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.

<u>Response</u>

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 CN-2803

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 INFORMATIN

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.

<u>Response</u>

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 w
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

<u>Response</u>

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.

<u>Response</u> (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 x 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 x 10^{-8} failures per hour. Assuming yearly testing, this hourly rate corresponds to an unavailability of 3 x 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.

<u>Response</u>

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.

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* WASH-1400, "Reactor Safety Study", U. S. NRC, October, 1975.

<u>Response</u> (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 1000 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 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.

CN-3136

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 $\pm$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.

<u>Response</u> (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.