-	Expand the preoperation test phase such that the following instrumentation used to track the course of postulated accidents is tested: a) containment wide range pressure indicators b) containment sump level monitors c) humidity monitors
1.k (4)	-	Modify the appropriate test abstracts to ensure that testing in accordance with Regulatory Guide 1.52, position C.5.a, is accomplished (in-place DOP [Dioctyl phthalate] tests).

4. <u>Low Power Testing</u>

4k	-	Modify Phase II test number 58, Feedpump Turbine (FPT) and FPT Gland Steam Test, such that testing of the main feedwater pump is included.
4t	-	(See Q423.56)

Question 640.8N (Continued)

5. Power Ascension Tests

5.0 - Include an abstract of the leak integrity test which will be performed as standard operating procedure every time the reactor head is removed.

5w - Provide a preoperational test description to test containment penetration coolers. On these penetrations where coolers are not used, provide a startup test description that will demonstrate that concrete temperatures surrounding hot penetrations do not exceed design limits.

5.kk - Revise Phase II test number 32, Feedwater Temperature Reduction Test, such that the testing occurs at both 50 percent and 90 percent power levels.

5.mm - Either provide technical justification for performing the MSIV closure test at 15 percent power and demonstrate how the results of this test can be extrapolated to show proper plant response at full power, perform this test at higher power level where such a justification or extrapolation can be made, or perform this test at full power.

The response to Regulatory Guide 1.68, Appendix A.5.W, is to be provided later. Provide either the information or a schedule for its delivery.

Response

HL&P is committed to use Revision 2 of Regulatory Guide (RG) 1.68 in the development of the STPEGS Startup Program.

HL&P now intends to conduct acceptance tests on nonsafety-related systems. Acceptance testing is defined in Section 14.2.1.1 and a partial list of systems that will be acceptance tested is provided in Section 14.2.12.2.

The preoperational test summaries in Section 14.2.12.2 contain only the general objectives and acceptance criteria. Specific information regarding the test will be contained in the individual test procedures. Preoperational test procedures are submitted to the responsible design organization for a technical review prior to approval by the Startup Manager.

Therefore, in response to the individual parts of Question 640.8N, the details requested will be included in the individual preoperational test rather than in the test summary. Identification has been provided for the preoperational test summary number and/or the acceptance test that will be prepared for the specific system.

Response (Continued)

1. Preoperational Testing

1.a (2) (i)	-	See revised Test Summary 98. The pressurizer safety valves will be bench tested to verify their setpoints. Data will be obtained during hot functional testing to determine the actual environmental temperature of the pressurizer safety valves and allow extrapolation of any temperature effects on the setpoint.
1.e (5) (10)	-	See new Section 14.2.12.3, Test Summary 33.
1.h (10)	-	See revised Section 14.2.12.2, Test Summaries 29 and 93.
1.j (17)	-	See revised Section 14.2.12.2, Test Summary 65.
1.j (22)	-	See revised Section 14.2.12.2, Test Summary 44.
1.k (4)	-	See revised Section 14.2.12.2, Test Summaries 29, 32, 33, and 35.

4. Low Power Testing

4.k	-	See new Section 14.2.12.3 Test Summary 33.
4.t	-	Unable to respond, Question 423.56 does not exist.

5. Power Ascension Tests

5.0	-	Individual startup test procedures will include instructions and precautions for establishing conditions necessary for conducting the test. The completion of a leak integrity test will be a necessary condition for startup testing and will be performed as a standard operating procedure every time the head is removed, utilizing approved plant operating procedures. Since the leak integrity test is a standard plant operating procedure rather than a startup test, the abstract is not included in Chapter 14. Standard operating procedures will be completed and available for review six months prior to initial fuel load as per Section 13.5.1.2.
5.w	-	Heat transfer analyses for those penetrations with operating temperatures above 200°F, have been performed. For those penetrations where the concrete temperature exceeds the design basis temperature of 200°F, cooling will be provided.

Response (Continued)

The penetrations where localized heating, ventilating, and air conditioning (HVAC) cooling is to be provided include the mainstream feedwater primary sampling penetrations.

Local temperature surveys will be made to verify concrete temperature during power ascension testing.

5.kk - See revised Section 14.2.12.3, Test Summary 32.

5.mm - Section 14.2.12.3 Test Summary for the steam line isolation valve closure test has been deleted. The plant response to a transient for the case of automatic closure of all main steam line isolations valves (MSIVs) will be similar to the plant response to a turbine trip at 100 percent power except that the automatic closure of all MSIVs at 100 percent power would force the opening of safety-relief valves and place unnecessary burden upon the plant protective systems. The demonstration of proper plant response to this type transient is described in Section 14.2.12.3 Test Summary 23 Full Load Rejection Test

Operability testing and functional testing of the MSIVs will be demonstrated during the Hot Functional Testing performed in the Preoperational Testing program and through surveillance testing of the MSIVs required by Technical Specifications.

The current design creates the capability of testing the electrical circuit logics, the air actuation system, and the movement of the MSIV at any power level. A test circuit is provided to test the signal and logics from the control panel to the air controlling solenoid without necessitating any actuation of the MSIVs. This test serves to verify the functionality of the circuitry. Additionally, a test circuit is provided to individually close each MSIV in turn to the 90 percent open position and return each to the full open position.

Technical Specification surveillance testing will assure that the MSIVs are operable (not sticking). As each MSIV plant protection system is presented

The steam pressure in the main steam lines during hot functional testing will be approximately 1180 psia. The 100 percent load has a line pressure of 1100 psia. Therefore, the line pressure of steam does not differ appreciably between Hot Functional Testing and 100 percent, and the velocity pressure is insignificant in comparison to the line pressure.

Response (Continued)

RG 1.68, Appendix A.5.W requires that licensees provide a preoperational test description to test containment penetration coolers. On these penetrations where coolers are not used, provide a startup test summary that will demonstrate that concrete temperatures surrounding hot penetrations do not exceed design limits.

Heat transfer analysis for those penetrations with operating temperatures above 200°F have been performed. For those penetrations where the concrete temperature exceeds the design basis concrete temperature exceeds the design basis temperature of 200°F, cooling will be provided.

The penetrations where localized HVAC cooling is to provided includes the main steam, feedwater, steam generator blowdown, and primary sampling penetrations.

Local temperature surveys will be made to verify concrete temperature during power ascension testing.

Question 640.11N

Our review of licensee event reports has disclosed that many events have occurred because of dirt, condensed moisture, or other foreign objects inside instruments and electrical components (e.g., relays, switches, breakers). Describe any tests or inspections that will be implemented during your initial test program to prevent component failures such as these at your facility.

Response

When systems are released or turned over from Construction to Startup, the components in the system are included in the normal plant maintenance program which includes preventive maintenance procedures for maintaining proper component cleanliness on a predetermined schedule.

Question 640.12N

Review of licensee event reports disclosed that a number of sensing lines were rendered inoperable due to being frozen and/or blocked with crud, dirt, and entrapped gas. Provide a description of the inspections or tests that will be performed to ensure that the sensing lines are clear prior to utilization.

Response

A documented flushing program, which includes instrument sensing lines, will be conducted to eliminate the crud and dirt problem. Instrument calibration and/or surveillance procedures will include provisions for ensuring entrapped gas is removed when placing the instrument in service. In the event a system is drained for maintenance etc., instruments will be vented when the system is refilled in preparation for placing the system in operation.

Question 640.13N

Review of licensee event reports disclosed that some instrumentation drift problems are due, in part, to extremes of local temperature and humidity. Provide a description of the inspections or tests that will be performed to minimize set point drift due to local temperature and humidity extremes.

Response

As part of the normal calibration and/or surveillance program, which begins with initial instrument calibration, test results will be reviewed for set point drift. When a drift problem is identified, all factors including local temperature and humidity extremes will be investigated in determining corrective actions.

Question 640.14N

We could not conclude from our review of the preoperational test phase description (Phase II tests) and the response to item 423.33 that comprehensive testing is scheduled for several systems and components. Therefore, clarify or expand the description of the preoperational test phase to address the following:

1) The response item 423.23 (f) is inadequate. Modify your test descriptions to ensure that individual cell limits are not exceed during the design discharge test and to demonstrate that the DC loads will function as necessary to assure plant safety at a battery terminal voltage equal to the acceptance criterion that has been established for minimum battery terminal voltage for the discharge load test.

2) The response to item 423.23 (k) is inadequate. Modify Phase II test number 31, Containment HVAC Isolation Valve Critical Subsystem Test, such that all auxiliary feedwater pumps are in operation to assure that design heat loads are produced in the AFW pump areas. Note - this can be done in conjunction with the Hot Functional Test (Phase II test number 98) test methods 9 and 16.

3) Recently the Westinghouse Water Reactor Division's Safety Review Committee identified a potential control and protection system interaction concern involving Volume Control Tank (VCT) level instrumentation. The concern involves failure of the VCT level control system resulting in a loss of suction to the charging pumps. Modify Phase II test number 80, Chemical and Volume Control System (CVCS) Test, to verify that adequate procedures, testing, operator training, design, changes, and/or circuitry modifications are being conducted prior to fuel loading to address this potential safety system failure.

4) Modify Phase II test number 85, Auxiliary Feedwater System (AFWS), to address the following:

   a) Include testing to ensure that a loss of auxiliary feedwater (AFW) flow will not occur due to pump runout and subsequent tripping of the AFW pump motors.

   b) Our review of licensee event reports has disclosed several instances of emergency feedwater pump failure to start on demand. It appears that many of these failures could have been avoided if more thorough testing had been conducted during the plant's initial test programs. In order to discover any problems affecting pump startup and to demonstrate the reliability of our emergency cooling system, state your plans to demonstrate at least five consecutive, successful, cold, quick pump starts during your initial test program.

5) The response to item 423.34 (kk) is inadequate. Include in Phase II test number 86, Fuel-Handling Equipment Test, the polar crane, and cask handling crane. Furthermore, specify the levels of the static (125 percent rated load) and dynamic (100 rated load) tests.

Question 640.14N (Continued)

6) The response to item 423.23 (mm) is inadequate. Include testing of the compartment watertight doors in Phase II test number 88, Essential Cooling Water System (ECWS) Test.

7) Expand the Reactor Coolant System (RCS) Hot Functional Preoperational Test Summary (Phase II test number 98) or other tests to address the following:

   a) Modify test method 8 to reference the pre and post-hot functional examinations presented in Section 3.9.2.4.

   b) Modify test method 23 or provide an additional Phase II test abstract that demonstrates conformance with Regulatory Guide 1.68.2, position C.4 (Cold Shutdown Demonstration Procedure).

Response

1) See revised Section 14.2.12.2 Test Summary 21.

2) See revised Section 14.2.12.2 Test Summary 31.

3) Section 14.2.12.2 Test Summary 28 defines the testing requirements for the volume control tank (VCT) level control system as currently designed. Design changes and/or circuitry modifications, if required, will be referenced in the UFSAR chapter which describes the VCT level control system. The purpose of the startup program described in Chapter 14 is to test the systems as designed. Any design changes will be tested appropriately.

4) a) See revised Section 14.2.12.2 Test Summary 85.

   c) The present testing requirements require the demonstration of a minimum of three successful cold, quick pump starts for each pump in the following tests:

      1. Test 85 - (d.3) - Auxiliary Feedwater preoperational testing
      2. Test 81 - (d.3) - Diesel generator individual preoperational testing
      3. Test 81 - (d.4) - Diesel generator integrated preoperational testing

      The performance of five successful, cold, quick pump starts is not expected to provide significant additional assurance of pump start reliability as opposed to the present testing requirements outlined above.

5) See revised Section 14.2.12.2 Test Summary 86.

Response (Continued)

6) No preoperational tests are planned for the Essential Cooling Water (ECW) Structure compartment watertight doors because (a) they are passive in nature, (b) they are conservatively designed and constructed, (c) simulation of flooding conditions is impractical, and (d) minor leakage can be tolerated by the compartment sumps and floor drains.

7) See revised Section 14.2.12.2 Test Summary 98.

Question 640.15N

The response to item 423.27 is inadequate. Expand Phase II test number 2, Unit Startup Transformer test to include testing of the automatic transfer feature as stated in the response to item 423.27.

Response

Subsequent design changes have eliminated the automatic transfer. Therefore, this question is no longer valid.

Question 640.17N

The response to item 423.31 is inadequate. Provide assurance that any preoperational tests unintentionally not completed prior to fuel load will be completed and that rescheduling information (cite power level at which test will be performed) will accompany the technical justification submitted to the NRC.

Response

The Startup Program has been structured to ensure that any test which has been delayed due to unforeseen circumstances such as design changes, unavailability of materials, or constructibility problems will be rescheduled and completed. Each of the affected systems will be evaluated to determine if there is any impact to the fuel load schedule, or to determine if the test may be accomplished after fuel load. At that point in time, rescheduling information, technical justification, and anticipated power level will be provided to the NRC.

Question 640.21N

By letter dated August 17, 1981, you stated your intent to comply with the TMI-2 Action Plant Item I.G.1 testing requirements by referencing the results of testing completed at "comparable plants." You also indicated you intend to comply with the training requirements by use of your simulator.

Comparisons of STPEGS Units 1 and 2 with other plants reveal design differences in electrical distribution systems, circulating water systems, HVAC Systems, and possibly other support systems. Therefore, it is considered unlikely that any other plant is comparable with STPEGS Units 1 and 2. However, if you can provide adequate verification that the results of natural circulation tests performed at another plant are valid for STPEGS, we will accept your position. In particular, we are interested in the results of testing that verified the ability to feed and steam the steam generators in the event of the testing items of our June 12, 1981, letter.

NOTE: An acceptable response to this concern is contained in a letter from E. P. Rahe (Westinghouse) to H. R. Denton dated July 8, 1981, (NS-EPR-2465).

With respect to the "training" objectives being accomplished by the use of a simulator, you should verify that your simulator training program includes the natural circulation operations noted in our June 12, 1981, letter. Furthermore, it should be demonstrated that the simulator to be used for natural circulation training, tracks real plant behavior by comparing the simulator responses with test data from a plant which has performed the tests.

Response

The STPEGS startup program has been revised to meet the recommendations listed in Appendix 4 of the Westinghouse Letter from E. P. Rahe to H. R. Denton dated July 8, 1981 (NS-EPR-2465).

The guidance followed in our startup program revision is listed below:

1. During Hot Functional testing (or prior to fuel loading) with reactor coolant pumps (RCPs) supplying heat input to the secondary side, remove onsite AC power sources and operate the plant utilizing manual control and steam-driven auxiliary feedwater (AFW) pump.

2. After fuel loading, but prior to Initial Criticality, establish stable conditions at T_{no} load and 2235 psig with two RCPs in operation (RCPs are not to be in loops with pressurizer surge line or spray lines). Reduce pressure by turning off pressurizer heaters noting depressurization rate. Reestablish heaters and reduces pressure further by use of auxiliary spray noting depressurization rate and effect on margin to saturation temperature.

Response (Continued)

At reduced pressure observe the effects of changes in charging flow and steam flow on margin to saturation temperature.

3. Per requirements of Regulatory Guide (RG) 1.68, Rev. 2 (item 4.t), place the plant in natural circulation mode observing the length of time for plant to stabilize, flow distribution, power distribution, and ability to maintain cooling mode.

4. Per requirements of RG 1.68, Rev. 2 (item 5.j.j), perform Loss-of-Offsite Power/Station Blackout test with plant trip from 10-20 percent rated thermal power. Operate plant establishing stable conditions in natural circulation using batteries and emergency diesels.

5. Referencing boration and cooldown tests performed at Sequoyah I, North Anna II, Farley II, and Diablo Canyon I, verify similar plant response by parameter and plant comparison. Operator training for cooldown on natural circulation will be provided on plant simulator at the earliest opportunity.

We have implemented the above recommendations as follows:

1. See revised Section 14.2.12.2, Test Summary 85.

2. See new Section 14.2.12.3, Test Summary 33.

3. See revised Section 14.2.12.3, Test Summary 13.

4. See revised Section 14.2.12.3, Test Summary 24.

5. The South Texas Project Electric Generating Station (STPEGS) simulator training program for reactor operator (ROs) and senior reactor operator (SROs) will include initiation, maintenance and recovery from natural circulation. ROs and SROs will be trained to recognize when natural circulation has stabilized, and to control saturation margin, RCS pressure, and heat removal rate without exceeding specified operating limits. The STPEGS simulator response will be compared with test data from a plant that has performed natural circulation tests to demonstrate that the simulator tracks real plant behavior.

Question 640.26N

The response to Item 640.7 is not acceptable. Modify existing preoperational and startup test abstracts to indicate the source of acceptance criteria to be used in determining test adequacy.

Response

As stated in the response to Question 640.7N, HL&P does not intend to include the details of the test acceptance criteria or its source in the test summaries in Section 14.2.12.2. These details will be in the individual preoperational test procedures.

Acceptance criteria for preoperational tests will be derived from project approved documents, reviewed by the responsible design organization (via the Joint Test Group), and approved by the Startup Manager before they are utilized in the field.

Startup test abstracts for initial startup testing have been modified to indicate the source of acceptance criteria to be used in determining test adequacy. See revised Section 14.2.12.3 and Test Summaries 2, 3, 4, 6, 8, 9, 12, 15, 16, 17, 18, 19, 21, and 27.

Question 640.27N

The response to Item 640.10 is not appropriate. Verify that the essential cooling pond is tested to verify adequate NPSH and the absence of vortexing over the range of pond level for maximum to the minimum calculated 30 days following LOCA.

Response

There are no current plans to test the essential cooling water (ECW) pumps for net positive suction head (NPSH) and vortexing over the anticipated range of essential cooling pond levels. The pumps will be tested for proper operation at the pond level existing during Startup which will be at or below the normal maximum operating level.

The pump vendor has supplied a typical NPSH curve for the pump. A calculation was performed which shows that adequate NPSH is available. The pond level will not fall below the minimum submergence required for the ECW pumps.

The matter of vortexing has been considered. The design of the sumps is in close agreement with the guidance provided in the Hydraulic Institute Standards and Cameron Hydraulic Data. The ECW pumps are within individual sumps and they have satisfactory clearance from the back wall, bottom and traveling screens.

As delineated in Table 9.2.5-3.1 of the UFSAR, the ECP has a level which ranges from 25.5 to 21.5 ft during the worst case scenario. The ECW pumps are of the vertical type with a required submergence of 6.3 ft. Based on the lowest ECP water level (21.5 ft), there will be approximately 3 ft of margin available to the pumps, thus ensuring their continued operation.

Question 640.30N

The response to Item 640.16 is incomplete.

a) Performance testing of pressurizer PORVs will be addressed later via response to Item II.D.1 of NUREG-0737, "Clarification of TMI Action Plan requirements". Provide a schedule for the response.

b) Describe the manufacturer's test of valve capacity as described in response to Item 423.29 in sufficient detail or provide a test abstract to demonstrate that the maximum capacity of any single steam dump or relief valve is less than the value assumed in FSAR Section 15.1.4 (Inadvertent Depressurization of the Main Steam System).

Response

a) A report has been prepared by Westinghouse to address NUREG-0737, Item II.D.1. This report has been completed and was provided under separate cover letter (see ST-HL-AE-1466, dated October 31, 1985).

b) No manufacturer of which Westinghouse is aware has capacity tested the steam dump valves. This is due to the expense associated with full flow steam testing of a valve this size (8-inch). Rather, the manufacturers use formulas provided by the Instrument Society of America Standard ISA-S39.3 for compressible flows for steam sizing and flow verification.

Using the valve flow coefficient C, for the steam dump valve listed on the valve drawing (Fisher Drawing 56A2244) and applying the critical sizing formula recommended by the ISA Control Valve Handbook, the valve flow capacity at 1300 psia is 273 1b/sec which is less than the maximum capacity assumed in Section 15.1.4 (292 lb/sec at 1300 psia). The SG PORVs are specified with a maximum flow rate of 1,050,000 lb/hr which will not exceed the 292 lb/sec used in the analysis found in Section 15.1.4. In order to ensure this maximum flow rate is not exceeded, the valve supplier has provided a flow with a flow coefficient (C_v = 398) which is approximately 80 percent of that required to pass 1,050,000 lb/hr of steam at 1300 psia. This will ensure the safety analysis value of 292 lb/sec is not exceeded.

In addition, please note that startup tests which have been conducted at the Surry Station suggest that valve inlet pressures are considerably lower than 1300 psia. The highest pressure that was recorded was 865 psig (880 psia). This lower pressure which is more realistic yields a flow rate of 185 lb/sec.

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HISTORICAL INFORMATION

Question 211.41

For those transients which result in the pressurizer being filled water solid, address the capacity of the quench tank to contain the water discharge and/or the radiological consequences of spillage of primary coolant water into the Containment.

Response [HISTORICAL INFORMATION]

The only transient that fills the pressurizer is the feedline rupture. The feedline rupture is analyzed with and without offsite power. The case with offsite power results in the highest water relief rates. A new analysis has been done assuming the reactor coolant pumps are on throughout the transient. The results of the analysis are as follows.

The pressurizer relief tank (PRT) cannot contain the water discharge associated with the feedline rupture. With the PRT initial level at the High Level Alarm Setpoint (resulting in the greatest discharge to the Containment), a total of 11,669 pounds (8800 pounds of steam and 2869 pounds of water) is discharged into the Containment.

The radiological consequences of spillage of primary coolant into the Containment are substantially less than that of a MSLB since no fuel failures are postulated. See UFSAR Section 15.2.8.

HISTORICAL INFORMATION

Question 211.43

HISTORICAL INFORMATION

Several of the analyses result in or have the potential for filling the pressurizer water solid. Discuss the potential for this causing a more severe transient, since the sizing of the safety valves was based on steam flow.

Response [HISTORICAL INFORMATION]

Although the safety valve capacity is based on steam relief, the water relief capacity of the valves is much larger than the amount of water relief required during a transient. Thus, a more severe transient would not occur.

More details are provided in response to Q211.45 on the capacity of relief and safety valves.

HISTORICAL INFORMATION

Question 211.44

HISTORICAL INFORMATION

Many of the transient descriptions refer to the Emergency Boration System which was deleted by a recent amendment. Remove references to this system from the analyses and verify that the analyses have been revised to no longer take credit for the high concentration boron from the EBS.

Response [HISTORICAL INFORMATION]

The Emergency Boration System (EBS) has been deleted from the STPEGS Units. Current analysis presented in Chapter 15 of the UFSAR no longer takes credit for the high concentration boron from the EBS.

HISTORICAL INFORMATION

Question 211.45 Deleted

TABLE Q211.45-1 .Deleted

Question 211.46

Confirm that during the preoperational or startup test phase you intend to verify the valve discharge rates and response times (such as opening and closing times for main feedwater, auxiliary feedwater, turbine and main steam isolation valves, and steam generator and pressurizer relief and safety valves) to show that they have been conservatively modeled in the Chapter 15.0 analyses.

Response [HISTORICAL INFORMATION]

Valve Discharge Rates

Valve discharge rates are confirmed during the preoperational test phase for the auxiliary feedwater valves.

Valve discharge rates are not confirmed during the preoperational or startup test phase for the following valves:

a. Main Feedwater, Turbine and Main Steam Isolation Valves - During the Phase III portion of the startup test program, the intent will be to confirm that the discharge rates for these valves are sufficient to control the various systems (within design values) for steady state operation (up to 100 percent of rated power) and during all Condition I events listed in Chapter 15.

b. Steam Generator and Pressurizer Relief Valves, and Steam Generator and Pressurizer Safety Valves - Testing of each pressurizer and steam generator power-operated relief valve (PORV) and safety valve (to demonstrate the discharge rates have been conservatively modeled) is neither practical or justified for the following reasons:

   1. There is no practical method of measuring steam flow rate from any of these valves after they are installed.

   2. Assuming that a method of measuring flow rate could be developed, testing of each valve would put the unit through numerous undesirable transients, because there are 2 pressurizer PORVs, 4 steam generator PORVs, 20 steam safety valves, and 12 steam dump valves. A relatively lengthy blowdown period would be required for each test in order to measure either steam flow rate or cooldown rate, which could be extrapolated to flow rate. Imposing a modified Condition II event on the unit is not justified.

   3. Testing of the unit's full load rejection capability adequately demonstrates that the capacities of the PORVs and steam dump valves are consistent with design. (See Phase IV startup test description 23, Section 14.2.12.3.)

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Response (Continued)

4. The safety valves are ASME Section III components and have been tested by the manufacturer in accordance with the code requirements. The other relief/steam dump valve capacities have been verified by the respective manufacturers to be in accordance with design flow rates. These verifications are based on standard industry practices, which include obtaining flow characteristics by testing and/or calculating flow capacities based on specified conditions. The present test program verifies the valve stroke length to be in accordance with the manufacturers' specifications for each valve, thus ensuring that the specified valve opening is not exceeded.

Valve Response Times

Valve response times are confirmed during the preoperational or startup test phase for the following valves:

a. Main Feedwater Valves

b. Auxiliary Feedwater Valves

c. Turbine Valves

d. Main Steam Isolation Valves

e. Steam Generator Power-Operated Relief Valves

f. Pressurizer Power-Operated Relief Valves

Valve response times are not confirmed during the preoperational or startup test phase for the Steam Generator and Pressurizer Safety Valves - The safety valves are ASME Section III Components and as such have been tested by the manufacturer in accordance with the code requirements.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.48

Based on recent operating experience, provide an evaluation of the "Loss of Instrument Air" event, in particular as it relates to the potential for causing and compounding other more serious events.

Response [HISTORICAL INFORMATION]

"Loss of Instrument Air" would not result in the loss of any safety-related control functions and would not prevent shutdown of the reactor. The instrument air system is not required for safe shutdown during any design basis accident or transient. The loss of instrument air does not jeopardize plant safety.

The loss of instrument air during RHR operation would result in the loss of the ability to control the flow rate through the RHR heat exchanger. In this situation a controlled cooldown can be accomplished by starting and stopping the RHR pumps as required.

The loss of instrument air may cause plant transients as a result of main steam isolation valve (MSIV) and feedwater control valve (FCV) and feedwater bypass control valve (FBCV) closure. The most immediate effect of the loss of instrument air will be the closure of the FCV thereby eliminating feedwater flow to the steam generators. The loss of feedwater transient, a Condition II event, is discussed in Section 15.2.7. The results of the analysis show that a loss of feedwater transient does not adversely affect plant safety. No fuel damage occurs and the steam release from the secondary system does not result in a release of radioactivity unless there is leakage from the RCS to the secondary system in the steam generators.

HISTORICAL INFORMATION

Question 211.49 Deleted

Question 211.50 Deleted

Question 211.51

For Chapter 15 accident events, provide the number of fuel rods calculated to be in DNB.

Response [HISTORICAL INFORMATION]

For Condition II events, it is demonstrated that DNBR remains greater than the limiting value; thus, the number of rods calculated to be in DNB corresponds to the criteria set forth in Section 4.4.1.

For large and small LOCAs, uncovering of the core results in DNB for all rods. For the steam line break events (Section 15.1.5), the feedwater line break events (Section 15.2.8), and the complete loss of forced reactor coolant flow events (Section 15.3.2), the DNBR does not fall below the limiting value as indicated in the appropriate sections of Chapter 15. Therefore, the criteria for rods in DNB presented in Chapter 4 applies to these events also.

As stated in Section 15.4.3, the number of fuel rods with DNBR less than the limiting value for the single RCCA withdrawal event is less than 5 percent of the rods in the core. For an improper fuel loading event, undetected errors will cause sufficiently small perturbations to be acceptable within calculational uncertainties, as stated in Section 15.4.7; thus, the effect due to improper loading on rods in DNB for transient event will be negligible.

The RCCA ejection analysis presented in Section 15.4.8 conservatively assumes that 10 percent of the rods in the core go into DNB and fail. For the locked rotor event presented in Section 15.3.3, the maximum number of fuel rods in DNB is conservatively calculated to be less than 10 percent of the rods in the core. As stated in Section 15.3.4, the consequences of an reactor cooling pump shaft break will be less severe than those for a locked rotor event.

Evaluation of the steam generator tube rupture indicates that no clad damage would be expected in this transient. The RCS depressurization due to flow out of the tube rupture presents the possibility of obtaining a low DNBR. However, the depressurization in a tube rupture is much less severe than the depressurization transient analyzed in Section 15.6.1. In this accident, it was determined that the DNBR is always greater than the limiting value, and thus no clad damage is expected. From this, it is concluded that no clad damage is expected in the steam generator tube rupture accident. For all other events discussed in Chapter 15, DNBR remains above the limiting value.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.52 Deleted

Question 211.53Q

A change in the Westinghouse fuel rod internal pressure design criteria is in the process of being approved. This change will permit the internal fuel rod pressure to exceed system pressure. For some Condition III and IV overpower events, this will result in an increase in the number of rods normally expected to fail as a result of these events. This is due to the probability of a rod simultaneously being in DNB and exceeding system pressure. Subsequent ballooning and touching the adjacent rods follows, thereby causing more rods to go into DNB and fail. Therefore, for the Chapter 15 analyses of Condition III and IV events, confirm if this change in the fuel rod internal pressure design criteria has been factored into the number of rods predicted to fail.

Response [HISTORICAL INFORMATION]

The NRC staff has completed its review of the revised Westinghouse fuel rod internal pressure design criteria and has decided on an acceptable amended criterion.

"The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause (1) the diametrical gap to increase due to outward cladding creep during steady-state operation and (2) extensive DNB propagation to occur."

WCAP-8963, "Safety Analysis for the Revised Fuel Internal Design Basis", was found to be acceptable to support the conclusion that an insignificant number of additional DNB events would occur during transients and accidents as a result of operating with fuel rod pressure (1) greater than nominal system pressure and (2) limited by the above criterion.

For all Condition III and IV overpower events, the number of rods that are assumed to fail is less than 10 percent. Therefore, the analyses for STPEGS are bounded by the analysis presented in the WCAP. The results presented in the WCAP are based on the detailed probability analysis performed to determined the maximum extent of core damage that could lead to DNB propagation. It was shown that the propagation mechanism causes only a small incremental increase in the percentage of rods in DNB. In view of the conservative nature of the failure propagation scheme and the small percentage increase in the number of failed rods, the potential increase in site release is inconsequential.

Although this effect resulting from the revised fuel rod internal pressure design criterion is small, it was factored into the number of rods predicted to fail.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 211.54 Deleted

Figure Q211.54-1 (Deleted)

Figure Q211.54-2 (Deleted)

Figure Q211.54-3 (Deleted)

Question 211.56

HISTORICAL INFORMATION

Question 211.8 addressed an error in a Westinghouse evaluation model and the response was that the reanalysis was provided in revised Sections 15.6.5 and 6.2.1.5. For other Chapter 15 transients which are predicted to experience DNBR, verify that the corrected analysis has been used or is not applicable.

Response [HISTORICAL INFORMATION]

The subject error discussed in the answer to Question 211.8 is the correction to the zirconium-water heat of reaction in the large LOCA models. It is not applicable to any accidents except large break LOCA.

HISTORICAL INFORMATION

Question 211.57

HISTORICAL INFORMATION

Provide or reference analyses for all transients which show that the acceptance criteria are met for initial operation with less than four loops.

Response [HISTORICAL INFORMATION]

The STPEGS UFSAR analyses are not intended to cover N-1 loop operation. Currently, STPEGS intends to operate the plant with four loops in operation only. Therefore, no analysis for operation with less than four loops is required.

HISTORICAL INFORMATION

Question 211.85

STPEGS indicated in a previous amendment that the Emergency Boration System would be deleted. Please provide complete justification for this deletion. For each transient that relies on the EBS, or any of its functions, justify its deletion and show that the safety margin has not been reduced.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

Westinghouse has developed improved analytical techniques which allow a deletion of the Emergency Boration System (EBS). The sole function of the EBS is to provide concentrated boric acid to the reactor coolant to mitigate the consequences of postulated steam line break accidents. The cases which serve as the Westinghouse steam line break licensing basis are the main steam system depressurization accident (Section 15.1.4) and the main steam line rupture accident (Section 15.1.5).

The effect of deleting the EBS on the main steam depressurization accident analysis is that the reactor returns to criticality. Historically, Westinghouse's criterion for this Condition II event had been to show that no return to criticality occurs. However, Westinghouse has adopted a new criterion, whereby the reactor may return to criticality, but no fuel damage may occur. This new criterion is in compliance with the criteria used by the NRC and ANS, which require that radiation releases during Condition II steam line breaks remain within the limits set forth in 10CFR Part 20. This limit can be met with a return to criticality, if it is assured that there is no consequential fuel damage.

The effect of EBS deletion on the main steam line rupture analysis is that the reactor returns to a higher power level after the rupture. For this accident, Westinghouse demonstrates that the DNB design basis is met and, therefore, the radiation releases limits of this Condition IV event set forth in 10CFR Part 100 are not violated.

HISTORICAL INFORMATION

Question 211.86

As part of the NRC review of the licensees submitted of South Texas Unit 2, the staff will conduct an independent audit of the limiting small break LOCA and Chapter 15 transients. In order to conduct our audit, we require the information listed in the attachment. In order to conclude our evaluation within the time frame of the requested license, we require the applicant to provide the requested information within 6 weeks of receipt of this request for additional information.

Response [HISTORICAL INFORMATION]

In a letter dated June 16, 1982 from D. G. Eisenhut (U.S. NRC) to E. P. Rahe (Westinghouse), the NRC agreed to request RESAR-41 generic data rather than STPEGS plant-specific information; detailed information will be required at some future time prior to licensing of STPEGS

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.47N Deleted

Question 440.48N

Provide as part of a table; or where appropriate, the initial pressurizer water volume assumed in all Chapter 15 transients and accidents analyses. Include a discussion to indicate the degree of conservatism assumed. Discuss whether those values are compatible with the planned STPEGS technical specification limits.

Response **(HISTORICAL INFORMATION)**

HISTORICAL INFORMATION

The accident analyses assume event initiation from nominal conditions with allowances for uncertainties such as measurement error and rod controller dead band. These nominal conditions are maintained by automatic control systems such that deviation from the nominal operating points are limited to within the allowance bands. It is not necessary to add to the Technical Specifications restrictions on the pressurizer water level used in the Safety Analysis. Where the Technical Specifications do contain restrictions on process variables the specified limiting values are typically actual values, that is either design values or those used in the analysis without additional allowances for measurement uncertainty.

All values in the Technical Specifications other than those whose uncertainties are specifically specified as analytical, design, etc. may be treated as indicated values without regard for instrument uncertainties. This is acceptable because of the relatively small magnitude of typical measurement uncertainties (one to two percent of calibrated span) when compared to the conservatisms included in the plant design and safety analysis. Small deviations in plant parameters resulting from measurement uncertainty are negligible considering the conservatisms upon which the "limiting" values are based.

HISTORICAL INFORMATION

Question 440.50N

Your response to Questions 211.43 and 211.45 indicate that the pressurizer safety and relief valves have adequate capacity for liquid relief in the event of a feedwater line break or inadvertent continued charging pump operation. However, because of previous incidents with these type of valves, there is a concern whether the valves would reseat properly after prolonged relieving of liquid or two phase flow. State whether these valves are designed specifically for this service. If they are not designed for liquid or two phase relief, please justify why this is acceptable and conforms with the ASME code. Confirm that all Chapter 15 events which either predict or expect a two-phase or liquid relief from the safety or relief valves assumed the valves to fail open in the analysis.

HISTORICAL INFORMATION

Response **(HISTORICAL INFORMATION)**

Only two events predict the pressurizer will fill during or as a result of the transient, Chemical and Volume Control Systems malfunction and Feedwater System Pipe Break. In Section 15.5.2, "Chemical and Volume Control Systems Malfunction that Increases Reactor Coolant Inventory", it is specifically stated that to prevent filling the pressurizer water solid, the operator must terminate charging and the sequence of events presented in Table 15.5-1 shows that the operator has sufficient time to take corrective action. For the Feedwater System Pipe Break refer to revised Sections 15.0.9 and 15.2.8 which show that the pressurizer does not become water solid due to a feedwater line break.

Note:
Q&Rs 211.43 and 440.50N are considered historical information. Q&R 211.45 has been deleted from the UFSAR and the response has been partially incorporated into UFSAR text (Section-15.0.8.2).

HISTORICAL INFORMATION

Question 440.51N

Your response to Question 211.52 is incomplete. The following requested information is missing and should be provided:

a. No information is given for anticipated operational occurrences (AOOs). Pages "Q&R 15.0-18 a-d" are missing.

b. For accidents, the requested delay time for operator action is not given. Provide this information and justify the acceptability of the assumed delay times if they are less than those recommended in draft ANSI N-660.

Response [HISTORICAL INFORMATION]

a. Following an Anticipated Operational Occurrence (AOO), the plant should be able to return to power operation given that the initiating fault has been corrected. No operator action has been assumed for any of the AOO, except for the boron dilution event. In Section 15.4.6, the Standard Review Plan requires that, for operator action to terminate the transient, at least 15 minutes (30 minutes for refueling) be shown available between the time when an alarm announces an unplanned moderator dilution and the time of loss of all shutdown margin. Refer to Section 15.4.6 for details concerning alarms, delay times, actions and equipment for use in mitigating the boron dilution event. No other analysis of an AOO assumes (i.e., requires) operator action.

b. The response to Question 211.52 has been revised to reflect safety analysis assumptions concerning times of operator action for the steam line break, feedwater line break, and LOCA events.

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

Question 440.52N Deleted

Question 440.53N Deleted

Question 440.54N Deleted

Question 440.55N

Table 7.2-1 indicates that the low flow reactor trip is "blocked below P-7". Define the P-7 power level. Provide analyses for this power level which demonstrate that adequate core cooling will be maintained with natural circulation flow. Demonstrate that the core fission power is controllable and table under natural circulation. State whether you intend to perform a natural circulation test at this power level at STP. If not, explain why not and whether this is due to any safety concerns, and demonstrate that blocking the reactor trip below P-7 for forced circulation flow will not degrade plant safety.

Response

The P-7 power level blocks reactor trip from a 2/4 power range neutron flux below the setpoint value for the following trip signals:

1. Low reactor coolant flow in more than one loop

2. Undervoltage

3. Underfrequency

4. Pressurizer low pressure

5. Pressurizer high level

For STPEGS, this setpoint is 10 percent of rated thermal power. It should be noted that this power level is not intended to be a normal mode of operation, but has been put into the design to aid in the plant startup.

At 10 percent power, there is flow resulting from the natural circulation head in the Reactor Coolant System (RCS). This flow is approximately proportional to the cube root of the power. At 10 percent power, this flow is typically 6.5 percent of nominal, therefore, power increases above ten percent would result in only small flow increments. It is known that for a constant DNB ratio, the power-to-flow ratio increases as the power and flow are decreased.

Provisions have been made as indicated in Section 14.2.12.3 for a natural circulation test during plant startup at a power level less than that defined by the P-7 interlock setpoint.

Question 440.56N

The staff cannot fully complete its evaluation of the Chapter 15 AOO and PA analyses until the Technical Specification safety limits and limiting conditions for operation (LCOs) are compared with the parameters utilized in the AOO and PA analyses to assure their conservatism. Therefore, unless the STPEGS Technical Specifications become available to the staff within a time frame sufficient to allow a full evaluation prior to final SER issuance, the staff will not be able to conclude in the SER that the Chapter 15 analyses are fully acceptable, unless the applicant commits at this time to make the technical specification safety limits and LCOs fully compatible and consistent with the Chapter 15 analysis parameters.

Response

The Technical Specifications will be made consistent with the Chapter 15 analyses.

Question 440.57N

In Amendment 43, Figure 15.0-9 and the information in Sections 15.1.4 and 15.1.5, and the revised response to Question 440.01 (Amendment 44) all indicate that the MSIVs are closed on any SI signal. Amendment 44 indicates that this includes SI actuation on low RCS pressure. The previous FSAR version indicated that the MSIV would close on high containment pressure or evidence of steam line break, which is typical of most Westinghouse plants. Closure of the intact steam generator MSIVs on any SI signal would prevent utilization of condenser steam dump in the event of steam generator tube rupture (SGTR) or a small break LOCA when offsite power is available. This would probably result in slower mitigation of the accident and increase the offsite dose. The Westinghouse Emergency Response Guidelines (ERGs) which have been approved by NRC take credit for condenser steam dump when it is available. Therefore, please justify this design change on the basis of increased safety.

Response

See the response to Question 440.80N.

Question 440.58N Deleted

Section 15.1

Question 032.23

Describe the Emergency Boration System's (EBS) redundant heat tracing system. Identify and justify any deviation from your preliminary design presented in the PSAR. In the Safety Evaluation Report related to construction of STPEGS (NUREG-75/075) the staff requested that the applicant provide a design feature or perform a test that would assure that during switching from one ESF power source to the other, a fault which may exist on one system would not be transferred over to the redundant system, thereby compromising the independence of redundant Class 1E power systems. Provide this information. Also provide the design details for EBS temperature monitoring system indicating how the requirements of IEEE-279 are satisfied.

Response

As a result of analyses performed after FSAR submittal, the EBS is no longer required at STPEGS and has been deleted.

Question 211.58

Provide the basis for the different flow rates for the full power and zero load conditions (i.e., 14 percent vs. 200 percent) and verify that the lower value is appropriate for the full power case.

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

The feedwater flow rates used in full load and zero load excessive feedwater transients are different because the number of steam generators receiving feedwater is different.

At full load conditions, the feedwater flow is divided between all four steam generators. The faulted steam generator receives 140 percent of its nominal full load flow rate. The unaffected steam generators each receive the nominal full load flow rate.

At zero load conditions during an excessive feedwater transient, one steam generator receives all the feedwater flow (200 percent of nominal full load flow). The other three steam generators are assumed not to receive any feedwater flow.

NOTE: The feedwater flow rates assume bounding values. Flow rates for the current analyses are provided in UFSAR Section 15.1.2.

HISTORICAL INFORMATION 37

Question 211.60 Deleted

Question 211.61

Figure 15.0-9 indicates operator termination of safety injection to limit RCS pressure and pressurizer level. Address the time frame associated with this action and/or the consequences of failure to perform the action or premature termination of SI flow.

Response

Operation action is not assumed for at least 10 minutes following a depressurization of the main steam system. If the operator fails to terminate SI at the appropriate time, no adverse consequences will occur. The SI pumps have a maximum shut off head approximately 1600 psia. Thus, no overpressurization of the RCS can occur due to the SI system. If the operator prematurely terminates SI and criticality is attained, the core power will increase until it reaches equilibrium with steam demand.

Further information is provided in the response to Q211.52.

Question 211.64 Deleted

Question 211.67 Deleted.

Question 211.69 Deleted

Question 211.70

Figures 15.1-13, 15.1-16, and 15.1-19 indicate that the pressurizer is emptied during the safety valve and steam line break transients. Discuss the potential effects of this conditions, including the potential for and recovery from void formation in the RCS. Also address the applicability of the models during the period when the pressurizer is empty.

<u>Reponse</u> [HISTORICAL INFORMATION]

Figure Q211.70-1 and Q211.70-2 show the void volume in the reactor vessel upper head and the and the pressurizer as a function of time for the 1.4 ft^2 steam line ruptures presented in Section 15.1.5 of the UFSAR. The figures show that voids never completely fill the reactor vessel head, thus no steam flow out of the head will occur. The fluid in the reactor coolant loops remains subcooled throughout the transient, therefore no voiding will occur in the loops. The void in the reactor head is removed once the coolant temperature decreases below the saturation temperature for the equilibrium pressure (approximately 1,000 psia).

The inadvertent opening of a relief valve presented in Section 15.1.4 had no void formation in the reactor vessel head. The fluid in the reactor coolant loops remained subcooled, thus no voiding will occur in the loops.

LOFTRAN will model transient conditions where voids are formed in the reactor vessel upper head. As a steam void in the reactor vessel upper head increases, water is assumed to be pushed out of the reactor vessel using a slug flow model. This model is applicable as long as no voiding occurs in the reactor coolant loops. Therefore, the analysis is independent of the pressurizer level. If the steam void completely fills the reactor vessel upper head, then steam flow from the reactor vessel would occur. The South Texas units showed only small amounts of void formation in the upper head and the reactor coolant loops remained subcooled. The situation where voids occur in the reactor coolant loops need not be considered.

HISTORICAL INFORMATION

Figure Q211.70-1

Figure Q211.70-2

Question 440.1N

In response to our previous question (211.85) regarding deletion of the emergency boration system (EBS) from the STPEGS design, you have indicated that EBS deletion was justifiable, since, in the event of a main steam line break, the DNB design bases are met and the radiation releases are within the limits set forth in 10 CFR Part 100. We have reviewed the system aspects of the revised steam line break analysis in FSAR Section 15.1.5. Based on our review we have determined that the following additional information is required. If this information has been included elsewhere in your FSAR, appropriate references in Section 15.1.5 will suffice. Likewise, if the information has been provided in the form of other documentation (e.g., Westinghouse topical reports), reference to such documentation (please be specific) is appropriate.

a. Clarification of the methodology for calculating reactivity feedback, including the effect of nonuniform core inlet temperatures from the reactor coolant loops; justification of the conservatism in the methodology with regard to the peak power obtained.

b. Clarification of the methodology used in calculating DNBR and verification that the power distributions used for DNBR calculations reflect the effect of nonuniform core inlet temperatures from the reactor coolant loops.

c. With respect to ESF actuation functions for an SLB, describe and justify the differences between the protection functions at the STPEGS and the actuation functions in NUREG-0452, "Standard Technical Specifications for Westinghouse PWR's". Describe the "excessive cooldown protection" function, which, in accordance with the FSAR, provides safety injection in the event of an SLB. Identify the actuation set points.

<u>Response</u>

a) See revised Section 15.1.5.

b) See revised Section 15.1.5.

c) With respect to Engineered Safety Features (ESF) actuation functions for a SLB, the current differences between the protection functions at STPEGS and NUREG-0452 are as follows:

   1. For safety injection (SI) actuation, the function of low compensated steamline pressure has been added. The functions of high differential pressure between steam lines and high steam flow in two steam lines coincident with low-low T_{avg} or low steam line pressure have been deleted.

   2. For steamline isolation, the function of high steam flow coincident with low steamline pressure or low-low T_{avg} has been deleted. In addition, the functions of high steam pressure rate has been added.

Response (Continued)

The excessive cooldown protection logic has been deleted from the STPEGS protection system. This system, first described in RESAR-41, is not taken credit for in the STPEGS plant specific licensing basis analysis.

The actuation setpoints are given in the Technical Specifications.

Question 440.59N Deleted

Question 440.60N

Provide plots of DNBR versus time for the 1.4 ft^2 steam line break analysis, for both "offsite power available" and "offsite power not available" cases.

Response

Transient plots of the 1.4 ft^2 steam line break analysis are illustrated in Figures 15.1-15 through 15.1-20 of the STPEGS UFSAR. Historically, departure from nucleate boiling ratio (DNBR) versus time plots have never been presented in Chapter 15 of the FSAR. The main steam line break is a Condition IV event and, consequentially, must meet the radiological dose release requirements of l0CFRl00. Limited fuel damage is permitted as long as the above criteria are met.

Based on previous steam line break results, the minimum DNBR has always been found to occur at the time of maximum return to power. Therefore, only a few statepoints in the range of peak core heat flux are evaluated.

In evaluating the minimum DNBR for the steam line break transient, a detailed statepoint evaluation method is employed. First, the core heat flux transient is generated by the LOFTRAN code. Several statepoints are taken around the time of maximum return to power. Then peaking factor and axial power shapes are calculated using more detailed nuclear computer codes. The LOFTRAN state-points, peaking factors, and axial power shapes are used in the DNBR calculation by the THINC computer code. Using the statepoint method only, the minimum DNBR was calculated. The minimum DNBR for STPEGS was above the design basis limit and no fuel was calculated to fail.

Question 440.61N

State what assurance is provided that the MSIVs will close under the dynamic blowdown loads of a steam line break.

Response

Assurance is provided that the main steam isolation valves (MSIVs) of STPEGS will close under the dynamic blowdown loads of a steamline break by virtue of the following:

1. Those Atwood and Morrill valves are tested in accordance with the Westinghouse Valve Operability Program discussed in the FSAR.

2. Atwood and Morrill has conducted both static and operational tests to qualify its designs and to ensure that the valves met current specifications. A test of considerable significance in this ongoing program was a Sonic Flow Test designed to comply with one of the preferred methods of testing described in USNRC Regulatory Guide (RG) 1.48, i.e., full scale prototype testing. This test was the first ever performed on a valve as large as a 26-in. valve.

   The purpose of the Sonic Flow Test was to show that the Atwood and Morrill MSIV would close within specified time limits against high reverse flow rates and pressure differentials such as would occur after a steam line break in a nuclear power station.

   The valve selected for the flow test was a 26-in. production valve modified to represent an even larger 32-in. valve. Both valves are designed to close and shut-off flow in either direction. Basic construction of the test valve was carbon steel with stainless steel and hard-faced trim. The operator was an air-and-spring system of the "fail closed" design. The bi-directional valve design is presently being furnished for active service in pressurized water reactor (PWR) plants, and conforms to ASME Class 2 requirements.

Question 211.71 Deleted

. Figure Q211.71-1 Deleted

Question 211.73

Provide the time frame assumed for operator isolation of the break in the feedwater line break analysis. Provide justification and a list of all assumptions used to determine this time frame.

Response

The feedwater system pipe break analysis presented in Section 15.2.8 does not assume the operator isolates the break.

Question 440.62N Deleted

Question 440.63N

Figure 15.2-10 "S.G. Water Volume Transient for Loss of Normal Feedwater" shows the secondary volume curve as peaking at 6000 ft^3. Can this result in liquid flooding the steam lines, dryers, or separators? Can steam line flooding result from other analyzed AOO's, e.g., turbine trip without pressurizer spray, no PORV actuation, and no turbine bypass? Discuss the consequences of steam line flooding (See Question 440.70b.).

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

A steam generator (SG) water volume of 6000 ft^3 will result in liquid flooding of the separators but will not fill the SG such that the steam lines are flooded. A volume of 8000 ft^3 will fill the SGs. The Loss of Normal Feedwater analysis presented in Section 15.2.7 assumes that the operator terminated (AFW) auxiliary feedwater flow at 3350 seconds to prevent flooding of the separators. Operator action at 3100 seconds or sooner (minimum of 30 minutes) is needed to prevent flooding. For the other anticipated operational occurence (AOO) mentioned, e.g., turbine trip, no credit is taken for AFW flow and feedwater isolation will be achieved once the SG hi-hi level is reached. Thus, there is no chance of flooding the steam lines as a result of any other AOO.

NOTE: Plant operators are trained to perform actions specified in the emergency operating procedures (EOPs). The EOPs instructs operators to take specific actions to prevent flooding of the steam generators.

HISTORICAL INFORMATION

Question 440.64N

For the main feedwater system pipe break accident analysis, provide the following information:

a. Justify the conservatism of your assumption that the initial steam generator level is at the nominal value +5 percent in the faulted steam generator and at the nominal value -5 percent in the intact steam generators. Compare this assumption with that of other Westinghouse plant analyses.

b. Clarify whether the analysis takes credit for PORV actuation, as stated on page 15.2-17, or for safety valve actuation only, as indicated in Figure 15.0-13. If credit is taken for PORV actuation, verify that the PORVs, including ancillary systems such as controls, power and/or air supplies are safety grade, redundant, designed to IEEE 279, where applicable, and seismically and environmentally qualified. Also states whether credit is taken for PORV actuation in other Chapter 15 transient and accident analyses.

c. Your response to Question 211.73 states that the feedwater system pipe break analysis does not assume that the operator isolates the break. The analysis described in Section 15.2.8.2 does assume break isolation by the operator. Please clarify this discrepancy, and explain whether this refers to isolation of auxiliary feedwater, main feedwater or both (See also Question 440.58N regarding automatic feedwater isolation). If credit is taken for operator action, please justify why it can be taken.

Response

a. The analyses assumptions regarding the initial steam generator (SG) level are consistent with those specified in WCAP-9230, "Report on the Consequences of a Postulated Main Feedline Rupture", dated January 1978. The results of a sensitivity study to initial (SG) level in both the faulted and intact SGs on the peak Reactor Coolant System (RCS) temperatures are provided in Table 5.1-1. As demonstrated, the peak RCS temperature reaches the highest value when the initial SG level in the faulted loop is (+)5 percent of nominal level and the initial SG levels in the intact loops are (-)5 percent of nominal level. These assumptions are utilized on all recent main feedwater system pipe breaks analyzed by Westinghouse.

b. Sensitivity studies within Westinghouse have demonstrated that plants without centrifugal charging pumps which serve a safety injection (SI) function, the normal operation (i.e., expected operating characteristics) of pressurizer power-operated relief valves (PORVs) results in a lower margin to RCS hot leg saturation. If the PORVs were not assumed to operate normally (PORVs in manual mode or assumed to fail closed) in the STPEGS main feedline rupture analyses, the margin to RCS hot leg saturation would have been considerably higher. Hence, an assumption of normal operation of the pressurizer PORVs is made even through the PORV control system is control grade hardware.

Response (Continued)

This criterion is consistent with the assumptions made in all other STPEGS Chapter 15 accident analyses. The normal operation of the pressurizer PORVs, because of the control grade actuation circuitry, is assumed in the accident analyses only if the normal operation results in a more severe RCS transient; e.g., higher peak RCS temperature for the main feedline rupture.

c. The STPEGS Auxiliary Feedwater System (AFWS) is designed such that the operator is not required to take manual action to ensure the minimum required auxiliary feedwater (AFW) flow is injected into the intact SGs even assuming the worst single active failure is one AFW pump. However, the transient analyses provided in Section 15.2.8.2 of the STPEGS UFSAR assume the operator takes action following the feedline rupture to isolate the AFW flow spilling out the ruptured feedwater line. This operator action is not required to mitigate the consequences of a main feedline rupture. However, the operator action to isolate the AFW flow spilling out the rupture is assumed in order to conserve the plant condensate quality water supply to the AFW pumps. Should this action not be taken by the operator, the first required action by the operator would be to terminate the SI flow within a minimum of 30 minutes in the accident analysis following the initiation of the rupture.

   All main feedwater flow to the SGs is isolated on receipt of a SI signal on 2/3 low steam line pressure in the faulted SG. AFW flow is automatically initiated on a SI signal or on low-low SG level in any SG.

Question 211.55

Deleted

Question 211.75

Provide an analysis for the loss of flow from two or more reactor coolant pumps or provide a justification, with bases, why this condition is not credible.

Response

The types of loss of forced reactor coolant flow cases analyzed are based on the reactor coolant pump power supply configuration.

STPEGS has four different reactor coolant pump power supplies (one for each pump). Only the complete loss of flow and the loss of flow from one reactor coolant pump are analyzed. With this power supply arrangement, loss of flow from two or three reactor coolant pumps is not considered credible because multiple faults would have to be postulated.

Question 211.76 Deleted.

Question 211.77

Section 15.3.2.1 of the FSAR states that the reactor trip on reactor coolant pump undervoltage is blocked below 10 percent power. Discuss what reactor trip provides protection on a decrease in reactor coolant flow below 10 percent power. Discuss what analyses have been conducted to verify the adequacy of this trip.

Response

For a decrease in reactor coolant flow during operation below approximately 10 percent power (interlock P-7), there is no immediate reactor trip function required. Natural circulation flow in the RCS provides adequate core cooling capability.

Question 211.78

The Standard Review Plan, Section 15.3.3/4 classified the RC pump rotor seizure and RC pump shaft break as infrequent transients. Provide a justification for your classification of the transient results meet the acceptance criteria for an infrequent event as required by the SRP.

Response

The reactor coolant pump seizure and reactor coolant pump shaft break events are classified according to the ANS as Condition IV events - limiting faults. Westinghouse follows this classification in the Chapter 15 safety analysis. However, the results of the analysis for this event meet the safety analysis for a Condition III event. The peak RCS pressure is maintained below 2750 psig. The peak clad temperature is well below 2700°F.

Question 211.79 Deleted

Section 15.4

Question 211.80

Discuss the uncertainty in the calculations for the nuclear power transient during the startup of an inactive loop. Of primary concern is the possibility that the loop flow may have exceeded the low reset point before the P-8 setpoint has been reached, resulting in the loss of the trip function assumed in the analysis. Also, confirm that the 15 second startup time for the inactive pump is conservative and that a faster startup would not make the transient more severe.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

Generic studies of the startup of an inactive loop have been performed. Table Q211.80-1 lists results of these studies where pump startup times were varied from 7.5 seconds to 30.0 seconds. In all cases examined, nuclear flux reached the P-8 interlock setpoint (reset for 3 loop operation) before loop flow increased above the low reactor coolant flow trip setpoint. In all cases examined, the DNBR remained well above the limit. These case with a 7.5 second startup time yielded the lowest DNBR. Startup times of approximately 7.5 seconds were considered unrealistic. Pump startup times less than 30 seconds are conservatively faster than actual plant values. Thus, for UFSAR analysis purposes, startup times of approximately 20 seconds were selected.

Figure Q211.80-1 shows the nuclear flux and RCS loop flow transients corresponding to the case presented in Section 15.4.4. The case presented uses a startup time of approximately 18 seconds. The P-8 interlock setpoint is reached approximately 7 seconds before loop flow increases above the low reactor coolant flow trip setpoint.

HISTORICAL INFORMATION

TABLE Q211.80-1

INACTIVE LOOP START RESULTS

[HISTORICAL INFORMATION]

HISTORICAL INFORMATION

Pump Start Time (sec)	Time of Reactor Trip (sec)	Time of Loop Flow Reaching Low Reactor Coolant Flow Trip Setpoint (sec)
30.0	7.77	25.87
22.4	6.40	19.66
16.8	5.12	14.94
11.9	3.86	10.79
7.5	2.51	6.67

HISTORICAL INFORMATION

Figure Q211.80-1

Question 211.81 Deleted

Question 211.82

Recently, an operating PWR experienced a boron dilution incident due to the inadvertent injection from the NaOH tank into the Reactor Coolant System while the reactor was in the cold shutdown condition. This event occurred due to a single failure - misposition of the isolation valve of the NaOH tank while the decay heat removal system was lined up for reactor coolant recirculation. Discuss the potential for a boron dilution incident caused by dilution sources other than the CVCS.

Response [HISTORICAL INFORMATION]

Other than the CVCS, the only sources with water of a boron concentration which could be less than the RCS boron concentration are the Recycle Holdup Tanks (RHTs) in the Boron Recycle System. There are also reactor makeup water connections to the Boron Recycle System; but, as the only path between them and the RCS is via the RHTs, they do not constitute a separate dilution source. No single failure can allow flow from the RHTs to enter the RCS or the refueling canal, so dilution of the RCS from the RHT need not be considered.

Question 232.7 Deleted

Question 232.8 Deleted

Question 312.14 Deleted

Figure Q312.14-1 Deleted

Figure Q312.14-2 Deleted

Question 440.66N

With regard to your "Startup of an Inactive Reactor Coolant Loop at an Incorrect Temperature" analysis, provide the following information:

a. Figure 15.4-16 shows an initial power level of about 72 percent. Discuss how this compares to Tech Spec values for the initial power level with 3 loop operation. Also discuss what the time limit for this type of operation is.

b. Provide the Tech Spec value for the maximum allowable cold leg temperature difference between the idle loop and the highest cold leg temperature of the operating loops for idle RCP start and compare this limit with the assumptions in your analysis.

Response

Houston Lighting and Power is not pursuing a license for N-1 (3) loop operation thus no Technical Specification values for the initial power level with 3 loop operation are required. In addition, there is no Technical Specification value for the maximum allowable cold leg temperature difference.

Question 440.67N Deleted

Question 440.68N Deleted.

Section 15.6

Question 211.84 Deleted

Question 312.9 Deleted

Question 312.10

Provide figures showing (1) primary and secondary system temperature and pressure and (2) liquid level in the affected steam generator for the time period between tube failure and the time when primary system and secondary system pressures equilibrate.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

Analyses performed for the Δ94 replacement steam generators are documented tin WCAP-15136 South Texas Unit 1 Replacement Steam Generator Program Safety Analysis and Licensing Report, November 1998, which provides the details of the analysis. The replacement steam generator analysis follows the methodology of WCAP-10698 and Supplement 1 of WCAP-10698. Consistent with the approach taken in WCAP-12369 for STP, the effect of iodine scrubbing of steam bubbles as they rise from the rupture site to the water surface has been conservatively neglected in the analysis. The Model Δ94 analysis therefore does not include a figure showing the liquid level in the affected steam generator.

HISTORICAL INFORMATION

Question 440.2N

Verify that the reflood heat transfer model utilized for the double ended cold leg guillotine (DECLG) break LOCA analysis is acceptable for the STPEGS 14 foot core. (Refer to the attached SER on the 1981 version of the Westinghouse large break ECCS model.)

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

The DECLG break LOCA analysis was recalculated utilizing the Westinghouse 1981 ECCS evaluation model in conjunction with BART (WACP-9561). Therefore, use will no longer be made for the FLECHT correlation to calculate heat transfer coefficients. A SER for BART was issued in December 1983. Since BART has no restriction on the applicability to 14 foot cores, this question is no longer relevant for STPEGS. The results of this analysis will be presented in Section 15.6.5.

HISTORICAL INFORMATION

Question 440.3N

HISTORICAL INFORMATION

Verify that the STP large break ECCS model incorporates the revised staff requirements for cladding swelling and rupture models described in NUREG-0630, "Cladding Swelling and Rupture Models for LOCA Analysis", April 1980. (See also attached SER.)

On October 14, 1980, Houston Lighting & Power Company received a letter from the NRC requesting additional information concerning the application of the cladding swelling and rupture models for the Loss-of-Coolant Accident (LOCA) analysis. Specifically, the request was made that HL&P provide supplemental information which utilized the materials model of draft NUREG-0630. In response, HL&P submitted an evaluation of the potential impact of using fuel rod models presented in draft NUREG-0630 on the LOCA analysis for STPEGS, Units 1 and 2. That evaluation was contained in a letter from J. H. Goldberg to D. G. Eisenhut dated February 27, 1981. Use of the NRC fuel rod models caused a ΔF_Q penalty of 0.0364, which was offset by NRC credit of 0.20.

HISTORICALINFORMATION

Question 440.5N

Clarify which Westinghouse ECCS evaluation model is utilized for the STPEGS DECLG break analysis, the 1978 model (as stated on page 15.6-17) or the 1975 model (as stated on page 15.6-18).

Response [HISTORICAL INFORMATION]

The 1978 Westinghouse ECCS model is utilized for the STPEGS DECLG break analysis. The reference to the 1975 model has been deleted.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.6N

Verify that the LOCA analyses utilize the correct upper head fluid temperature.

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]
The upper head cooling spray nozzle flow is 0.4 percent of the total flow. This small spray nozzle flow rate indicates that the upper head fluid temperature should be conservatively modeled as being equal to the vessel outlet temperature. A review of the analysis for STPEGS showed that the upper head fluid temperature was modeled as being equal to the vessel outlet temperature.

HISTORICAL INFORMATION

Question 440.7N

The STPEGS ECCS design appears to be unique in that only 3 of the 4 RCS loops are connected to the ECCS. Discuss whether the STPEGS DECLG break LOCA utilized split downcomer nodalization. Provide justification for the nodalization method for the split downcomer in light of the fact that STPEGS has one loop without ECCS and the 1981 model justification did not have such an arrangement. If STPEGS did not use a split downcomer provide justification. (Note: See also page 6 of the attached SER.)

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

STPEGS was analyzed using the 1978 Westinghouse ECCS evaluation model which utilizes a non-split downcomer.

Although the ECCS is asymmetric, it is modeled in such a way as to minimize injection into the RCS and maximize spill to containment, i.e., the break occurs in a loop equipped with ECCS. In addition, during the blowdown portion of the transient the bypass region has been modeled as consisting of three intact loops plus the annulus region. This is in contrast to the actual case in which only two intact loops contain injection. This larger bypass region extends the time required to fill the region and delays the end of bypass. A conservation amount of water is calculated to be lost because of the requirement for 100 percent bypass.

During the reflood portion of the transient, a penalty for steam-water mixing is taken in all three intact loops instead of only two. This penalty increases the loop pressure drop and reduces the core flooding rate below that which is actually expected for the postulated break location.

HISTORICAL INFORMATION

Question 440.8N Deleted

Question 440.69N

a. The information provided in the "Inadvertent Opening of a Pressurizer Safety or Relief Valve" is incomplete. Since this event is equivalent to a small break LOCA, extend your calculational results shown in the submitted tables and figures to the time utilized in LOCA analyses. (See also Question 440.39N). Include plots of core mixture height, clad temperature, and hot spot fluid temperature versus time. Discuss how long-term decay heat removal will be accomplished using equipment qualified for the LOCA environment if the stuck open valve subsequently reseats or is isolated with a block valve.

b. Figure 15.6-4 for the above analysis indicates that no SI train failure is assumed. We require that the stuck safety valve analysis assume the most severe single active failure. Either describe the single failure assumed and explain why it is the most severe, or provide an analysis with the most severe single failure. Also provide times for SI actuation and RCP trip, mode of primary loop heat removal (e.g., by single or two phase natural circulation, refluxing, etc.) and operator actions required.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

a. The acceptance criteria for this event as described in the Standard Review Plan (SRP) are different from that of the small break Loss-of-Coolant Accident (LOCA) event. For this reason, only the plots of nuclear power, pressurizer pressure, core average temperature, and departure from nucleate boiling ratio (DNBR) are provided in the UFSAR, and only out as far as required such that it is evident that the transient has reversed. With respect to long-term decay heat removal, the case of inadvertent opening of a pressurizer safety or relief valve was analyzed generically in WCAP-9600 "Report on Small Break Accidents in W NSSS", Section 3.0. Two cases of break size were analyzed representing one small power-operated relief valve (PORV) and three large PORVs opening, and then sticking in the full open position. This break size range covers a safety valve opening as well. The characteristics of both cases were similar as shown in WCAP-9600. In both cases pressurizer water level rises, Reactor Coolant System (RCS) depressurization occurs resulting in automatic actuation of reactor trip and safety injection (SI) based on low pressurizer pressure signals. The RCS depressurizes to the point where leak flow equals the SI flow. If only minimum safeguards SI is available, there is voiding in the core and hot legs, but no core uncovery. The clad temperature remains below steady state operating temperatures, and decay heat is removed via natural circulation. If maximum safeguards SI is available, depending on the leak size the RCS may repressurize and return to subcooled conditions. The scenario of a stuck open pressurizer PORV or safety valve does not represent the limiting small break scenario. The small cold leg breaks analyzed in the UFSAR are the worst small breaks.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Response (Continued)

b. Figure 15.6-4 was deleted in Amendment 45 of the STPEGS FSAR. However, the Inadvertent Opening of a Pressurizer Safety or Relief Valve event assumes the opening of a pressurizer PORV or safety valve which initiates the transient. Although Engineered Safety Features (ESF) components might be actuated, they are not required to mitigate the consequences of the event from the standpoint of the core response, since the DNBR rises after reactor trip. Thus, ESF failures are not limiting and the worst single failure is loss of one protection train.

Because the minimum DNBR occurs within the first 30 seconds of the transient, the criteria delineated in the SRP are satisfied during this period. No SI actuation or RCP trip is assumed within this short transient. Likewise, the loop heat removal and operator action are beyond the scope of this event and must be determined via the small break LOCA analysis.

Question 440.70N

Steam generator tube rupture (SGTR events at R. E. Ginna and other PWRs) indicate the need for a more detailed review of the analysis for this accident. Our review of the STPEGS FSAR Section 15.6.3 in view of this plant experience has resulted in a need for the following additional information and clarification:

a. FSAR Section 15.6.3 indicates equalization of primary and secondary pressure 30 minutes after the SGTR event, with consequent termination of steam generator tube leakage. We consider this time period unrealistic based on previous SGTR incidents. Assuming loss of offsite power, provide the sequence of events which includes the automatic initiations and actuations as well as identification of operator action in chronological order. Justify the timing of operator actions if they are less conservative than those recommended in draft ANSI N660 for a condition IV event. Include the most limiting single active failure in your analysis.

b. Discuss whether as a result of possible modifications to your analysis including consideration of longer leak times, liquid can enter the main steam lines. If so, discuss the effects on the integrity of the steam piping and supports.

   Consider both the liquid dead weight and the possibility of water hammer. Also discuss whether the steam generator safety and relief valves would function properly if their actuation pressures are reached with the main steam lines filled with liquid and whether they would reseat at the proper pressure.

c. Provide the following parameters as a function of time, until releases from the ruptured steam generator are terminated:

   1. the primary system pressure

   2. the secondary system pressure in each steam generator

   3. the secondary liquid water mass and level in each steam generator

   4. the charging and safety injection flow rate

   5. the intact and ruptured loop T_H and T_{ave}

   6. the integrated mass released out of the atmospheric relief valves or safety valves for the intact steam generators and for the ruptured steam generator

   7. pressurizer level

   8. the tube rupture flow rate and integrated tube rupture flow

   9. the extent of upper head voiding if predicted

Question 440.70N (Continued)

10. the steam and feedwater flow rates for the ruptured and intact steam generators

11. the primary system liquid mass

12. the reactor vessel and steam generator temperatures

13. the intact and ruptured loop mass flow rate

These analyses should be based on loss of offsite power, the most severe single active failure, and the most reactive control rod stuck in the fully withdrawn position.

d. Describe, or reference the computer codes utilized to calculate the primary and secondary system response. Justify that the code is appropriate for the STPEGS SGTR analysis.

e. Identify all equipment which is relied upon to mitigate a design basis SGTR event. Justify that this equipment meets NRC requirements for safety-related equipment. If reliance on the primary PORVs and/or steam generator ADVs is essential for the SGTR mitigation, the applicant should either: (1) develop appropriate Technical Specification limits to ensure the continued operability of this equipment or (2) explain why in the absence of any Technical Specification requirements, credit should be given for operability of these valves. Describe what controls will be put in place to prevent operators taking valves out of service such that safety analysis assumptions are violated.

f. The analysis should assume that the accident begins with the primary cooling iodine concentrations at the Technical Specification limit. Both pre-existing and concurrent iodine spikes should be assumed for calculating offsite consequences.

Response [HISTORICAL INFORMATION]

The steam generator tube rupture (SGTR) has been reanalyzed in accordance with the methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A. The methodology in WCAP-10698-P-A and Supplement 1 to WCAP-10698-P-A has been accepted by the NRC. Section 15.6.3, WCAP-12369-P, and letter ST-HL-AE-3236, dated October 13, 1989, contains STP specific details of the reanalysis.

Analyses performed for the Δ94 replacement steam generators are documented in WCAP-15136 South Texas Unit 1 Replacement Steam Generator Program Safety Analysis and Licensing Report, November, 1998, which provides the details of the analysis. The replacement steam generator analysis follows the methodology of WCAP-10698 and Supplement 1 of WCAP-10698.

HISTORICAL INFORMATION

HISTORICAL INFORMATION

Question 440.72N

The FSAR does not provide analytical results for the large break LOCA recirculation phase. State whether the heat removal capacity of one RHR heat exchanger is sufficient for decay heat removal during recirculation phase initiation, or whether two RHR heat exchangers are required. For the most limiting combination of break location and single active or passive failure, provide core and downcomer water level and peak clad temperature for the early part of the recirculation phase.

Response [HISTORICAL INFORMATION]

HISTORICAL INFORMATION

Based upon the calculated containment pressures, sump temperatures, safety injection (SI) and Residual Heat Removal (RHR) heat exchanger (HX) performance curves, one RHR HX can adequately provide core cooling for the entire recirculation phase. The fluid exiting the break under this condition would be a low quality mixture with the injection rate from one train much in excess of steady state core boiloff. The loss of one low-head safety injection (LHSI)/RHR heat removal path would have some impact on Containment conditions and sump temperatures, but calculations show that the effect on the SI conditions would be small and would not effect core coolability.

Also, since the injected SI water still has some subcooling, there will be no significant change in fluid density. Therefore, there is no apparent mechanism whereby the core mixture level could decrease to the point that another core temperature excursion would occur. Conditions for core cooling would continually improve with the decreasing core decay heat generation rate. Clad temperatures would remain near fluid saturation.

The current Emergency Core Cooling System (ECCS) model used in large break LOCA calculations assumed that only one LHSI/high-head safety injection (HHSI) train injects into the RCB. One train is assumed to be unavailable and one spills to the containment through the broken loop. Water is supplied from the refueling water storage tank (RWST) for the entire 300 second duration of the calculation at assumed conditions of 90°F and 1 atm. At the end of the calculation the downcomer is liquid full and the core is covered and well cooled.

HISTORICAL INFORMATION

Question 440.80N

a. In Question 440.57N the staff requested information regarding the effect of the STPEGS design for MSIV closure on mitigation of steam generator tube rupture (SGTR) or small break LOCA. It is our understanding that the MSIVs would automatically close on low RCS pressure SI actuation, while the Westinghouse emergency response guidelines (ERGs) are based on use of the condenser for steam dump when it is available and thus assume that the MSIVs for intact SGs remain open. Your response indicated that for this type of event the MSIVs would be reopened, and that the time required for reopening the MSIVs would be offset by the time it takes to isolate a ruptured SG in the event of SGTR. You concluded that automatic closure of the MSIVs on any SI signal would not adversely affect recovery. We do not concur with this conclusion for the reason discussed below.
In our conference call of December 3, 1985, on this subject, you stated that several operations are required prior to reopening the MSIVs, including SI reset and equalization of MSIV upstream and downstream pressures. First, it is not clear that SI Reset would be possible at the times when MSIV opening is necessary. Second, it is not clear whether the STPEGS emergency operating procedures (EOPS) for SGTR and small break LOCA mitigation reflect these additional steps for re-establishment of steam dump to the condenser, and whether this will be part of operator training, including simulator runs. It is not clear that this mode of plant operation is consistent with our approval of generic Westinghouse ERGs. Please address the above concerns.

b. Please provide detailed information on the effect of STPEGS design for MSIV closure on the frequency of challenges to the MSIVs, steam generator safety valves (SVs) and atmospheric dump valves (ADVs). Consider the possible effect of more frequent challenges on the reliability of these valves. For SVs consider previous operating incidents during which a SV was actuated and then did not reseat properly, thus causing excessive steam leakage (e.g., Ginna SGTR event). Can the number of lifetime design cycles for these components be exceeded as a result of this design? Your response should consider operating history during various modes of operation, including testing and spurious actuations.

c. The evaluations currently conducted by the Westinghouse Owners Group (WOG) to address SGTR accident mitigation do not assume closure of the MSIVS on SI signal. The operator action times assumed in these analyses are based on typical MSIV closure actuation systems, which are not the same as for STPEGS. Thus, it is not apparent that these analyses are representative of the STPEGS plant. Therefore, unless it can be demonstrated that the WOG analyses clearly apply to STPEGS, provide the results of plant specific analyses that address the spectrum of SGTR concerns being addressed by the WOG. These include but are not limited to, the required time to stop the primary-to-secondary break flow and the time margin to overfill.

HISTORICAL INFORMATION

Response [HISTORICAL INFORMATION]

The Main Steamline Isolation Valve (MSIV) closure logic has been modified to be consistent with that of other Westinghouse plants. The MSIV closure on manual and high steam pressure rate signals will be maintained. The MSIV closure on a safety injection signal has been modified to MSIV closure only on a HI-2 containment pressure signal and on a low steam line pressure signal.

HISTORICAL INFORMQTION

Section 15.7

Question 211.42

For each event in Chapter 15, provide a discussion of the potential for and impact of incorrect operator action. The discussion should include incorrect actions during normal procedures as well as actions resulting from an incorrect identification of a transient.

Response

Refer to Section 15.7 for postulated events.

1. Liquid-Containing Tank Failures

   The rupture of a Recycle Holdup Tank (RHT) in the Boron Recycle System (BRS) is considered as the most limiting event. The description and analysis of a liquid-containing tank failure is provided in Section 15.7.3.

   For the analysis of the radiological consequences of this event, a tank filled to 80 percent capacity (64,000 gal) is assumed to be released. High level alarms are provided in the RHT, ensuring the influent to the tank will be terminated at approximately 80 percent of tank capacity.

   If the RHT ruptures while it is being filled, it is unlikely that the combined release of the liquid in the tank and the influent (flowing at a low rate of 100 gal/min) released prior to isolation of the tank will exceed 64,000 gallons. The required operator action is to terminate the influent upon receipt of a high RHT sump level alarm and low RHT level alarm. Incorrect operator action, resulting in delayed isolation of the RHT, will not significantly impact the offsite dose consequences of a RHT failure.

Response (Continued)

If the RHT ruptures when it is not receiving influent, incorrect operator actions have no impact on the offsite dose consequences. An operator error during recovery from this accident does not result in equipment malfunctions.

2. Design Basis Fuel Handling Accidents

For the design basis fuel handling accidents, all actions which minimize the offsite dose consequences are automatic, except for a scenario where the Personnel Airlock is open during a fuel handling accident in Containment. Inside the Containment, a high activity signal from the RCB Purge Isolation Monitors initiates Containment ventilation isolation. If the Personnel Airlock is open an operator action is required to close the door. The impact of an incorrect operator action (failure to close the Containment Personnel Airlock) was not considered in the licensing amendment which allows the airlock to remain open during refueling since the potential for an incorrect operator identification of a fuel handling accident is considered very low. It is considered low because Technical Specifications require an individual to be assigned the responsibility of closing the airlock if the door is left open during refueling and a fuel handling accident occurs. This was found to be acceptable to the NRC as evident in the approved licensing amendment for this change (Reference 1).

For a fuel handling accident in the Fuel Handling Building, a high activity signal from the spent fuel pool ventilation monitors diverts the building exhaust through carbon filter units. Thus, incorrect operator actions will have no impact on the offsite dose consequences of a design basis fuel handling accident.

References

1. ST-AE-HL-94116, South Texas Project, Units 1 and 2 - Amendment Nos. 69 and 58 to Facility Operating License Nos. NPF-76 and NPF-80, (TAC Nos. M90796 and M90797).

HISTORICAL INFORMATION

3. Spent Fuel Cask Drop Accident [HISTORICAL INFORMATION]

The design of the wet cask handling system incorporates features to limit cask drops to 30 feet. Thus, no radiological consequences are expected, and incorrect operator actions will have no impact on the offsite dose consequences.

Note: Additional discussion is provided in the response to Q211.52.

HISTORICAL INFORMQTION

CN-3214

Question 450.2N

Please provide the basis for using the dilution volumes shown in Table 15.7-9 of the FSAR in the analyses of the radiological consequences of fuel handling accidents inside containment and in the fuel handling building.

Response

For the fuel handling accident inside the Fuel-Handling Building (FHB) the dilution volume is the volume directly above the fuel pool serviced by the HVAC. Thus the surface area of the pool was multiplied by the height from the surface of the water to the exhaust ducts. This results in a volume of 53,000 ft^3. Thus a value of 50,000 ft^3 was conservatively used in the analysis.

A similar methodology was assumed in the Reactor Containment Building (RCB). The southeast corner (closest approach) of the refueling water pool is 45 ft from the exhaust duct of the Containment purge. In addition the purge exhaust duct is 17.5 ft above the surface of the water. A cylinder with a radius of 45 ft and a height of 17.5 ft was assumed. This results in a dilution volume of approximately 111,000 ft^3.

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Question 260.9N

HISTORICAL INFORMATION

Provide an organization chart which shows the relationship between the various organizations which will perform design work for STPEGS during the operations phase. Describe the function(s) of the "Engineering Assurance" organization shown on Figure 17.2-3 (Amendment 24). Describe the interface relationships and division of responsibilities between Engineering Assurance and Quality Assurance (QA). With each organization performing "its own design verification" per Section 17.2.3.4, describe how the independence of the verifier is assured.

Response [HISTORICAL INFORMATION]

The response to this question has three parts.

(a) An organization chart is provided in Figure 17.2.-2

(b) The purpose of the Engineering Assurance Program is to provide confidence in the technical adequacy of the engineering and design work performed by HL&P and its major contractors. The program consists of activities directed at assessing the adequacy of the technical aspects, as well as the methods of control, of the engineering and design activities of HL&P and its major contractors in producing a quality engineering product. This is accomplished by independently sampling the design activities and products for confirmation by analytical techniques. Therefore, the Engineering Assurance Program is in addition to and separate from normal QA measures established to meet the requirements of 10CFR50 Appendix B Criterion III, Regulatory Guide 1.64, and ANSI N45.2.11. The Engineering Assurance Department provides an ongoing third party design review over the balance of the construction program. The Engineering Assurance Department is supplemented by outside resources from competent engineering firms where and when required. In summary, the Engineering Assurance Program is an additional voluntary step taken by HL&P to provide confidence in design and engineering work performed for the South Texas Project. The inclusion of the Engineering Assurance Department on Figure 17.2-2 was for the sake of completeness and does not imply that the organization or its activities are part of the QA program for design.

(c) The context of the statement in Section 17.2.3.4 is in regard to the organizations in Section 17.2.3.1. As stated, each organization will have procedures to cover the design verification. An element of these procedures will be the incorporation of ANSI N45.2.11 requirements on independence of the design verifier.

HISTORICAL INFORMATION

Question 421.39

Following the third paragraph of FSAR Section 17.2.4.1, a paragraph that was present in Amendment 2 concerning procurement initiated by the Maintenance Department has been deleted in Amendment 4. This deletion is not noted in the margin, and it is not clear whether the deletion was intentional or not. If the deletion was unintentional, reinstate the paragraph. If intentional, explain why the paragraph was deleted.

Also, the last paragraph of the FSAR Section 17.2.4.1 still refers to "the Engineering Assurance Division of the QA Department," but this division is no longer shown on Figure 17.2-1. Clarify this discrepancy.

Response

The paragraph discussed was deleted intentionally. However, Section 17.2 has since been substantially revised, and this concern no longer applies.

Question 421.49

Replace or justify the deletion of "and approval" from item 4 on page 17.2-17 which, in amendment 4, stated "After QA review and approval, the requisition is returned to the Plant Superintendent or the General Manager of the Generation Engineering Department (or their respective designees) for final approval". In lieu of "approval", "documented concurrence" would be an acceptable alternative.

Response

Sufficient measures have been established and implemented by having QA review procurement documents without approving them to meet the requirements of 10CFR50 Appendix B Criterion IV and ANSI N45.2-1971. The QA review of procurement documents is to ensure the requirements of various standards, codes, and regulations are met and is not to approve or concur with the item being procured. Therefore, approval or concurrence is not necessary.

Question 421.52

Explain the significance of the changes at the middle of page 17.2-29 which amendment 9 revised from: "Corrective action for problems identified by DNs are documented by the cognizant plant supervisor on the DN form. The plant QA staff verifies that satisfactory correction action has taken place by reinspection or audit. Unacceptable corrective action, as determined by the plant QA staff, requires further action by the responsible supervisor and may result in suspension of the deficient activity." to "Corrective action for problems identified by DNs are determined by the cognizant plant supervisor on the DN form. the plant QA staff verifies satisfactory completion of the corrective action by reinspection or audit. Unacceptable completion of corrective action, as determined by the plant QA staff, requires further action by the responsible supervisor and may result in suspension of the deficient activity." Also, it is the staff position that the QA organization concur with the corrective action. Revise the FSAR to meet this position or provide an alternative for our evaluation.

Response

UFSAR Section 17.2.16.1, third paragraph, second sentence: Changing from "documented" to "determined" was done to emphasize that an evaluation was necessary to cause a corrective action to occur. Third sentence: changing from "has taken place" to "completion of corrective action" was done to emphasize our concern that corrective action required be completed prior to verification.

We do not agree that the QA organization concur with the corrective action. It is the Plant Manager's responsibility for safety and safe operation of the plant. Therefore, the determination of corrective action by the cognizant plant supervisor, who is responsible to the Plant Manager, does not require concurrence by QA. What is important and is very much a QA concern is that the corrective action be accomplished and completed in accordance with approved procedures, instructions, or drawings.

Question 422.1

Your description in Table 1 of Section 6 of your Fire Hazards Analysis Report relative to your compliance with the Branch Technical Position does not provide adequate information on your fire protection organization for us to complete our review. Therefore, please provide the following information:

1. Describe the upper level offsite management position that has the overall responsibility for the formulation, implementation, and assessment of the effectiveness of the fire protection program.

2. Describe the offsite position(s) that has direct responsibility for formulating, implementing, and periodically assessing the effectiveness of the fire protection program for the nuclear plant, including fire drills and fire protection training.

3. Describe the onsite management position that has overall responsibility for the fire protection program. In addition, describe any further delegation of responsibilities for the fire protection program such as training, maintenance of fire protection systems, testing of fire protection systems, fire safety inspections, fire fighting procedures, and fire drills.

4. Describe the proposed composition of your station fire brigade.

Response

1. The Fire Hazards Analysis Report is prepared and assessed under the cognizance of the Manager, Engineering. The implementation of the fire protection program is controlled by the Plant General Manager.

2. The Plant General Manager is the offsite position responsible for:

   a. Formulating, implementing and periodically assessing the effectiveness of the fire protection program, including fire drills and training conducted by the plant fire brigade and plant personnel.

   b. Using the following NFPA Publications for guidance to develop the fire protection program:

      No. 4 - "Organization for Fire Services"

      No. 4A - "Organization of a Fire Department"

      No. 6 - "Industrial Fire Loss Prevention"

      No. 7 - "Management of Fire Emergencies"

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Response (Continued)

No. 8 - "Management Responsibilities for Effects of a Fire On Operations"

No. 27 - "Private Fire Brigades"

The Plant General Manager will receive assistance in these activities from a consultant who must meet as a minimum the eligibility requirements for membership in the Society of Fire Protection Engineers.

CN-3103

3. The STPEGS Plant General Manager has the overall responsibility for the administration of plant operations and emergency plans which includes the fire protection and prevention program. Direct responsibility for the implementation of the plant fire protection program is delegated by the Plant General Manager to the Safety Department. In addition to the direct responsibility for the formulation, implementation and assessment of the effectiveness of the plant fire protection program, the Safety Department has the direct responsibility for:

   a. Implementing periodic inspections to minimize the amount of combustibles in safety-related areas and determining the effectiveness of housekeeping practices. The coordinator must assure the availability and acceptable condition of all fire protection systems/equipment, emergency breathing apparatus, emergency lighting, communication equipment, fire stops, penetration seals and fire retardant coatings. The coordinator also must assure that prompt and effective actions are taken to correct conditions adverse to fire protection and to preclude their recurrence.

   b. Providing fire fighting training for operating plant personnel and the plant fire brigade.

   c. Inspection and testing of plant fire protection systems and equipment in accordance with approved plant procedures and evaluating test results to determine the acceptability of systems and equipment tested.

   d. Planning and establishing training objectives for all fire drills and evaluating drills to determine if training objectives have been met.

   e. Reviewing and evaluating proposed work activities to identify potential fire hazards.

   f. Implementing a program for indoctrination of all plant contractor personnel in appropriate fire protection procedures.

   g. Instructing personnel on the proper handling of accidental events such as leaks or spills of flammable materials.

Response (Continued)

h. Preparing plant fire protection procedures.

i. Insuring proper maintenance of plant fire protection systems and equipment.

4. There will be one fire brigade per shift. Each brigade will, as a minimum, consist of members of the Plant Operations shift crew serving as Fire Brigade leaders, and as members. CN-3103