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APPENDIX A - PRESSURE INTEGRITY OF PIPING AND EQUIPMENT PRESSURE PARTS

A.1 SUMMARY DESCRIPTION

This appendix provides additional information pertinent to the preceding sections concerning the pressure integrity of piping and equipment pressure parts.

Piping and equipment pressure parts are specified according to service and location. The design, fabrication, examination, and testing requirements are defined for the equipment of each category to assure the proper pressure integrity.

For the purpose of this appendix, the pressure boundary of the process fluid includes, but is not necessarily limited to: branch outlet nozzles or nipples, instrument wells, reservoirs, pump casings and closures, blind flanges, studs, nuts, and fasteners in flanged joints between pressure parts, bodies and pressure parts of inline components such as traps and strainers, and instrument lines up to and including the first shutoff valve.

Specifically excluded from the scope of this appendix are vessels and heat exchangers or any components (except piping) which are within the scope of the ASME Boiler and Pressure Vessel Code, Sections III and VIII; non-pressure parts such as pump motors, shafts, seals, impellers, wear rings, valve stems, gland followers, seat rings, guides, yokes, and operators; non-metallic material such as packing and gaskets; fasteners not in pressure part joints such as yoke studs and gland follower studs; and washers of any kind.

This appendix defines the design limitations for piping and valves associated with the reactor coolant primary pressure boundary (nuclear steam supply), primary containment pressure boundary (drywell and torus), and related auxiliary systems within the power generation (operational) systems.

Table A.9.1 specifies systems falling within the applicable codes and the scope of this appendix.

A.1.1 Codes and Specifications

The piping and equipment pressure parts in this nuclear power plant are designed, fabricated, inspected, and tested in accordance with recognized codes, as far as these codes can be applied, and in accordance with the project specifications. Where conflicts occur between the industrial codes and project specifications, the project specifications take precedence.

In the replacement recirculation and RHR piping systems, the original piping was installed in accordance with ANSI B31.1, 1967 Edition. For replacement work, as defined in ASME Section XI, 1980 Edition, the replacement may meet all or portions of the requirements of later editions of the Construction Code. The replacement recirculation piping material and fabrication is in accordance with ASME Section III, 1980 Edition, including addenda through Winter 1981. The recirculation piping systems was designed in accordance with ASME Section III, 1980 Edition, including addenda through Winter 1981. The piping is installed in accordance with ASME Section XI, 1980 Edition, including addenda through Winter 1981. Nondestructive testing is performed in accordance with ASME Section XI, 1980 Edition, including addenda through Winter 1981. Section XI refers to Sections III and V for procedures and acceptance criteria.

The valves in these systems are in accordance with ANSI B31.1.

In the Peach Bottom Atomic Power Station emergency service water systems, the original piping was installed in accordance with ANSI B31.1.0, 1967 Edition. Replacement piping and selected valves for Modifications 2106 and 5046 are designed and fabricated in accordance with requirements of ASME Section III, 1980 Edition, including addenda through Winter 1981, with the exception that portions shown on Isometrics 3-33-10, 3-33-12, and 3-33-13 will be designed and fabricated in accordance with the original code and specifications. Shop fabrication, installation, and testing of piping on the above-mentioned isometrics will be in accordance with original specification requirements which require all butt welds to be radiographed. The remaining piping within the scope of Mod 2106 will be installed and tested to requirements equivalent to that of ASME Section III, Class 3. All replacement piping materials will be in accordance with ASME Section II.

For the High Pressure Service Water (HPSW) and Emergency Service Water (ESW) systems, large bore butt weld piping was installed and maintained in accordance with USAS/ANSI B31.1.0, 1987 Edition. Fabrication, installation, and testing of piping was performed in accordance with original construction project specification requirements which required all circumferential butt welds to be radiographed. As part of the Extended Power Uprate Project (2013), the radiography requirement for HPSW piping circumferential butt welds has been eliminated. Subsequently, the radiography requirement for ESW piping circumferential butt welds has been eliminated as well. This safety-related B31.1 piping (Group II, Design Schedule I) is classified per the station ASME Section XI program as Class 3, making it comparable to ASME Section III Class 3 piping systems requiring no radiography. As such, inspection requirements will reflect quality standards commensurate with the importance of the safety function to be performed. The original requirements were a hardship to maintain during the operational phase, without a compensating increase in the level of quality or safety. Elimination of butt weld radiography on these systems will facilitate maintenance, reduce the burden on resources, and reduce the risk of accidental radiological exposures to personnel.

All other piping systems within the scope of this appendix, including pipe, flanges, bolting, valves, and fittings are in accordance with ANSI B31.1, "Power Piping," including requirements for design, erection, supports, tests, inspections, and additional requirements specified herein, except where deviations are in accordance with the requirements of later editions of codes approved by the NRC and listed in the Code of Federal Regulations. Additionally, for torus attached piping subject to Mark I hydrodynamic loads, design requirements are as described in the following paragraph.

A re-analysis of the torus attached piping systems was performed as part of the Mark I Containment Long-Term Program as described in Section M.3.5. The codes used to evaluate the acceptability of the design of the existing piping systems for Mark I loads are:

ANSI B31.1-1967 Edition Power Piping Code	Code used for original piping stress analysis.
ASME Section III Division I, Class 2 1977 Edition including Summer 1977 Addenda	Code used for Hydrodynamic analysis and allowable stress limits for all load cases (static and dynamic).
ANSI B31.1-1973 including Summer of 1973 Addenda (ANSI B31.1-1977 Edition for stress intensification factors)	Code used for static and seismic analyses.

In order to meet the requirements of ultrasonic examination for inservice inspection of welds within the primary coolant pressure boundary (Group I), the weld reinforcement contour is controlled and blended smoothly into the base metal. In addition, the main steam lines from downstream of the outer isolation valves to the main turbine stop valves and the feedwater lines from the pump discharge to the reactor coolant pressure boundary meet the weld reinforcement requirements of ANSI B31.1.

The plant piping is classified in three groups, depending on the design requirements for the service.

The design requirements for piping systems designated in Groups I and II are in accordance with the requirements of ANSI B31.1 and supplementary requirements in the project specifications except as noted above. These systems require full radiography and supplementary surface inspections of the weld joints and supplementary nondestructive test requirements of the pressure components.* Additionally, some of these piping systems are analyzed for seismic Class I design criteria as indicated in Table A.9.1.

The methods used for the seismic analysis of Class I systems and components are presented in paragraph C.5.3 of Appendix C. The results of the analyses are presented in Tables C.5.6, C.5.7, and C.5.8. In general, piping 2 1/2 in and larger is dynamically analyzed by the response spectrum method. Piping 2 in and smaller is analyzed by one of the methods specified in paragraph A.3.1.4.

*except as noted above

The design requirements for some piping in Group III, such as main steam lines downstream of the outer isolation valve to the main turbine stop valve, but excluding the stop valves, are in accordance with the requirements of ANSI B31.1 and supplementary requirements in the project design specifications, namely, full radiography of pressure weld joints.

The above mentioned systems in Groups I and II and a portion of Group III are designated as "critical piping" for design, stress analysis, fabrication, inspection, erection, testing, and quality control purposes.

The remaining portion of piping systems in Group III is in accordance with ANSI B31.1 and these systems are designated as noncritical systems.

Table A.9.1 summarizes the classification of piping systems, and Table A.9.2 lists design codes and standards for plant equipment.

A.2 CLASSIFICATION OF PIPING AND EQUIPMENT PRESSURE PARTS

Piping and equipment pressure parts may be classified as follows and as shown in Figure A.2.1:

Group I - Piping and equipment pressure parts within the reactor primary pressure boundary through the outer isolation valve, inclusive.

Group II - Piping and equipment pressure parts downstream of the outer isolation valve and extensions of containment and the core standby cooling systems.

Group III - Balance of plant piping and equipment pressure parts, including power generation systems.

A.3 DESIGN

A.3.1 Piping Design

Pressure and temperature conditions to which the piping pressure components are subjected are described in the appropriate system design section of the FSAR.

A.3.1.1 Allowable Stresses

The allowable stresses for piping design are as follows:

1. For carbon steel, the allowable stress values of ANSI B31.1 are used.

2. For austenitic stainless steel, the allowable stress values of ANSI B31.1 are used. For material not covered by ANSI B31.1, stress values of the ASME Boiler and Pressure Vessel Code, Section I, Appendix A-24, are used.

3. For piping designed to ASME Section III, including torus attached piping (ASME Class 2), the allowable stress values from ASME Section III, Division 1, Appendix I are used.

A.3.1.2 Wall Thickness

Pipe wall thickness, fittings, and flange ratings are in accordance with the design code, including adequate allowances for corrosion and erosion according to individual system requirements for a design life of 40 years. For recirculation and RHR shutdown cooling piping inside the containment, pipe and fitting wall thickness are in accordance with ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1980 Edition, up to and including Winter 1981 addenda.

A.3.1.3 Reactor Vessel Nozzle Load

All piping, including instrument piping connecting to the reactor pressure vessel nozzles, is designed so that the nozzle to pipe interface load does not result in stresses in excess of the allowable material stresses. Thermal sleeves are used where nozzles are subjected to high thermal stresses.

A.3.1.4 Seismic Design

Seismic Class I piping is defined as that portion of a piping system whose failure might cause, or increase the severity of, the design basis accident, or which is essential for safe shutdown of the reactor.

The piping is designed and supported to satisfy seismic criteria specified in the loading criteria (Appendix C).

The piping systems indicated as seismic Class I in Table A.9.1 are analyzed for the maximum credible seismic condition, including the maximum relative differential movement associated with the design or the maximum credible earthquakes which could occur at the support points. Since the stresses resulting from this maximum relative differential movement are not likely to occur in phase with the maximum stresses due to dynamic response of the pipe, if any, the two were combined on a root-mean-square (the square root of the sum of the squares) basis. The seismic stresses are combined with other piping stresses in accordance with the design rules of Appendix A.

Buried seismic Class I pipes are laid in a prepared trench and backfilled with select material. The backfill material is compacted to 95 percent of maximum density as determined by the AASHO T180 Method "D" and field QC is performed in accordance with AASHO T147.

All Class I structures are founded either directly on rock or the loads are carried to the rock by structural elements, thus limiting vertical motion to insignificant amounts. Backfill around structures is compacted under control similar to that for the Class I piping. Where Class I piping enters a building near the base, differential movement between the building and soil at the location of pipe penetrations may be considered to be zero. Where Class I piping enters the secondary containment near the ground surface, flexible or rigid seals are provided as required.

A.3.1.4.1 Supplementary Analysis of Seismic Class I Piping

Seismic Class I piping is classified as either rigid or flexible. Rigid piping is that which has a fundamental frequency in the rigid range of the spectrum curves for the building locations. Typically, this corresponds to frequencies greater than 20 Hz. These piping systems are analyzed with static loads corresponding to the acceleration in the rigid range of the spectrum curves.

The dynamic analysis of flexible seismic Class I piping systems for seismic loads is performed using the spectrum response method to compute shears, moments, stresses, deflections, and/or accelerations.

The piping system is idealized as a fixed base mathematical model. An analysis was performed to verify the accuracy of assuming a fixed base. The results of this analysis (Table A.3.1) indicate that the frequencies and mode shapes did not vary appreciably between those derived from a fixed base model and those obtained when translational and rotational springs, representing soil-structure interaction, were applied to the base of the model.

The mathematical model consists of lumped masses separated by elastic members. The lumped masses are carefully located so as to adequately represent the dynamic and elastic properties of the piping system. The three-dimensional stiffness matrix of the mathematical model is determined by the direct stiffness method.

The mass matrix is also calculated. The torsional effects of valves and other eccentric masses (i.e., valve operators) in the seismic piping analysis are taken into account by using a cantilevered member with a lumped mass at the free end to model the valve and motor operator. The lumped mass is the corresponding mass of valve operator or any other eccentric mass. After the stiffness and mass matrices of the mathematical model are calculated, the natural frequencies of vibration and corresponding mode shapes are determined using Equation (1):

$$(\underline{K} - W_N^2 \, \underline{M}) \, \underline{\phi}_N = \underline{0} \tag{1}$$

where:

$\underline{K}$ = stiffness matrix

W_N = natural circular frequency for the Nth mode

$\underline{M}$ = mass matrix

$\underline{O}$ = zero matrix

$\underline{\phi}_N$ = mode shape matrix for the Nth mode

The mode shapes are normalized according to Equation (2):

$$\underline{\phi}_N^T \, \underline{M} \, \underline{\phi}_N = 1 \tag{2}$$

The maximum response of each mode is found through Equation (3):

$$\underline{Y}_N{}^{(t)}{}_{max} = \frac{\underline{\phi}_N^T \underline{MD} \; Sa}{W_N^2 \; M_N} \tag{3}$$

where:

Sa = spectral acceleration value for the Nth mode

$\underline{D}$ = earthquake vector matrix, used to introduce earthquake direction to the response analyses

ϕ_N^T = transposition of the Nth mode shape

M_N = generalized mass of the Nth mode

$\underline{Y}_N$ = generalized coordinate for the Nth mode

Using the maximum generalized coordinates for each mode, the maximum deflections associated with each mode are calculated using Equation (4):

$$\underline{V}_N = \underline{\phi}_N \quad Y_N{}^{(t)} \max \tag{4}$$

The square root of the sum of the squares method is used to combine the total modal responses as indicated in Equation (5):

$$Vi = \sqrt{Vi_1^2 + Vi_2^2 + --- + Vi_N^2} \qquad Vi = \sqrt{Vi_1^2 + Vi_2^2 + --- + Vi_N^2} \tag{5}$$

where:

Vi = deflection at ith point due to the response of N modes

Vi_N = deflection at ith point due to Nth mode

Once the appropriate deflections have been determined for each mass and each mode, the effective applied forces for each mode are computed using Equation (6):

$$\underline{Q}_N = \underline{KV}_N \tag{6}$$

where:

$\underline{Q}_N$ = inertial forces due to mode N.

The accelerations for each mode are calculated through Equation (7):

$$\underline{a}_N = \underline{M}^{-1}\ \underline{Q}_N \qquad (7)$$

where:

$\underline{a}_N$ = accelerations due to Nth mode

$\underline{M}^{-1}$ = the inverse of mass matrix

After the effective forces have been determined, the internal forces (thrusts and shears) and moments for each mode are calculated using Equation (8):

$$\underline{S}_N = \underline{bQ}_N \qquad (8)$$

where:

$\underline{S}_N$ = internal forces and moments due to the Nth mode

$\underline{b}$ = force transformation matrix

The internal forces (thrusts and shears) and moments are combined on the same basis as Equation (5), thereby giving the maximum response quantities resulting from all modes. Except for recirculation, RHR shutdown cooling piping inside the containment, torus attached piping, and portions of the emergency service water system, the response thus obtained is combined with the results produced by other loading conditions, in accordance with ANSI B31.1 criteria, to obtain the total resultant stresses. For torus attached piping see Section C.5.3.3.3, "Piping Mark I Load Analysis". For emergency service water system, refer to Section A.1.1. For recirculation and RHR shutdown cooling piping inside the containment, the seismic response is combined with the results produced by other loading conditions in accordance with ASME B&PB Code Section III, Subsection NB, 1980 edition up to and including winter 1981 addenda criteria to obtain the total resulting loads. All modes are used which have frequencies less than 20 Hz. The percentage of critical damping for all modes is 0.5 for the design earthquake and 1.0 (for PBAPS 3) and 0.5 (for PBAPS 2) for the maximum credible earthquake. Additionally, in the case of the 1997 re-analysis of the Recirculation system piping, and the Residual Heat Removal and Reactor Water Clean-up piping inside primary containment, the seismic analysis was based on NRC Regulatory Guide 1.60 (Design Response Spectra for Seismic Design of Nuclear Power Plants). This regulatory guide was used because it is required by Regulatory Guide 1.84 when using ASME Code Case N-411-1 (Alternative Damping Values for Response Spectra Analysis of Class 1, 2, and 3 Piping Section III, Division 1) as described in UFSAR Table C.2.1.

In lieu of the above procedure, some seismic Class I piping is statically analyzed. The seismic load is considered to be a load equivalent to the peak value of the appropriate floor spectrum curve times the weight of the pipe. The restraints of these pipes are located so that the natural frequency of the first mode of vibration is 10 Hz or greater. The peak of the floor response spectrum occurs at a lower frequency. For the sake of analysis, the pipes which have many straight runs between changes in direction may be considered to be a continuous beam. The response of the continuous beam to seismic loads is very small, due to the alternating sign of the mode shape in the adjacent spans. Thus, a single span beam may be considered to be a more severe case than the continuous beam. For the simple beam and the mode shape assumed to be a sine curve, the acceleration at any point is given by:

$$a(x) = \mathrm{SIN}\,\frac{\pi x}{L}\;\frac{\int_{o}^{L} \mathrm{SIN}\,\frac{\pi x}{L}}{\int_{o}^{L} \mathrm{SIN}^2\,\frac{\pi x}{L}}\;S_{AF}$$

where:

L = the span length
x = the distance to the point in question
S_{AF} = the spectral acceleration at the natural frequency (10 Hz in this case).

At x = L/2, i.e., the point of maximum acceleration, the above expression simplifies to $a_{max} = \frac{4S_{A(10)}}{\pi} = 1.27S_{A(10)}$

The load is then $p_{max} = wa_{max} = 1.27wS_A$ where w is the pipe weight per unit of length. For the piping design the load was taken to be $p_{max} = wSp$, where Sp is the peak of acceleration of the floor response spectra. Since, for all cases, $Sp \gg 1.27S_{A(10)}$, the analysis used for piping design is conservative.

Furthermore, in order to verify that the above conclusions were accurate, a sample problem was solved using dynamic analysis methods. The sample problem contained several typical changes in direction separated by continuous spans and a typical expansion loop. The resulting stress was less than 1,000 psi. Restraints were also located at valves, so that their concentrated mass could not cause a significant load on the pipe.

From the above analysis it is concluded that the maximum total stresses, as calculated in paragraph A.3.1.5, are less than the allowable stress limits permitted by the piping code.

Figure A.3.1 shows the layout of the sample problem, with a total weight of 5.09 lb/ft, including insulation and water. The problem contains several typical changes in direction separated by continuous spans, and a typical expansion loop. The lumped mass model is shown with the locations of the lumped masses and members. The system was analyzed by the response spectrum method using the same procedures as those used to analyze large diameter piping. The analysis was made using the response spectrum curve for the lowest floor of the reactor building, since many of these lines are at that location. The maximum resulting seismic stress was 250 psi. This value is quite low. For other systems, which are subjected to more severe response spectrum curves, the maximum ratio of the curves at any frequency is less than 10. Therefore, for other locations, the maximum stress would be less than 2,500 psi. For the maximum credible earthquake, the stresses would be multiplied by 2.4. Even this would result in low stresses, less than 6,000 psi.

For design of piping, the following method was used. For straight runs, the maximum span was set to correspond to 10 cps, with the frequency calculated as if the piping was a simple beam with the same span, weight per foot, and moment of inertia. This relation holds for the 10-ft span in the sample problem. The changes in direction were made to conform to a similar relation for span lengths and natural frequency. The low stresses obtained by the sample problem confirm that the method is adequately conservative, since the simplified analysis gave stresses of about six times the stresses from the dynamic analysis.

The static method of analysis described was applied only to small piping 2 in or less. For the method of seismic analysis of larger diameter piping, refer to paragraph C.5.3.3.2.

For both dynamic and static seismic analysis the horizontal acceleration spectrum curves applied to the piping systems are developed as part of the seismic analysis for the building in which the piping is located.

A.3.1.5 Analysis of Piping (Other than recirculation and RHR shutdown cooling piping inside the containment, torus attached piping, and portions of the emergency service water system)

a. Primary Stresses (S_P)

Primary stresses are as follows:

1. Circumferential primary stress (S_R) - circumferential primary stresses are below the allowable stress (S_h) at the design pressure and temperature.

2. Longitudinal primary stresses (S_L) - the following loads are considered as producing longitudinal primary stresses: internal or external pressures; weight loads including valves, insulation, fluids, and equipment; hanger loads; static external loads and reactions; and the inertia load portion of seismic loads.

When the seismic load is due to the design earthquake (0.05g horizontal), the vectorial combination of all longitudinal primary stresses (S_L) does not exceed 1.2 times the allowable stress (S_h)

When the seismic load is due to the maximum credible earthquake (0.12g horizontal), the vectorial combination of all longitudinal primary stresses does not exceed 2.4 times the allowable stress (S_h) unless higher allowable limits are calculated and substantiated by the methods outlined in Appendix C.

b. Secondary Stresses (S_E)

Secondary stresses are determined by use of the Maximum Shear Stress theory:

$$T_{MAX} = \frac{1}{2}\sqrt{S^2 + 4S_t^2} = \frac{1}{2} S_E$$

therefore:

$$S_E = \sqrt{S^2 + 4S_t^2}$$

The following loads are considered in determining longitudinal secondary stresses:

1. Thermal expansion of piping.

2. Movement of attachments due to thermal expansion.

3. Forces applied by other piping systems as a result of their expansion.

4. Any variations in pipe hanger loads resulting from expansion of the system.

5. Anchor point movement portion of seismic loads.

The vectorial combination of longitudinal secondary stresses (S) does not exceed the allowable stress range S_A, i.e., $S_E \leq S_A$, where:

$$S_A = f\ [1.25(S_c + S_h) - S_L]$$

(This is Equation 1 from paragraph 102.3.2 of ANSI B31.1 modified to include the additional stress allowance permitted when S_L is less than S_h.)

A.3.1.6 Analysis of Recirculation and RHR Shutdown Cooling Piping Inside the Containment

Primary Stress Intensity - The following loads are included in the calculation of the primary stress intensity: internal pressure; weight loads including valves, insulation, fluids, equipment and hanger loads, and the inertia portion of seismic loads. In the combination of weight moments with seismic moments, all directional moment components in the same direction are combined before determining the resultant moment. The primary stress intensity is calculated by adding the longitudinal pressure stress to the absolute value of the stress due to the moments.

When the seismic load is due to the design earthquake (0.05g horizontal) and the longitudinal pressure stress is due to the design pressure, the primary stress intensity does not exceed 1.5 times the allowable design stress intensity value (Sm). When the seismic load is due to the design earthquake and the longitudinal pressure stress is due to the peak upset condition pressure, the primary stress intensity does not exceed 1.8 times the allowable design stress intensity (Sm) and also does not exceed 1.5 times the yield strength value (Sy).

When the seismic load is due to the maximum credible earthquake (0.12g horizontal), the primary stress intensity does not exceed 3.0 times the allowable design stress intensity (Sm).

Primary plus secondary stress intensity range and the cumulative usage factor were calculated in accordance with ASME B&PV Code

Section III Subsection NB 1980 edition up to and including Winter 1981 addenda.

A.3.1.7 Analysis of Torus Attached Piping

For suppression chamber torus attached piping systems, in addition to the longitudinal primary stresses (S_L) described in Section A.3.1.5, Mark I hydrodynamic loads are also considered in the combination of longitudinal primary stresses. Allowable stresses are in accordance with the requirements of ASME, Section III 1977 Edition through Summer 1977 addenda as outlined in Plant Unique Analysis Addendum report of Appendix M, paragraph M.3.5. Additional requirements for torus attached piping subject to Mark I hydrodynamic loads are in accordance with the codes listed in Section A.1.1. Thermal stresses in torus attached piping were evaluated for normal (Level A) and upset (Level B) conditions in accordance with ASME Section III, Subsection NC-3652.3 requirements.

A.3.2 Valve Design

Valves are designed and rated by the manufacturer to meet the design pressure and temperature. They are in compliance with ANSI B31.1, "Power Piping"; ANSI B16.5, "Steel Pipe Flanges and Flanged Fittings"; or Manufacturers Standardization Society, Standard Practice MSS-SP-66, "Pressure-Temperature Ratings for Steel Butt-Welded End Valves." As an alternative ASME Section III valves may also be employed when they are determined to be suitable for the particular service intended.

In addition, for those valves in torus attached piping systems which have an active or passive function during normal and upset conditions, structural integrity and operability are shown by verifying, for those conditions, that the stress levels remain respectively within the Level A and B allowable stress limits of the ASME Boiler and Pressure Vessel Code Section III-1977 up to and including Winter 1977 Addenda (Code). For those valves which have an active function during a faulted condition, structural integrity and operability are shown by verifying, for that condition, that the stress levels remain within the Level B allowable stress limits of the Code. For those valves which have a passive function during a faulted condition, structural integrity is shown by verifying, for that condition, that the stress levels remain within the Level D allowable stress limits of the Code.

A.3.3 Pump Design

The pressure retaining parts of pumps are designed to meet the design pressure and temperature in the piping to which they are attached.

a. For pumps used in piping systems classified as Group I, the requirements of Section III of the ASME Boiler and Pressure Vessel Code for Class C were used as a guide in calculating the thickness of pressure retaining parts and in sizing the cover bolting.

   Additionally, Group I pumps in torus attached piping systems were evaluated for structural integrity and operability. Structural integrity is shown by meeting the upset and faulted condition allowables as established by the ASME B&PV Code Section III, 1977 edition with addenda up to and including Winter 1977. Operability is shown by meeting the Service Level B allowable stress limits (upset allowables), of the ASME Section III code referenced above, with Service Level D loading (faulted loads).

b. For pumps used in piping systems classified as Group II, the requirements of Section VIII, Division I of the ASME Boiler and Pressure Vessel Code were used as a guide in calculating the thickness of pressure retaining parts and in sizing the cover bolting.

c. When a pump is used in piping systems classified as Group III, the standard commercial design is accepted for the specific service.

PBAPS

TABLE A.3.1

FIXED BASE MATHEMATICAL MODEL ANALYSIS RESULTS

Natural Frequency	Model with Fixed Base (Hz)	Model on Springs Soil-Structure, Interaction (Hz)
f_1	6.42	6.16
f_2	10.49	10.43
f_3	18.10	16.55
f_4	22.02	21.88
f_5	27.32	24.64

A.4 MATERIALS

The material for piping and equipment pressure parts is in accordance with the applicable design code and the supplementary requirements of the project design specifications.

A.4.1 Brittle Fracture Control for Ferritic Steels

The fracture or notch toughness properties and the operating temperature of ferritic materials in systems which form the reactor coolant boundary (Group I) are controlled to ensure adequate toughness when the system is pressurized to more than 20 percent of the design pressure. Such assurance is provided by maintaining the material service temperature at least 60°F above the NDT temperature. Further requirements are:

1. For the reactor vessel NDT and postulated shift in NDT due to neutron embrittlement over the life of the plant, see Section 4.2.5.

2. Ferritic steel piping that forms the reactor coolant boundary (Group I) is tested by the Charpy V-notch impact test (ASTM A-370) or drop weight test (ASTM E-208). Such tests are not required for: bolting, with a nominal size 1 in and smaller, including nuts; materials whose section thickness is 1/2 in and less; piping, valves, and fittings whose nominal inlet pipe size is only 6 inches in diameter and less, regardless of thickness; consumable insert material.

3. Impact testing is not required on components or piping within the reactor coolant boundary having a minimum service temperature of 250°F or more when pressurized at more than 20 percent of design pressure. For example, the main steam line is excluded from the brittle fracture test requirement since the steam temperature will exceed 250°F when the steam line pressure is at 20 percent of the design pressure.

4. Impact testing is used to determine that the material and weld metal will meet brittle fracture requirements at test temperature. The acceptance standards are in accordance with Table N-421 of the ASME Boiler and Pressure Vessel Code, Section III, for the minimum service temperature.

A.4.2 Furnace-Sensitized Stainless Steel Materials

An effort has been made to minimize furnace-sensitized austenitic stainless steel materials in the reactor pressure vessel, piping, and pressure retaining components in the critical systems. Austenitic stainless steel is considered to be furnaced-sensitized if it has been heated by other than welding within the range of 800°F to 1,800°F, regardless of the subsequent cooling rate.

Nitrogen addition of not less than 0.060 weight percent for recirculation piping for the purpose of enhancing the strength of the 316 stainless steel with maximum carbon content of 0.02 weight percent was employed. This material is commonly referred to as 316 nuclear grade (NG).

A.4.3 Mitigation of Intergranular Stress Corrosion Cracking

Operating experience has shown that the heat-affected zone of types 304 and 316 stainless steel is susceptible to intergranular stress corrosion cracking (IGSCC) in the BWR coolant environment. This susceptibility increases for pipe runs containing stagnant or low-velocity fluid, high stresses, and high temperatures. The low-carbon stainless steel grades have been found to be highly resistant to this oxygen-assisted IGSCC. Therefore, to minimize the susceptibility to stress corrosion, the following pipe runs have been replaced by 316L stainless steel:

1. The core spray piping between reactor pressure vessel and inboard isolation valve.

2. Reactor water cleanup system suction piping between the connection to the RHRS and the drywell penetration.

3. The Induction Heating Stress Improvement (IHSI) Treatment Process was applied to certain welds in the Recirculation and RHR Shutdown Cooling Piping Systems during 1983 refueling outages/shutdowns of PBAPS Units 3 and 2. Results of this treatment and subsequent nondestructive examinations and/or repairs are outlined in licensee submittals to the USNRC on I.E. Bulletin No. 83-02.

In addition, the following pipe runs and components have been replaced with 316 NG stainless steel:

1. Recirculation loops A&B-risers, ring header and suction, and discharge header.

2. Stainless steel portions of the RHR piping between the recirculation piping and the drywell penetrations.

3. All reactor recirculation inlet safe ends.

4. Jet pump instrument seal penetration assemblies.

5. For Unit 2, portions of the RHR head spray piping.

6. Portions of the reactor water cleanup system outside containment.

Noble metals may also be injected to the vessel in support of reactor core component protection from SCC. Noble metals works in conjunction with hydrogen water chemistry to mitigate stress corrosion crack (SCC) initiation and existing SCC growth on the reactor pressure vessel wetted internal components and associated piping.

A.5 WELDING PROCEDURES AND PROCESSES

A.5.1 General

All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of Section IX of the ASME Boiler and Pressure Vessel Code for the materials to be welded. Qualification records, including the results of procedure and performance qualification tests and identification symbols assigned to each welder, are maintained.

A.5.2 Procedures and Processes

Welding procedures and processes are employed which produce welds of complete penetration, of complete fusion, and free of unacceptable defects. The finished surfaces of the weld (both root and crown) merge smoothly into the adjacent component surfaces. Weld layers are built up uniformly around the circumference and across the width of the joint. Weld starts and stops are staggered. Pressure containing and attachment welds are made by any of the following processes within the limitations described in this appendix:

1. Gas tungsten-arc welding with filler metal added.

2. Shielded metal-arc welding with low hydrogen coated electrodes.

3. Submerged-arc welding with multipass technique.

4. Gas metal-arc welding within the limitations in the project specifications.

5. Gas metal-arc welding using shorting-arc mode on carbon steel only.

A.5.3 Dissimilar Metal Welds

Transition pieces are used wherever possible when carbon steel components are welded to stainless steel piping. For piping systems with nominal wall thicknesses 3/4 in and greater, the carbon steel transition piece mating to stainless steel is clad, a minimum of 3/16 in after machining, with stainless steel weld metal (type 309) and stress relieved if required.

A.5.4 Electroslag Welding

The process of electroslag welding was used in the manufacture of the Peach Bottom Units 2 and 3 reactor vessels. The electroslag welding process variables, quality control procedures, and other technical details presented in Appendix F of the FSAR for the Dresden Nuclear Power Station Units 2 and 3 (AEC Docket Nos. 50-237 and 50-249) were applied to Peach Bottom.

A.6 FABRICATION AND ERECTION

A.6.1 Welded Construction

Piping and equipment pressure parts are assembled and erected by welding, except that flanges or screwed joints are used where necessary for maintenance.

Generally, piping 2 1/2 in and larger is butt welded (unless specifically evaluated) and piping 2 in and smaller is socket welded.

A.6.2 Branch Connections

For critical piping, branch connections are made by using commercially available standard welding fittings. In order to reduce the number of welds in the recirculation piping, extruded outlets and nonstandard welding fittings were used. Integrally reinforced fittings are used for branch connections where standard fittings are not available; however, these fittings are not used for branch connections with nominal sizes larger than one-half the nominal size of the main run. For piping where the branch is 2 in or smaller, welded-on forged fittings suitable for full penetration attachment welding are used. Branch connections are attached by full penetration welds.

For noncritical piping, standard fittings are used for the same size branches or one size reductions. Integrally reinforced fittings are used for two or more size reductions; however, stub-ins are permitted in certain special cases.

A.6.3 Bending

A section of pipe may be bent by either cold or hot methods within the following limitations:

1. Sections of pipe shall be selected so that thinning will not reduce the wall thickness below the minimum specified.

2. Hot bending of austenitic stainless steel is not permitted unless followed by solution annealing heat treatment.

3. The bend radius is limited to five times the nominal pipe diameter, unless otherwise specified.

A.6.4 Heat Treatment

A.6.4.1 Heat Treatment of Welds

Pre-heat and post-heat treatment of welds are in accordance with qualified welding procedures per the ASME Boiler and Pressure Vessel Code, Section IX.

A.6.4.2 Carbon and Low Alloy Steel

The heat treatment of carbon steel and low alloy steel piping components and equipment pressure parts is in accordance with requirements of the ASTM material specifications.

A.6.4.3 Austenitic Stainless Steel

Austenitic stainless steel piping components and equipment pressure parts are solution annealed at least once. Materials are annealed by heating to a temperature between 1,900 and 2,050°F, and held at this temperature for 1 hr/in of thickness, but not less than 1/2 hr, followed by rapid cooling to below 800°F.

Peach Bottom 2 and 3 recirculation piping and 12-inch risers and Peach Bottom 3 fittings are annealed by heating to a temperature between 1,900 and 2,000°F (metal temperature) and held at this temperature for a minimum of 15 minutes and a maximum time at temperature of 30 minutes when batch furnaces are used. When continuous furnaces are employed the piping and 12-inch risers are annealed by heating to a temperature between 1,900 and 2,050°F (metal temperature) for a time sufficient to solutionize the piping and also to meet all specification requirements. Regardless of which type of furnace is used, the piping and 12-inch risers are quenched in water to a temperature below 800°F within 3 minutes following the heating.

Peach Bottom 2 recirculation fittings (excluding risers) and subassemblies are solution annealed by heating to a temperature between 1,900 and 2,100°F (metal temperature) and held at this temperature for a minimum of 15 min/inch of thickness, but not less than 15 minutes regardless of thickness, followed by quenching in water. When continuous furnaces are employed, fittings are heat treated at a temperature between 1,900 and 2,150°F (metal temperature) for times sufficient to meet specification requirements. Regardless of which type is used, the fittings and subassemblies are quenched in water to a temperature below 800°F within 3 minutes following heating.

Austenitic stainless steel, which is susceptible to sensitization, is not heated in conjunction with any heat treatment or tempering of ferritic steel components.

The welding processes used for fabrication and assembly welds on austenitic stainless steel limit the welding electrode size, the welding current, and the welding voltage so that a maximum of 110,000 joules/in are introduced to the weld joint, or a maximum interpass temperature of 350°F is not exceeded during welding in order to minimize sensitization.

A.6.5 Defect Repair

A.6.5.1 General

Repair of base metal or weld metal defects is in accordance with the following requirements:

1. Surface defects, such as laps, scabs, slivers, seams, or tears, which do not encroach on minimum wall thickness, are removed by machining or grinding and are blended into the adjacent metal surfaces.

2. When defects or defect removal encroaches on minimum wall thickness, repairs are made by welding.

A.6.5.2 Repair Welding

Repair welding is performed employing welding procedures and welders qualified in accordance with Section IX of the ASME Boiler and Pressure Vessel Code.

A.6.5.3 Inspection of Repair Welds

Repair welds of a depth greater than 10 percent of the wall thickness must meet the inspection requirements for welds specified for the applicable classification of piping. Other inspection methods are not employed without approval.

A.6.5.4 Heat Treatment After Repair by Welding

Base material repair welds are heat treated as required by the applicable materials specifications. Weld repairs are heat treated as required, in accordance with the project specifications.

A.7 TESTING AND INSPECTION REQUIREMENTS

The specific paragraphs of codes that are referenced in this subsection reflect the requirements to which the plant was originally constructed. Additions and/or modifications to the plant will be in accordance with these original requirements or the requirements of the editions of the codes approved by the NRC and listed in the Code of Federal Regulations.

A.7.1 Radiography

A.7.1.1 Welds

Radiographic procedures and standards of acceptance for welds are in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division I, Paragraph UW-51; Section III, Paragraph N-624; or Section I, Paragraph PW-51.

A.7.1.2 Castings

Radiographic procedures for inspection of castings and casting repair welds are in accordance with ASTM E-94 and E-142, plus the following:

1. Radiographic film shall be of the high contrast, high definition, fine grain type: "Kodak AA," "Ansco Superay A," "Dupont 506," or approved equal.

2. All radiography is done with lead screens.

3. Film density in the area to be interpreted is within the range 1.7 to 3.5 as determined by either a film density strip or by a densitometer.

4. Film location and identification markers are permanently marked on weldments and castings in accordance with the manufacturer's standard shop practice.

Acceptance standards for casting and casting repair welds less than 2 in thick are in accordance with ASTM E-71 as follows:

Category	Severity Level (acceptable)
A	A2
B	B2
C	C2

D	None acceptable
E	None acceptable
F	None acceptable
G	None acceptable

Acceptance standards for casting and casting repair welds 2 in to less than 4 1/2 in thick shall be in accordance with ASTM E-186 as follows:

Category	Severity Level (acceptable)
A	A2
B	B2
C	Type 1 - CA2
	Type 2 - CB2
	Type 3 - CC2
D	None acceptable
E	None acceptable

Acceptable standards for casting and casting repair welds 4 1/2 in to 12 in thick shall be in accordance with ASTM E-280 as follows:

Category	Severity Level (acceptable)
A	A2
B	B2
C	Type 1 - CA2
	Type 2 - CB2
	Type 3 - CC2
D	None acceptable
E	None acceptable

A.7.2 Ultrasonic Examination

A.7.2.1 Forgings

Ultrasonic methods and acceptance standards for forgings are in accordance with ASTM A-388, "Ultrasonic Testing and Inspection of Heavy Steel Forgings," or the standard of acceptance is in accordance with Paragraph N-322.1 of the ASME Boiler and Pressure Vessel Code, Section III, as modified in the following paragraphs.

A.7.2.1.1 Normal Beam Testing - Acceptance Standards

The materials are considered unacceptable, unless repaired, based on the following test indications:

1. Indications of discontinuities in the material that produce a complete loss of back reflection not associated with the geometric configuration of the piece. (A complete loss of back reflection is assumed when the back reflection falls below 5 percent of full screen height.)

2. Traveling indications of discontinuities with 10 percent or more of the back reflection lost. (A traveling indication is defined as an indication which displays sweep movement of the oscilloscope pattern at a relatively constant amplitude as the search unit is moved along the part being examined.)

A.7.2.1.2 Angle Beam Testing - Acceptance Standards

Materials are unacceptable where oscilloscope indications exceed those produced by the reference standard. The reference standard notch depth is equal to 5 percent of the material thickness or 3/8 in, whichever is smaller.

A.7.2.2 Piping and Fittings

Ultrasonic methods and acceptance standards for seamless pipe are in accordance with paragraph N-324.3 of the ASME Boiler and Pressure Vessel Code, Section III. Plate for seam-welded piping and fittings is examined prior to fabrication in accordance with paragraph N-321.1 of the ASME Boiler and Pressure Vessel Code, Section III, or ASTM A-435 or E-273 or A-388.

Seamless fittings made from pipe are ultrasonically examined in accordance with paragraph N-324.3 of the ASME code, Section III, or ASTM E-213 prior to forming of the fitting. After final forming and any required heat treatment specified in the material specifications, seamless fittings will be magnetic particle or liquid penetrant examined on all accessible surfaces.

For replacement piping Class HB and HBC of Modifications 2106 and 5046 in Peach Bottom Atomic Power Station emergency service water system, ultrasonic methods and acceptance standards for all materials are in accordance with ASME Code 1980 Edition through Winter 1981 Addenda.

A.7.3 Liquid Penetrant Testing

Methods, techniques, and acceptance standards for liquid penetrant testing are in accordance with Section VIII, Appendix VIII, of the ASME Code or Section III, Paragraph N-627.

For replacement piping Class HB and HBC of Modifications 2106 and 5046 in Peach Bottom Atomic Power Station emergency service water system, methods, techniques, and acceptance standards for liquid penetrant testing are in accordance with the ASME Code 1980 Edition through Winter 1981 Addenda.

A.7.4 Magnetic Particle Testing

Methods, techniques, and acceptance standards for magnetic particle testing are in accordance with Section VIII, Appendix VI, of the ASME Code or Section III, Paragraph N-626.

For replacement piping Class HB and HBC of Modifications 2106 and 5046 in Peach Bottom Atomic Power Station emergency service water system, methods, techniques, and acceptance standards for magnetic particle testing are in accordance with the ASME Code 1980 Edition through Winter 1981 Addenda.

A.7.5 Ferrite Testing

Austenitic stainless steel welding materials are subject to delta ferrite tests in order to determine the presence of a controlled amount of ferrite. The range of ferrite shall be 8 to 25 percent (3 - 8 percent was valid prior to February 22, 1973) as determined by the Schaeffler Diagram or by the magnetic ferrite indicator.

The delta ferrite content of the Peach Bottom 2 recirculation pipe longitudinal seam filler metal in the undiluted weld pad was required to be a minimum of 5 FN (ferrite number) and a maximum of 15 FN. There are no longitudinal seam welds in Peach Bottom 3 (seamless) recirculation pipe.

The delta ferrite content of the filler metal for recirculation pipe subassemblies in the undiluted weld pad is a minimum of 8 FN and a maximum of 20 FN.

For recirculation and RHR shutdown cooling stainless steel piping field welds, the filler and consumable insert material shall have a delta ferrite content range between 8 FN and 20 FN.

A.7.6 Hydrostatic Testing

Hydrostatic testing of pipe and components is in accordance with ANSI B31.1 or the ASME Code, as appropriate.

A.8 CLEANING

A.8.1 Stainless Steel Piping

Austenitic stainless steel interior surfaces are mechanically cleaned, blast cleaned, or in a pickled condition and are free of scale. Blast cleaned surfaces are free of residual quantities of the cleaning medium. New recirculation and RHR piping has been mechanically polished and electropolished to minimize inservice crud build-up. The final cleaning operation consists of cleaning with demineralized water or process controlled water with chemical additive.

A.8.2 Carbon Steel and Low Alloy Piping

Carbon steel and low alloy piping steel surfaces are mechanically cleaned per PFI Standard ES-5, shot blast cleaned per Steel Structural Painting Council Standard SP-5, or pickled. After cleaning, piping assemblies are blown out with clean, oil-free air.

A.9 PIPING DESIGN REQUIREMENTS

A.9.1 General

Piping design requirements for the plant piping systems may be classified into the following schedules:

Schedule I summarizes the pipe material specifications and design requirements for piping systems in Group I and Group II. Note that Group I piping has additional design requirements above Group II.

Schedule II summarizes the pipe material specifications and design requirements for certain piping systems in Group III. These systems are:

> Main steam lines downstream of outer isolation valves to the first remotely operated stop valves, excluding the turbine stop valves.
>
> Feedwater lines upstream of outer isolation check valves to the first remotely operated stop valve in the feedwater pump discharge lines.

Schedule III summarizes the balance of plant piping.

The piping design requirements for the major components of the piping are described in general. No attempt has been made to completely describe each and every detailed component requirement in these piping systems. Various minor deviations from the basic design requirements, e.g., materials substitution, have been reviewed to ensure that such deviations meet the applicable codes and standards to assure the structural integrity of piping systems. However, no deviations are made for nondestructive testing required by codes (radiographic, magnetic particle, and liquid penetrant examinations).

SCHEDULE I

PIPING DESIGN REQUIREMENTS FOR GROUPS I AND II

1. MATERIAL SPECIFICATIONS

a. Carbon Steel Piping

Seamless pipe is ASTM A-106, Gr. B. or ASME SA-333, Gr. 6.

Seam-welded pipe is ASTM A-155, Gr. KC-70 (firebox quality) Class 1 or ASTM A-672, Gr. C-70 Class 22 (ASTM A-655 applies).

Socket-welding fittings are forged carbon steel ASTM A-105, Gr. II or ASTM A-105.

Butt-welding fittings are ASTM A-234, Gr. WPB, WPB-W, or WPC-W. Welded seams are 100 percent radiographed after forming operation, and either magnetic particle or liquid penetrant inspection is made on the final weld layer. Surfaces of fittings in the finished condition are examined by either magnetic particle or liquid penetrant method.

Replacement piping, Classes HB and HBC, of Modification 2106 and 5046 in Peach Bottom Atomic Power Station Emergency Service Water Systems contains the following material:

Seamless pipe is ASME SA-106, Grade B.

Socket-welding fittings, 2 inch and smaller, are forged carbon steel ASME SA-105.

Butt-welding fitting ASME SA-234, Grade WPB.

Carbon steel flanges are ANSI Standard forged to ASTM A-105, Gr. II or ASTM A-105 except for the replacement piping, Class HBC, of Modifications 2106 and 5046 in the Emergency Service Water Systems. The flanges for this replacement piping are carbon steel SA-105.

b. Stainless Steel Piping

The recirculation piping and RHR system contains the following material:

Seamless pipe is ASME SA-376, Gr. TP 316 (controlled chemistry), Class 1.

Seam-welded pipe is ASME SA-358, Gr. TP 316 (controlled chemistry), Class 1.

Forgings are ASME SA-182, Gr. 316 (controlled chemistry).

Fittings are ASME SA-182, GR. F 316; or ASME SA-403, GR. WP 316 or GR. WP 316W (controlled chemistry).

Piping spool piece, Class YSW, used in the ECW system common to both Units 2 and 3 for flow measurement (Mod 5110) meets the requirements of seam-welded ASTM B-673 (UNS N08925, 6% Molybdenum), Class 2, ANSI Code B31.1.0, Case 151. (The equivalent ASME material has been used as an acceptable alternative).

All other stainless steel piping is made using the materials identified below:

Seamless pipe is ASTM A-376, Gr. TP 304 or ASTM A-312, Gr. TP 304 or TP 316L.

Seam-welded pipe is ASTM A-358, Gr. TP 304 Class 1.

Socket-welding fittings, 2 in and smaller, are forged stainless steel ASTM A-182, Gr. F304 or F316L.

Butt-welding fittings are ASTM A-403, Gr. WP304, WP316L, or WP304-W. Welded seams are 100 percent radiographed after forming operations, and a liquid penetrant test is made on the final layer. Surfaces of fittings, 2 1/2 in and larger, are examined by liquid penetrant method.

Stainless steel flanges are ANSI Standard, forged to ASTM A-182, Gr. F304 or F316, or F316L. Surfaces of stainless steel flanges, 2 1/2 in. and larger, are examined by either magnetic particle or liquid penetrant method.

c. Low Alloy Piping

Seamless pipe is ASME SA-335, Gr. P-11.
Fittings are ASME SA-234, Gr. WP-11.
Flanges are ASME SA-182, Gr. F-11.

Flange material on the piping spool piece, Class YSW, used in the ECW system common to both Units 2 and 3 for flow measurements (Mod 5110) meets the requirements of ASTM B-462 (UNS N08925, 6% Molybdenum) per ANSI B31.1, Code Case 151. (The equivalent ASME material has been used as an acceptable alternative).

2. INSPECTION

a. Butt welds for 2 1/2 in and larger pipe joints in the shop and field are 100 percent radiographed.(*)(***)

b. The final layer of pressure welds in the shop and field are examined by either magnetic particle or liquid penetrant method. This requirement covers all pipe sizes for butt welds.(*)

c. Pressure-retaining forgings over 4 in in thickness are examined by ultrasonic method plus either liquid penetrant or magnetic particle methods.(*)

d. Pressure-retaining parts of castings for fittings and valves 4 in and larger in nominal pipe sizes are radiographed.(*)(**)

e. Valve butt weld end preparations for field welding are examined by either magnetic particle or liquid penetrant method.(*)

f. Valves are shop hydrostatic tested in accordance with the ANSI B16.5 or MSS SP-66 requirements.(*)

NOTE * : Additions and/or modifications to the plant will be in accordance with the original design requirements as stated or the requirements of the editions of the codes approved by the NRC and listed in the Code of Federal Regulations.

NOTE **: Pressure retaining parts of valves MO-2-12-68 and MO-3-12-68 were not radiographed. They were determined to be satisfactory for their intended service by analysis.

Note ***: Radiographic examination not required for HPSW and ESW piping welds.

3. FABRICATION REQUIREMENTS

Fabrication requirements are in accordance with the project design requirements for critical systems.

4. SPECIAL REQUIREMENTS FOR GROUP I SYSTEMS

a. Brittle fracture control for ferritic steel is required for the following portions of Group I systems:

   Feedwater System - from reactor pressure vessel to the outer isolation check valve (valve 6-96) and startup recirculation line isolation valves 38 A and 38 B.

   HPCI Line - from feedwater line to testable check valve (valve 23-18).

   Core Spray - isolation valves 14-14A and 14-14B.
   For Unit 3: body to bonnet bolting of testable check valves AO-14-13A and AO-14-13B.

   RCICS - from feedwater line to testable check valve (valve 13-22).

   RHRS shutdown cooling isolation valves (10-17, 10-18, and 10-88), LPCI valves (10-81A and 10-81B).

   Cleanup System Return - from feedwater line to check valve (valve 12-62).

   Control Rod Hydraulic System Return Line - from valve 3-110 to 3-114.

b. Pressure-retaining bolting greater than 1 in is examined by either magnetic particle or liquid penetrant method.

c. Pipe and fittings, 2 1/2 in and larger pipe sizes, in Group I systems are 100 percent volumetrically examined per Section III of the ASME code.

SCHEDULE II

PIPING DESIGN REQUIREMENTS FOR GROUP III

1. MATERIAL SPECIFICATIONS

    a. Carbon Steel Piping

    Seamless pipe is ASTM A-106, Gr. B.

    Seam-welded pipe is ASTM A-155, Gr. KC-70 (firebox quality) Class 1 or ASTM A-672, Gr. C-70 Class 22 (ASTM A-655 applies).

    Socket-welding fittings are forged carbon steel ASTM A-105, Gr. II or ASTM A-105.

    Butt-welding fittings are ASTM A-234, Gr. WPB, WPB-W, or WPC-W. Welded seams are 100 percent radiographed after forming operations, and magnetic particle inspection is made on the final weld layer.

    Flanges are ANSI Standard, forged carbon steel to ASTM A-105, Gr. II or ASTM A-105.

    b. Stainless Steel Piping

    Not applicable

    c. Low Alloy Piping

    Seamless pipe is ASME SA-335, Gr.P-11
    Fittings are ASME SA-234, Gr. WP-11
    Flanges are ASME SA-182, Gr. F-11

2. INSPECTION

    a. Butt welds for 2 1/2 in and larger pipe joints in the shop and field are 100 percent radiographed.

    b. The final layer of pressure welds are examined by either magnetic particle or liquid penetrant method.

    c. Pressure-retaining parts of castings for fittings and valves, 4 in and larger, are radiographed.

    d. Valve butt weld end preparations for field welding are examined by either magnetic particle or liquid penetrant method.

e. Valves are shop hydrostatic tested in accordance with ANSI B16.5 or MSS SP-66 requirements.

3. FABRICATION REQUIREMENTS

Fabrication requirements are in accordance with the project design specifications for critical systems.

SCHEDULE III

PIPING DESIGN REQUIREMENTS FOR BALANCE OF PLANT

1. MATERIAL SPECIFICATIONS (Partial List)

   a. Carbon Steel Piping

      Seamless pipe is ASTM A-106, Gr. B or ASTM A-53, Gr. A or B.

      Seam-welded pipe is ASTM A-155, Gr. KC-70 Class 2 or Gr. C-55 Class 2 or ASTM A-672, Gr. C-70 Class 20 or Gr. A-55 Class 20.

      Fittings are ASTM A-234, Gr. WPB, WPB-W, or WPC-W or ASTM A-105, Gr. II or ASTM A-105.

   b. Stainless Steel Piping

      Seamless pipe is ASTM A-376, Gr. TP304 or ASTM A-312, Gr. TP304, TP304L, or TP316L.

      Seam-welded pipe is ASTM A-312, Gr. TP304 or Gr. TP304L plus eddy current test or ASTM A-358, Gr. TP304 or Gr. TP304L Class 1.

      Fittings are ASTM A-403, Gr. WP304, WP304L, WP316L, WP304L-W or ASTM A-182, Gr. F304, F304L, or F316L.

   c. Low Alloy Piping

      Seamless pipe is ASTM A-335, Gr. P11 or P5.

      Seam-welded pipe is ASTM A-155, Gr. 1 1/4 CR Class 2 or ASTM A-691, Gr. 1 1/4 CR Class 20.

      Fittings are ASTM A-234, Gr. WP11, WP11-W, WP5, or WP5-W or ASTM A-182, Gr. F11 or F5.

2. INSPECTION REQUIREMENTS

Inspections are in accordance with material specifications or the requirements of ANSI B31.1.

Inspection of valves conforms to ANSI B31.1 requirements.

3. FABRICATION REQUIREMENTS

Fabrication requirements conform to the project design specifications. Those systems requiring thermal stress analysis and special fabrication techniques are identified as Schedule IIIc, the "c" denoting a critical system.

TABLE A.9.1

SUMMARY CLASSIFICATION OF PIPING SYSTEMS

Group I (Primary Pressure Boundary)	Design Schedule	Seismic Class
Recirculation System	I	I
Systems from Reactor Pressure Vessel to Outer Isolation Valve:		
Feedwater Lines	I	I
Main Steam Lines	I	I
Main Steam Drain Lines	I	I
Steam to HPCI	I	I
Steam to RCIC	I	I
Core Spray	I	I
RHR:		
Shutdown Supply	I	I
LPCI	I	I
Reactor Water Cleanup Supply & Return	I	I
Standby Liquid Control	I	I
Reactor Vessel Instrumentation	I	I
Sample Lines	I	I
Small Lines, 2-in size and under:		
To and including first shutoff valve	I	I
Beyond shutoff valve	III	-

TABLE A.9.1 (Continued)

Group I (Continued)	Design Schedule	Seismic Class
CRDS:		
Insert and Withdraw Lines	I	I
Scram Discharge Volume	I	I

TABLE A.9.1 (Continued)

Group II (Core Cooling and Containment Extension)	Design Schedule	Seismic Class
RHR:		
LPCI	I	I
Containment Cooling and Spray (excluding spargers)	I	I
Shutdown Cooling	I	I
Reactor Head Spray	I	I
Core Spray	I	I
HPCI:		
Steam Supply and Exhaust	I	I
Suction	I	I
Discharge	I	I
RCIC:		
Steam Supply and Exhaust	I	I
Suction	I	I
Discharge	I	I
Reactor Water Cleanup System:		
High-Pressure System Only	I	-
Standby Liquid Control System:		
Excluding system test components	I	I
Essential instrument lines for Standby Core Cooling Systems	I	I
Inerting System:		
From Containment to the Second Isolation Valve	I	I

TABLE A.9.1 (Continued)

Group II (Continued)	Design Schedule	Seismic Class
Containment Ventilation System:		
From Containment to the Second Isolation Valve	I	I
Special Auxiliary Systems:		
High Pressure Service Water	I	I
Emergency Service Water	I	I
Emergency Cooling Water	I	I

TABLE A.9.1 (Continued)

Group III (Balance of Plant Systems)	Design Schedule	Seismic Class
Main Steam:		
Downstream of Outer Isolation Valves to Main Stop Valve	II	(a)
Turbine Steam Bypass	II	--
Feedwater:		
Upstream of Outer Isolation Check Valves to First Remotely Operated Valves	II	--
Feed Pump Recirc.	IIIc*	--
Control Rod Hydraulic System:		
Suction line to Pump	III	--
Condensate Supply to CSCS Pumps	III	I
Off-Gas System:		
Air Ejector to Holdup Pipe	IIIc**	--
Holdup Pipe	IIIc**	--
Holdup Pipe to Off-Gas Filters	IIIc**	--
Downstream of Off-Gas Filter to Stack	III	--
Inerting System:		
From the Second Isolation Valves to Storage Tank	III	--
Standby Liquid Control System:		
System Test Components	IIIc	--

* All welds 100 percent radiographed

** Unit 2 and 3 - All orginal welds radiographed. New piping welds for the modification to an ambient charcoal delay system were magnetic particle tested on the final passes per ANSI B31.1 - 1980. The holdup pipe manway welds were magnetic particle tested on internal and external finished surfaces and the root after back-gouging in accordance with ASME VIII-1980.

TABLE A.9.1 (Continued)

Group III (Balance of Plant Systems)	Design Schedule	Seismic Class
(a) Will meet the stress requirements of Seismic Class I Piping as defined in Appendix A. (Ref: Appendix C.5.3.3.2)		
Reactor Water Cleanup System:		
Blowdown to Condenser and Radwaste	IIIc	--
Low Pressure System	IIIc	--
RCIC:		
Suction from Cond. Storage Tank	IIIc	I
Radwaste:		
Liquid Process	III	--
Fuel Pool Cooling and Cleanup	III	--
From RHR X-tie to Fuel Pool	III	I
From Skimmer Surge Tank to RHR X-tie	III	-
Extraction Steam	IIIc	--
Condensate:		
Pump Suction	IIIc	--
Pump Discharge	IIIc	--
Condensate Service	III	--
Auxiliary Steam	IIIc	--
Plant Heating	III	--
Service Water:		
To and from RBCW heat exchanger including first non-check isolation valve	III	I
All other service water	III	--
Reactor Building Cooling Water Piping	III	--

TABLE A.9.1 (Continued)

Group III (Balance of Plant Systems)	Design Schedule	Seismic Class
Reactor Building Cooling Water heat exchangers	III	I
Turbine Building Cooling Water	III	--
Instrument Air	III	--
Service Air	III	--
Fire Protection System	III	--
Domestic Water	III	--
Lube Oil	III	--
Fuel Oil	III	--
Chemicals	III	--
Chilled Water System	III	--
Makeup Water System	III	--

TABLE A.9.2

SUMMARY OF EQUIPMENT DESIGN CODES

Group I

Reactor Pressure Vessel	ASME III, C1.A
Recirc. Pumps	See Par. A.3.3
Recirculation Valves	MSS-SP-66
Safety Valves, RV	ASME III
Relief Valves, RV	ASME III
Main Steam Valves	B16.5
Recirc. Venturi Flow Element (Unit 2)	ASME III
Recirc. Flow Nozzle (Unit 3)	B31.1
Steam Flow Nozzle	B31.1
Feedwater Isolation Check Valves	MSS-SP-66
Isolation Valves: Except Listed Below:	B16.5
MO-10-25, AO-46	MSS-SP-66
AO-13-22, AO-23-18, AO-14-13	MSS-SP-66 (Unit 2) ASME III, Class 1, Less N-Stamp (Unit 3)
MO-14-12	MSS-SP-66

TABLE A.9.2

SUMMARY OF EQUIPMENT DESIGN CODES

Group II

Containment Vessel	ASME III, Cl. B
Cleanup System:	
Non-Regenerative Heat Exchanger	Shell: ASME VIII Tube: ASME III, Cl. C
Regenerative Heat Exchanger	ASME III, Cl. C
Filter Demineralizer	ASME III, Cl. C
HPCI:	
Turbine	Per design specification
Pump	See Par. A.3.3
RCIC:	
Turbine	Per design specification
Pump	See Par. A.3.3
Core Spray:	
Pumps	See Par. A.3.3
RHR:	
Pump	See Par. A.3.3
Heat Exchanger	Shell: ASME III, Cl. C Tube: ASME VIII
Standby Liquid Control:	
Pump	See Par. A.3.3
Containment Vacuum Relief Valves and Drywell Vacuum Breakers	B31.1 & ASME Sec. III, Cl. B

TABLE A.9.2

SUMMARY OF EQUIPMENT DESIGN CODES

Group III (Partial List)

Radwaste:	
Waste Filter	ASME III, Cl. C
Floor Drain Filter	ASME III, Cl. C
Waste Demineralizer	ASME III, Cl. C
Fuel Pool Heat Exchangers	ASME VIII, Div. I
Reactor Building Cooling Water Heat Exchangers	ASME VIII, Div. I
Off-Gas Filter Vessels	ASME VIII, Div. I
Off-Gas Guard Bed	ASME VIII, Div. I
Air Compressor After Coolers	ASME VIII, Div. I
Condensate Demineralizer Vessels	ASME VIII, Div. I
Makeup Demineralizer Vessels	ASME VIII, Div. I
Auxiliary Boilers	ASME I
Auxiliary Boiler Blowoff Tank	ASME VIII, Div. I
Auxiliary Boiler Deaerator	ASME VIII, Div. I
Compressed Air Receivers	ASME VIII, Div. I
Moisture Separator Tanks	ASME VIII, Div. I
Moisture Separator Drain Tanks	ASME VIII, Div. I

A.10 HIGH ENERGY PIPE BREAK OUTSIDE THE PRIMARY CONTAINMENT

A.10.1 Introduction

Subsection A.10 is in response to the U.S. AEC/NRC's letter to the licensee dated December 15, 1972 on the subject of high energy piping system failure outside the primary containment. The licensee conducted an analysis to substantiate that the design of PBAPS Units 2 and 3 is adequate to withstand the effects of a postulated rupture in a high energy fluid piping system outside the primary containment, including main steam or feedwater piping, and to provide the AEC/NRC Staff with the requested information. The analysis was conducted according to the criteria presented in paragraph A.10.2.

A meeting was held between the licensee and the AEC/NRC Staff on January 19, 1973 to discuss qualitatively the effects of postulated high energy pipe failure outside the primary containment. In that meeting the Staff confirmed that high energy piping to be considered were those pipes containing fluid above 200°F <u>and</u> 275 psig. It was also acknowledged that the preliminary analysis indicated that PBAPS Units 2 and 3 had no major design deficiencies with respect to high energy pipe failure outside the containment. Paragraphs A.10.2 through A.10.11 present a detailed discussion and definitive analysis as committed in the January 19, 1973 meeting. Although the recirculating piping is entirely within primary containment and therefore not part of the analysis requested by the AEC/NRC, a discussion of design criteria for the Recirculating System restraints is included in Paragraph A.10.7.

A.10.2 Criteria for Consideration of the Effects of a Piping System Break Outside Containment

1. The systems (or portions of systems) for which protection against pipe whip is required are identified. Protection from pipe whip need not be provided if any of the following conditions exist:

    a. Both of the following piping system conditions are met:

        (1) The service temperature is less than 200°F; and

        (2) The design pressure is 275 psig or less; or

    b. The piping is physically separated (or isolated) from structures, systems, or components important to safety by protective barriers, or restrained from whipping by plant design features, such as concrete encasement; or

c. Following a single break, the unrestrained pipe movement of either end of the ruptured pipe in any possible direction about a plastic hinge formed at the nearest pipe whip restraint cannot impact any structure, system, or component important to safety; or

d. The internal energy level[(1)] associated with the whipping pipe can be demonstrated to be insufficient to impair the safety function of any structure, system, or component to an unacceptable level.

2. Where pipes carrying high energy fluid are routed in the vicinity of structures and systems necessary for safe shutdown of the nuclear plant, supplemental protection of those structures and systems is provided to cope with the environmental effects (including the effects of jet impingement) of a single postulated open crack at the most adverse location(s) with regard to those essential structures and systems, the length of the crack being chosen not to exceed the critical crack size. The critical crack size is taken to be one-half the pipe diameter in length and one-half the wall thickness in width.

3. The criteria used to determine the pipe break orientation are:

   a. Longitudinal[(2)] breaks in piping runs and branch runs, 4 in nominal pipe size and larger; and/or

   b. Circumferential[(3)] breaks in piping runs and branch runs exceeding 1 in nominal pipe size.

A.10.3 <u>Summary of Assumptions</u>

1. The assumed modes of pipe failure are as follows:

See Notes at end of section.

a. Circumferential breaks are those breaks which are perpendicular to the pipe axis. The break area is taken to be the same as the internal cross-sectional area of the pipe unless the pipe is adequately restrained to prevent relative motion of the two sides of the break. Dynamic forces resulting from such breaks are assumed to separate the piping axially and to cause whipping in any direction normal to the pipe axis, unless the pipe is adequately restrained to prevent such motion.

b. Longitudinal breaks are those breaks which are parallel to the pipe axis. The break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis, unless the pipe is adequately restrained to prevent such motion.

c. Critical size cracks are those breaks which are taken to be one-half the pipe diameter in length and one-half the wall thickness in width.

2. Circumferential and longitudinal breaks have been assumed to occur at the following locations in piping run or branch runs (other than recirculation piping):

a. Terminal ends.

b. Any intermediate locations between terminal ends where either the circumferential or longitudinal stresses derived on an elastically calculated basis under the loadings associated with seismic events and operational plant conditions exceed $0.8(S_h + S_A)$[4] or the expansion stresses exceed $0.8\ S_A$.

c. Two intermediate locations in addition to those determined by above, selected on the basis of highest stress determined by taking the sum of normal operation stresses and seismic stresses.

3. Circumferential and longitudinal breaks have been assumed to occur at the following locations in the recirculation piping.

a. Terminal ends.

b. Intermediate locations where the maximum stress range between any two loads sets (including zero load set) according to subarticle NB-3600, ASME Code Section III, for Service Level A and B including an operating basis earthquake (OBE) event transient as calculated by Equation 10 of the Code and either Equation (12) or (13) exceeds 2.4 S_m.

c. Intermediate locations where the cumulative usage factor exceeds 0.1.

d. If two or more intermediate locations cannot be determined by (b) or (c), a total of two intermediate locations as a minimum is identified based on highest stress calculated by Equation (10).

4. A critical size crack has been postulated to occur at any location along the length and at any point around the circumference of a pipe carrying high energy fluid.

5. The postulated break has been conservatively assumed to occur during normal steady state operating conditions at rated power.

6. Loss of offsite AC power has been assumed to occur concurrently with the postulated failure of the high energy pipe. This is, in general, a conservative assumption. However, in some cases loss of normal AC power actually mitigates the effects of the postulated pipe break, e.g., failure in the feedwater system. In those cases it has been conservatively assumed that offsite power is not lost.

7. No other accident has been assumed to occur concurrently with the pipe failure outside the containment.

8. A single failure of an active component has been assumed to occur in analyzing the accident and the ability to safely shut down the plant.

A.10.4 General Approach

The analysis has been conducted using the following general procedure:

1. The high energy piping systems were identified using the criteria that the service temperature is greater than 200°F and the design pressure is greater than 275 psig. The systems meeting those criteria are:

a. Main steam

b. Feedwater

c. HPCI steam

d. RCIC steam

e. Reactor water cleanup

f. High energy sampling and instrument sensing lines

g. Reactor recirculation system.

2. The systems required for safe shutdown of the reactor for the postulated pipe failure of each of the high energy systems were identified based on the analyses presented in Appendix G. By verifying that these systems are maintained operational in the event of the postulated failure of the piping systems, it is assured that the plant can be safely shut down and maintained in a safe shutdown condition. The systems required for safe shutdown of the reactor for each line rupture are presented in Tables A.10.1 through A.10.5.

3. The physical arrangement of each high energy piping system was investigated to determine the potential effects of pipe whip or jet impingement on structures, systems, and components required for safe shutdown of the plant.

4. The electrical cables that could be broken by either pipe whip or jet impingement were identified. It was conservatively assumed that if a high energy pipe was routed in the same space as the conduit with no structure between them, the cable would be broken by the postulated failure of that high energy line. Each cable that could be broken was tabulated and the effects of its loss analyzed with respect to the ability to safely shut down from that high energy pipe failure. The loss of required redundancy was considered. The results of that study have been incorporated in the analyses of shutdown capability that are included in the study of each high energy system.

5. The effects of steam pressurization of the compartments that could be pressurized by failure of any of the identified high energy lines were investigated.

6. The environmental effects of postulated ruptures of any of the high energy lines were evaluated.

7. A site study was made of each of the areas of concern to verify that no other potential problems exist. Vent areas between compartments were quantitatively checked.

8. For those problem areas identified by the above process, alternative corrective measures were considered and a method of correction decided upon.

9. The single failure of an active component and the loss of offsite AC power assumptions were applied in the Appendix G analyses described in item 2. The specific line blowdown analyses used to determine the pressure and temperature transients utilize the maximum closure times for the isolation valves as specified in UFSAR Table 7.3.1, without a time delay associated with a loss of offsite power.

A.10.5 General Comments Concerning Inherent Safety Features of Peach Bottom Atomic Power Station Units 2 and 3

The general arrangement of the plant is shown in Figure 12.1.1 and Drawings M-2 through M-7. The seismic classification of the various structures and systems is given in Appendix C.

Safeguard equipment is located within seismic Class I structures with redundant equipment being physically separated by distance as well as seismic Class I walls. Each of the engineered safeguard equipment rooms has been provided with watertight doors and is otherwise protected as required from flooding to Elevation 111 ft.

The control room complex, consisting of the battery rooms, switchgear rooms, cable spreading rooms, and the main control room, is centrally located in a seismic Class I structure. Using the criteria previously outlined, it has been determined that no postulated high energy pipe failure can cause damage from pipe whip, jet impingement, external overpressurization, or environmental conditions to the control room complex.

The diesel generators which provide the onsite supply of emergency AC power are housed in a seismic Class I building that is physically remote from the reactor and turbine buildings. There are no high energy lines in the vicinity of the diesel generator building. The power cables that connect the diesel generators to the safeguard loads that they supply are routed below ground from the diesel generator building to the turbine building and are routed below the turbine building floor slab in a seismic Class I structure to the emergency switchgear rooms located within the control room complex. No postulated high energy pipe failure can cause damage from pipe whip, jet impingement, or environmental conditions to the onsite emergency AC power supply.

All systems and components in the turbine building that are required for safe shutdown following a postulated high energy pipe failure are located in the seismic Class I pipe tunnel area below grade level (Elevation 102 ft 0 in) (see Figure 12.1.1 and Drawing M-2). The slab that separates the tunnel area from the turbine building above is seismic Class I. The only high energy piping systems located within the turbine building are the main steam and feedwater systems, both of which are above Elevation 150 ft 0 in. The main steam and feedwater piping are separated from the tunnel by a seismic Class I structure. Therefore, the effects of postulated failure of the main steam or feedwater piping in the turbine building can be neglected. The postulated failure of a high energy pipe occurring in the turbine building does not prevent safe shutdown of the reactor.

Information on pressure integrity of piping, applicable codes, specifications, and piping classification is presented in paragraph A.1.1. The quality control and inspection programs that have been utilized for piping systems outside the containment are specified in Appendix D.

The following general comments apply to the design of PBAPS Units 2 and 3 relating to the environmental effects of a postulated high energy pipe failure (also see subsection 7.19, "Class 1E Equipment Environmental Qualification"):

1. A special type of cable was used throughout PBAPS Units 2 and 3 for control and low voltage (<600 V) applications. Representative samples of the cable have been tested in a steam environment at 146°C (295°F) for a 12-hr duration without failure.

2. Safety-related high voltage power cabling is enclosed in metallic conduit.

3. The valve motor operators used outside the primary containment are Limitorque operators similar to those used inside the primary containment. The testing of the Limitorque operators used within the primary containment under high temperature saturated steam conditions is documented in Section J.3.4.4. The tests conducted on the primary containment motor operators included tests at temperatures equal to the design rating of the motor insulation (Class H) which is 180°C

(356°F) for 100 hr and immersion in a saturated steam environment at pressures of 15 psig and greater for a period of 6 days. The tests showed reliable operation under those severe conditions. From a steam-high temperature standpoint the only significant difference between the operators used within the primary containment and those used outside is the rating of the motor insulation (Class H versus Class B or better). Class B insulation has a rating of 130°C (266°F). It is therefore concluded that as long as the temperature of the saturated steam environment remains below the rating of the motor insulation, the motor will operate satisfactorily for short periods of such adverse conditions. Under the worst environmental conditions that could possibly result from the postulated pipe failure, the pressure-temperature relationship will be well below the rating of the motor insulation. Furthermore, the adverse conditions will be short term due to the isolation of the affected high energy line. It is therefore concluded that the motor operators outside the primary containment will operate reliably as needed to safely shut down and maintain the reactor in a safe shutdown condition.

4. Safeguard equipment is protected from the direct and environmental effects of the postulated pipe failure since it is housed in separate compartments as mentioned above. No high energy line is routed through a safeguard equipment room unrelated to the high energy line.

5. The criteria for routing of electrical cabling are presented in subsection 8.1. Factors such as physical separation and encasement of cabling in conduit further mitigate the effects of the postulated pipe failure on the ability of the plant to safely shut down.

6. There are no safeguard instrument panels located in compartments through which high energy piping is routed, nor are there direct line-of-sight paths of communication (doors, wall penetrations, etc) between high energy pipes and safeguard panels. Therefore, the direct effects of pipe whip and jet impingement on such panels due to the postulated pipe failures can be neglected.

7. The ventilation supply to the control room is on the west side of the building, i.e., the side away from the turbine building (Drawings M-4). As such, it is highly

unlikely that steam from a high energy pipe failure would be drawn into the control room.

A.10.6 Analytical Techniques

A.10.6.1 Structural Loading

Structures that are subjected to jet impingement due to a high energy line break outside primary containment have been designed for the loads shown in Appendix C.

A.10.6.2 Jet Impingement Loading

In summary, the following formulas were used to evaluate the various categories of jet impingement loading:

1. Jet impingement from a circumferential high energy pipe failure as a function of distance from the break (x):

$$P_x = \frac{K_j\ (Po-Pa)}{(1 + \frac{2x\ \tan \phi^2)}{D}}$$

where:

K_j = thrust coefficient

K_j = 1.26 for steam or two-phase flow

= 1.9 for subcooled water such as feedwater or cleanup flow

P_o = pressure in pipe just upstream of break (psi)

P_a = ambient pressure outside of pipe prior to break (psi)

ϕ = half angle of jet dispersion

= 10° (tan = 0.17633)

D = pipe inside diameter (in.)

X = distance from break (in.)

P_x = pressure of jet as a function of distance

2. Jet impingement from a longitudinal high energy pipe failure as a function of distance from the break (x):

$$P_x = \frac{K_j\ (P_o - P_a)}{\left(1 + \frac{2x}{\ell} \tan\phi\right)\left(1 + \frac{2x}{w} \tan\phi\right)}$$

   where the terms are as defined in item 1 above and:

   ℓ = crack length (in.)

   w = crack width (in.)

3. Jet impingement from a critical crack failure in a high energy pipe as a function of distance from the break (x):

   Same as for longitudinal failure. It has been assumed that jet impingement forces are developed in zero time and that any changes in the forces as a function of time are negligible. Jet impingement is assumed to cease when the high energy line is isolated.

A.10.6.3 <u>Factors to Account for Geometrical Shape of Jet Impingement Target</u>

1. For flat or concave surfaces the effective area of jet interaction was taken to be equal to the projected area of the target normal to the jet or the expanded area of the jet normal to the target, whichever was smaller.

2. For circular targets, such as pipes, the effective area of interaction was taken to be 0.6 of the cross-sectional area of the target normal to the jet or the expanded area of the jet normal to the target, whichever was smaller. Therefore, the force on a circular target is given by:

   $F = 0.6\ P_x A_T$

   where:

   P_x = jet impingement pressure as calculated by the appropriate formula in paragraph A.10.6.2

   A_T = cross-sectional area of the target normal to the jet

A.10.6.4 Jet Thrust Forces

The reaction forces acting upon the pipe caused by the momentum change of fluid flowing through the break were calculated using the following relationship:

$$F_j = K_j A_b (P_o - P_a)$$

where:

F_j = jet reaction force (lb)

A_b = area of break (sq in)

K_j, P_o, P_a as defined in paragraph A.10.6.2

A.10.6.5 Compartment Pressure Analysis Model

A postulated high energy pipe rupture results in the expulsion of high energy steam or a steam and water mixture out of the ruptured pipe into the surrounding compartment. As the pressure builds up within the compartment, the steam-air-water mixture flows through openings to relieve the resultant pressure. The equilibrium pressure achieved depends on the number and shape of the openings between the compartments, the volume of each compartment, and the blowdown rate from the broken pipe. Differential pressure analyses were made to calculate the pressure responses of two compartments during the postulated event. The calculations include mass and energy balances of the two-phase, two-component, steam-air-water mixture as high energy fluid enters the compartments during the event and through the various compartment vent openings. There is no provision in the calculations for heat transfer since heat transfer would have a negligible effect on compartment pressures for the short time following the rupture within which peak differential pressure occurs.

The analyses conducted yielded pressure versus time relationships which were used to determine if the structures surrounding the affected compartments of vital equipment within the compartment are capable of withstanding the pressurization. If increased vent area was indicated, the required vent area was determined by rerunning the analysis.

A.10.7 Detailed System Analysis

A.10.7.1 Main Steam System

Pipe failure in the main steam system outside the primary containment has been discussed in paragraph 14.6.5 and Appendix G.

The design of the main steam lines, flow restrictors, and isolation valves is presented in Section 4.0.

The main steam system piping configuration is shown in Figure A.10.1. Although the entire main steam system is considered high energy piping (>200°F and >275 psig), the only sections of the main steam piping for which protection against pipe whip is required are those portions lying within the reactor building. All main steam piping within the turbine building is physically separated from structures, systems, and components important to reactor safety by both distance and structural walls. No main steam line failure in the turbine building prevents the safe shutdown of the plant.

The main steam lines automatically isolate in the event of a postulated failure. A break is sensed by high steam line flow, high temperature in the pipe tunnel, or low reactor water level. Descriptions of these automatic isolation systems appear in subsection 7.3.

With respect to pipe whip, the postulated main steam line break locations are the terminal ends and the two highest stressed intermediate points, there being no points where the stress levels described in item A.10.3.2.b above are exceeded. Specifically, these locations are:

1. The connections at the downstream side of the outboard main steam isolation valves.

2. The two intermediate high stress points on each line as identified in Figure A.10.1.

3. The connections at the turbine stop valves.

4. At any single location in the reactor feed pump steam supply piping that connects to main steam line A (Figure A.10.1).

Of the above-listed postulated break locations, only the first require protection against pipe whip since those are the only postulated break points that are within the reactor building. It is assumed that at those locations a longitudinal or a circumferential break could occur at the junction of the steam pipe to the isolation valve. From Figure A.10.2 it can be seen that immediately downstream of the isolation valve there is a 90-deg elbow. The longitudinal failure is assumed to occur in that 90-deg elbow starting at the junction of the pipe to the isolation valve and extending two pipe diameters from that point through the elbow parallel to the axis of the pipe.

Protection against pipe whip from a postulated break at the connection of the main steam lines to the outboard isolation valves is currently provided as follows:

1. The main steam lines in the pipe tunnel are restrained at several locations. The design criteria used for these restraints are presented in Appendix C and their configuration is shown in Figure A.10.3.

2. Although the above-mentioned restraints are sufficient to prevent pipe whip due to the postulated main steam line pipe failure, additional protection is provided by the main steam line tunnel structure.

It is concluded that pipe whipping of the main steam lines from the postulated failure does not result in failure of any other high energy lines or equipment required for safe shutdown of the plant.

Jet impingement from a postulated circumferential or longitudinal failure of a main steam line has been examined for the effects on surrounding structure and components. The break locations are assumed to be in the same locations postulated in the above discussion of main steam line pipe whip considerations.

It has been determined by analysis that the steam tunnel structure can withstand the combined effects of dead loads, live loads, and steam tunnel peak pressurization plus the jet impingement loads from the above postulated steam line break. Seismic loads have not been considered simultaneously with those loads.

Jet impingement and environmental effects from a critical crack in the main steam lines within the reactor building have been investigated. The critical cracks have been assumed to occur at any point along the main steam pipes and at any point on the circumference of the pipe. It has been assumed that breaks can occur at the most adverse location with respect to structures or components required for safe shutdown. It has been determined that no such critical longitudinal failure in the main steam lines will adversely affect the ability to safely shut down the plant. The analysis leading to this conclusion included a study of the effects of jet impingement on the adjacent pipes, the floor walls and ceiling of the tunnel, the ventilation duct penetrations, and the power and control cabling routed in the steam pipe tunnel.

Compartment pressurization analysis was done for the postulated failure of main steam lines in the steam pipe tunnel. The assumptions used in performing the analysis are presented in subsection A.10.9. The results of the analysis show that with the vent area provided in the tunnel the peak pressure does not exceed the 10 psig design pressure. Vent area from the tunnel is provided by ventilation ducts, doorway and blowout panels between the tunnel and the turbine building and between the tunnel and the reactor building. The latter blowout panel is added in the place of a previously blocked-in equipment removal opening. The blowout panel was installed prior to reactor power operation. The personnel access openings have been left without doors to provide unimpeded vent paths from the tunnel into the secondary containment. Shielding walls as required were also installed prior to plant operation.

The turbine building below the operating floor at Elevation 165 ft is protected against overpressurization by existing vent area to above the operating floor and by the metal siding above elevation 165 ft that will relieve to atmosphere.

Analysis of Shutdown Capability

The ability to safely shut down the plant following a postulated main steam line failure has been analyzed using the guidelines presented in Appendix G. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in Table A.10.1. The required equipment is operable with the required redundant components available.

For a main steam line break outside the primary containment the reactor is automatically scrammed by turbine control valve fast closure, by shutting of the MSIV's, or by low reactor water level. The MSIV's will be closed automatically by high steam flow, by high temperature in the vicinity of the pipe chase, or by low-low-low reactor water level. The reactor pressure vessel isolation is completed by the closure of the MSIV's. After isolation of the reactor pressure vessel, pressure increases until the set point of the safety/relief valves is reached (1,135 psig). Pressure is then automatically relieved by the discharge of steam to the pressure suppression pool.

Reactor pressure vessel water level can be maintained by automatic operation of the HPCIS and/or operation of the RCICS. If no high pressure injection is available, adequate core cooling can be accomplished by operation of the ADS in conjunction with LPCI or Core Spray.

The operator initiates reactor pressure vessel depressurization from the control room using the power-operated safety/relief valves. No manual operations are required until 10 min after the accident. The operator will also initiate cooling of the suppression pool using the RHRS. Subsection 14.5 and Appendix G contain a detailed analysis of the use of the RHRS to achieve long-term safe shutdown.

Since it is assumed that offsite power is lost at the time the steam line break occurs, the second (non-accident) unit also scrams due to turbine control valve closure and is fully shut down. Subsection 14.5 and Appendix G addressed the simultaneous shutdown of both units. For this analysis it has been assumed three out of the four diesel generators are available for providing emergency AC power for the shutdown of both plants. As mentioned in paragraph A.10.5, the emergency AC power system is protected from the effects of any postulated high energy pipe failure. It has been determined that both units can be safely shut down under that condition (subsection 14.5 and Appendix G).

The emergency service water system and high pressure service water system are not affected by the postulated main steam line break. Therefore, adequate component cooling to the equipment identified in Table A.10.1 would be available.

Conclusion

It is concluded that with the addition of the above mentioned blowout panel, the plant can be safely shut down following a postulated main steam line failure outside the primary containment.

A.10.7.2 Feedwater Systems

The configuration of the feedwater system piping is shown in Figures A.10.2 and A.10.4. The pressure at the discharge of the feed pumps during normal conditions is approximately 1,100 psig and the temperature is approximately 380°F. At the inlet to the reactor the pressure is about 1,060 psi and the temperature is approximately 380°F. Thus, the feed system is considered a high energy system. However, as for the main steam system, only that portion of the main feed system lying within the reactor building requires protection against pipe break. All feedwater piping within the turbine building is physically separated from structures, systems, and components important to reactor safety by both distance and seismic Class I structural walls. No feedwater line failure in the turbine building prevents the safe shutdown of the plant.

The failure of a feedwater line is less severe than the failure of a main steam line discussed above. Backflow from the reactor vessel to the break is prevented by closure of the feedwater check valves coincident with flow reversal. Thus, flow through the break would be from the feed pumps only. It is assumed that water from all three feed pumps would discharge through the break. As soon as the postulated break occurs, the discharge pressure of the pumps would decrease and the flow will increase until pump runout occurs. It is conservatively assumed that the steam driven feed pumps would continue running until the steam supply is terminated by closure of the main steam isolation valves due to high temperature in the pipe tunnel or low reactor water level. After the feed pumps stop, the condensate pumps would continue to pump water from the postulated break until the condenser hot wells are empty. This assumption implies that offsite AC power is not lost for this accident. If offsite AC power is lost, the condensate pumps would lose power which would cause the feed pumps to trip due to low suction pressure almost immediately and only a small quantity of water would be discharged through the break.

For pipe whip considerations circumferential or longitudinal failures are assumed to occur at the terminal ends, at the points of connection of branch lines to the main lines, and at the two highest stressed intermediate points. These points are identified in Figure A.10.4. There are no locations in the feedwater piping where the stress levels described in item A.10.3.2.b above are exceeded.

Of the identified postulated break locations, only those in the steam tunnel require protection against pipe whip. All of the postulated break points are at about the same location in the pipe tunnel. The two locations at the upstream side of the feedwater check valves are in 24-in OD lines which have a nominal wall thickness of greater than 1 ½ in. The other three break locations are in 18-in OD lines which have a wall thickness of 1 1/8 in.

It has been determined that no significant secondary damage would occur from whipping of the feedwater pipe due to failure at any one of the five postulated break points in the pipe tunnel. For a terminal end failure in either of the 24-in OD feedwater pipes the main steam lines are protected from pipe whip impact by the main steam line restraints (Figure A.10.3). For a failure at the terminal ends of the 18-in cross tie lines the main steam lines are protected by virtue of their significantly larger size.

The effect on the pipe tunnel structure of a feedwater break is much less severe than the main steam line rupture. The energy released from the break is about a factor of 10 less than for a main steam line rupture. The pipe whip and jet impingement loads are also less limiting than for the main steam line break. It has been determined that none of the postulated feedwater failures in the pipe tunnel results in loss of structural integrity of the tunnel due to pipe whip, jet impingement, or compartment pressurization.

The effects of water flooding due to a feedwater pipe rupture were investigated. A maximum of about 100,000 gal of water would be discharged from the postulated break in the feedwater piping assuming that offsite power is not lost. Most of that water would be pumped out by the condensate pumps after the MSIV's have shut. Therefore, most of the water would be relatively cool (<100°F) since it would be pumped from the condenser hotwells with no heating. If the break is in the main steam pipe tunnel, the water would flow out of the tunnel through the doors and side blowout panel and then by gravity through grated hatch openings into the torus compartment. The resulting water level in the torus compartment would be less than 1 ft (Elevation 92 ft 6 in). The safeguard equipment rooms adjacent to the torus compartment are protected against flooding to Elevation 111 ft 0 in. Thus, safeguard equipment would not be affected.

Analysis of Shutdown Capability

The structures, systems, and components required for the safe shutdown of the plant following a postulated feedwater pipe break are presented in Table A.10.2. Paragraph 14.5.4.3 presents a detailed parametric analysis of the transient conditions following loss of feedwater flow.

As has been pointed out, it is more conservative for this accident to assume that offsite AC power is not lost than to assume it is lost. If offsite power were lost coincident with the feedwater pipe failure, the reactor would be scrammed by the fast closure of the turbine control valves, by low reactor water level, or by closure of the MSIV's. If offsite power were not lost, the scram will be initiated by low reactor water level or by MSIV closure. Reactor pressure vessel isolation would be initiated by low reactor water level and completed by MSIV closure which would be initiated by high pipe tunnel temperature or by low-low reactor water level.

After the reactor has been scrammed and the reactor pressure vessel isolated, the sequence of events is similar to that given above for the main steam line break accident. The analysis of equipment availability following a main steam line break accident is applicable to a feedwater pipe break accident as well.

Conclusion

It is concluded that the plant can be safely shut down following a postulated feedwater pipe break outside the containment with no modifications to existing design.

A.10.7.3 <u>High Pressure Coolant Injection</u>

During normal plant operation the HPCI steam line is pressurized at 1,035 psig from the primary containment to the HPCI turbine stop valve located in the HPCI room at Elevation 91 ft 6 in (Figure 12.1.1). Therefore, although there is no flow in the line during normal operating conditions, the pipe is considered a high energy line. Figures A.10.5, A.10.6, A.10.7, and A.10.8 show the configuration of the line from the primary containment penetration to the HPCI turbine inlet nozzle. The HPCI steam line is 10-in diameter, schedule 80 pipe.

The postulated break locations for pipe whip considerations are at the terminal ends and, for Unit 2 only, at the two intermediate points of highest stress, there being no points where the stress levels described in item A.10.3.2.b are exceeded. Arbitrary intermediate high stress break locations were eliminated on Unit 3 by Modification P00634 based on Generic Letter 87-11.

Specifically, these points are:

1. The connection of the pipe to the downstream side of the outboard isolation valve (Figure A.10.5).

2. The two highest stressed intermediate points in the torus compartment as indicated in Figure A.10.6 (Unit 2 only).

3. At the connection of the pipe to the upstream side of the HPCI turbine stop valve (Figure A.10.8).

Since the HPCI steam line is totally within the reactor building, there is a potential for damage to structures, systems, or compartments required for safe shutdown of the plant in the event of a postulated failure in the HPCI steam line. Therefore, each of the postulated break points have been examined to determine if additional protection against pipe whip is required.

Automatic isolation of the HPCI steam line is initiated by either high steam line flow or high temperature in the vicinity of the steam line. Those isolation signals are described in subsection 7.3. The maximum operating time of the isolation valves specified in subsection 7.3 is 25 sec.

The analysis of the above postulated break locations has revealed that the HPCI steam line must be restrained in three locations for Unit 2 and one location for Unit 3. One of these restraints is required on both Units 2 and 3 in the vault that houses the HPCI steam line outboard isolation valve (Figure A.10.5) to prevent vertical movement of the outboard isolation valve and upstream piping in the event of a circumferential failure at the postulated location immediately downstream of the outboard isolation valve. The other restraints have been added in the torus compartment at two locations identified in Figure A.10.6 for Unit 2. On Unit 2 these restraints are required primarily to prevent potential damage to the emergency service water piping that is routed adjacent to the HPCI steam line in the torus compartment. On Unit 3, the piping was re-analyzed considering the intermediate pipe break criteria of GL 87-11 and, as a result, two of the pipe whip restraints were abandoned in place.

Critical cracks postulated to occur anywhere along the HPCI steam line would not result in damage that would impair the capability to safely shut down the plant.

The potential effects on electrical cables routed in the vicinity of the HPCI steam line were examined, and it was determined that none of the cables that could possibly be broken as a result of a postulated pipe failure are required for safe shutdown.

The results of the compartment pressurization analysis indicated that additional vent area was required in the torus compartment to preclude exceeding the external pressure limits of the torus. The additional vent area has been provided by replacing two concrete hatch plugs with steel grating. This achieved the required vent area without making any new openings in the torus compartment structure. This steel grating was installed prior to reactor power operation. No required shielding was deleted.

It has been determined that the postulated break at the connection of the HPCI pipe to the HPCI turbine stop valve will not cause overpressurization of the HPCI pump room with the existing vent area.

<u>Analysis of Shutdown Capability</u>

The ability to safely shut down the plant following a postulated HPCI steam line failure has been made using the guidelines of Appendix G. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in Table A.10.3. All of the required equipment is operable with the required redundant components available.

Break isolation is accomplished by automatic isolation of the HPCI steam line initiated by high steam flow and/or high temperature in the vicinity of the HPCI steam line.

For a postulated break in the HPCI steam line it is conservative to assume that loss of offsite power occurs concurrently with the steam line break. A reactor scram would be initiated by turbine control valve fast closure, and the sequence of events will follow closely that presented in the response to subsection 14.5 and Appendix G. If the RCICS is available, it will be able to maintain reactor pressure vessel water level until the operator initiates depressurization of the reactor. If a single active component failure causes the RCICS to be unavailable, there would be sufficient water inventory in the reactor pressure vessel to ensure that the water level will stay well above the top of the active fuel for the 10 min after the break during which no manual action is assumed. The operator will initiate depressurization of the reactor at 10 min after the break has occurred. After the reactor pressure vessel is depressurized, the LPCIS or the core spray system is more than adequate to supply makeup water to the reactor pressure vessel.

Suppression pool cooling would be accomplished by remote manual operation of the RHRS as detailed in subsection 14.5 and Appendix G.

Conclusion

It is concluded that with the above mentioned design changes the plant can be safely shut down and maintained shut down following a postulated HPCI steam line failure outside the primary containment.

A.10.7.4 Reactor Core Isolation Cooling

During normal plant operation the RCIC steam line is pressurized at 1,035 psig from the primary containment to the RCIC turbine stop valve located in the RCIC pump room at el 91 ft 6 in. Therefore, although there is no flow in the line during normal operating conditions, the pipe is considered a high energy line. Figures A.10.2, A.10.9, A.10.10, and A.10.11 show the configuration of the line from the primary containment penetration to the RCIC turbine inlet nozzle. The RCIC steam line is a 4-in schedule 80 pipe.

The postulated break locations for pipe whip considerations are at the terminal ends and at the two intermediate points of highest stress, there being no points where the stress levels described in item A.10.3.2.b above are exceeded. Specifically, these points are:

1. At the connection of the pipe to the downstream side of the outboard isolation valve (Figure A.10.2).

2. At the first of the two highest stressed intermediate points in the torus compartment (Figure A.10.9).

3. At the second of the two highest stressed intermediate points in the RCIC pump room (Figure A.10.11).

4. At the connection of the pipe to the RCIC turbine stop valve (MO-23-131) (Figure A.10.11).

Automatic isolation of the RCIC steam line is initiated by either high steam line flow or high temperature in the vicinity of the steam line. Those isolation signals are described in subsection 7.3. The maximum operating time of the isolation valves specified in subsection 7.3 is 25 sec.

From an analysis of the potential effects of RCIC steam pipe failing at the above postulated locations, it has been determined that no damage that would prevent safe shutdown of the plant would occur. The postulated RCIC steam line failure in the torus and the effects of steam pressurization of the torus compartments are much less severe than for a postulated HPCI steam line failure. On Unit 3 a hypothesized break at one of the two highest stressed intermediate points could cause damage to adjacent emergency service water piping. A restraint is added to preclude such potential damage. Pipe rupture at the two postulated failure points in the RCIC pump room would not cause damage to equipment other than that related to the RCICS.

Critical cracks postulated to occur anywhere along the RCIC steam line would not result in damage that would impair the capability to safely shut down the plant.

The potential effects on electrical cables routed in the vicinity of the RCIC steam line were examined, and it was determined that none of the cables that could possibly be broken as a result of a postulated failure are required for safe shutdown.

It has been determined that RCIC steam line failure will not result in pressurization of any of the compartments, through which the RCIC steam line runs, beyond their design capabilities.

<u>Analysis of Shutdown Capability</u>

The ability to safely shut down the plant following a postulated RCIC steam line failure has been made using the guidelines of Appendix G. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in Table A.10.4. All of the required equipment is operable with the required redundant components available.

Rupture of the RCIC steam line will have minor effects on the nuclear boiler system, i.e., automatic reactor shutdown, reactor vessel isolation, or initiation of core cooling systems will probably not occur as a direct result of the steam line failure. However, if the transient is such that any of those functions are required, they will automatically be initiated by the appropriate set point being reached. If the RCIC steam line failure occurs in the main steam pipe tunnel (Figure A.10.2), closure of the main steam isolation valves may occur due to high temperature in the tunnel. A reactor scram would then be initiated by MSIV closure and events would proceed as described in subsection 14.5 and Appendix G.

For a postulated failure of the RCIC steam line it is conservative to assume that loss of offsite AC power occurs concurrently. The reactor will be automatically scrammed upon fast closure of the turbine control valves. The sequence of events will then follow closely that presented in subsection 14.5 and Appendix G.

Conclusion

It is concluded that the plant can be safely shut down and maintained shut down following a postulated RCIC steam line failure outside the primary containment without any modifications being made.

A.10.7.5 Reactor Water Cleanup System

The reactor water cleanup system (RWCUS) is described in subsection 4.9. The system contains high energy fluid in only a portion of its piping. The high energy portions of the system that are outside the primary containment are (Drawings M-354, Sheets 1 and 2 and M-1-DD-5):

1. From the primary containment to the outlet nozzle of the nonregenerative heat exchanger in the system supply line.

2. From the discharge of the regenerative heat exchanger to the connection into the feedwater system in the return line.

The design conditions of pressure and temperature for various points in the cleanup system are shown in M-1-DD-5. The configuration of the high energy portions of the cleanup system is shown in Figure A.10.2, and Drawings M-86 and M-96. The postulated break locations for circumferential or longitudinal failures are:

1. At the connection of the supply pipe to the outboard isolation valve (MO 12-18) (terminal end).

2. At the connection of the supply pipe to each of the two cleanup system pumps (suction and discharge).

3. At the connection of the supply pipe to the regenerative heat exchangers (inlet and outlet).

4. At the connection of the supply pipe to the non-regenerative heat exchangers (inlet and outlet).

5. At the connection of the return line to the discharge nozzle of the non-regenerative heat exchanger.

6. At the connection of the cleanup return line to the upstream side of the check valve which returns RWCUS flow to the "B" feedwater line. (Figure A.10.2).

At least one of the above postulated break points is in each one of the cleanup system cells. Therefore, they are representative of a break at any point in the RWCUS.

A postulated failure in the cleanup system will result in a single-ended failure. A check valve in the return line immediately upstream of the connection into the feedwater piping would prevent backflow from the return side of the break. Automatic isolation of the cleanup system is initiated by high flow in the supply header. High temperature in the cleanup system equipment cells (except for the RWCU pump rooms) will initiate an alarm in the main control room. The operator would then isolate the system remotely from the main control room. Descriptions of these isolation systems appear in subsection 7.3. Subsection 7.3 requires that the isolation valves close within 30 sec.

It has been determined that pipe whip or jet impingement from pipe failure at any postulated break point will not adversely affect the ability to safely shut down the plant. The substantial shielding walls surrounding each of the equipment cells prevent damage to any equipment outside the cell containing the postulated break. The cleanup system equipment cells do not contain any components not related to the cleanup system that are required for safe plant shutdown.

Critical cracks at any location in the high energy portions of the cleanup system have been considered. No such failure has potential for damaging structures, systems, or components required for safe shutdown of the plant.

The potential effects on electrical cables routed in the vicinity of the RWCU high energy lines were examined, and it was determined that none of the cables that could be broken as a result of a postulated pipe failure are required for safe shutdown.

The results of compartment pressurization analysis indicated that additional vent area was required to preclude the buildup of excessive pressure in the vault that houses the RWCU supply containment penetration (Drawing M-86). Therefore, a section of blocked-in wall that was not serving any structural function was removed. With the additional vent area, the pressure peak resulting from a circumferential failure at the connection of the 6-in pipe to the outboard isolation valve (MO-12-18) will be within the design capabilities of the surrounding structure.

The peak pressures in RWCU heat exchanger and pump cells would be within the design capabilities of the surrounding structure for the postulated breaks in those rooms.

Analysis of Shutdown Capability

The ability to safely shut down the plant following a postulated RWCUS failure has been conducted using the guidelines of Appendix G. The structures, components, and systems that must be available to ensure meeting the criteria for safe shutdown are presented in Table A.10.5. Required equipment is operable with the required redundant components available.

A postulated rupture of the RWCUS will probably not cause a severe enough transient on the nuclear boiler system to result directly in a reactor scram, reactor vessel isolation (other than isolation of the RWCUS), or automatic initiation of the core standby cooling systems. However, if the transient is such that any of those functions are required, they will automatically be initiated by the appropriate set point being reached. If offsite power is lost concurrent with the occurrence of the RWCU pipe rupture, both the reactors will be scrammed by the fast closure of the turbine control valves. The sequence of events will then follow that presented in subsection 14.5 and Appendix G.

Conclusion

It is concluded that with the design modification mentioned above the plant can be safely shut down and maintained shut down following a postulated RWCUS line failure outside the primary containment.

A.10.7.6 High Energy Sampling and Instrument Sensing Lines

A.10.7.6.1 Sample System

There are only five sample lines that contain high energy fluid under normal plant conditions. They are:

1. RWCUS sample line from the regenerative heat exchanger outlet: Normally, there is no flow in this line; however, it is pressurized about 1,230 psig from the sample point to the isolation valve in the sample station, and the water being sampled is greater than 237°F.

2. Feedwater (two sample lines) from the feedwater pipes upstream of the outboard check valves:

   Normally, these lines have continuous sample flow and are pressurized to about 1,100 psig at 380°F.

3. Reactor water sample line from recirculating pump discharge: Normally, this sample line is pressurized to about 1,100 psig at about 530°F. The sample line has inboard and outboard containment isolation valves which automatically close within 5 sec after receiving an isolation signal.

4. Crack arrest verification (CAV) sampling from the reactor recirculation system sampling line outboard isolation valve: This sample line has a design pressure and temperature of 1500 psig and 575°F. The CAV system was permanently installed in 1991 under Mod 1549E. HELB Postulations and Analysis, do not apply on the basis of A.10.2.3. All CAV piping is less than 1 inch nominal pipe size.

The following discussion excludes the CAV sampling line:

All four of these sample lines are routed in the same vicinity at Elevation 165 ft in the reactor building (Drawing M-96). The sample station is located at the intersection of column lines H and 15. The piping used for these sample lines is 3/8-in OD stainless steel tubing with a wall thickness of 0.065 in. These lines are surrounded by a protective channel which reduces the possibility of physical damage to the sample lines. All sample lines connected to the nuclear boiler system are designed to seismic Class I standards.

The postulated break locations for the sample lines are:

1. At the connection of the sample line to the process line being sampled.

2. At the two intermediate locations of highest stress in each of the lines.

3. At the connection of the sample line to the isolation valve in the sample station.

The rupture of a sample line is a single-ended failure that does not result in any direct effects on structures, systems, or components required for shutdown. Pipe whip and jet impingement effects would be negligible due to the small size of the sample lines and the fact that they are completely enclosed in protective channel. Therefore, the only potential effects of a postulated sample line failure are environmental in nature.

There is no automatic isolation of the sample lines in the event of their failure except as noted below. Sample lines identified above in item 2 can be isolated by closing the RWCUS supply line isolation valve. The feedwater sample lines can be isolated remotely by shutting down the reactor feed pumps (after shutting down the reactor and closing the MSIV's).

The indications available to the operator that a sample line break has occurred are:

1. High space temperature alarm from the RWCU leak detection system. There are temperature detectors located in each of the RWCU equipment cells where a sample line break is postulated to occur and one located in the vicinity of the sample station. The temperature alarm is set between 105-160°F.

2. Reactor building high radiation alarm: Subsection 7.12 describes the operation of this system. A sample line failure results in higher than normal radiation levels in the reactor building ventilation exhaust which may initiate an alarm in the main control room and automatically initiate isolation of the secondary containment.

3. Area radiation monitor alarm: There is an area radiation monitor in the vicinity of the sample station. In the event of a postulated sample line failure the general area radiation levels may rise and result in an alarm in the main control room.

4. If the break is in the RWCU sample line identified above in Item 1, high system flow may occur (depending on the size of the break). This condition automatically isolates the RWCUS.

5. If the break is in the feedwater sample lines at the point of connection into the feedwater lines (Figure A.10.4), the break is sensed by the steam pipe tunnel high temperature monitors. In that event the break is automatically isolated by closure of the MSIV's and subsequent tripping of the reactor feed pump on loss of steam. The plant is then safely shut down by the normal station operating procedures.

6. Visual observation by plant operating or maintenance personnel: The most likely cause of a sample line break is physical damage during plant operation or maintenance. In this unlikely event the personnel involved would inform the control room operators and/or manually isolate the leak locally.

A.10.7.6.2 Instrument Sensing Lines

Instrument lines connecting to the reactor coolant pressure boundary and penetrating the primary containment up to and including the excess flow check valve meet the design requirements of Group I, Schedule I, and seismic Class I as described in Appendix A. The quality assurance program includes thermal and seismic design analyses, fabrication and installation conformance surveillance, and post-erection hydrostatic testing and installation verification by a representative from design engineering. Instrument line routing has been reviewed to ascertain that:

1. The possibility of a loss of more than one redundant subsection of a vital safety system or a loss of more than one functionally independent safety system from an adverse failure of an instrument line is minimized. This will be accomplished by spatial separation and utilization of the biological shield or structural members to the maximum extent practical and will be consistent with the requirement for in-service inspection.

2. Flow-limiting devices are located as close to the primary sensing point as practical to minimize the possibility of one line causing failure in another downstream of the devices.

3. Instrument line routing downstream of excess flow check valves is made in protective trays in order to minimize the potential of accidental damage to tubing.

The lines are equipped with flow-limiting orifices and excess flow check valves of the same size and schedule.

Conclusion

It is concluded that the reactor can be safely shut down and maintained in a safe shutdown condition following a postulated failure of a high energy sample line or instrument sensing line.

A.10.7.7 Reactor Recirculation System

For the restrained recirculation primary coolant pipe loops, damage to other piping systems and engineered safety systems was not considered. The design criteria for the restraints are as follows:

1. For recirculation pipe, the maximum distance between postulated break locations and corresponding restraints is no greater than the distance between the restraint bracket and the containment drywell shell plate.

2. The position of restraint brackets limits excessive motion to assure that a rupture in the recirculation system does not result in cascading pipe failures which would preclude safe shutdown of the reactor.

3. For original recirculation pipe, pipe ruptures were assumed to occur anywhere in the system and were assumed to be instantaneous circumferential guillotine breaks or longitudinal pipe splits.

4. For replacement recirculation pipe, the following criteria have been used to determine break type:

    a. Circumferential breaks are assumed at all terminal ends and at intermediate locations identified by the criteria in item 3d. of Paragraph A.10.3.

    b. At each of the intermediate postulated break locations identified to exceed the stress or usage factor limits of the criteria in Paragraph A.10.3(3), either a circumferential or a longitudinal break, or both is postulated per the following:

1. Circumferential breaks are postulated at fitting joints.

2. Longitudinal breaks are postulated in the center of the fitting at two diametrically opposed points (but not concurrently) located so that the reaction force is perpendicular to the plane of the piping and produces out-of-plane bending.

3. Consideration shall be given to the occurrence of either a longitudinal or circumferential break. Examination of the state of stress in the vicinity of the postulated break location was used to identify the most probable type of break.

4. At intermediate locations chosen to satisfy the minimum break location criteria, only the circumferential breaks are postulated.

5. The pipe restraints are arranged in order to not interfere with the normal operation of the system, including earthquake motions.

6. The allowable stresses for the restraint brackets and support steel are 150 percent of the AISC code allowables for the materials used. The restraint ring is designed to limit bending stresses within the ultimate strength of the material and to limit the tensile stress to 90 percent of yield. The recirculation pump restraint cables (wire rope) are limited to 90 percent of their breaking strength.

7. The design loads for the restraint system are the product of the reactor vessel operating pressure times the flow area.

A.10.8 Design Description of Main Steam Line Restraints

A.10.8.1 Description

The main steam lines and their supports are designed to accommodate the effects of and to be compatible with the environmental conditions associated with the normal operation, maintenance, testing, and postulated accidents including pipe failure. The restraints adequately protect other structures, systems, and components important to safety against dynamic effects, including the effects of pipe whipping and discharging fluids that may result from pipe failures and from events and conditions outside the nuclear power unit.

A.10.8.2 Location

The main steam line restraints are located in the main steam pipe tunnel shown in Drawing M-3. The pipe tunnel design has been discussed in Appendix C. The restraints are shown in Figures A.10.3 and A.10.14.

A.10.8.3 Method of Analysis

The methods used are the same as previously submitted for other similar structures and components. The working stress design method was used for steel and concrete.

A dynamic analysis was performed to evaluate the response of the structure under the dynamically applied loading, and the structure was found adequate. The design of the restraints was done in accordance with ACI 318-63, ACI 318-71, and AISC "Specifications for the Design Fabrication and Erection of Structural Steel for Buildings" (sixth and seventh edition).

It was decided to post tension the restraint anchors which pass through the existing concrete in order to provide a mechanism of shear resistance from applied loads. Tensile capacity of the anchors and their design has been verified by testing. Controls were imposed on the tensioning sequence to limit losses associated with the post tensioning operation.

A.10.8.4 Design Criteria

The main steam pipes are free to move axially through the restraints. The loads due to postulated pipe rupture are applied in any direction transverse to the pipe axis.

The design and positioning of the restraints limit excessive motion of the main steam lines to assure that a postulated longitudinal or circumferential rupture downstream of the outboard main steam isolation valve does not result in damage to structures, systems, or components required for the safe shutdown of the reactor following a main steam line failure.

Instantaneous circumferential or full area longitudinal breaks have been assumed to occur at any location in the main steam lines for the purposes of restraint design.

The pipe restraints have been arranged in order to not interfere with the normal operation of the main steam or adjacent systems with consideration given to earthquake motions.

The same design is used for both units. The restraints are adequate to protect other items from damage due to the postulated pipe breaks.

The allowable stresses for the design of the restraints are:

1. Steel - $0.9F_y$ (yield strength of steel)

2. Concrete - $0.85f'_c$ (compressive strength of concrete)

3. Reinforcement - $0.9f_y$ (yield strength of reinforcement)

4. Restraint cables around the pipes are tensioned to 50 percent of their breaking strength. The post tensioned anchor rods are jacked to 80 percent of their guaranteed minimum ultimate strength and stress transferred at 70 percent of ultimate. The maximum allowable effective prestress is 60 percent of ultimate.

A.10.8.5 Materials

Concrete: f'_c = 4,000 psi at 28 days maximum strength.

Reinforcing: ASTM Designation A615 Grades 40 and 60

Structural steel: ASTM Designation A-411 and A-36

Anchor rods: minimum guaranteed ultimate stress 150 ksi

Wire rope cables: minimum guaranteed breaking strength = 76 kips per cable

A.10.9 Relationship of Mass Blowdown Rates Versus Time for Circumferential and Longitudinal Breaks

The relationship of the mass blowdown rates versus time used for evaluating the radiological effects of main steam line failure is presented in Figure 14.6.16. That analysis was based on the model shown in Figure A.10.16. For a postulated main steam line failure in the steam pipe tunnel (subsection A.10.7.1), the model shown in Figure A.10.16 is not realistic. The steam line restraints that have been added to the PBAPS Units 2 and 3 design since the analysis presented in subsection 14.6 was conducted preclude the separation of the main steam lines in the unlikely event of a complete circumferential failure at the postulated breaks locations. Therefore, the postulated full area longitudinal failure of the main steam lines in the steam tunnel causes the most severe effects on the main steam line tunnel structure. For such a longitudinal failure, the structures must be able to withstand the combined effects of compartment pressurization and localized jet impingement loads. For determining the blowdown mass flow rates from the break into the steam line tunnel the model shown in Figure A.10.17 has been used. For the model shown in Figure A.10.17 the blowdown mass flow rate is limited by critical flow at the break itself. The mass blowdown limited rate versus time relationship can be determined by multiplying the mass blowdown rate presented in Figure 14.6.16 by a factor of 0.74. The following is a derivation of that factor:

Definition of Terms:

A_B = Effective area of break

A_p = Cross-sectional area of pipe (inside diameter)

A_R = Cross-sectional area of flow restrictor

$\dot{M}_C$ = Mass flow rate from circumferential break

$\dot{M}_\ell$ = Mass flow rate from a full area longitudinal break.

For Figure A.10.16 the flow through the break is limited by critical flow through the flow restrictor ($A_B = 0.36\ A_p$) for the blowdown directly from the reactor in steam line (1) and by critical flow from the break ($A_B = A_p$) for flow coming from lines (2), (3), and (4). Therefore, the total area available to flow is equivalent to the sum of effective areas for each side of the break, i.e., 1.36 A_p. Therefore, $\dot{M}_C \propto 1.36\ A_p$.

For Figure A.10.17 all the flow must pass through the area of the break A_B which is assumed to be equal to A_p. Since critical flow occurs at the break, A_p limits the flow from the break.

Therefore, $\dot{M}_\ell \propto 1.0\ A_p$.

The resulting relationship between mass blowdown rate for Figures A.10.16 and A.10.17 is:

$$\dot{M}_\ell = \frac{1}{1.36}\ \dot{M}_C$$

$$\dot{M}_{\ell} = 0.74\ \dot{M}_c$$

A.10.10 <u>Summary of Plant Modifications Required to Mitigate the Effects of a Postulated High Energy Pipe Failure Outside the Primary Containment</u>

1. The removable blocks in the opening on the north side of the main steam piping tunnel have been replaced with a blowout panel. Labyrinth shielding walls have been added outside the blowout panel to replace the shielding provided by the removable blocks (Figure A.10.2). The design of the blowout panel is complete. It was designed to blow out at the same pressure as the blowout panel between the steam tunnel and the turbine building.

   The blowout panel and shield walls were installed prior to reactor power operation.

2. Restraints were added to the HPCI steam line in the torus compartment. Figure A.10.6 shows the location for these new restraints for Unit 2. The design of the restraints are similar to the main steam line restraints which are described in subsection A.10.8.

   The restraints were designed and installed so that failure at the postulated break points does not result in pipe whip impact on the emergency service water pipes in the vicinity of the HPCI steam line in the torus compartment or cause damage to the primary containment boundary.

3. Restraints were added to the HPCI steam line upstream of the outboard isolation valve (Figure A.10.5). These restraints restrict motion of the outboard isolation valve in the vertical or horizontal planes such that the failure of the HPCI steam line upstream of the outboard isolation valve is precluded and rupture of the pipe at the postulated break point downstream of the outboard isolation valve results in steam discharge into the torus compartment below.

4. A portion of a non-structural shield block wall in the RWCUS equipment space at Elevation 180 ft was removed to provide about 50 sq ft additional vent area. The structural integrity of the reactor building is not affected by this modification. Shielding of another configuration is added to make up for the shielding lost by this modification.

5. Two hatch shield plugs in the torus compartment at Elevation 135 ft have been replaced with steel grating to provide additional vent area between the torus compartment and the reactor building compartment above. It has been determined that the plugs to be replaced are not required for shielding purposes. The hatch plugs that have been replaced are shown in Figure A.10.5. One is just west of the primary containment on the reactor centerline and the other is in the southwest corner of the reactor building at Elevation 135 ft.

6. A restraint has been added on the Unit 3 RCIC steam line at the location shown in Figure A.10.10a. The restraint was designed and installed so that failure at the postulated break point does not result in pipe whip impact on the emergency service water pipes in the vicinity of the RCIC steam line in the torus compartment.

A.10.11 Summary of Conclusions

The licensee believes that the quality of design and installation of the high energy piping systems in PBAPS Units 2 and 3 makes their postulated failure an extremely unlikely event. However, as requested by the AEC/NRC Staff, such postulated failures have been analyzed and the results of that analysis are summarized in the preceding subsections.

The licensee has concluded that the design of PBAPS Units 2 and 3 is adequate to assure the ability to safely shut down the plant from a postulated failure of any high energy piping system. To further mitigate the effects of such an occurrence and to assure protection of certain structures, systems, and components required for the safe shutdown of the plant following a postulated failure outside containment, some design modifications were made. These modifications have been summarized in the preceding subsections.

A.10 HIGH ENERGY PIPE BREAK OUTSIDE THE PRIMARY CONTAINMENT

NOTES

(1) The internal fluid energy level associated with the pipe break reaction may take into account any line restrictions (e.g., flow limiter) between the pressure source and break location, and the effects of either single-ended or double-ended flow conditions, as applicable. The energy level in a whipping pipe may be considered as insufficient to rupture an impacted pipe of equal or greater nominal pipe size and equal or heavier wall thickness.

(2) Longitudinal breaks are parallel to the pipe axis and oriented at any point around the pipe circumference. The break area is equal to the effective cross-sectional flow area upstream of the break location. Dynamic forces resulting from such breaks are assumed to cause lateral pipe movements in the direction normal to the pipe axis.

(3) Circumferential breaks are perpendicular to the pipe axis, and the break area is equivalent to the internal cross-sectional area of the ruptured pipe. Dynamic forces resulting from such breaks are assumed to separate the piping axially and cause whipping in any direction normal to the pipe axis.

(4) S_h is the material allowable stress defined in NC-3600 and ND-3600 for Class 2 and 3 components, respectively, of the ASME Code, Section III.

S_A is the allowable stress range for expansion stress calculated by the rules of NC-3600 of the ASME Code, Section III, or the USA Standard Code for Pressure Piping, ANSI B31.1.

TABLE A.10.1

EQUIPMENT REQUIRED FOR SAFE SHUTDOWN FOLLOWING A MAIN STEAM LINE BREAK

1. Pressure relief equipment
   a. Safety/relief valves
   b. Pressure suppression pool (passive)
2. Flow restrictors (passive)
3. Main control room complex and control room ventilation including intake radiation monitoring equipment
4. Reactor scram protection
   a. Turbine control valve fast closure (from loss of offsite power) signal, or
   b. Main steam line isolation signal, or
   c. Reactor low water level signal
   d. CRDS (portion required for scram)
5. Reactor vessel isolation
   a. Primary containment and reactor vessel isolation system control
      1) High temperature in main steam line chase, or
      2) High steam line flow, or
      3) Low reactor water level
   b. Main steam line isolation valves
6. Core cooling
   a. Incident detection circuitry (start HPCI and/or RCIC)

TABLE A.10.1 (Continued)

b. HPCIS plus remote manually operated safety/ relief valves (four or less valves) plus LPCI (one loop/one pump)

or

c. HPCIS plus remote manually operated safety/relief valves (four or less valves) plus core spray (one loop)

or

d. RCICS plus remote manually operated safety/ relief valves (four or less valves) plus LPCI (one loop/one pump)

or

e. RCICS plus remote manually operated safety/ relief valves (four or less valves) plus core spray (one loop)

or

f. No high pressure injection plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump)

or

g. No high pressure injection plus remote manually operated safety/relief valves (four or less valves) plus core spray (one loop)

h. RHR torus cooling mode (one loop/one pump)

i. RHR cooling water (high pressure service water) to available RHR heat exchanger

j. Pressure suppression pool (passive)

7. Electrical power

a. Emergency AC power (three of four diesel generators) (offsite power is assumed lost)

TABLE A.10.1 (Continued)

b. Emergency DC power (125/250 VDC power system)

8. Emergency service water to:

    a. Diesel generator jacket cooling

    b. Available RHR or core spray pump motors

    c. RHR or core spray room coolers

    d. HPCI room cooler (if HPCI available)

TABLE A.10.1 (Continued)

e. RCIC room cooler (if RCIC available)

9. Instrumentation

a. Reactor pressure indication

b. Reactor water level indication

c. Torus water level and temperature indication

TABLE A.10.2 - EQUIPMENT REQUIRED FOR SAFE SHUTDOWN FOLLOWING A FEEDWATER LINE BREAK

1. Pressure relief equipment

    a. Safety/relief valves

    b. Pressure suppression pool (passive)

2. Main control room complex and control room ventilation including intake radiation monitoring equipment.

3. Reactor scram protection equipment

    a. Reactor low water level signal, <u>or</u>

    b. Main steam line isolation signal

    c. CRDS (portion required for scram)

4. Reactor vessel isolation

    a. Feedwater check valves

    b. Primary containment and reactor vessel isolation system control.

        1) High temperature in main steam line chase, <u>or</u>

        2) Low reactor water level

    c. Main steam line isolation valves

5. Core cooling

    a. Incident detection circuitry (start HPCI and/or RCIC)

    b. HPCIS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump)

<u>or</u>

    c. HPCIS plus remote manually operated safety/ relief valves (four or less valves) plus core spray (one loop)

TABLE A.10.2 (Continued)

or

d. RCICS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump)

or

e. RCICS plus remote manually operated safety/relief valves (four or less valves) plus core spray (one loop)

or

f. No high pressure injection plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump)

or

g. No high pressure injection plus remote manually operated safety/relief valves (four or less valves) plus core spray (one loop)

h. RHR torus cooling mode (one loop/one pump)

i. RHR cooling water (high pressure service water) to available RHR heat exchanger

j. Pressure suppression pool (passive)

6. Electrical power

   a. Emergency AC power (three of four diesel generators) (offsite power is assumed lost)

   b. Emergency DC power (125/250 VDC power system)

7. Emergency service water to:

   a. Diesel generator jacket cooling

   b. Available RHR or core spray pump motors

   c. RHR or core spray room coolers

   d. HPCI room cooler (if HPCI available)

TABLE A.10.2 (Continued)

e. RCIC room cooler (if RCIC available)

8. Instrumentation

   a. Reactor pressure indication

   b. Reactor water level indication

   c. Torus water level and temperature indication

TABLE A.10.3 - EQUIPMENT REQUIRED FOR SAFE SHUTDOWN FOLLOWING A HIGH PRESSURE COOLANT INJECTION STEAM LINE BREAK

1. Pressure relief equipment
    a. Safety/relief valves
    b. Pressure suppression pool (passive)
2. Main control room complex and control room air conditioning including intake radiation monitoring equipment.
3. Scram protection (if required)
    a. Turbine control valve fast closure (from loss of offsite power) signal, <u>or</u>
    b. Reactor low water level signal
    c. CRDS (portion required for scram)
4. Reactor vessel isolation
    a. Primary containment and reactor vessel isolation system control.
        1) High temperature in HPCI steam line chase, <u>or</u>
        2) High HPCI steam line flow
5. Core cooling
    a. Incident detection circuitry (start RCIC)
    b. RCICS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump) <u>or</u> core spray (one loop)

<u>or</u>

    c. Remote manually operated safety relief valves (four or less valves) (operated 10 min or longer after break occurs) plus LPCI (one loop/one pump) or core spray (one loop)

TABLE A.10.3 (Continued)

d. RHR torus cooling mode (one loop)

e. RHR cooling water (high pressure service water) to available RHR heat exchanger

f. Pressure suppression pool (passive)

6. Electrical power

a. Emergency AC power (three of four diesel generators)(offsite power is assumed lost)

b. Emergency DC power (125/250 VDC power system)

7. Emergency service water to:

a. Diesel generator jacket cooling

b. Available RHR or core spray pump motors

c. RHR or core spray room coolers

d. RCIC room cooler (if RCIC available)

8. Instrumentation

a. Reactor pressure indication

b. Reactor water level indication

c. Torus water level and temperature indication

TABLE A.10.4 - EQUIPMENT REQUIRED FOR SAFE SHUTDOWN FOLLOWING A REACTOR CORE ISOLATION COOLING STEAM LINE BREAK

1. Pressure relief equipment

   a. Safety/relief valves

   b. Pressure suppression pool (passive)

2. Main control room complex and control room air conditioning including intake radiation monitoring equipment.

3. Reactor scram protecton (if scram is required)

   a. Turbine control valve fast closure (from loss of offsite power) signal, or

   b. Reactor low water level signal

   c. CRDS (portion required for scram)

4. Reactor vessel isolation

   a. Primary containment and reactor vessel isolation system control.

      1) High temperature in RCIC steam line chase, or

      2) High RCIC steam line flow

5. Core cooling

   a. Incident detection circuitry (start HPCI)

   or

   b. HPCIS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump)

   or

TABLE A.10.4 (Continued)

c. HPCIS plus remote manually operated safety/relief valves (four or less valves) plus core spray (one loop)

or

d. Remote manually operated safety/relief valves (four or less valves) (operated 10 min or longer after break occurs) plus LPCI (one loop/one pump) or core spray (one loop)

e. RHR torus cooling mode (one loop)

f. RHR cooling water (high pressure service water) to available RHR heat exchanger

g. Pressure suppression pool (passive)

6. Electrical Power

   a. Emergency AC power (three of four diesel generators)(offsite power is assumed lost)

   b. Emergency DC power (125/250 VDC power system)

7. Emergency service water to:

   a. Diesel generator jacket cooling

   b. Available RHR or core spray pump motors

   c. RHR or core spray room coolers

   d. HPCI room cooler (if HPCI available)

8. Instrumentation

   a. Reactor pressure indication

   b. Reactor water level indication

   c. Torus water level and temperature indication

TABLE A.10.5

EQUIPMENT REQUIRED FOR SAFE SHUTDOWN

FOLLOWING A REACTOR WATER CLEANUP LINE BREAK

1. Pressure relief equipment

    a. Safety/relief valves

    b. Pressure suppression pool (passive)

2. Main control room complex and control room air conditioning including intake radiation monitoring equipment.

3. Reactor scram protection (if scram required)

    a. Turbine control valve fast closure (from loss of offsite power) signal, <u>or</u>

    b. Reactor low water level signal

    c. CRDS (portion required for scram)

4. Reactor vessel isolation

    a. Primary containment and reactor vessel isolation system control.

        1) High cleanup system flow, <u>or</u>

        2) Low reactor water level

        3) High cleanup system space temperature alarm and remote manual isolation

5. Core cooling

    a. Incident detection circuitry (start HPCI and/or RCIC)

    b. HPCIS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump) <u>or</u> core spray (one loop)

TABLE A.10.5 (Continued)

or

c. RCICS plus remote manually operated safety/relief valves (four or less valves) plus LPCI (one loop/one pump) or core spray (one loop)

d. RHR torus cooling mode (one loop)

e. RHR cooling water (high pressure service water) to available RHR heat exchanger

f. Pressure suppression pool (passive)

6. Electrical power

a. Emergency ACac power (three of four diesel generators) (offsite power is assumed lost)

b. Emergency DC power (125/250 VDC power system)

7. Emergency service water to:

a. Diesel generator jacket cooling

b. Available RHR or core spray pump motors

c. RHR or core spray room coolers

d. HPCI room cooler (if HPCI available)

e. RCIC room cooler (if RCIC available)

8. Instrumentation

a. Reactor pressure indication

b. Reactor water level indication

c. Torus water level and temperature indication

TABLE A.10.6

SUMMARY OF DESIGN CRITERIA

RESULTS OF ANALYSIS

FOR THE MAIN STEAM LINE TUNNEL

Description/Criteria	Method of Analysis	Load Combination	Maximum Allowable Stress (psi)	Calculated Maximum Stress Resulting From Maximum Load at Restraint #2(psi)	Location
The MSL Restraint supporting structure is a reinforced concrete inverted L-shaped rigid frame. See Figures A.10.14 and A.10.15.	Rigid frame analysis was used in evaluating the load carrying capacity of the existing structure which was originally designed by the Working Stress Method.	D + R	Rebar: Tension: 0.9Fy #7 and smaller-36,000 others-54,000	18,000	Under load
The following loads were considered:			Concrete: Compression $0.85\ f'_c$ -3,400	830	Under load
			Concrete: Shear $\left[1.9\phi\left(\sqrt{f'_c} + 1300\frac{p\ Vd}{M}\right)\right]$ = 115	38.5	At point 1
D - Dead load, which includes the weight of piping and restraints.					
R - Restraint load on the structure due to pipe rupture which includes the jet effect of steam escaping.			Rebar: Tension: 0.9Fy #7 and smaller-36,000 others-54,000	33,000	At point 3
L - Live load			Concrete: Compression $0.85\ f'_c$ -3,400	330	At point 2
T - Temperature load			Concrete: Shear $\left[1.9\phi\left(\sqrt{f'_c} + 1300\frac{p\ Vd}{M}\right)\right]$ = 115	105	At point 2
p - Pressurization load					
The loading combination used was L+D+R+p+T. L and p were conservatively neglected in cases where they reduced the stresses produced by other loads; T was neglected since it lags the other effects substantially and affects the surface only.					

TABLE A.10.6 (Continued)

Description/Criteria	Method of Analysis	Load Combination	Maximum Allowable Stress (psi)	Calculated Maximum Stress Resulting From Maximum Load at Restraint #2(psi)	Location
Critical loading is when the R load is acting away from the structure. The worst R loading for restraint No. 2 is about 1,500 K. The R loading for restraint No. 3 is about 790 K. The above loadings are transferred into the structure by means of anchor rods and distributed laterally and uniformly over 20 ft.			REFER TO HARD COPY FOR GRAPHIC		